Michigan's Statewide Energy Assessment Fact Sheet

September 11, 2019

What happened?

A combination of extreme weather and energy emergency events during January 30-31, 2019 challenged the natural gas and electric systems in Michigan. Though service was maintained, Michigan's energy supply and delivery systems were strained due to the extreme weather event dubbed Polar Vortex 19, or PV19, during which temperatures dropped below -25° F. The abnormal weather caused reduced regional power plant output and historically high natural gas demand, at the same time as an unexpected failure of critical natural gas infrastructure.

The regional electric grid operator, Midcontinent Independent System Operator (MISO), declared a system-wide (15 states) electric emergency requiring all generation to operate at maximum output.

On the morning of January 30, a fire ignited at the Ray Compressor Station, Consumers Energy's largest natural gas storage facility (supplying over one third of customer needs at peak times), leading to a severe disruption of natural gas supply and deliverability.

Photo Credit: Todd McInturf/The Detroit News

The impact of these overlapping emergencies led Michigan utilities to request conservation measures and the State Emergency Operations Center to make a broad public appeal to all residents to conserve natural gas. The statewide appeal included a text message alert from the Michigan State Police.

Charge from Governor

Governor Gretchen Whitmer called upon the Michigan Public Service Commission (MPSC) to evaluate whether the design of the electric, natural gas, and propane delivery systems are adequate to account for changing conditions and extreme weather events. The Governor asked the Commission to provide recommendations on how to mitigate risk on the energy system. An initial statewide energy assessment from the MPSC was delivered July 1. Comments were accepted and informed the final report issued on September 11, 2019.

The MPSC goal is to ensure safe, reliable energy for Michigan residents and businesses and to be prepared to alleviate impacts during future events. The Commission took this opportunity to assess the potential vulnerabilities of the natural gas, electricity, and propane systems, and to review the cyber and physical security of our energy systems and our emergency operations protocols.

Statewide energy assessment process

The MPSC formed the following specific teams:

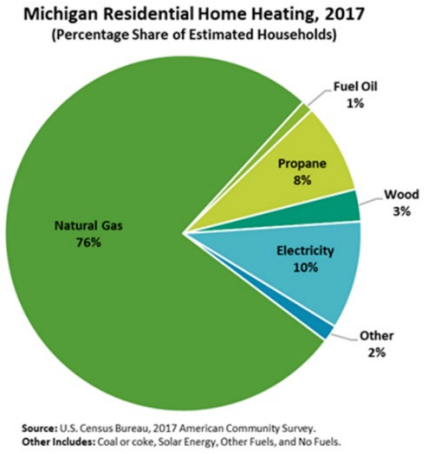
- Electric
- Natural Gas
- Propane
- Cyber and Physical Security
- Energy Emergency Management

Over several months, each team collected data from rate-regulated and non-rate regulated energy providers and reviewed existing studies addressing system planning, risks, and best practices. The Commission hosted over 40 internal and external meetings and conference calls with a variety of stakeholders to help inform the development of the report.

Michigan's energy position

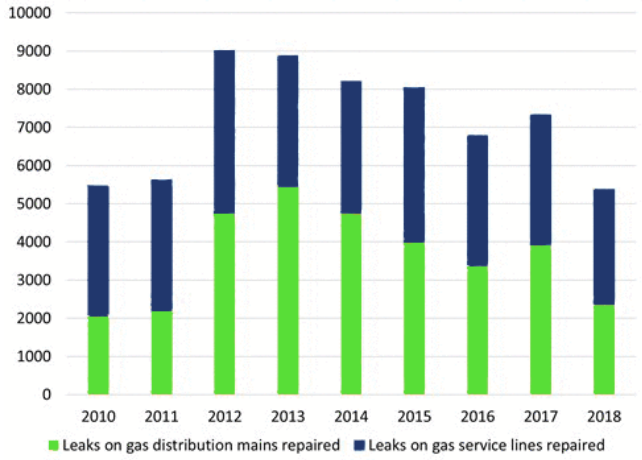
Michigan has an extensive system for supplying electricity, natural gas, and propane that is tied to regional markets.

Natural Gas:
Consumption of natural gas in Michigan is greatest in the residential sector, where it is used as the primary heating fuel in more than 75% of Michigan households.



- ✓ Michigan ranks first in natural gas storage capacity with over 50 natural gas storage fields, allowing the state to meet demand year-round with more stable supply and pricing.
- ✓ There are 9,215 miles of natural gas transmission pipeline with access to diverse supplies (Canada, Gulf Coast, Rockies, and Marcellus/Utica).
- ✓ Almost 115,000 miles of distribution pipelines support the delivery of natural gas to businesses and residents.
- ✓ Over 11,000 miles of natural gas pipeline is considered "high risk" due to corrosive materials (e.g., cast iron, unprotected steel). Since 2011, utilities have accelerated the removal of these pipelines, decreased pipeline leaks, and made other investments to improve the safety of the natural gas system.

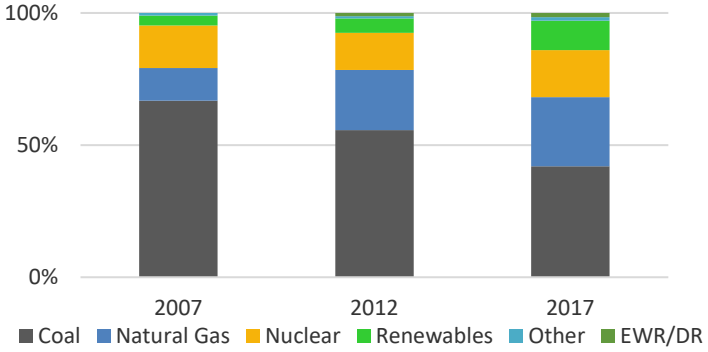
Corrosion-Related Leaks Repaired 2010-2018



Electricity: With generation from nuclear, natural gas, coal, and renewable energy, including a large (2,000 megawatt) pumped hydroelectric storage facility in Ludington, Michigan's electricity supply mix ranks among the most diverse in the country.

Aging coal plants are retiring and Michigan's energy mix is rapidly evolving to cleaner sources such as natural gas, renewable energy, and other programs that shift or cut energy demand.

Michigan's Evolving Net Generation Mix from 2007-2017



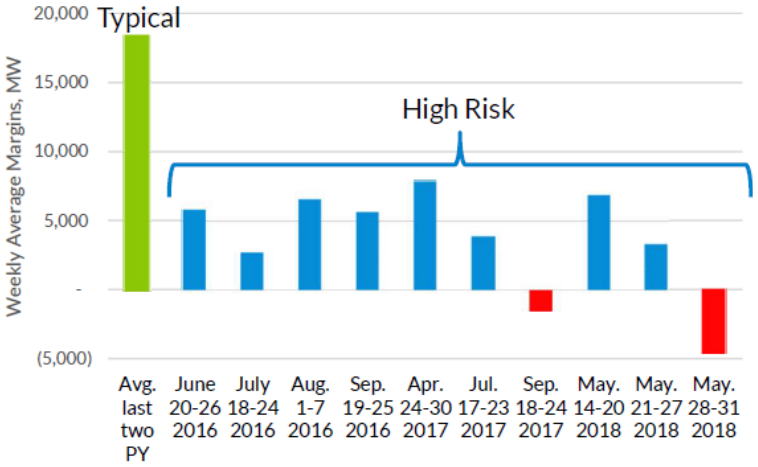
Michigan's electric transmission and distribution systems are expansive. Wind and ice are the leading cause of power outages due to broken poles and trees contacting distribution wires. Many distribution poles, wires, substations and other equipment are beyond their design life and utilities are making major investments in infrastructure and maintenance to improve safety and reliability.

Coal - 1950s - 1980s Nuclear - 1970s	Natural gas - 1990s;	2000s - current coal plants replaced by renewable energy and natural gas

Propane: Propane is not regulated by the MPSC and supplies 8% of Michigan households for home heating (8% for the Lower Peninsula and 18% for the Upper Peninsula). Michigan ranks first in residential propane consumption among states. In addition to the propane produced at Michigan's two fractionators and one refinery, propane is also delivered by truck, rail and pipeline.

Aside from aging infrastructure, Michigan's energy infrastructure could be impacted by various threats. Extreme weather events such as the December 2013 ice storm or the March 2017 windstorm (70 mph wind gusts) are increasing, causing extended power outages. With increased use of natural gas to generate electricity, our energy systems become increasingly connected, and physical or cyber security threats require vigilance to protect our energy security.

The electric system has a cushion of supplies to handle equipment failure and high demand. The chart below depicts how that cushion can be depleted, leading to the declaration of "maximum generation events" and other operational steps to avoid power shortages and blackouts. These have occurred in all seasons, not just at the traditional summer peak.



Source: MISO 2019 PY=Planning Year (June 1 – May 31)

Statewide energy assessment report findings and recommendations

The assessment determined that Michigan has sufficient and unique assets that help ensure reliable supply and delivery of energy to help meet peak demand.

Although Michigan's energy infrastructure is designed and operated to maintain and deliver energy supplies during emergency conditions, there is an inherent risk of disruption. Such emergency events could have a high impact on the economy and well-being of Michigan residents.

To ensure reliable, resilient supplies in the future, the Commission recommends a number of actions to be taken by the MPSC, regulated utilities, policymakers, and others. Several highlights include:

Risk based, integrated natural gas planning

Undertake long-term, risk-based, integrated natural gas maintenance and infrastructure planning that includes storage, transmission, and distribution assets as well as long-term risk mitigation plans.

Integrated electricity system planning

Better integrate distribution and transmission plans as part of utility integrated resource plans to ensure truly integrated electricity system planning. This should include examining options to strengthen Michigan's electrical connections between its peninsulas and with neighboring states.

Valuing resource diversity

Work with stakeholders to understand the value of resource supply diversity to better inform decisions related to power plant development, retrofitting, and retirement beyond traditional planning and financial analyses.

Quantifying the value of resilience

Work with stakeholders to develop a methodology to evaluate the benefits of resilience improvements to ensure that expenditures made to capture resilience improvements are reasonable and prudent.

Gas-electric interdependencies and prioritization

Identify revisions to natural gas utility curtailment procedures to prioritize home heating over electric generation.

Demand response program improvement and development

Improve customer demand response programs since some customers did not respond as expected during PV19 and utility tariffs were inconsistent.

Cyber security standards for natural gas distribution utilities

Enact rules for cyber security and incident reporting for natural gas utilities.

Expansion of emergency drills

Expand emergency drills to provide a wide range of scenarios besides outage management restoration. Communication during PV19 was confusing, inconsistent, and erratic.

Propane contingency planning

Through participation in the UP Energy Task Force, develop a formal contingency plan for the continued supply and delivery of propane or other energy alternatives in the event of supply disruptions, including a temporary or permanent shutdown of Line 5.

What's next?

The Commission accepted the final SEA report in U-20464 and is issuing orders to take initial steps in the following dockets:

- U-20147: Distribution system planning
- U-20539 – U-20552: Gas cost recovery plans
- U-20628: Demand response tariffs collaborative
- U-20629: Electric distribution system service quality and reliability standards workgroup
- U-20630: Electric service technical standards workgroup
- U-20631: Mutual aid agreements and transmission contingency planning collaborative for natural gas
- U-20632: Natural gas curtailment procedures

Michigan Statewide Energy Assessment

Final Report

September 11, 2019

Sally A. Talberg, Chairman
Daniel C. Scripps, Commissioner
Tremaine L. Phillips, Commissioner

Table of Contents

Executive Summary ..... **i**
1. Introduction **1**
1.1 Governor's Charge to MPSC 1
1.2 Scope of the Statewide Energy Assessment 2
1.3 Evaluation and Recommendation 2
1.4 Organization 3
2. Michigan's Energy System: Facing Challenges of Today and Tomorrow **4**
2.1 Overview of Michigan's Energy System 4
2.1.1 Electric 5
2.1.2 Natural Gas 9
2.1.3 Propane 12
2.2 Michigan's Unique Advantages 13
2.3 Changing Landscape of Risks 15
2.3.1 Fuel Procurement and Gas Supply Availability 18
3. Electric **28**
3.1 System Overview and Operational Practices 28
3.1.1 Generation/Transmission (Bulk Power System) 28
3.1.2 Distribution 31
3.2 Regulatory Oversight of Planning and Infrastructure 35
3.2.1 Generation 35
3.2.2 Transmission 44
3.2.3 Distribution 49
3.3 Risk Assessment 52
3.3.1 Infrastructure 52
3.3.2 Investment Trends and Projections 58
3.3.3 Adequacy of MPSC Rules Related to Customer Safety, Reliability, and Resilience; Customer Notification 64
3.4 Vulnerabilities 65
3.4.1 Aging Distribution Infrastructure 65
3.4.2 Generation Shift in Supply and Operations Considerations Across Multiple Timeframes and Seasons 65
3.4.3 Natural Gas and Electric Coordination 67
3.4.4 Equipment Damage 69
3.4.5 Ability to Import Capacity into the Lower Peninsula 69
3.5 Contingency Planning Methodologies and Assumptions 71
3.5.1 Electric Distribution Risk-Based Planning Models 71
3.5.2 Load Forecasting Methodologies and Risks 71
3.5.3 Available Mutual Aid From Regional/National Utility Resources 76
3.6 Electric Recommendations for Mitigating Risks 78
3.6.1 Commission's Electric Recommendations 78

3.6.2 Commission's Electric Observations 79
4. Natural Gas 81
4.1 System Overview and Operational Practices 81
4.1.1 Natural Gas Technical and Safety Standards 82
4.1.2 Storage Facility Operations 88
4.2 Regulatory Oversight of Energy Planning/Infrastructure 92
4.2.1 Natural Gas System Planning 92
4.2.2 Infrastructure and O&M Prudence Reviews Through Rate Proceedings 97
4.2.3 Review of Supply Arrangements to Meet Customer Demand and Redundancy in Gas Cost Recovery Proceedings 98
4.3 Vulnerabilities 100
4.3.1 System Limitations 100
4.3.2 Infrastructure Failures 102
4.3.3 Interconnections 102
4.3.4 System Redundancy 103
4.3.5 Single Source Supplies 103
4.4 Risk Assessment 104
4.4.1 Infrastructure 104
4.4.2 Investment Trends and Projections 109
4.4.3 Adequacy of MPSC Rules and Best Practices Related to Customer Safety, Reliability, and Resilience; Customer Notification 112
4.5 Contingency Planning Methodologies and Assumptions 114
4.5.1 Transmission 114
4.5.2 Distribution 117
4.5.3 Load Forecasting Methodologies and Risks 118
4.6 Natural Gas Recommendations for Mitigating Risks 119
4.6.1 Commission's Natural Gas Recommendations 119
4.6.2 Commission's Natural Gas Observations 120
5. Propane 120
5.1 System Overview and Operational Structure 122
5.1.1 Production 122
5.1.2 Transportation 123
5.1.3 Storage 123
5.2 Regulatory Oversight of Propane Market 124
5.2.1 Pipeline Sighting 124
5.2.2 Safety Oversight of Hazardous Liquid Pipelines 124
5.2.3 Non-Pipeline Transportation Regulations 125
5.2.4 Storage 125
5.2.5 Pricing 127
5.3 Unique Strengths 128
5.3.1 In-State Storage Capacity 128
5.3.2 Infrastructure 129
5.3.3 Market Access Diversity 131

5.3.4 Market Size 131
5.4 Vulnerabilities 132
5.4.1 Driver Shortages 133
5.4.2 Infrastructure Availability 133
5.4.3 Exports 134
5.4.4 Unregulated Marketplace 135
5.4.5 Extreme Weather 135
5.5 Contingency Planning 136
5.5.1 National and Regional Coordination of Supply Monitoring and Waiver Requests 136
5.5.2 Public Education and Awareness 136
5.5.3 Access to Appalachian Basin Resources 137
5.5.4 UP Energy Task Force 137
5.6 Propane Recommendations for Mitigating Risk 138
5.6.1 Commission's Propane Recommendations 138
5.6.2 Commission's Propane Observations 138
6. Cyber and Physical Security 140
6.1 Today's Infrastructure Security Landscape 140
6.1.1 Cybersecurity 140
6.1.2 Physical Security 142
6.2 An Evolving Threat Environment 143
6.2.1 Cybersecurity 143
6.2.2 Physical Security 146
6.2.3 Cyber and Physical Security Incidents 146
6.3 Sector Response 151
6.3.1 Strategies, Goals, and Principles 152
6.3.2 Standards and Controls 153
6.3.3 Information Sharing and Partnerships 154
6.3.4 Cyber Mutual Assistance 154
6.3.5 Exercises 154
6.4 MPSC Response 155
6.4.1 Annual Cybersecurity Reporting 155
6.4.2 Cybersecurity Incident Reporting 156
6.5 Vulnerabilities 156
6.5.1 Security Governance 157
6.5.2 Implementation of Basic Cybersecurity Controls 157
6.5.3 Phishing Vigilance 158
6.5.4 Third-Party Risk 158
6.5.5 Human Capital 158
6.5.6 Insider Threats 159
6.6 Cyber and Physical Security Recommendations for Mitigating Risk 160
6.6.1 Commission's Cyber and Physical Security Recommendations 160
7. Energy Emergency Management 161

7.1 Nature of Energy Emergencies 161
7.2 Statutory Authorities Addressing Energy Emergencies 162
7.2.1 Declaration of State of Energy Emergency, PA 191 of 1982 162
7.2.2 Emergency Management Act, PA 390 of 1976 162
7.2.3 Federal Motor Carrier Safety Administration 49 CFR Parts 300-399 163
7.2.4 Clean Air Act - US Environmental Protection Agency 163
7.2.5 Motor Fuels Quality Act, PA 44 of 1984 163
7.3 Roles and Responsibilities 163
7.3.1 Overview 163
7.3.2 Federal 168
7.4 Energy Emergency Procedures 169
7.4.1 General Info 169
7.4.2 Utility Mitigative Measures 171
7.4.3 Petroleum Shortage Response Plan 175
7.5 Public Information and Communication 177
7.6 Ongoing Projects 178
7.6.1 Local Energy Assurance Planning (LEAP) 179
7.6.2 Critical Infrastructure Generator Assessment 180
7.6.3 Petroleum Backup Readiness 181
7.6.4 Statewide Energy Sector Sub-Committee 181
7.6.5 Lifeline Sector Restoration Prioritization 181
7.7 Emergency Management Recommendations to Mitigate Risk 183
7.7.1 Commission's Emergency Management Recommendations 183
7.7.2 Commission's Emergency Management Observations 184
8. Gaps in Existing Planning, Operational, and Emergency Response Processes 185
8.1 Gaps in Existing Planning, Operational, and Emergency Response Processes That Highlight opportunities to improve safety, reliability, and resilience 186
8.1.1 Better Integration of Gas and Electric Planning Functions Recognizing Interdependencies 186
8.1.2 Better Integration of Electric Resource, Distribution, and Transmission Planning 190
8.1.3 Quantifying the Benefits of an Increased Capacity Import Limit as an Opportunity for Increased Resilience and Diversity in Supply 192
9. Conclusions and Recommendations 194
9.1 System Adequacy to Account for Changing Conditions and Extreme Weather 194
9.2 Recommendations to Mitigate Risk and Ensure Safety 194
9.3 Compiled Recommendations and Observations for Mitigating Risks 195
9.3.1.1 Electric Recommendations 195
9.3.2.1 Natural Gas Recommendations 199
9.3.3.1 Propane Recommendations 201
9.3.4.1 Cyber and Physical Security Recommendations 203
9.3.5.1 Emergency Management Recommendations 204

10. Appendices..... 206

Appendix A - Location of Oil and Gas Wells Drilled in Michigan
Appendix B - Natural Gas Transmission Pipeline System in Michigan
Appendix C - Current List of Michigan's Natural Gas Mutual Assistance Participants
Appendix D - Natural Gas Operator Risk Assessment Methodologies, May 2019
Appendix E - LPG Pipeline Connections in Michigan
Appendix F - Propane Storage Locations in Michigan
Appendix G - Summary of Key Findings - 2019 Propane Survey
Appendix H - MPSC Emergency Communication Plans
Appendix I - MISO and PJM Electrical Emergency Curtailment
Appendix J - Natural Gas Curtailment Procedures

Acronyms

AGA	American Gas Association
AMI	Advanced Metering Infrastructure
API	American Petroleum Institute
BCF	Billion Cubic Feet
BES	Bulk Electric System
BTU	British Thermal Unit
C2M2	Cybersecurity Capability Maturity Model
CAIDI	Customer Average Interruption Duration Index
CE	Consumers Energy
CIS	Center for Internet Security
CON	Certificate of Necessity
CPCN	Certificate of Public Convenience and Necessity
DER	Distributed Energy Resource
DIMP	Distribution Integrity Management Program
DHHS	Department of Health and Human Services (Michigan)
DHS	Department of Homeland Security (U.S.)
DOD	Department of Defense (U.S.)
DOE	Department of Energy (U.S.)
DOT	Department of Transportation (U.S.)
DPP	Definitive Planning Phases
DR	Demand Response
DTE	DTE Energy Company
EEI	Edison Electric Institute
EERT	Energy Emergency Response Team
EGLE	Department of Environment, Great Lakes, and Energy
EIA	Energy Information Administration
EMHSD	Emergency Management and Homeland Security Division
EPA	Environmental Protection Agency
ERO	Electric Reliability Organization
ESF 12	Emergency Support Function #12
FEMA	Federal Emergency Management Agency (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
FMCSA	Federal Motor Carrier Safety Administration (U.S. DOT)
FOIA	Freedom of Information Act
GCR	Gas Cost Recovery
GIP	Generator Interconnection Process

HGL	Hydrocarbon Gas Liquids
ICS	Incident Command System
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
ISAC	Information Sharing and Analysis Center
IT	Information Technology
KW	Kilowatt
KWH	Kilowatt Hour
LARA	Department of Licensing and Regulatory Affairs
LCR	Load Clearing Requirements
LEAP	Local Energy Assurance Planning
LMR	Load Modifying Resource
LPG	Liquified Petroleum Gases
LRZ	Local Resource Zone
Mcf	1,000 cubic feet
MCL	Michigan Compiled Laws
MDARD	Michigan Department of Agriculture and Rural Development
MDOT	Michigan Department of Transportation
MEMP	Michigan Emergency Management Plan
MIOC	Michigan Intelligence Operations Center
MISO	Midcontinent Independent System Operator
MPSC	Michigan Public Service Commission
MRO	Midwest Reliability Organization
MSP	Michigan State Police
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NERC-CIP	NERC Critical Infrastructure Protection
NESC	National Electrical Safety Code
NGL	Natural Gas Liquids
NIPP	National Infrastructure Protection Plan
O&M	Operations and Maintenance
OFO	Operational Flow Order
OMS	Outage Management System
OT	Operational Technology
PA	Public Act
PHMSA	Pipeline and Hazardous Materials Safety Administration
PJM	PJM Interconnection - Pennsylvania, New Jersey, and Maryland

PRA	Planning Resource Auction
PRMR	Planning Reserve Margin Requirement
PSCR	Power Supply Cost Recovery
PV19	Polar Vortex 2019
PV14	Polar Vortex 2014
REP	Renewable Energy Plans
RF	Reliability First
RMAG	Regional Mutual Assistance Groups
RTEP	Regional Transmission Expansion Planning
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SEA	Statewide Energy Assessment
SEOC	State Emergency Operations Center
STEP	Spare Transformer Equipment Pro
TIMP	Transmission Integrity Management Program
TSA	Transportation Security Administration
UMERC	Upper Michigan Energy Resources

Table of Figures

Figure 2-1 Michigan Electric Utilities and Percentage of Michigan Residents Served 5
Figure 2-2 Michigan's Net Electric Generation by Fuel Type and Renewable Energy Breakout 6
Figure 2-3 Traditional Electricity Delivery System from Generation to Customer 7
Figure 2-4 Michigan RTOs: MISO and PJM 8
Figure 2-5 Michigan Residential Home Heating, 2017 9
Figure 2-6 Michigan's Natural Gas Distribution Companies and Customers Served 12
Figure 2-7 Relative increase in Extreme Weather Events 1960-2020 15
Figure 2-8 Coal Plant Retirements Midwest vs Michigan 16
Figure 2-9 MISO Maximum Generation Emergency Declarations 2009-2019 17
Figure 2-10 2017 Status Toward Reaching the PA 342 Goal 20
Figure 2-11 Michigan's Electric & Gas Savings Targets vs Savings Achieved 2015-2017 21
Figure 2-12 Corrosion-related Leaks Repaired 2010-2018 23
Figure 2-13 Gas Heat Rate Improvements in Electric Generation Plants 2007-2017 23
Figure 2-14 Michigan Utilities Announced Carbon Reduction Goals 24
Figure 2-15 DERs for Improved Resilience in the U.S. Army 26
Figure 3-1 Dispatch Stack 31
Figure 3-2 MISO Planning Resource Zones 37
Figure 3-3 MISO Zone 2 Resource Adequacy Requirements and Load Forecast 38
Figure 3-4 MISO Zone 7 Resource Adequacy Requirements and Load Forecast 38
Figure 3-5 MISO Zone 7 LMR Performance 1/30/19 42
Figure 3-6 Michigan Historical MTEP-Approved Transmission Investments 45
Figure 3-7 Michigan's Active Projects in MISO Generator Interconnection Queue 48
Figure 3-8 Average Number of Annual Customer Outages Excluding Major Event Days (SAIFI) 50
Figure 3-9 Average Duration of Annual Customer Outages Excluding Major Event Days (SAIDI) 50
Figure 3-10 Authorized vs Actual Tree Trim Expenses for DTE and CE, 2015-2018 52
Figure 3-11 Lower Peninsula Major Storm Statistics, 2013-2019 53
Figure 3-12 Five-Year Seasonal/Annual EFORd for MISO 55
Figure 3-13 MISO Michigan Daily Average Unplanned Generation Outages 56
Figure 3-14 Capital Expenditures for Investor-Owned Utilities , 2007-2017 58
Figure 3-15 Aggregated Generation O&M Expenditures 60
Figure 3-16 Decreasing Weekly Margins in MISO Region 62
Figure 3-17 Michigan's Evolving Net Generation Mix, 2007-2017 66
Figure 3-18 Michigan Capacity (GW) Showing When Resource Types Were Built 66
Figure 3-19 Michigan Natural Gas Fired Electric Generation and Cogeneration Plants 68
Figure 3-20 MISO Zone 7 Resource Adequacy 2014 - 2019 70
Figure 3-21 MISO Day Ahead Wind Forecast During PV19, January 29-31, 2019 73
Figure 3-22 Traditional Flow of Electricity 73
Figure 3-23 United States Plug-In Vehicle Sales & Market Share 75
Figure 4-1 Pipeline Safety Inspection Trends 2011-2018 86
Figure 4-2 State of Michigan Incident Investigations 2011-2018 87

Figure 4-3 Pipeline Safety Enforcement Actions 2011-2018 87
Figure 4-4 Number of Storage Fields for Michigan Natural Gas Utilities 88
Figure 4-5 Pipeline Operators' Storage Fields, Capacity and Number of Wells 90
Figure 4-6 Miles of Cathodically Unprotected Pipe 106
Figure 4-7 Natural Gas Distribution Main Replacement Programs 107
Figure 4-8 Historical Capital Expenditures by Plant Type 109
Figure 4-9 Historical Operations & Maintenance Expenditures by Plant Type 110
Figure 4-10 Michigan Natural Gas Residential Consumption 111
Figure 4-11 Michigan Natural Gas Commercial Customer Consumption 111
Figure 5-1 Top FIve Residential Sector Propane Consuming States 122
Figure 5-2 Bulk Storage, Natural Gas Plant, and Refinery Propane Stocks 129
Figure 5-3 Fractionators located in Michigan 131
Figure 5-4 State Propane Market Sizes, 2017 132
Figure 5-5 Propane Exports 135
Figure 6-1 Miles of US HL Transmission PL and Electric Transmission 2015-2017 143
Figure 6-2 Global Information and Communication Technologies Developments, 2001-2017 144
Figure 6-3 Cyber Threat Actors 145
Figure 6-4 Incidents by Sector, Fiscal Year 2016 150
Figure 6-5 Physical Security Incidents by Category 151
Figure 6-6 Security Resources 153
Figure 7-1 Michigan's Energy Emergency Organizational Structure 164
Figure 7-2 Emergency Responsibilities of the MPSC 165
Figure 7-3 Energy Emergency Phases 170
Figure 7-4 Steps to Achieve Emergency Preparedness 180
Figure 8-1 Illustrative List of DER Value Streams 189

Executive Summary

Explanation of the Statewide Energy Assessment

In late January 2019, an extreme cold weather event combined with a fire at the Ray Compressor Station[1] created an energy emergency in Michigan that challenged the natural gas and electric systems in a way rarely, if ever, experienced. A combination of the public appeal for natural gas conservation, curtailment of commercial and industrial electric customers, increased electric generation, as well as emergency procurement of additional natural gas supplies, provided the needed buffer for utilities to ensure safety and keep customers' homes heated. *It is important to acknowledge that this event was a success story reflecting a cooperative effort on the part of Michiganders to step up when called upon to keep homes heated and lights on.*

Despite the positive outcome, the events of January 30 and 31 raised significant concerns about whether Michigan's energy systems can reliably produce and deliver energy to all Michiganders as extreme weather events increase. Following the energy emergency, Governor Whitmer directed the Michigan Public Service Commission (MPSC or Commission) to conduct a Statewide Energy Assessment to: 1) evaluate whether the design of electric, natural gas, and propane delivery systems are adequate to account for changing conditions and extreme weather events, and 2) provide recommendations to mitigate risk.[2] The goal is to ensure safe, reliable energy for Michigan residents and businesses, and to be prepared to mitigate impacts during potential future events.

The Commission engaged with industry and stakeholders to gather and review information relevant to this report. The industry and stakeholder engagement activities are captured on a dedicated webpage.[3]

---

[1] The MPSC Staff report filed May 8, 2019 in Case No. U-20463 provides a preliminary response to a Consumers Energy Report of the Ray Compressor Station fire. In a separate report expected in early 2020, the MPSC Gas Operations Section Staff will complete a detailed root cause analysis assessment of the fire, and will include recommendations to mitigate gaps in processes, engineering, and safety measures.

[2] In Executive Order 2019-06, Governor Whitmer transferred legal responsibilities and personnel addressing energy emergencies from the Michigan Agency for Energy to the MPSC.

[3] https://www.michigan.gov/energyassessment.

Deliverables

1. Evaluate Whether the Energy Delivery System in Michigan is Adequate to Account for Changing System Conditions and Extreme Weather Events

Michigan's energy delivery systems are adequate to meet the needs of Michigan customers. Michigan has sufficient and unique assets that help ensure the reliable supply and delivery of energy. For example, Michigan ranks number one in natural gas storage capacity and has diverse power supplies including over 2,000 MW of pumped hydroelectric storage in Ludington to help meet peak demand. Market structures and regulatory oversight ensure needed investments are made for safe, reliable energy.

Michigan's energy infrastructure is designed and operated to maintain energy supplies and delivery even during abnormally high demand, equipment failures and inclement weather. There is, however, inherent risk of disruptions due to security threats, extreme weather, changing electricity supplies, and other factors. While the probability of a major emergency that disrupts energy supplies is low, such events could have a high impact on the economy, and the health and wellbeing of Michigan's residents. More routine events such as ice and wind storms causing power outages also have the potential to impact large numbers of customers for extended periods and cause safety concerns.

The fire at Ray Compressor Station in late January 2019 and subsequent loss of available gas supply for customers, combined with sustained extreme cold weather, illustrates these risks and vulnerabilities and the importance of energy security. The cascade of overlapping challenges that occurred in late January also highlights the need for continuing vigilance in assessing Michigan's energy landscape and emergency management response systems. As directed by the Governor, the MPSC took this opportunity to evaluate the adequacy of supply, design, and deliverability of Michigan's natural gas, electricity, and propane delivery systems.

2. Provide Recommendations to Mitigate Risk

To ensure reliable, resilient supplies going forward, the Commission recommends a number of actions to be taken by the MPSC, regulated utilities, policymakers, and others. Chapter 9 includes a full listing of the 37 recommendations made within this report. Several highlights include:

- **Risk-based, integrated natural gas planning** – The Commission recommends that natural gas distribution utilities develop long-term plans for maintenance and infrastructure covering all assets - storage, distribution, and transmission – based on probabilistic risk assessment to prioritize investments that will ensure safe, reliable, and

resilient operations. Plans should consider diversification, redundancies, and interconnections as well as system resilience.

- **Integrated electricity system planning** – The Commission recommends Michigan electric utilities and electric transmission owners better integrate the planning processes for electric generation, distribution, and transmission to optimize system reliability improvements and ensure a holistic review of alternatives. In the near term, this should include examining options to increase Michigan's ability to import additional electric generation capacity from out of state, thereby providing additional reliability and improved resilience amidst a major shift in our power supplies.
- **Valuing resource diversity and resilience** – The Commission recommends that the value of diversity in power supplies be quantified as part of future integrated resource plans filed by electric utilities. In addition, the value of resilience should be considered in future electric infrastructure planning and investment decisions related to energy supply and delivery, including generation sources, transmission and distribution upgrades, and grid modernization technologies. In the near term, replacing the transmission line connecting the Lower and Upper Peninsulas will help bolster reliability and resilience for residents in the Upper Peninsula.
- **Gas-electric interdependencies** – With an increased reliance on natural gas for electricity generation, the Commission recommends natural gas distribution utilities identify revisions to gas curtailment procedures to prioritize home heating over electricity generation and develop criteria in coordination with the Governor's office, State Police, regional grid operators, and gas and electric utilities to prioritize natural gas and electricity service under declared energy emergencies affecting both industries. This could consider the severity and extent of health and safety risks, outage duration and customers affected, critical facilities, restoration effort, and other factors.
- **Demand response** – The Commission recommends electric utilities improve demand response program design, communications protocols, and testing to ensure participating customers are capable of reducing their usage when needed for electric system reliability. The Commission recommends natural gas distribution utilities develop demand response programs as an alternative to broad emergency appeals.
- **Emergency drills** – The Commission recommends that utilities expand upon traditional drills to include emergency drills that also focus on curtailment and demand response procedures rather than just outage management and restoration. The Commission recommends that state agencies participate in the emergency drills with the utilities and that state agencies receive regular emergency response training.
- **Cyber security standards for natural gas distribution utilities** – The Commission recommends the promulgation of rules for cyber security and incident reporting for natural gas utilities based upon industry standards.
- **Propane contingency planning** – The Commission recommends a formal contingency plan for the continued supply and delivery of propane or other energy alternatives for

Michigan residents that would be necessary in the event of a temporary or permanent shut down of Line 5. The Commission will continue to participate in the Governor's UP Energy Task Force to identify alternatives to energy sources used in the UP, including propane.

Comments

An initial report was released on July 1, 2019, and the Commission accepted comments on the draft report in Case No. U-20464. The Commission appreciates the time and effort taken by stakeholders to participate in ensuring this Statewide Energy Assessment is complete, thorough, and accurate. The Commission has incorporated many modifications to this assessment, and although not an exhaustive list, some of the changes from the initial draft include:

- Additional information on the resilience of distributed energy resources in Chapter 2;
- The addition of background on older distribution infrastructure in Chapter 3;
- Additional background on capacity imports in the Lower Peninsula in Chapter 3;
- Broadening the focus from diversity to resilience and contingency plans in Chapter 4;
- Additional information on cyber security in Michigan, as well as insider threats in Chapter 6;
- An additional recommendation for protection of critical energy infrastructure information in Chapter 7; and
- Additional information related to the value of resilience improvements in Chapter 8.

Throughout the report, many other minor updates, corrections and adjustments have been made. At this time, the Commission is also directing the utilities to take appropriate actions to ensure the continued safety, adequacy and resilience of Michigan's energy infrastructure, delivery systems and emergency management protocols in several dockets opened by the Commission on September 11, 2019. The Commission will also continue to engage with stakeholders to ensure that additional steps are taken to address any shortfalls highlighted in the report that may require consultation and cooperation to ensure the continued safety, adequacy and resiliency of the energy delivery systems in Michigan.

1. Introduction

1.1 Governor's Charge to MPSC

Michigan experienced both electric and natural gas energy emergencies, related to an extreme weather event dubbed Polar Vortex 19 (PV19), on January 30 and 31, 2019. Temperatures in the upper Midwest dropped below -25° F. Unplanned electric generation outages and historically high natural gas demand, paired with the unexpected failure of critical energy infrastructure, strained both systems to the point that mitigative measures were necessary.

On the electric system, frigid temperatures caused unplanned equipment failure in parts of the Midwest region, which decreased expected electric generation to levels below what is needed to maintain reliability. As a result, a system-wide (15 states) electric emergency was declared by the regional transmission operator, Midcontinent Independent System Operator (MISO), that required: 1) all available generation to provide electricity at maximum emergency capacity; and 2) certain entities to reduce demand according to applicable emergency tariffs. In response to this emergency declaration, Michigan's electric utilities required customers on interruptible rates to immediately reduce their electricity usage. Although the electric emergency was a regional event affecting both Michigan and surrounding states, Michigan was a net exporter of electricity during PV 19, providing support for the region-wide emergency.

Amid the regional electric system emergency and immediately preceding forecasted record-breaking natural gas demand, a fire ignited at the Ray Compressor Station, which is part of the Ray Storage Field, Consumers Energy Company's (CE) largest natural gas storage facility. The incident instantly and severely limited the ability to flow gas from the storage field into the pipeline system. This led to severe disruption in the natural gas supply and deliverability on CE's system, greatly impacting its ability to reliably serve natural gas customers.

The impact of these overlapping energy emergencies created the need to decrease the strain on the energy systems, leading utilities to request conservation measures and the State Emergency Operations Center (SEOC) to make an unprecedented broad public appeal to customers and all residents for voluntary reductions of natural gas usage including a text message alert from the Michigan State Police. The public appeal and voluntary reductions were effective at reducing demand to stabilize the electric and natural gas systems, and combined with additional supply arrangements, Consumers Energy Company was able to maintain service to customers.

Following the event, Governor Gretchen Whitmer tasked the Michigan Public Service Commission (MPSC or Commission) with conducting a Statewide Energy Assessment (SEA) to review the supply, engineering, and deliverability of Michigan's natural gas, electricity, and propane systems, assess potential vulnerabilities of these systems, provide recommendations to improve energy emergency preparedness, as well as review the possibility of ongoing threats of cyber or physical security breaches. The SEA aligns with the overarching goal of the Commission to ensure safety and reliability by mitigating risks of energy supply or delivery disruptions due to equipment failure, extreme weather, security threats, and other factors. The

SEA also discusses strategies to limit impacts of future energy emergencies while simultaneously planning for recovery.

1.2 Scope of the Statewide Energy Assessment

Per Governor Whitmer's direction, the scope of the SEA includes a review of the following:

1. Commission's current infrastructure planning criteria and methodologies concerning distribution, transmission, and generation, as well as contingency plans;
2. Existing planning processes for electric and natural gas utilities and best practices for integration;
3. Linkages and gaps between real time operational reliability and infrastructure planning for long-term reliability;
4. Demand response and mutual assurance protocols by natural gas utilities and opportunities for enhancement;
5. Contingency risks, interdependencies, and vulnerabilities of supply and/or delivery disruptions from physical and/or cybersecurity threats as well as a projected cost estimate of potential enhancements;
6. Adequacy of Commission rules addressing customer safety, reliability, resilience, and utility notifications;
7. Evaluation of the existing gas efficiency program; and
8. Identification of areas or types of systems most at risk.

1.3 Evaluation and Recommendation

The PV19 and the subsequent fire at the Ray Compressor Station created an energy emergency in Michigan that challenged the natural gas and electric systems in a way rarely experienced before. A combination of the public appeal for natural gas conservation, curtailment of commercial and industrial electric loads, increased electric generation, and emergency procurement of additional natural gas supplies provided the needed buffer to ensure safety and keep customers' homes heated during arctic weather conditions.

Successful contingency planning and emergency response provides a valuable opportunity to learn from experiences, review policies and procedures, and identify areas for improvement. This assessment evaluates whether the design of electric, natural gas, and propane delivery systems are adequate to account for changing conditions and extreme weather events and provides recommendations to mitigate risk. The goal is to ensure safe, reliable energy for Michigan residents, and to be prepared to mitigate impacts during potential future events. The Commission is taking swift action regarding recommendations concerning changes to energy planning criteria and approaches, communications protocols, regulatory review, and proposed oversight improvements. The Commission may also pursue regulatory actions such as rulemakings and direct other changes over time to implement the recommendations.

1.4 Organization

To accomplish the SEA, the Commissioners asked the MPSC Staff to gather and analyze data for the assessment. Staff began the process by forming five sector specific workgroups: Electric, Natural Gas, Propane, Cyber and Physical Security, and Energy Emergency Management. To streamline the collection of statewide data, each workgroup developed a questionnaire to distribute to rate regulated natural gas and electric providers, and the non-rate regulated energy providers including the Michigan Electric Cooperative Association (MECA), the Michigan Municipal Electric Association (MMEA), and the Michigan Propane Gas Association. All interested stakeholders were invited to answer any applicable survey questions. These workgroups held over 25 external meetings and conference calls with stakeholders, including utilities, and representatives from Michigan Propane Gas Association, Natural Resources Defense Council, Michigan Environmental Council, Sierra Club, and American Council for an Energy Efficient Economy. In addition, some workgroups met offsite to review gas system planning models, review electric risk planning models, conduct cyber and physical security interviews, and visit the Kalkaska fractionation facility. Staff also held over 20 internal meetings to discuss data findings.

This report is organized to provide an overview of the electric, natural gas, and propane energy systems. It also includes a review of cyber and physical security and energy emergency management. Sector specific recommendations and observations were developed and conclude each Chapter. The Commission recognizes there are statutory limitations when it comes to its authority to make recommendations for improvements to mitigate risk and therefore provides two types of advice: Recommendations and Observations.

Recommendations – concepts, actions, programs, initiatives, or projects which ***fall within the Commission's jurisdiction***, and may be considered as potential opportunities for utilities to improve the reliability and resilience to any potential future energy emergencies.

Observations – concepts, actions, programs, initiatives, or projects which ***fall outside the Commission's jurisdiction,*** but which may be considered as potential opportunities for discussion with stakeholders in other venues.

In addition, all recommendations and observations are included in the conclusions section of this report, Chapter 9.

2. Michigan's Energy System: Facing Challenges of Today and Tomorrow

2.1 Overview of Michigan's Energy System

The availability of reliable energy to heat and power homes and businesses is something most Americans take for granted. However, as more examples of weather extremes driven by climate change buffet the world, there is a realization that more scrutiny of energy systems is needed. A recently published National Association of Regulatory Utility Commissioners (NARUC) whitepaper discussed the value of energy infrastructure resilience:

> *"Recent extreme weather events, natural disasters, and cyber incursions have brought the vulnerability of the electric system into sharp focus. These events have demonstrated that planning for long-duration power interruptions caused by high-impact, low-probability events will require new approaches to power system resilience above and beyond previous hardening efforts."*[4]

Michigan is not immune to experiencing climate extremes. As a state with more than 75% of the residential population reliant upon natural gas for home heating and 24% of in-state electric generation fueled by natural gas[5], the potential impact of energy emergencies is significant. Understanding the integrated nature of energy infrastructure and providing recommendations for improvements will enhance the reliability and resilience of Michigan's energy framework.[6]

What follows is a brief overview of the energy delivery systems for electricity, natural gas, and propane, each of which will be discussed in greater detail in subsequent chapters. These chapters will be followed by a chapter covering physical and cybersecurity threats and finally, an

[4] NARUC, *The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices, April 2019*, https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198, p. 1.

[5] https://www.eia.gov/state/data.php?sid=MI.

[6] A major distinction between resilience and reliability is the scale and duration of the power interruptions contemplated. Reliability focuses on preventing disruptions that are "more common, local, and smaller in scale and scope," whereas resilience "addresses high-impact events, the consequences of which can be geographically and temporally widespread" (EPRI, 2016, p. 45). A second distinction between resilience and reliability is that "reliability focuses primarily on power interruption prevention, whereas resilience focuses on preserving system function during the period post-event as well." Source: NARUC, *The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices, April 2019*, p. 8.

explanation of Michigan's response to energy emergencies, with an overview of the Emergency Management System.

2.1.1 Electric

The electric system is comprised of generating plants, transmission lines, and distribution facilities. The MPSC is responsible for electric utility regulation in the state of Michigan, including regulatory responsibility over eight privately owned electric utilities (investor-owned) and limited oversight of ten rural electric distribution cooperatives.[7] Municipally owned electric utilities are not subject to MPSC regulation. The MPSC ensures regulated utilities have adequate supply of electric energy to serve all Michigan's homes and businesses when demand is highest and approves the rates and conditions of service for residential, commercial, and industrial customers.

Figure 2-1 Michigan Electric Utilities and Percentage of Michigan Residents Served

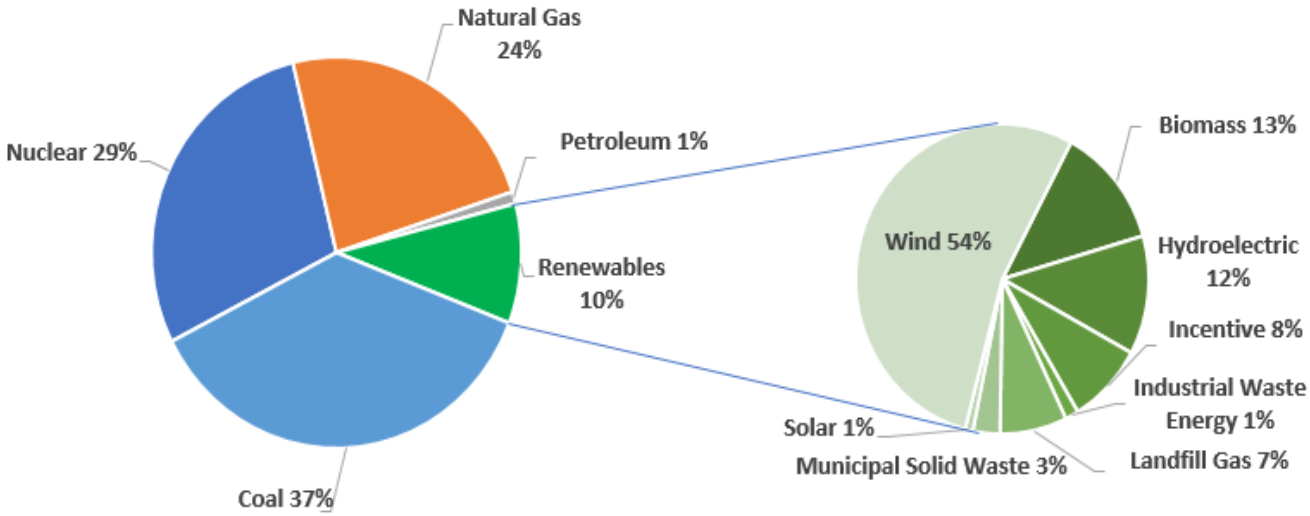
Investor-Owned	*Customers*	*%*	*Cooperative Utility*	*Customers*	*%*
Alpena Power	17,691	0.4%	**Alger Delta**	9,982	0.2%
AEP (I & M)	128,637	2.8%	**Cherryland Electric**	35,145	0.8%
Consumers Energy	1,816,439	39.8%	**Cloverland Electric**	42,591	0.9%
DTE Electric	2,181,941	47.8%	**Great Lakes Electric**	124,622	2.7%
UMERC	36,727	0.8%	**Midwest Energy**	35,960	0.8%
Upper Peninsula Power	52,166	1.1%	**Ontonagon County REA**	4,873	0.1%
Wisconsin Electric	5	0.00%	**Presque Isle Electric & Gas**	33,390	0.7%
Xcel Energy	8,962	0.20%	**Thumb Electric**	12,212	0.3%
			Tri-County Electric	25,879	0.6%

*Based upon 2017 end of year data: https://www.michigan.gov/documents/mpsc/electricdata_594998_7.pdf
*Non-regulated municipal utilities (40) provide ~10% of Michigan's electric needs for 300,000 customers.

[7] The MPSC does not regulate the retail rates of electric cooperatives whose rates are member-regulated per PA 167 of 2008 but does regulate choice rates, service territories, and service/safety standards.

2.1.1.1 Generation - Electricity in Michigan is predominantly generated using coal, natural gas, and nuclear fuel. Additional sources include hydroelectricity, oil or diesel, wind, solar, biomass, and fuel cells. In Michigan, coal supplies 38% of the market, nuclear fuel supplies 29%, natural gas fuels 24%, renewable power generation contributes roughly 10%, and petroleum accounts for about 0.3%. Renewable energy is poised to reach 15% by 2021. Figure 2-2 shows the 2017 fuel mix for electric generation, including a break-out of renewable energy types.

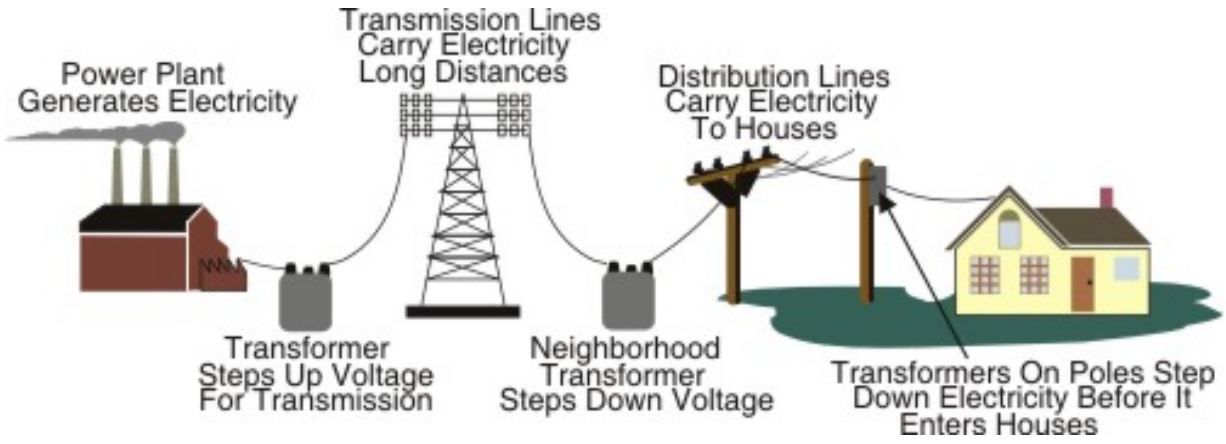
Figure 2-2 Michigan's Net Electric Generation by Fuel Type and Renewable Energy Generation Break-out



Source: MPSC (2017 All Electric Providers (MWhrs) / 2017 Energy Credits)
Note: Nuclear includes total output of DC Cook plant even though a large portion of the output is used to serve customers in Indiana.

2.1.1.2 Transmission and Distribution - After electricity is generated, a system of high voltage transmission wires carry it to distribution systems where it is then delivered to customers. This system of transmission and distribution wires, poles, substations, and transformers is commonly referred to as the "grid." The high voltage transmission system links power plants across the Midwest and Eastern U.S., providing fuel diversity and reliability for the grid, and energy cost savings to customers. The distribution system delivers electricity locally to homes, businesses, and other customers through thousands of miles of lower voltage power lines. The distribution system, due to its proximity to population centers and developed areas, is the most susceptible to disruptions associated with natural or man-made disasters.

Figure 2-3 Traditional Electricity Delivery System from Generation to Customer



When electricity leaves a power plant, its voltage is increased at a "step-up" substation. The energy then travels along a transmission line to a load center. Once there, the voltage is decreased, or "stepped-down," at another substation before it is delivered to the home or business through the distribution system.

2.1.1.3 Regional Transmission Organizations - Regional transmission organizations (RTOs) are responsible for operating wholesale electricity markets, as well as managing and planning the electric transmission system over large geographic areas. Figure 2-4 shows the two RTOs covering the state of Michigan: MISO operates in most of the Lower and Upper Peninsulas and PJM provides service in the southwest part of Michigan.[8]

The physical assets of the transmission system are owned by many fully integrated utilities, municipal utilities, cooperatives and stand-alone transmission companies. In Michigan, there are seven utilities that own, construct, and maintain the transmission system. These include ITC Transmission (ITC), Michigan Electric Transmission Company (METC), American Transmission Company (ATC), Wolverine Power Supply Cooperative (Wolverine), American Electric Power (AEP), Xcel Energy, and Consumers Energy. Transmission utilities work to maintain reliability of the transmission system in accordance with Federal Energy Regulatory Commission (FERC)-approved North American Electric Reliability Corporation (NERC)[9] Reliability Standards. The operation of the transmission system is planned to ensure that the most severe single

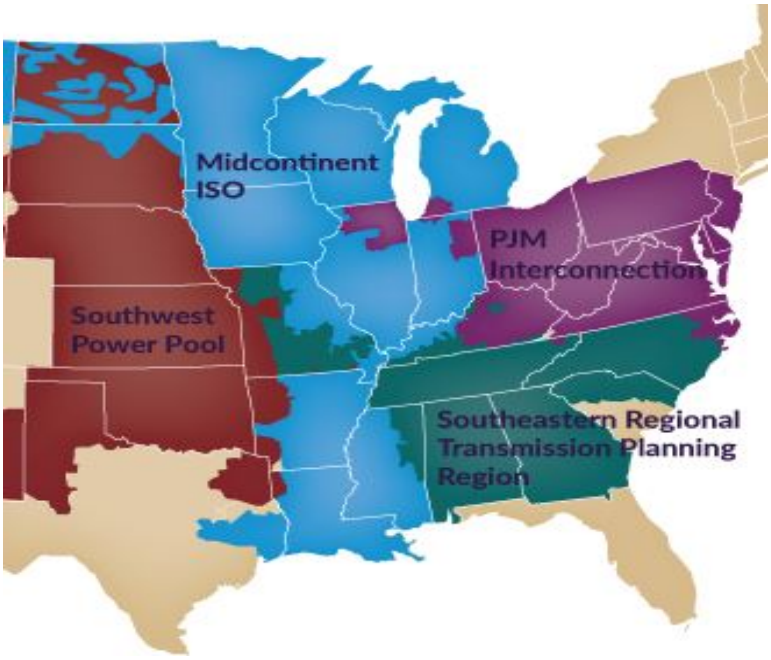
[8] MISO: https://www.misoenergy.org/ ; PJM: http://www.pjm.com/.
[9] NERC: https://www.nerc.com.

contingency,[10] as well as any multiple element contingency, will not result in instability or cascading outages.

Michigan customers realize several benefits related to RTO participation. They are:

- Facilitation of competition among wholesale suppliers;
- Provision of non-discriminatory access to transmission by scheduling and monitoring the use of transmission;
- Planning and operation of the grid to ensure reliability;
- Interconnection of new supply-side and demand-side resources are facilitated and managed; and
- Oversight of competitive energy markets to guard against market power and manipulation.

Figure 2-4 Michigan RTOs: MISO and PJM

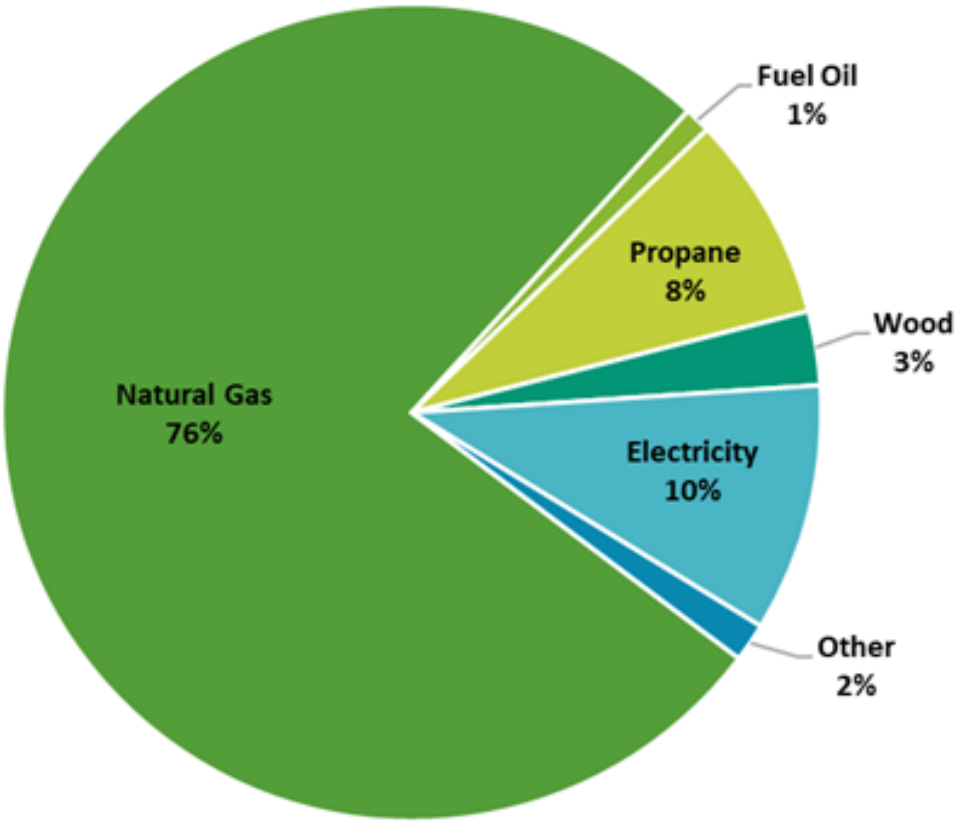


[10] An example of a contingency is the April 2018 anchor strike in the Straits of Mackinac, which destroyed one of the two 138 kV circuits electrically connecting the lower peninsula to the upper peninsula, leaving only one remaining interconnection.

2.1.2 Natural Gas

Michigan's natural gas system is complex and diverse with over 55,000 miles of distribution pipelines and over 3.2 million service lines that serve the needs of customers in the Upper and Lower Peninsulas. As mentioned earlier, natural gas consumption is greatest in the residential sector, where it is used as the primary heating fuel in more than 75% of Michigan households. Usage is split relatively evenly between the commercial and industrial sectors where it is used for space heating and a variety of industrial processes.

Figure 2-5 Michigan Residential Home Heating, 2017 (Percentage Share of Estimated Households)



Source: U.S. Census Bureau, 2017 American Community Survey.
Other Includes: Coal or coke, Solar Energy, Other Fuels, and No Fuels.

In recent years, the largest increases in natural gas usage have occurred in the electric power generation sector. This is due in part to abundant and cost-effective supplies in addition to the beneficial emissions reductions compared to other fossil fuels when combusted.[11] Moving forward, more baseload generation is expected to be produced from natural gas-fired plants, which will increase the state's reliance on in-state storage capabilities and out-of-state imports, both of which highlight the interconnected energy systems in Michigan.

2.1.2.1 Exploration and Production - Natural gas from production wells goes into "gathering" lines, which are like branches on a tree, getting larger as they get closer to the central collection point. Some natural gas gathering systems also include a processing facility, which performs such functions as removing impurities like water, carbon dioxide, or sulfur that might corrode a pipeline, or inert gases, such as nitrogen, that would reduce the energy value of the gas. Processing plants may also remove small quantities of byproducts, such as propane and butane. Propane derived from natural gas processing has become an increasingly important source for the propane industry, helping increase supplies and reduce prices across the nation. Appendix A depicts the location of oil and natural gas wells drilled in the state of Michigan.

2.1.2.2 Transmission - From the processing plant, the natural gas moves into the transmission system. Transmission pipelines are generally large in diameter and operate at higher pressures.[12] Modern gas pipelines are as large as 42 inches in diameter and constructed of heavy wall thickness high strength steels. Along the pipeline, compressor stations are located approximately every 50 to 60 miles to boost the pressure that is lost through the friction of the natural gas moving through the steel pipe. Compressors are also located adjacent to storage fields to get the gas flowing into the pipeline system. Appendix B depicts the natural gas transmission pipeline system in the state of Michigan.

Natural gas moves through the transmission system at up to 30 miles per hour, so it takes several days for gas from Texas to arrive at a utility receipt point in the Midwest. Along the way, there are many interconnections with other pipelines and utility systems, which offers system operators increased flexibility in moving gas.[13]

[11] See National Renewable Energy Laboratory, "Harmonization of Initial Estimates of Shale Gas Lifecycle Greenhouse Gas Emissions for Electric Power Generation," Proceedings of National Academy of Sciences, July 2014.

[12] The pipelines and related facilities are built and maintained in accordance with the Minimum Federal Safety Standards which are promulgated and enforced by the Pipeline and Hazardous Materials Safety Administration (PHMSA). In cooperation with PHMSA, the MPSC also enforces the Michigan Gas Safety Standards.

[13] Michigan's natural gas pipelines: https://www.michigan.gov/mpsc/0,4639,7-159-16385-413020--,00.html.

Interstate natural gas pipeline operators that deliver gas to Michigan from other states and Canada include:

- ANR Pipeline Company (TC Energy)
- Great Lakes Gas Transmission (TC Energy)
- NEXUS
- Northern Natural Gas
- Panhandle Energy
- Rover
- Vector Pipeline Company[14]
- Bluewater

2.1.2.3 Storage - Consumer demand for natural gas in Michigan is seasonal with higher demand during the winter due to home heating purposes and lower demand during the warmer summer months. Natural gas supply is delivered year-round, and while consumption may vary depending upon the season, uniform deliveries of supply are accommodated by injecting natural gas into Michigan's extensive underground geological features that support large storage capabilities. These underground storage reservoirs can balance receipts and deliveries for Michigan as well as provide winter deliveries to neighboring states.[15]

Michigan has over 50 storage fields[16], all of which are located throughout Michigan's Lower Peninsula. All but two were once oil or gas producing reservoirs. The geologic properties and resulting design of gas storage fields are such that certain volumes of gas can be cycled in and out of the field each year, while the remaining volume of base gas remains in the storage field to maintain adequate pressure and deliverability rates, and to ensure reservoir integrity. Michigan benefits from having access to some of the best storage fields in North America and boasts over 690,000 million cubic feet (MMcf) of working gas capacity which can be cycled on an annual basis. Additionally, there is about 300,000 MMcf of "base" gas in storage fields.

2.1.2.4 Distribution - From the gate station, the point where natural gas exits the transmission system, natural gas moves into distribution lines or "mains" that range from two inches to more than 24 inches in diameter. The closer natural gas gets to a customer, the smaller the pipe diameter and the lower the pressure.

[14] Vector Pipeline Company operates an interstate pipeline for DTE Gas Company.
[15] Michigan's natural gas storage fields: https://www.michigan.gov/mpsc/0,4639,7-159-16385_59482-426107--,00.html#tab=Active
[16] Map of Natural Gas Storage Fields in Michigan: https://www.michigan.gov/mpsc/0,4639,7-159-16385-413020--,00.html.

2.1.2.5 Service - Natural gas runs from distribution lines into a home or business in what is called a service line. This line is usually a small plastic line, an inch or less in diameter, with gas flowing at a pressure range of over 60 psi to as low as .25 psi. The nine utilities that distribute natural gas in Michigan serve over 94% of Michigan's retail natural gas customers.[17] Figure 2-6 provides the natural gas distribution utilities serving Michigan residents.

CE and DTE Gas provide more than 80% of the gas service to Michigan. In addition to selling gas, Michigan's gas utilities also offer transportation for gas sold by marketers directly to their customers.

Figure 2-6 Michigan's Natural Gas Distribution Utilities and Customers Served

Natural Gas Distribution Utilities[18]	Customers Served	% of Total
Consumers Energy	1,760,269	50%
DTE Gas	1,086,978	31%
SEMCO Energy Gas Co	278,978	8%
Michigan Gas Utilities Corp	150,575	4%
Other 5 Utilities*	43,123	1%

* Citizens, Presque Isle Electric & Gas, Superior Energy Co., UMERC, and Xcel Energy

In addition to delivering natural gas to end-use customers, gas utilities deliver natural gas and petroleum to electric power production facilities. To meet the need of Michigan's petroleum-fueled power plants, Michigan stores about 300 thousand barrels of petroleum liquids per month on site at electric power production facilities, a significant decline from a decade ago when monthly average reserves neared one million barrels.

2.1.3 Propane

Propane is a colorless, flammable gas produced as a byproduct of natural gas processing and crude oil refining. Chiefly used as a home heating fuel, additional uses of propane include grain drying, transportation fuel, and as a petrochemical feedstock. Michigan's two in-state propane fractionators are in Kalkaska and Rapid River, producing approximately 1,050 and 2,000 barrels per day (bpd) of propane, respectively. Aside from in-state production, propane is also brought in from a variety of additional locations by truck, rail, or pipeline. One noteworthy location includes the Sarnia, Ontario fractionator, the largest fractionator in eastern Canada, which can produce 120,000 bpd. Most propane is stored at the customer's site in varying sized tanks (smaller for residential use; larger for commercial/industrial). According to the U.S. Energy

[17] Natural Gas Utility Service Area Map: https://www.michigan.gov/mpsc/0,4639,7-159--41313--,00.html.
[18] 2017 Annual Reports to MPSC: https://www.michigan.gov/mpsc/0,4639,7-159--411851--,00.html.

Information Administration (EIA), Michigan's residential sector consumes more propane than any other state in the country.

2.2 Michigan's Unique Advantages

Michigan's peninsular geography is nestled within four of the largest freshwater lakes in North America. This geography is also responsible for many unique features from an energy delivery perspective. These include:

- **Underground Natural Gas Storage -** Multiple natural gas storage fields greater than 40 billion cubic feet (BCF) account for roughly 37% of the state's total storage capacity. In addition, Michigan produces 10-15% of the natural gas supply within the state.
- **Access to Electricity Markets -** Michigan utilities and other market participants operate as part of the MISO and PJM regional transmission organizations that provide regional electric transmission planning, reliability coordination of the bulk electric power system, and organized wholesale electricity markets for access to lowest-cost power. However, Michigan's peninsular geography also limits to some extent the balancing function the RTOs provide based on associated challenges with electricity deliverability.
- **Access to Gas Markets and Gas Transmission Capacity -** Seven interstate natural gas pipelines within Michigan, which provide diversity in supply from all regions in the U.S. and one non-interstate pipeline interconnecting with Canada.
- **Ludington Pumped Storage -** The crown jewel of energy storage facilities, Ludington is a hydroelectric plant and reservoir 110 feet deep, 2.5 miles long, and one mile wide, that holds 27 billion gallons of water. The plant is owned jointly by Consumers Energy and DTE Electric and operated by Consumers Energy. The power plant consists of six reversible pump/motor turbines that, when upgrades are completed later this year, can each generate 360 MW of electricity for a total output of more than 2,150 MW. At night and during other times of low demand for electricity, the turbines run in reverse to pump water 363 feet uphill from Lake Michigan into the reservoir. During periods of peak demand, water is released to generate power. Electrical generation can begin within two minutes, achieving a peak output of 1.8 gigawatts in less than 30 minutes.
- **Diversity in Power Supply -** In-state generation comes from a variety of power supply sources including nuclear, coal, natural gas, and an increasing contribution from renewable energy, including wind and solar resources, as well as demand side resources such as energy waste reduction and demand response. The new integrated resource planning (IRP) framework administered by the MPSC requires consideration of fuel diversity in planning future electricity supplies for investor-owned utilities. Considering the mix of electricity produced by nuclear, coal, natural gas, and renewable energy, Michigan's generation portfolio is among the most diverse in the continental U.S.
- **Propane Storage Capacity and Proximity to Sarnia, Ontario -** Michigan has approximately 13.8 million barrels of underground storage capacity for hydrocarbon gas liquids, such as propane. A significant portion of this storage capacity is directly connected – or in close proximity to – the Sarnia, Ontario fractionator, the largest in Eastern Canada with a capacity of nearly 120,000 bpd.

- **In-State Propane Production -** Michigan has two in-state propane fractionation facilities. Located in Rapid River of the Upper Peninsula and Kalkaska of the northern Lower Peninsula, these two fractionators help to meet demand in more remote areas of the state where propane is heavily used for home heating. Additionally, Marathon Petroleum Corporation's Detroit Refinery also produces propane as a byproduct of crude oil refining operations.
- **Electric Demand Response (DR) Capabilities -** Michigan's electric utilities are continuing to develop and refine their demand response programs and tariffs. Current DR capacity is just under 1,200 MW.[19]
- **Energy Efficiency Savings –** PA 295 of 2008 enacted energy efficiency requirements in Michigan. The cumulative total energy savings since program initiation in 2009 has been over 11.5 million MWh of electricity and over 4.3 million Mcf of natural gas. Those figures amount to over 11% of current annual electricity sales and 4% of annual natural gas sales to Michigan customers.
- **Legislation -** The Michigan Legislature passed comprehensive energy laws in 2000 (PA 141), 2008 (PA 286 and PA 295) and in 2016 (PA 341 and PA 342). The energy legislation provides a framework the Commission is required to follow when making decisions.

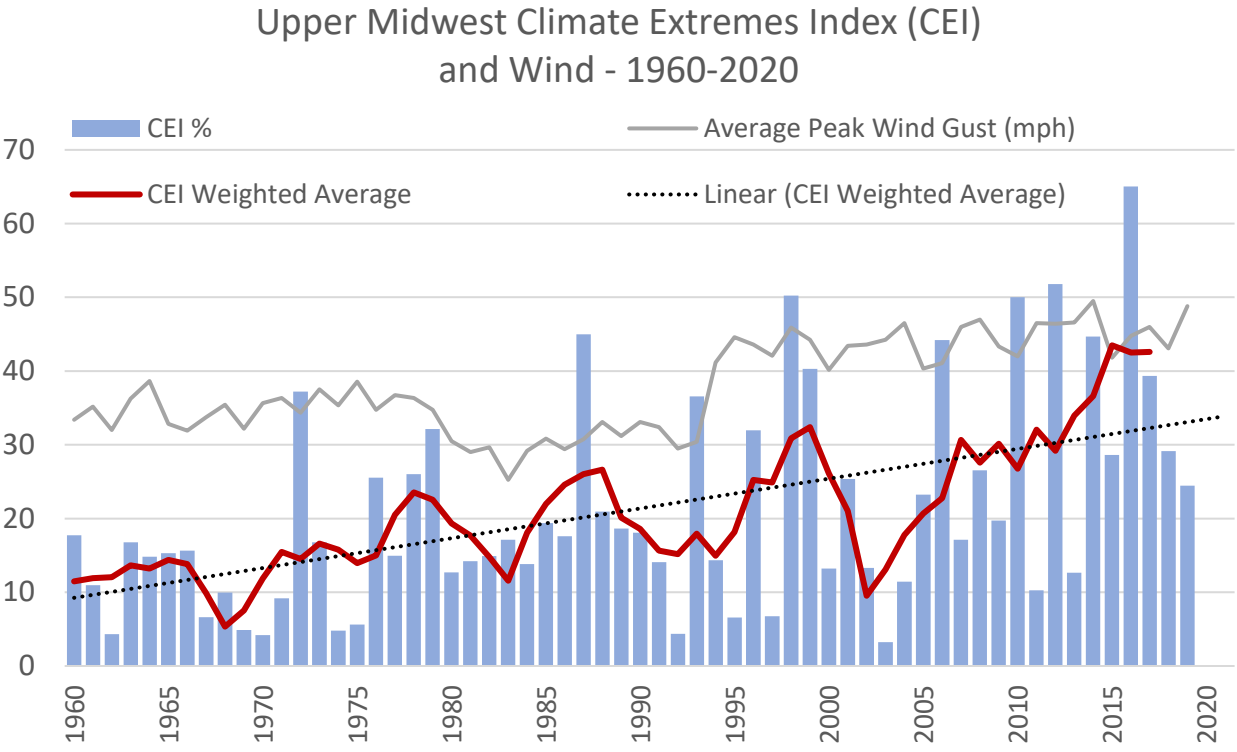
These energy system attributes provide a baseline level of redundancy, contribute to the resilience of those systems, and position the state to better cope with an accelerated rate of change observed in the energy industry. The diversity in natural gas supply, access to energy markets, varied fuel sources for in-state electric generation, billions of cubic feet of underground storage for natural gas and thousands of barrels of underground propane storage, and in-state propane manufacturing may also mitigate risks from weather-related energy emergencies and other disruptions.

[19] CE Company for 2019: 477 MW (Source: Capacity Demonstration Case No. U-20154; IRP Case No. U-20165). DTE Company for 2019: 709 MW (Source: Capacity Demonstration Case No. U-20154).

2.3 Changing Landscape of Risks

Michigan's proximity to the Great Lakes provides a buffer from some high impact weather events. Even so, the state is not immune to experiencing climate extremes, PV19 being the most recent example. As noted in Governor Whitmer's February 4 letter to the MPSC, "climate change is producing record-setting temperatures and increasing extreme weather events," and data shows extreme weather and storm events are occurring more frequently and with greater intensity over the past 60 years. This increasing trend can be observed in Figure 2-7 using data collected by the National Oceanic and Atmospheric Administration from the upper Midwest region of Minnesota, Wisconsin, and Michigan.

Figure 2-7 Relative Increase in Extreme Weather Events 1960-2020



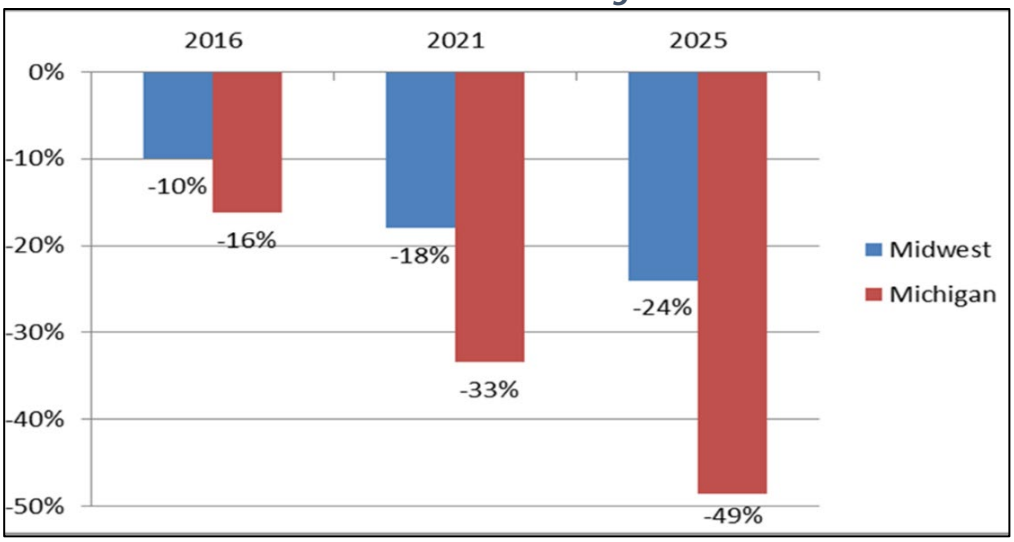
Source: National Oceanic and Atmospheric Administration reports
Note: Wind data gathered from several locations near Detroit (Detroit Metro and Willow Run airports) at various methods of measurement since 1960 including fastest 1 minute, peak wind, maximum 5 second and maximum 3 second

The National Oceanic and Atmospheric Administration's Climate Extreme Index above provides an average of unusual weather conditions over a year using the percent of time and location in the Upper Midwest which experiences abnormally high temperatures, abnormally low temperatures, severe droughts or floods, severe storm events, and long periods with and without rain.

In addition to extreme weather, other events with the potential to impact energy supply and deliverability include: the rapid evolution of the electric grid from a grid dominated with

traditional large baseload electric generation to one with more intermittent energy resources; the transition to cleaner energy options such as renewable energy, demand reduction, and energy efficiency; the potential for energy storage to balance fluctuations in generation and customer demand; the overlap of natural gas used for home heating and electric-fired generation; and the increasing threat of malicious physical and cybersecurity events. Michigan is experiencing an unprecedented shift in its electric generation supplies with approximately half of its coal capacity retiring in the 2015 to 2024 timeframe, and additional coal and nuclear plant retirements planned thereafter. Figure 2-8 compares coal plant retirements in Michigan and the Midwest.

Figure 2-8 Coal Plant Retirement in Midwest vs Michigan



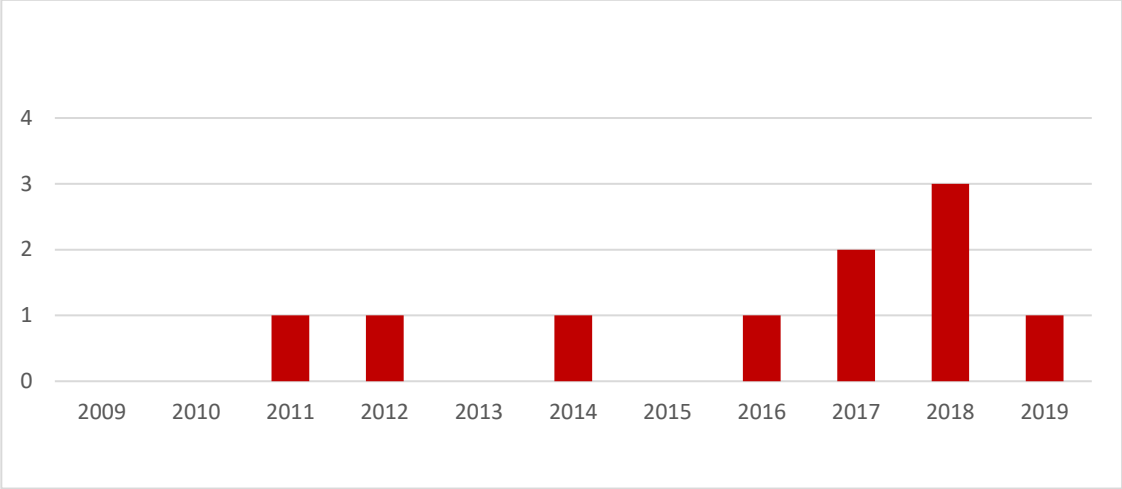
Source: MISO and MPSC

On a regional scale, MISO experienced an increasing number of generation warnings and events, which happen when there is not enough available electric capacity to meet the expected customer load plus an operating reserve margin, since 2016, compared to 2009 to 2016.[20] The increase in regional generation warnings and events may correlate to increasing occurrences of extreme weather events. Figure 2-9 provides data from 2009 to 2019.[21]

[20] MISO did not become a regional balancing authority (BA) until 2009.

[21] Max Gen event data found by year on the Informational Forum reports: https://www.misoenergy.org/markets-and-operations/#nt=%2Fmarketsandopstype%3AMarket%20Analysis%2Fmarketanalysistype%3AMonthly%20Market%20Operations%20Reports&t=10&p=5&s=FileName&sd=desc.

Figure 2-9 MISO Maximum Generation Emergency Declarations Events Called 2009-2019



Source: MISO

Amid these complicated industry changes, increased investments to modernize infrastructure are putting pressure on utility rates. With the declining cost of new generation sources, some customers may look for ways to potentially bypass or reduce their dependence on the utility system through alternatives such as microgrids, distributed generation (e.g., solar, combined heat and power), and increased efficiency.[22] Such options may also be pursued by customers to enhance the level of reliability provided by the utility with their own on-site, back-up supplies. As outlined by NARUC in a recent report:

> *"[T]he rapid growth and declining costs of distributed energy resources (DERs) such as microgrids, solar photovoltaics, and batteries have introduced new technology options for energy resilience. Consequently, state policymakers across the country have established electricity resilience policies and programs, with several states focusing specifically on resilient DERs as part of clean energy programs and grid modernization efforts."*[23]

Many jurisdictions have been focused on improving the resilience of the electricity system. Although there is no universally accepted definition of resilience, many are similar. For instance, the National Infrastructure Advisory Council's definition of resilience, adopted in 2009, is "the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to,

[22] https://www.lsu.edu/ces/publications/2018/MISO-2033-INFRASTRUCTURE-REPORT-FINAL.pdf.
[23] https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198, p. 4.

and/or rapidly recover from a potentially disruptive event."[24] Similarly, NARUC defines resilience as "the robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event."[25]

Investments targeting increased reliability and resilience must consider all factors in order to cost-effectively plan for a wide range of threats. A document released by Grid Strategies LLC in May 2018 described the need for multi-threat planning related to electric system resilience:

> *From a customer-centric perspective, the most cost-effective measures to advance reliability and resilience are those that are effective against multiple threats and offer multiple benefits in addition to their merits for reliability and resilience. Such high-value measures include those that reduce distribution-level outages (e.g., tree-trimming and distribution automation systems), improve outage recoverability (e.g., emergency management drills, outage management systems, critical spares and mutual assistance programs), and improve customer survivability (e.g., energy efficient building shells, emergency supplies and distributed generation and storage with smart inverters).*[26]

Michigan stakeholders and the utilities would be well served to keep abreast of developments occurring across the U.S. to facilitate resiliency improvements to the electric system. The following sections provide additional detail on the current energy landscape in Michigan and describe areas which may impact the prioritization of investments to enhance reliability and resilience.

2.3.1 Fuel Procurement and Gas Supply Availability

2.3.1.1 Generation Diversity and Interdependencies - Michigan's electric generation fleet is evolving as aging coal plants are retired at an accelerated pace and replaced with natural-gas fueled electric generation, renewable energy, and energy efficiency. In Michigan, where natural gas is used to heat the homes of more than 75% of the residents, there is an inherent interdependency between natural gas used for electric generation and for home heating. For the time being, while natural gas supplies from the eastern shale and other producing regions in the nation are plentiful and accessible, Michigan is buffered from price swings in the market due to shortage conditions (although there have been localized, short-term price spikes due to pipeline outages during cold weather conditions). Disruptions to

[24] https://www.raponline.org/wp-content/uploads/2019/08/rap_shenot_linvill_dupuy_combinations_pv_other_ders_2019_august.pdf, p. 34.
[25] https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198, p. 7.
[26] Source: https://gridprogress.files.wordpress.com/2018/05/customer-focused-resilience-final-050118.pdf, p. 13.

natural gas supplies – whether due to political decisions, infrastructure disruptions, diversions of gas supply for export, or other outside forces – would expose Michigan's residents and businesses to commodity price and availability risk, even with Michigan's extensive pipeline access and underground natural gas storage network.

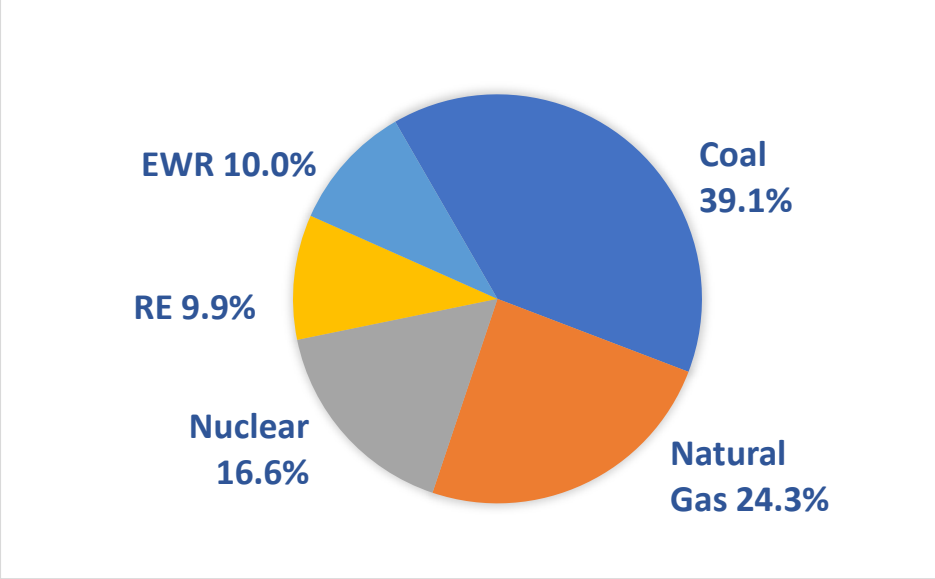
2.3.1.2 Fuel Supply Sourcing and Supply Chain - Fuel supplies and procurement strategies for natural gas utilities and electric generation are managed through annual proceedings conducted outside the rate case process and are referred to as gas supply cost recovery (GCR) and power supply cost recovery (PSCR) proceedings, respectively.[27] These annual proceedings allow the utility to make monthly adjustments to the fuel costs collected from customers and are intended to mitigate against volatile commodity pricing in the wholesale markets by arranging supplies in advance. Currently, natural gas prices are generally stable and consistent, due to abundant supply from shale production in the eastern U.S. This was not always the case, and without the flexibility to align the cost of fuel with the amount collected from customers, the quality of utility operations may decline due to cash flow impacts. Fuel adjustment clauses allow recovery of purchased gas in near real time with follow-up prudence review of the utility's actions to manage costs and reliable operations. Most states have similar cost recovery mechanisms.

2.3.1.3 Clean Energy Requirements, Goals, and Commitments - The 2008 energy law, PA 295, created renewable energy and energy efficiency targets and marked the beginning of Michigan's migration to cleaner energy sources for electric generation. The law was updated in 2016 with PA 342[28] which defined a new goal that, by 2025, the state would meet 35% of electrical energy needs through renewable energy (RE) and avoided MWhs from energy waste reduction (EWR). Figure 2-10 shows the status toward reaching the 35% by 2025 goal. Regionally, the resource mix on the electric grid could reach 50% renewable energy (wind and solar) by 2050.[29] The increasing reliance on intermittent renewable energy resources could create future operational challenges but should be manageable with proper planning, enhancement to wholesale market rules and products, infrastructure development such as new

[27] 1982 PA 304,- http://legislature.mi.gov/doc.aspx?mcl-460-6a. (See also MCL 460.6a,6b,6h,6i,6j,6k,6l,6m.)
[28] 2008 PA 295 - https://www.legislature.mi.gov/documents/2015-2016/publicact/htm/2016-PA-0342.htm.
2016 PA 341 http://www.legislature.mi.gov/documents/2015-2016/publicact/pdf/2016-PA-0341.pdf.
[29] https://renewablesnow.com/news/wind-solar-to-account-for-50-of-worlds-power-by-2050-bnef-617007/.

transmission facilities, and the effective deployment of emerging technologies such as energy storage.[30]

Figure 2-10 2017 Status Toward Reaching the PA 342 35% by 2025 Goal



Source: MPSC
Note: EWR means energy waste reduction and is synonymous with energy efficiency. RE means renewable energy. Nuclear output does not include portions of the DC Cook plant serving Indiana load.

Energy efficiency, while often overlooked in the discussion of resilience improvements, plays a vital role. Resilience is needed for critical operations to continue while the grid may be down, however, taking steps to ensure that critical loads are as efficient as possible is a key resilience improvement.

Legislated Clean Energy Targets:

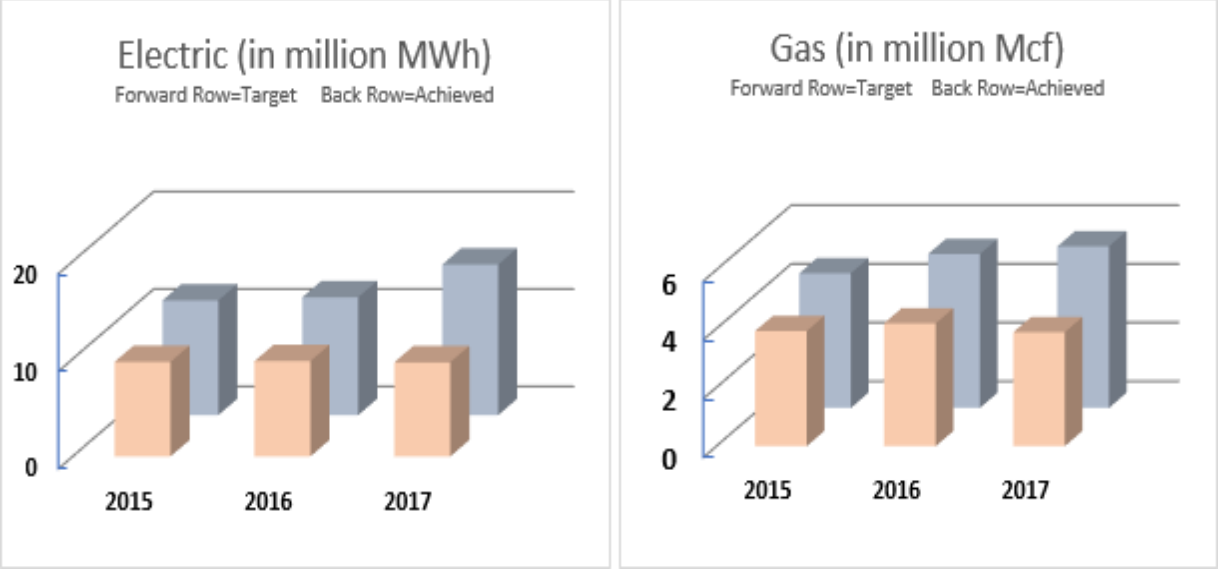
- The **Renewable Energy Program** has required electric utilities to meet a 10% renewable energy standard, based on the number of Renewable Energy Credits (RECs), since 2015. The standard has an interim requirement of at least 12.5% for 2019 and 2020 and increases to at least 15% by the end of 2021. To date, the RE standard has led to the development of over 1,714 MW of new RE projects. Additional amounts of renewable

[30] MISO is reviewing challenges and opportunities associated with integrating higher amounts of renewable energy on its system in its "Renewable Energy Integration Impact Assessment." https://cdn.misoenergy.org/20181128%20RIIA%20Workshop%20Presentation295441.pdf.

energy continue to be proposed based on economics even with the federal tax credits stepping down in the near term.

- **Electric and Natural Gas Efficiency Programs** decrease the amount of energy needed and play a unique role in energy supply diversity. Legislative targets reflect a 1.0% reduction and a 0.75% reduction per year in retail electric and natural gas sales respectively; however, recent utility IRPs call for increased electric energy savings of 1.5% or more. Electric and natural gas utilities have continued to cost effectively meet or exceed targets year over year based on verified savings reviewed by the Commission and an independent third-party evaluation.[31] Figure 2-11 shows projected versus actual electric and natural gas energy savings achieved from 2015 through 2017.

Figure 2-11 Michigan's Electric & Gas Savings Targets vs Savings Achieved 2015-2017



Source: MPSC

Non-Legislated Efficiency Programs

- **Electric Demand Response Programs** incentivize customers with pricing discounts to use less energy during peak times or during system emergencies. The Commission recognizes DR as an integral part of a utility's energy portfolio and recently created a DR

[31] 2017 Annual Report on Energy Efficiency: https://www.michigan.gov/documents/mpsc/2017_Energy_Waste_Reduction_Report_to_the_Legislature_Final_646391_7.pdf, p. 3.

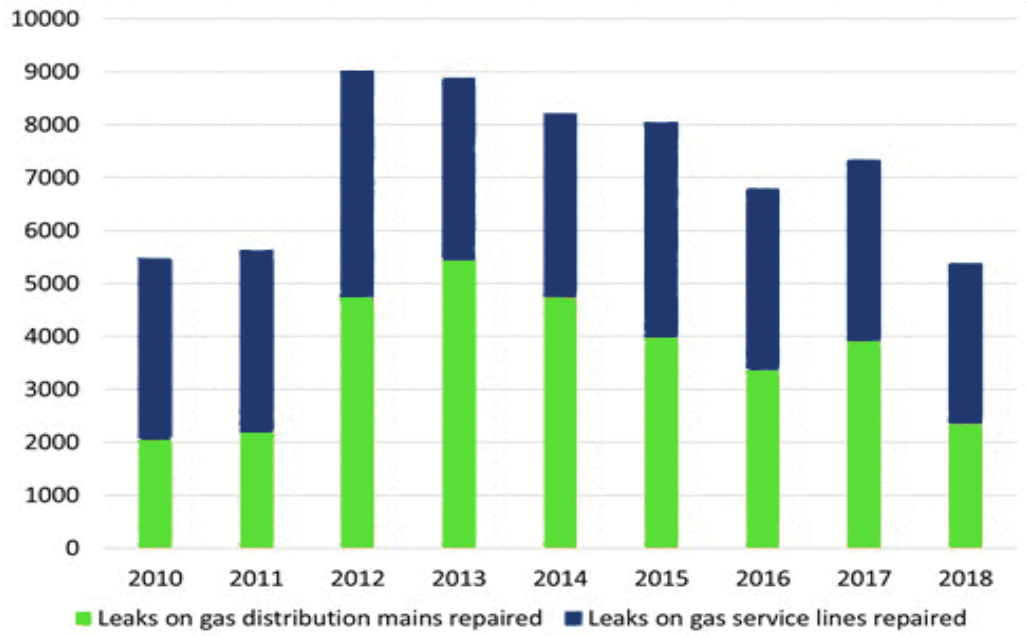
framework structured similarly to the process used for EWR programs. The first cases are ongoing.

- **Natural Gas Demand Response Programs** are not common compared to electric DR programs, but the concept has gained national legislative attention with an eye toward improving electric and gas system reliability.[32] Michigan's gas utilities do not currently have DR programs. This report identifies natural gas DR as an opportunity for the future as it could have avoided the need for a broad public appeal during PV19.
- **Natural Gas Pipeline Leak Mitigation** provides natural gas efficiency improvements by decreasing leaks and has been a feature of natural gas utility infrastructure Investment Recovery Mechanisms (IRM) since 2011/2012. The IRM was designed to accelerate the removal of high-risk pipelines, decrease the backlog of natural gas pipeline leaks, improve the integrity of the natural gas transmission and distribution systems, and reduce the need for annual rate cases. This reduction in natural gas rate cases is notable for SEMCO, MGU, and DTE Gas. Figure 2-12 is a compilation of corrosion-related leak mitigation, since 2010. The baseline year (pre-IRM) is 2010.[33]

[32] 1. Senator Sheldon Whitehouse (D-RI) sponsored a bill to "establish a natural gas demand response pilot program to use the latest demand response technology from the energy sector for natural gas." Energy Infrastructure Demand Response Act of 2018, S. 2649, 115th Congress (introduced Apr. 11, 2018). 2. A required Department of Energy (DOE) study will address "the costs and benefits associated with those savings, including avoided energy costs, reduced market price volatility, improved electric and gas system reliability, deferred or avoided pipeline or utility capital investment, and air emissions reductions." Energy and Water, Legislative Branch, and Military Construction and Veterans Affairs Appropriations Act, H.R. 5895, 115th Congress (Sept. 21, 2018). Source: American Bar Association, www.americanbar.org, March 1, 2019. By Laura Olive.

[33] Note: The number of leaks repaired increased drastically from 2011 to 2012. This is due in part to operators repairing the backlog of leaks that were on their system at a faster rate. After seven complete years of accelerated main replacement programs, corrosion leaks repaired in 2018 dipped to a level lower than they were in 2010 before the accelerated programs were implemented. Leak-prone material types continue to deteriorate and leak at an increasing rate, and the impact of harsh winter conditions (frost) increase the number of leaks. Remediation planning is keeping more identified leaks in a backlog for CE (e.g. 2010: 780 vs. 2018: 3916).

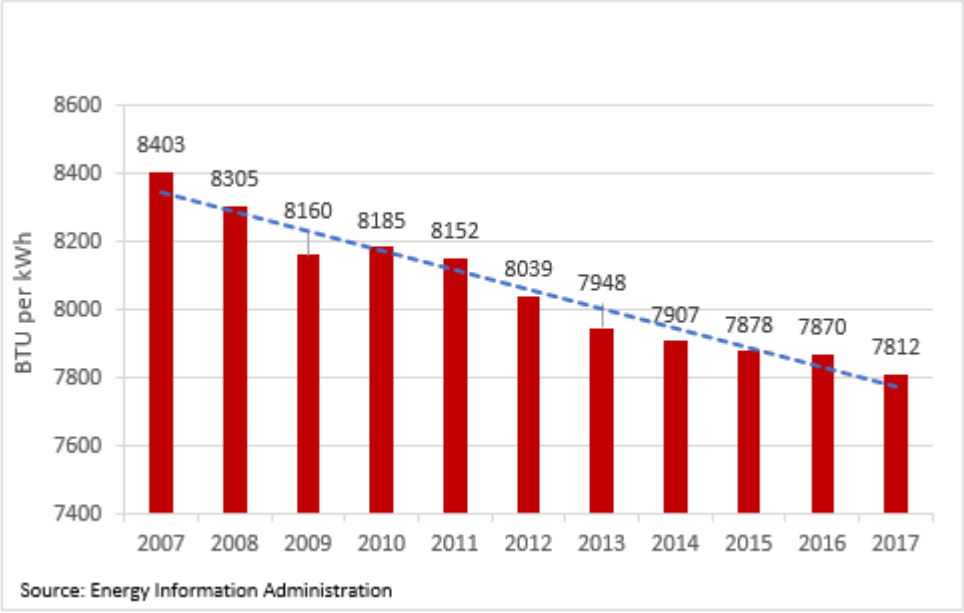
Figure 2-12 Corrosion-Related Leaks Repaired 2010-2018



Source: MPSC Gas Safety Database

- **Efficiencies in Natural Gas-fired Electric Generation Plants -** The heat rate for natural gas-fueled electric generation plants has continued to improve over the past 10 years. The heat rate (BTU/kWh) describes the amount of natural gas energy (BTU) needed to generate 1 kWh of electricity. The lower the heat rate, the more efficient the plant. Figure 2-13 below shows gas heat rate improvements in electric generation plants between 2007 and 2017.

Figure 2-13 Natural Gas Heat Rate Improvements in Electric Generation Plants 2007-2017



2.3.1.4 Utility Targets and Carbon Emissions Reduction Commitments - Nearly all electric utilities regulated by the MPSC have announced carbon reduction goals, including the two largest utilities, Consumers Energy and DTE Electric, committing to 80% reduction by 2040. Both utilities are accelerating the retirement of coal-fired plants. Recent utility filings for IRPs confirm a transition toward natural gas-fired facilities, renewable energy, and demand-side programs such as demand response and energy waste reduction. Figure 2-14 summarizes announced carbon reduction goals made by utilities operating in Michigan.

Figure 2-14 Michigan Utilities Announced Carbon Reduction Goals

Announced Carbon Reduction Goals		
Carbon Reduction Target	**Baseline Year**	**Target Year of Achievement**
DTE Electric		
30%	2005	Early 2020s
50%	2005	2030
80%	2005	2040
Consumers Energy		
80%	2005	2040
Upper Peninsula Power Company		
17%	*	2021
Indiana Michigan Power Company (American Electric Power)		
60%	2000	2030
80%	2000	2050
Northern States Power Company (Xcel Energy)		
80%	2005	2030
100%	2005	2050
Upper Michigan Energy Resources Corporation (WEC)		
40%	2005	2030
80%	2005	2050

*UPPCO's announcement does not indicate a baseline year. Source: utility public announcements

2.3.1.5 Impact on Infrastructure Needs - The electric and natural gas infrastructure in Michigan is aging and may benefit from an upgrade and modernization or additional redundancy. Three of the largest electric utilities recently submitted five-year electric distribution plans to outline the priority for repair, replacement, and system upgrades.[34] On the natural gas side, infrastructure recovery mechanisms focus primarily on natural gas distribution system enhancements. Some utilities are beginning to develop risk-remediation plans which roll all gas assets (transmission, distribution, compression, and storage) into one multi-year plan. This type of planning is identified as an opportunity and is addressed in this report.

2.3.1.6 Effects on Resilience and Reliability - As natural gas continues to be the preferred fuel for replacing retiring coal-fired electric generation while still the dominant fuel for home heating, the impacts of energy emergencies must be considered, and safeguards examined. This may include continued operation of nuclear plants and increasing the role of other resource options, including renewable energy, energy efficiency, demand response, energy storage and other types of distributed energy resources. Infrastructure investments made in these resources may improve reliability and resilience of the entire energy delivery system, if that is a consideration during the design phase.

2.3.1.7 Distributed Energy Resources for Improved Resilience - Distributed energy resources (DER), including energy efficiency, demand response, distributed solar, distributed wind, electric vehicles, storage, microgrids and other such distributed resources, while at varying stages of maturity, have been growing in Michigan, as well as across the country. Several states have initiated pilots and other programs regarding increasing the utilization of DERs to improve the resilience of the system. As outlined in a recent report by the Regulatory Assistance Project, "The U.S. Army views DER combinations as a smart supplement or alternative to diesel generators for energy resilience. Nearly 20 U.S. Army bases already have or are developing onsite renewable generation combined with energy storage or microgrid capabilities."[35] Figure 2-10 outlines the resilience improvement projects currently underway by the U.S. Army to continue operations and power critical infrastructure even when the grid goes down.

[34] MPSC Case No. U-20147, https://mi-psc.force.com/s/case/500t0000009gHerAAE/in-the-matter-on-the-commissions-own-motion-to-open-a-docket-for-certain-regulated-electric-utilities-to-file-their-fiveyear-distribution-investment-and-maintenance-plans-and-for-other-related-uncontested-matters.

[35] https://www.raponline.org/wp-content/uploads/2019/08/rap_shenot_linvill_dupuy_combinations_pv_other_ders_2019_august.pdf, p. 34.

Figure 2-15 DERs for Improved Resilience in the U.S. Army

Base	State	Technology Utilized
Ft. Drum	NY	
Ft. Detrick	MD	
Humphreys Engineer Center	VA	
Ft. Gordon	GA	
Ft. Benning 1-3	GA	
Ft. Stewart 1&2	GA	
Ft. Rucker 1&2	AL	
Anniston Army Depot 1&2	AL	
Redstone Arsenal	AL	
Camp Shelby	MS	
Ft. Sill 1&2	OK	
Ft. Hood	TX	
Camp Mabry	TX	
Ft. Huachuca 1&2	AZ	
Joint Forces Training Base - Los Alamitos	CA	
Camp Roberts	CA	
Military Ocean Terminal Concord	CA	
Schofield Barracks	HI	

Biofuel, Biomass, Solar
Natural Gas, Hydro, Wind
Battery Storage, Diesel, Generation
Storage/Supply, Controls
No Storage, No Controls, No Generation

Source: U.S. Army Office of Energy Initiatives Current Energy Projects Portfolio, August, 2019

Many other examples of the resilience of DERs happening across the country were pointed out by NARUC:

> *New York State's Reforming the Energy Vision (REV) proceeding, for example, explicitly links the issue of resilience with considerations of DER expansion (NY DPS, 2014). The California Public Utilities Commission (CPUC) recently mandated that IOUs in the state pursue at least one pilot for DERs to demonstrate distribution grid services—including "resiliency (microgrid) services" under the Integrated Distributed Energy Resources (IDER) proceeding (CPUC, 2016, p. 6). The use of DERs for resilience is also a prominent focus of power system reconstruction efforts in Puerto Rico (Siemens, 2018; Toussie et al., 2017).*[36]

As DERs are implemented in various jurisdictions across the country, lessons learned from the early adopters are worthy of further study and analysis. It is increasingly apparent that DERs play a role in improving the resilience of the electric system, although additional work is needed to unlock the full potential.

[36] https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198, p. 9.

3. Electric

3.1 System Overview and Operational Practices

3.1.1 Generation/Transmission (Bulk Power System)

3.1.1.1 Resource Adequacy - Resource adequacy refers to the ability to maintain reliability over the long term and is generally equated with having adequate electric capacity supplies arranged in advance to meet demand during peak times. Under the Federal Power Act (FPA), regulation of interstate electric transmission and wholesale power sales fall under federal jurisdiction, while regulation of the state distribution systems, retail sales, and resource adequacy are subject to state and local regulation.

FERC is the independent federal agency tasked with the regulation of the bulk electric system (BES).[37] Cooperative federalism enshrined in the FPA ensures that states have the power to shape their energy resource mix, choose where to build their electrical infrastructure, and ensure enough generation is online to meet the state's needs. In Michigan, resource adequacy is assured through the IRP and the annual capacity demonstration process.

The state processes are supported by resource adequacy requirements set by the RTOs and approved by FERC. The RTO's regional capacity markets allow utilities to trade excess generation capacity and, in the case of PJM, arrange for supplies several years into the future. These regional markets attempt to attract investment in new generation and incentivize reliability of the grid through market forces, although market prices in MISO are well below the level needed to spur new investment and PJM continues to struggle with market design issues. It is important to reiterate that the states retain jurisdiction over generation resource adequacy and that these regional market constructs are meant to support and enhance state-level efforts, not override them. Michigan has chosen to directly exercise its authority over generation resource adequacy and consequently the state does not rely solely on market signals to build adequate generation. Instead, regulation of utilities and processes like the IRP and capacity demonstrations help assure resource adequacy in the state while leveraging other benefits RTOs provide. Both federal and state regulators contribute to resource adequacy and work in concert to maintain the integrity of the electric grid.

[37] NERC defines the BES as encompassing all elements and facilities necessary for the reliable operation and planning of the interconnected bulk power system. See: https://www.nerc.com/pa/Stand/2018%20Bulk%20Electric%20System%20Definition%20Reference/BES_Reference_Doc_08_08_2018_Clean_for_Posting.pdf.

3.1.1.2 NERC Standards - NERC is the Electric Reliability Organization (ERO) for North America, including the United States, Canada, and the northern part of Baja California, Mexico. Following the 2003 Northeast blackout and subsequent changes to federal law, FERC designated NERC as the nation's ERO and charged it with developing mandatory grid reliability standards[38] that are enforced with FERC's delegated authority. These standards are developed with input from experts nationwide who have knowledge of the operational and technical needs of the industry. The standards address operating and planning standards for bulk power system transmission and generation. The standards also cover various aspects of physical and cyber critical infrastructure security, as discussed in Section 3.2.2.1.

NERC delegates its authority to monitor and enforce compliance with reliability standards to seven regional entities across North America. Most of Michigan is a part of Reliability First (RF)[39] while portions of the Upper Peninsula are part of the Midwest Reliability Organization (MRO).[40] RF and MRO ensure that their respective regions not only meet NERC standards, but also periodically perform reliability assessments and performance analyses to evaluate the reliability of the region under normal conditions as well as events such as PV19. NERC and its regional entities also audit owners, operators, and users of the bulk electric system for preparedness, and educate and train industry personnel. These processes are key to maintaining system reliability and are a critical defense against evolving cyber and physical security threats. NERC reliability standards are the foundation for RTO planning and operations, as outlined below.

3.1.1.3 Wholesale Electricity Markets - RTOs manage, plan, and provide open access for all electric generators to the transmission system. The goal of RTOs is to provide a reliable transmission system and promote efficiency in wholesale electricity markets to ensure that consumers pay the lowest price for energy. As part of this goal, RTOs typically oversee multiple wholesale markets, such as energy, capacity, and ancillary services, to promote competition while maintaining their basic goal of providing reliable electric service.

In order to reliably serve customer demand, electric generation and demand must remain balanced. To ensure generation and demand match, RTOs forecast demand one day ahead, determine the generation needed to meet that demand, and balance that selection on the delivery day. All these steps are accomplished in the day-ahead and real time energy markets. In the day-ahead market, the RTO develops a plan to serve demand and commits the generation necessary to do so. The RTO considers inputs such as renewable generation output,

[38] https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States.
[39] https://rfirst.org/about/Pages/AboutUs.aspx.
[40] https://www.mro.net/about/Pages/default.aspx.

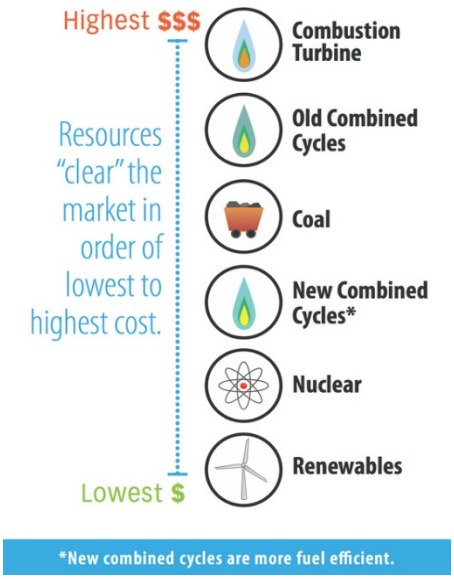
temperature, projected demand, etc., to develop its forecast supported by data, analysis, and experience, of the actual demand for the next operating day. Naturally, variations from the day-ahead forecast occur and these differences are handled in the real time market. The real time market balances supply and demand against the day-ahead forecast by bringing on or backing down generation in real time. RTO control room operators are dedicated to managing this system minute to minute and make incremental adjustments to supply throughout the day – a process known as security constrained economic dispatch.

The energy markets function as a clearinghouse with generator offers selected to serve demand based on the lowest marginal cost. As shown in Figure 3-1,[41] this means filling in the 'dispatch stack' with lowest cost generation, such as renewable energy and baseload units, then higher cost generation, such as natural gas peaking units, that are only needed during periods of high demand (peak).[42] The energy market price incentivizes generation to follow RTO dispatch instructions in real time while the RTO is also able to apply penalties to generation that does not follow dispatch instructions. While on most days there are enough resources offered into the energy markets to meet demand in a reliable, least cost manner, there are instances where emergency procedures are needed to maintain the reliability of the system and operator intervention is required.

[41] Source: PJM.

[42] In addition, dispatchable demand-side resources such as demand response are increasingly being integrated into the RTO market. Demand response, which helps reduce loads at peak times either through price signals or direct controls, operates as essentially a mirror image of a traditional peaker plant, with both the peaker plant and demand response sharing the goal of maintaining the balance between generation and demand response at peak times.

Figure 3-1 Dispatch Stack



Source: PJM

3.1.2 Distribution

3.1.2.1 MPSC Rules – Service Quality, Technical, and Customer Protection Standards - Although there are industry standards and best practices at a national level, there are no federal rules governing the electric distribution system because it is exclusively under state jurisdiction. The MPSC has adopted state-specific rules to govern the activities of electric distribution utilities in the state.[43]

The MPSC's Service Quality and Reliability Standards for Electric Distribution Systems[44] serve as a separate set of administrative rules promulgated for the purposes of monitoring the service quality and reliability performance of a distribution utility and are based on annual averages (in most cases) with reporting requirements. Part 4 of the rules are structured to penalize the electric utility if certain performance metrics are not met. In addition to penalties that can be

[43] Electric IOUs in Michigan are the only electric utilities under the full jurisdiction of the MPSC. Electric cooperatives in the state are subject to safety, interconnection, code of conduct, electric capacity, and customer choice requirements. Municipally owned electric utilities are not under the MPSC's jurisdiction except for the requirement to file a renewable energy plan, energy waste reduction plan, and electric capacity demonstration.

[44] Adopted in Case No. U-12270 in 2004. These administrative rules are available on the MPSC website located here: https://www.michigan.gov/mpsc/0,4639,7-159-16370_52012---,00.html#Electric.

assessed to utilities for non-compliance, the rules also provide bill credits for customer bills for extended or repeated outages but the customer has to notify the utility in order to claim the credit. These rules apply only to investor-owned utilities (IOU).

The Technical Standards for Electric Service[45] were adopted in 1983 to promote safe and adequate service to the public by providing standards for uniform and reasonable utility practices. The technical standards consist of requirements related to 1) records and reports, 2) meter and metering equipment requirements, 3) customer relations, 4) engineering, 5) quality of service, and 6) safety and cybersecurity. The technical standards apply to IOUs and electric cooperatives.

The MPSC Technical Standards for Electric Service incorporate the National Electrical Safety Code (NESC) for maintenance line clearance requirements while the Electrical Supply and Communication Lines and Associated Equipment[46] requirements incorporate the NESC to provide basic safety provisions related to the installation, operation, and maintenance of overhead and underground electric lines and stations. The NESC prescribes minimum design and maintenance requirements in the state which have often been exceeded by the electric utilities.

In 2002,[47] the Commission required regulated utilities and cooperatives to file annual service quality and reliability reports. In 2009, the Commission enhanced the reporting requirements for DTE and CE by requiring annual reliability metrics and power quality reporting. In 2014, the Commission expanded the annual reliability and power quality reporting to all regulated utilities and cooperatives, and required DTE and CE[48] to file more detailed reliability indices of system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI), and customer average interruption duration index (CAIDI),[49] following IEEE[50] standard 1366-2012 for distribution reliability.

3.1.2.2 Distribution Outage Preparedness and Response Activities - The MPSC is also responsible for emergency preparedness related to the state's electric supply and has internal procedures in place to support outage reporting by the utilities. The MPSC's Electric

[45] http://dmbinternet.state.mi.us/DMB/ORRDocs/AdminCode/1768_2017-091LR_AdminCode.pdf.
[46] http://dmbinternet.state.mi.us/DMB/ORRDocs/AdminCode/1683_2017-007LR_AdminCode.pdf.
[47] MPSC Case No. U-17542.
[48] MPSC Case Nos. U-16066 (Consumers) and U-16065 (DTE).
[49] SAIDI represents the average number of minutes of interruption per customer, SAIFI represents the average number of interruptions per customer per year, and CAIDI represents the average restoration time per outage.
[50] IEEE is a technical professional organization for the advancement of technology through development of industry standards. See: https://www.ieee.org/.

Operations Section staff is charged with the responsibility of receiving calls related to storm and outage notifications once the outages reach a certain threshold.[51] The manager of the Electric Operations Section is the primary contact to the utilities for such notifications. The utilities, in most cases, participate in a mutual assistance process to provide and receive resources to support emergency response by utilities, across different areas of the state or, in some instances, different areas of the country in order to return the electric system back to a reliable state as quickly and safely as possible after a severe weather event. Many utilities have online, publicly accessible outage maps and electronic methods for customers to provide notification of outage events and to check estimated restoration times. After major or extended outages, it is not uncommon for the MPSC to conduct follow-up investigations of the utilities' preparedness and response and identify lessons learned. These investigations have identified numerous improvements that have been incorporated into routine practices to mitigate the extent or duration of power outages.

3.1.2.3 Equipment Failures and Response - Electric utilities have historically relied on customers, employees performing maintenance in the field, and the general public to call in and notify the utility of abnormalities or issues on the electric distribution system. Field personnel must travel to the area, identify the fault location, and then manually resolve the situation. To speed up outage response times, utilities have begun investing in advanced grid technologies to enable real time observation of the evolving condition of the system and to respond with little to no human intervention. The use of advanced meters at a customer's home or business greatly assists the utility in identifying outages.

3.1.2.4 Distribution Management Practices Impacting System Operations, Reliability, and Resilience - Modern grid technology devices can be installed in strategic locations and facilities to monitor critical electric infrastructure and remotely respond to and/or mitigate emergency events. Certain devices, referred to as fault location and isolation, and service restoration (FLISR) devices, communicate directly with end-use customers via advanced metering infrastructure (AMI) or smart meters. These devices provide system operators with instantaneous information regarding power outages where operators would traditionally rely on customers to report outages and would enter the outage into the Outage Management System (OMS). Based on information in the OMS, the line workers can get reasonably close to the fault, but this system still required dispatching of line workers, and physically searching the lines in

[51] The MPSC issues storm outage reports when DTE has over 75,000 outages, when Consumers has over 50,000 outages and when the rest of the regulated utilities and cooperatives have more than 5% of their customers impacted.

that area to pinpoint the fault. With AMI linked to the OMS and distribution management system (DMS), the fault location can be pinpointed more efficiently and accurately. DTE Electric and Consumers Energy have both integrated AMI into OMS and are planning to utilize the FLISR application as part of the DMS to locate faults on the system and restore service to customers in a more timely manner than without the technology.

Advanced technologies are helping to provide significant reliability improvements. These devices and communication paths include automated switches and reclosers, secure communication networks, OMS, distribution management system and supervisory control and data acquisition (SCADA) among others. Specifically, utility five-year distribution plans include discussion of strategically placing line sensors that can detect issues online and using automatic switching and automatic transfer reclosers, so the fault can be automatically sectionalized. This is accomplished by opening switches on either side of the fault to isolate it and simultaneously closing a normally open switch so that power flows can be redirected to customers that are not directly affected by the cause of the fault.[52] These devices, along with proper communication, have the potential to greatly reduce the frequency (SAIFI) and duration (SAIDI) of customer outages. Advanced controls, communication, and automation technologies on the distribution grid also pave the way for the full potential of DER and Non-Wires Alternatives (NWA) to be utilized.

Advanced Distribution Management Systems (ADMS), along with line sensors, secure communication network, and remote controllable devices, allow utilities to manage distribution systems with higher levels of automation. The Commission recently approved DTE's proposed ADMS along with other grid modernization improvements. In addition to enhancing the ability to mitigate and respond to power outages due to storms and equipment failures, these controls and communications can provide opportunities for the utility to potentially offset distribution upgrades by optimizing DERs and NWAs. One of the most notable examples of how this works is the Brooklyn Queens Demand Management project.[53] New York's Consolidated Edison, Inc. was experiencing significant peak load growth in the Brooklyn and Queens area. The cost estimate to construct the necessary substation was approximately $1.2B. It was determined that through a combination of NWAs, DERs, energy waste reduction and communications networks at a cost of approximately $200M, the substation construction could be deferred. Additionally, battery technologies combined with solar photovoltaic and controls will help smooth out any intermittencies associated with solar power.[54] Customer-sited solar and battery technologies

[52] https://www.smartgrid.gov/files/B5_draft_report-12-18-2014.pdf.
[53] http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=45800.
[54] https://energy.sandia.gov/wp-content/gallery/uploads/PV-Energy-Smoothing.pdf.

can potentially be utilized for grid support functions such as frequency and voltage control compliant with IEEE 1547-2018[55] and equipped with communication capabilities while utility-sited projects can be utilized for power quality issues. Utilities can set inverters to provide these grid support functions if needed. The utility five-year electric distribution plans include discussions of how these technologies can be fully optimized.

3.2 Regulatory Oversight of Planning and Infrastructure

3.2.1 Generation

3.2.1.1 Integrated Resource Plan, Certificate of Necessity, and Renewable Energy Plan –

Integrated Resource Plan - Michigan's energy laws were updated by PA 341 and 342 of 2016 and took effect in 2017. The update included the Certificate of Necessity (CON) and Renewable Energy Plans (REP). PA 341 also established integrated resource plan (IRP) rules. An IRP is a plan developed by an electric utility which outlines its future resource strategy. Namely, an IRP will identify how the electric utility plans to provide reliable, cost-effective electric service to its customers while addressing the risks and uncertainties inherent in long-term planning.

Section 6t of PA 341 of 2016 requires Michigan regulated electric utilities to submit IRPs to the MPSC every five years that provide a 5, 10, and 15-year projection of the utilities' load obligations and their plan to meet those obligations. This includes plans to meet reliability requirements such as planning reserve margin requirements and local clearing requirements.

Regulated utilities with under one million customers may apply for waivers for portions of the IRP process, but still must file an application for review in a contested case. Each IRP is reviewed by a cross-divisional group of MPSC Staff for prudence and reasonableness in a contested case before the MPSC. The IRP requirements for Michigan utilities are further clarified through Commission orders establishing specific filing requirements and certain modeling parameters and assumptions that utilities must include. The filing requirements[56] and integrated resource planning parameters[57] were established through collaborative stakeholder processes with input from the Michigan Agency for Energy and the Department of

[55] https://standards.ieee.org/standard/1547-2018.html.
[56] December 20, 2017 Order, MPSC Case Nos. U-15896 and U-18461, Exhibit A, Integrated Resource Plan Filing Requirements. https://mi-psc.force.com/s/filing/a00t0000005pjSgAAI/u158960013.
[57] November 21, 2017 Order, MPSC Case No. U-18418, Exhibit A, Michigan Integrated Resource Planning Parameters. https://mi-psc.force.com/s/filing/a00t0000005pV0LAAU/u184180065.

Environmental Quality (now, collectively, Department of Environment, Great Lakes, and Energy). IRPs must include the following, among approved MPSC requirements:

- Long-term forecasting of the utility's peak demand and peak demand reduction.
- The type of generation facility proposed for a generation facility contained in the plan.
- Newly proposed generation facilities' capacity and fuel cost under each scenario.
- Projected energy purchased or produced by renewable energy or cogeneration.
- Projected load management and demand response savings.
- Projected rate impact.
- Projected long-term gas transportation and/or storage contracts.
- The utility's plan for energy waste reduction.
- The utility's plan to comply with all applicable state and federal regulations.
- Analysis of the current generation portfolio including age, capacity, and remaining time of operation.
- Analysis of new or upgraded transmission options.
- Analysis of the cost and viability for all proposed construction and major investments.

Certificate of Necessity - A CON issued by the MPSC through a contested case proceeding may provide assurance of cost recovery for new electric generation resources and is required for generation facilities over 225 MW and may be filed for projects over $100 million. The CON application must include an IRP, which is reviewed by the Commission under the applicable statutory provisions.

Renewable Energy Plan - PA 342 increased the renewable energy requirement to 15% of a utility's production by 2021. Once a REP is approved by the MPSC, the utility need only file a new REP if there is a material change to the existing plan.

3.2.1.2 Capacity Requirements and Demonstrations - MPSC and RTOs -

The MPSC ensures resource adequacy through its capacity demonstrations and requirements. At the regional level, the MISO and PJM RTOs have their own supplemental processes. MISO and PJM ensure that their own regions have enough resource capacity to meet peak load plus a reserve margin through their resource adequacy constructs.

Each MISO local resource zone (LRZ or zone) must demonstrate that it has an adequate supply of capacity resources to meet its reserve margin requirement for the upcoming planning year. Based upon load forecasts submitted by load serving entities (LSE), MISO calculates the planning reserve margin requirement (PRMR) for the region. The PRMR is the required amount of capacity and reserves necessary for the MISO region to maintain reliability. MISO also calculates the amount of resources that are required to be located in a specific zone, considering the import/export capacity of the transmission system in that zone, known as the Local Clearing Requirement (LCR). The PRMR and LCR calculated by MISO are based upon a 50/50 load forecast, meaning that there is a 50% probability that the actual peak load will be higher than forecast and a 50% probability that the actual peak load will be lower than forecast. It is also based on the historical outage performance of electric generation resources. The PRMR is a statistical calculation based upon a "loss of load expectation" of one day in ten years, or said another way, a power outage due to a lack of supply will happen only one time in ten years

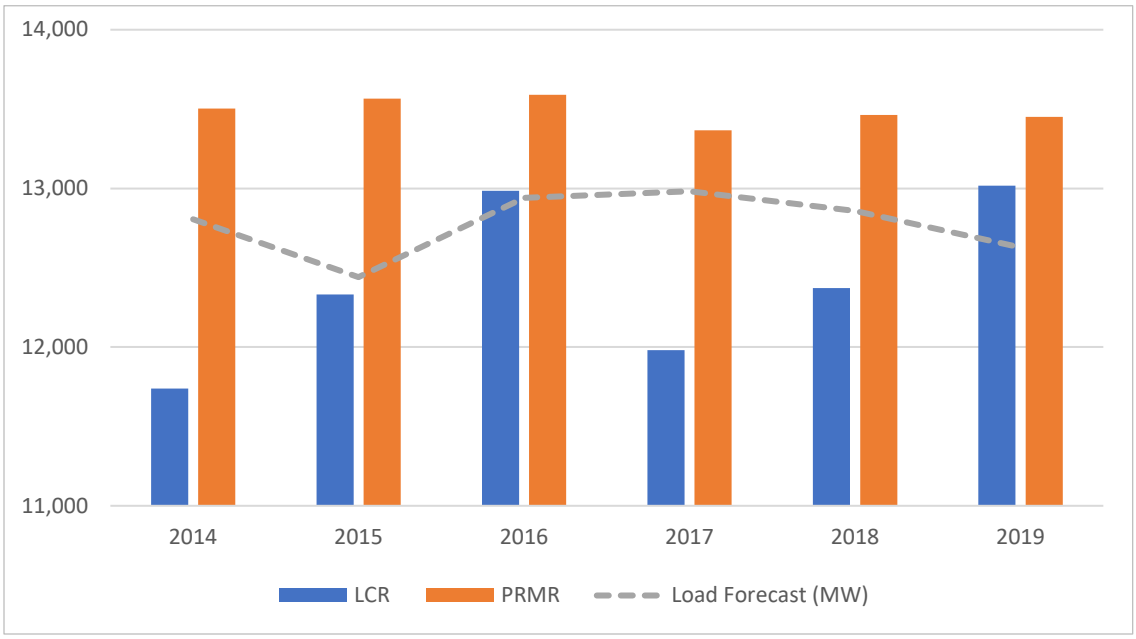
when the resource adequacy criteria are met. Not meeting the criteria does not mean an outage will occur but does increase the probability. Thus, the reserve margin ensures there is a supply cushion to be able to withstand a certain level of unplanned equipment outages (transmission and/or generation) and/or higher levels of electricity consumption. The reserve margin is based on preparing for the summer peak, although there have been operating challenges in the winter or spring/fall "shoulder" months due to unusual weather combined with additional transmission and generation facilities out of service for scheduled maintenance.

MISO calculates the resource adequacy requirements, the LCR, and the PRMR, for each zone on an annual basis. The Lower Peninsula of Michigan is in zone 7 while the Upper Peninsula is a portion of zone 2 as shown in Figure 3-2 below.

Figure 3-2 MISO Planning Resource Zones

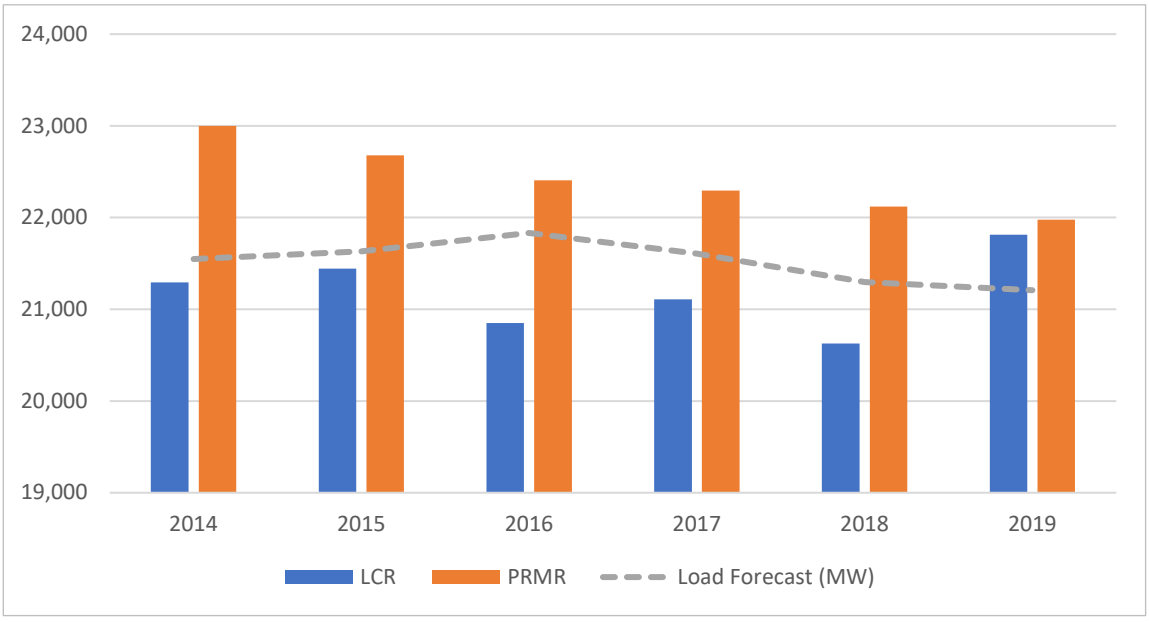
The charts in Figure 3-3 and Figure 3-4 below depict the LCR (the amount of local resources required in the zone), the PRMR (the total amount of resources required for the zone including imports), and the projected load forecast for the zones that include Michigan customers for the last several years for zone 2 and zone 7. The difference between the PRMR and the LCR is the amount of capacity that a zone is allowed to plan to import at the system peak. When compared to the last several years, the amount of allowable capacity imports into zone 7, Michigan's Lower Peninsula, decreased significantly, almost to zero, hampering the state's ability to more fully realize the benefits of being part of a large market. This concern is further addressed in Chapter 8 of this report.

Figure 3-3 MISO Zone 2 Resource Adequacy Requirements and Load Forecast



Source: MISO annual Loss of Load Expectation Studies and PRA Results

Figure 3-4 MISO Zone 7 Resource Adequacy Requirements and Load Forecast



Source: MISO annual Loss of Load Expectation Studies and PRA Results

PJM's resource adequacy construct is called the reliability pricing model (RPM). PJM's resource adequacy construct is also based upon the industry average loss of load expectation of one day in ten years. The primary difference between the MISO and PJM resource adequacy construct is the applicable time horizon. MISO plans one year at a time while PJM's RPM

includes a three-year forward capacity auction requiring LSEs to arrange or procure capacity three years into the future. To meet their load obligations, LSEs may use existing and planned generation resources, behind the meter generation[58], and other load management resources such as DR.

In addition to the planning reserve margin requirements, or planning reserves, utilized to ensure that there will be sufficient resources to meet the annual system peak load as discussed above, the electric system also relies on operating reserves to maintain reliability day-to-day, minute-by-minute. Operating reserves include the following and are managed by the RTO through markets or other means:

- **Regulating reserves –** resources already online that provide an automatic reaction to the momentary fluctuations in demand and frequency on the system. They include automatic control equipment that increase or decrease generation output in response to moment-to-moment changes in demand, while maintaining a frequency of 60 Hz on the system. (5-minute response time.)
- **Spinning reserves –** excess generating capacity (already online) that is immediately available by increasing the power output of generators already connected to the grid. (10-minute response time.)
- **Supplemental ("Non-Spinning") reserves –** the extra generating capacity that may or may not be currently connected to the system but can be brought online after a short delay. (10-minute response time.)
- **Contingency reserves –** composed of spinning and supplemental reserves and are used to relieve the generators currently providing those reserve products. (10-minute response time.)

The 2016 energy laws included important resource adequacy provisions that are implemented on an ongoing basis by the MPSC. Specifically, each Michigan electric provider that serves retail customers (investor-owned electric utilities, cooperatives, municipal electric utilities, and alternative electric suppliers) is required to demonstrate to the MPSC that it owns or has procured sufficient capacity to meet its load four years into the future[59] through the State Reliability Mechanism (SRM) requirements of Section 6w of PA 341 of 2016. Electric providers can use a variety of supply- and demand-side resources to meet their capacity demonstration

[58] Behind the meter generation is typically renewable energy generation, industrial generators, or diesel units that produce power intended for on-site use in a home, office building, or other commercial facility. The location of the generation is not on the side of the electric grid or utility.

[59] https://mi-psc.force.com/s/case/500t0000009gjGtAAI/in-the-matter-on-the-commissions-own-motion-to-open-a-docket-for-load-serving-entities-in-michigan-to-file-their-capacity-demonstrations-as-required-by-mcl-4606w.

requirement. Failure to demonstrate sufficient capacity may subject the electric provider to various penalties or additional capacity charges depending on the type of electric provider. The SRM includes the annual capacity demonstration requirements and process administered by the MPSC.

An individual electric provider's capacity requirements are based on peak forecasts coinciding with projected regional system peaks. The most recent capacity demonstration report projects adequate resources in MISO local resource zone 7 (lower peninsula) as well as the Michigan portions of MISO local resource zones 1 and 2 (upper peninsula), and PJM (SW Michigan) through 2022/23. This means Michigan electric providers are projected to have enough resources to meet their share of planning reserve margin requirements and sufficient amounts of resources are planned to meet projected load forecasts.

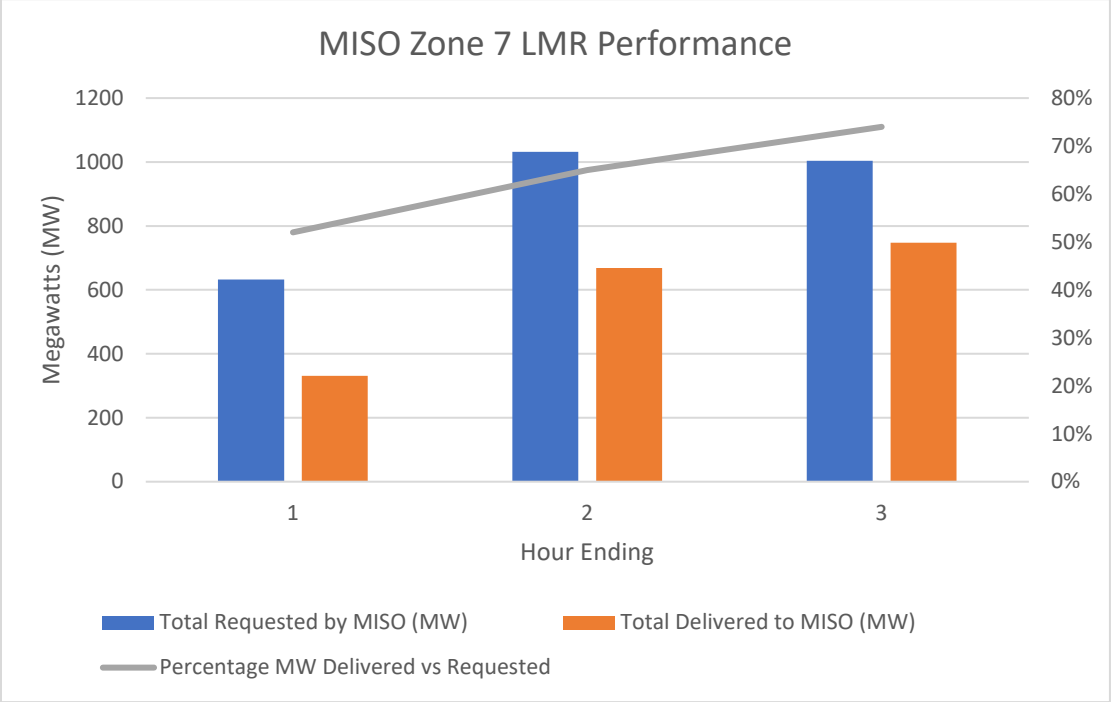
3.2.1.3 Emergency Operating Procedures and Demand Response (DR) - In the case of an electrical system emergency, such as extreme weather or cyber/physical events, RTOs have emergency operating procedures in place that detail how they plan to restore the system to normal functionality. These procedures are based on NERC standards and outline different steps operators and utilities throughout the RTO footprint can take to mitigate events and manage disruptions. As a system emergency worsens, RTOs progress further into their procedures and access more resources such as reserves, increased imports from other regions, maximizing generator output, demand response, voltage reductions, and in worst case scenarios, load shed (cutting off certain customers or areas from the transmission system to prevent cascading outages). With these tools, grid operators have been able to limit system emergencies and have been able to keep the system reliable throughout events such as PV14, PV19, various summer heat waves, and plant failures. One important tool operators are able to leverage is demand response (DR).

DR is a product that reduces a customer's peak demand temporarily, allowing grid operators to meet demand by lowering the system peak. DR can be called upon by utilities at the retail level or RTOs at the wholesale level in order to meet peak demand during emergencies or to displace generation on an economic basis. In either case, operators are essentially paying customers not to use energy when called upon. Emergency DR at the wholesale level is called upon to perform only when the RTO is in an emergency event. Typically, emergency DR is a higher cost resource (compared to non-emergency DR) and is used as a buffer when supply throughout the region is tight. Still, DR is preferred to other reliability measures and consequently is called before more drastic steps in emergency procedures such as "firm load shed" (service interruptions).

As the fuel mix of generators on the system continues to evolve, with increasing intermittent generation and the retirement of coal-fired and nuclear generating plants, utilizing DR may become more common. If resources do not generate (or reduce load levels) to their scheduled availability when called upon by an RTO during a maximum generation event, they may face financial penalties. RTOs and utilities are monitoring this trend and are having ongoing discussions to consider the availability of DR and whether appropriate incentives are in place to encourage performance regardless of whether there is an emergency.

Figure 3-5 below illustrates the performance of MISO's zone 7 emergency resources in Michigan that were dispatched January 30, 2019, in response to PV19 and shows the increased performance of the Market Participants (MPs) through each hour of the event. The difference from the MISO requested versus actual performance was due to multiple factors including, but not limited to, on-site generation equipment failure, nonparticipation by industrial customers to avoid economic losses, and confusion as to the timing of the requests. There was also inoperable equipment such as interruptible water heaters, that failed to respond and were later determined to have not been inspected or tested to ensure functionality since installation. It is critical to conduct post-installation functionality testing to ensure that interruptible equipment will function as intended when called upon. There also appeared to be a lag in load modifying resource (LMR) response after the RTO communicated the required actions needed from the utility customers. Communications from the utility to the customers during an emergency event should be improved. It is essential to ensure prompt and transparent communications are used when LMRs are deployed to efficiently reduce the load in a short period of time.

Figure 3-5 MISO Zone 7 (Lower Peninsula) LMR Performance 1/30/2019



Source: MISO

PJM also calls upon DR resources in certain emergency scenarios, once they reach the pre-emergency load management reductions step of their emergency operations procedures.[60] Furthermore, energy only demand response resources will be called on when PJM reaches the emergency voluntary energy only demand response reductions. DR is one tool operators can use to maintain reliability in various situations. It provides operators flexibility to respond to potential supply-demand imbalances, which is important with changing system conditions.

3.2.1.4 Infrastructure and Operations and Maintenance (O&M) Expense - The Commission approves recovery of generation (or production) capital expenditures and O&M expenses through the rate case process. MPSC Staff and other parties to a rate case evaluate the utility's projected expenses unless the investments were pre-approved in other proceedings such as the IRP and CON. In reviewing these costs, MPSC Staff and other parties thoroughly

[60] https://www.pjm.com/markets-and-operations/etools/emerg-procedure.aspx.

examine the utility's request by evaluating the reasons for the work, the project scope, the anticipated timeline, and the ability of the utility to complete the work as outlined. In recent years, utilities have invested in various emission control equipment for their coal-fired generation fleet to comply with environmental regulations. These investments include environmental controls as well as routine maintenance and plant upkeep that can affect operating performance, such as boiler maintenance, major turbine overhauls, and inspections of equipment as recommended by the original equipment manufacturer or as required for insurance purposes. It should be noted that consideration of the appropriateness of utility expenditures, including infrastructure capital projects and O&M expenses, as well as the safety and reliability of the generating plant, is an overarching focus of all of MPSC prudence reviews.

3.2.1.5 Review of Fuel Supplies and Purchased Power Arrangements in Power Supply Cost Recovery Proceedings - Utility fuel supply and purchased power contracts are reviewed in power supply cost recovery (PSCR) proceedings according to PA 304 of 1982. Per the statute, utilities are required to file an annual plan describing their expected sources of electric power supply and changes in the cost of power supply anticipated over the projected 12-month period covered by the plan. The description of major contracts includes the price of fuel (or energy and capacity), the duration of the contract, and a description of the terms and provisions. For natural gas fuel supply contracts or arrangements, the description must specify whether the supply contract includes long-term firm natural gas transportation, and if not, an explanation of how the utility proposes to ensure reliable and reasonably priced natural gas fuel supply to its generation facilities for the 12-month period covered by the plan. The plan also includes the utility's evaluation of the reasonableness and prudence of its decisions to provide power supply in the manner described in its plan, in light of its existing sources of electric generation, and an explanation of the actions taken by the utility to minimize its cost of fuel and purchased power to its customers.

After the completion of the plan year, the utility is required to file a power supply cost reconciliation case. This case is filed no later than three months after the plan year ends and is conducted as a contested case in which interested parties are able to review the costs and the actions that resulted in the costs. In reviewing the fuel and purchased power costs of regulated utilities, the MPSC Staff evaluates various factors for reasonableness and prudence, such as:

- Fuel procurement strategies, including the quality, location, and characteristics of the fuel
- Negotiated transportation contracts
- Bilateral purchased power contracts
- Power plant outages
- New or amended purchase power agreements for prudence and reasonable cost effectiveness
- Actions taken due to a weather or supply event that affects power supply costs, such as extreme cold or heat, flooding, fuel disruption, infrastructure failure
- Certain environmental compliance expenditures

At the conclusion of the PSCR plan and reconciliation process, the Commission determines whether the costs are reasonable and prudent for the time period and makes adjustments for cost recovery accordingly.

3.2.2 Transmission

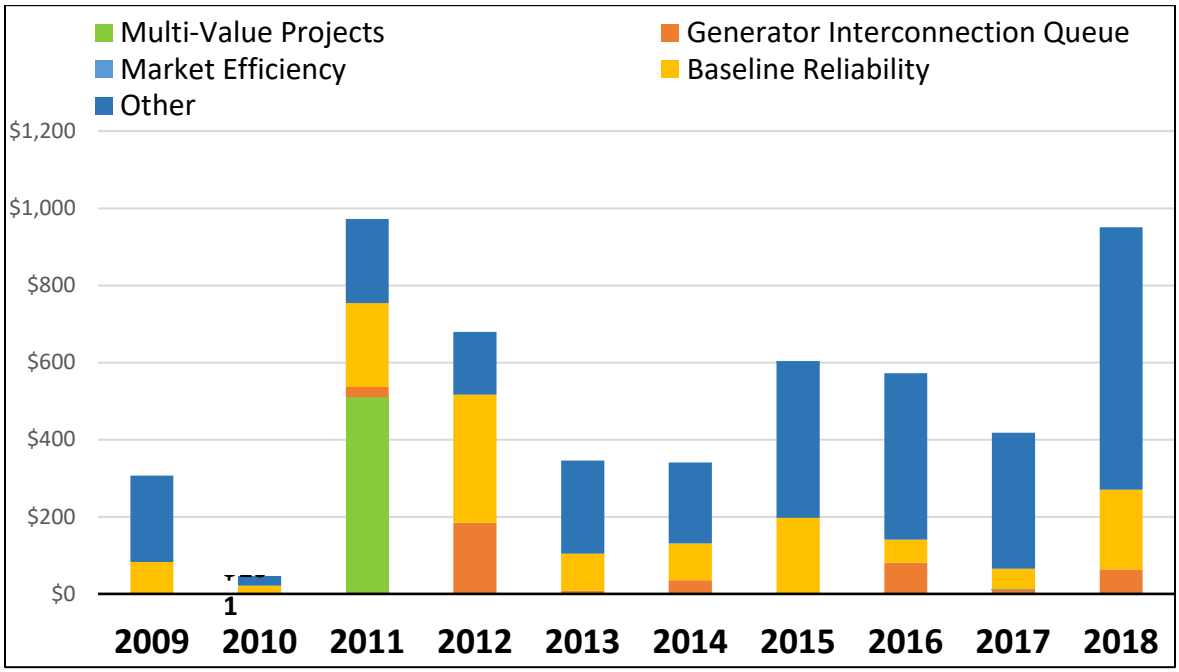
3.2.2.1 Reliability and Economic Planning by Transmission Owners and at RTO level; NERC Planning Criteria and RTO Review Role - MISO and PJM have processes to review and approve transmission projects for both reliability and economic planning. MISO's process is the MISO Transmission Expansion Plan (MTEP) and PJM's is the Regional Transmission Expansion Plan (RTEP).

In MISO, Transmission Owners (TOs) submit projects proposed to resolve reliability or economic issues on their systems to MISO to be analyzed by RTO planners and other utility stakeholders. During the MTEP process, MISO will analyze project proposals and determine whether a project is needed, or whether projects can be combined to achieve other reliability or economic benefits. There are several types of transmission projects that can be approved by the MISO Board of Directors:

- **Baseline Reliability Projects -** that are submitted for the purpose of meeting NERC reliability standards and regional reliability standards.
- **Market Efficiency Projects -** that will derive economic efficiency benefits to one or more market participants such as addressing transmission issues resulting from congestion.
- **Multi-Value Projects –** are proposed as a portfolio of several projects that can address multiple issues such as congestion, reliability, public policy, etc. on a regionwide basis.
- **Other Projects -** are localized projects to meet localized needs that satisfy the TO or state's local criteria. These projects are proposed for reasons that may not be included in NERC or regional reliability standards.

Figure 3-6 outlines the amount of transmission investment in the Michigan portion of MISO (most of the Lower Peninsula and all of the Upper Peninsula) for the last several years by project type.

Figure 3-6 Michigan Historical MTEP-Approved Transmission Investments ($M)



Source: MISO MTEP annual reports

Baseline reliability projects are proposed to resolve violations of NERC transmission planning standard criteria that are found when modeling projected changes to the electric grid over the next five years. All TOs must follow multiple NERC planning criteria ranging from cyber and physical security to facilities design standards and critical infrastructure protection.[61] NERC has specific transmission planning standards that outline transmission system planning performance requirements over a five year period, to be conducted annually, that will ensure reliable operation over a broad spectrum of system conditions and following a wide range of probable contingencies. The standards require both on-peak and off-peak analysis and include steady state, short circuit and stability analyses. The standards require the development of corrective action plans that list system deficiencies resulting from the analyses and the associated actions needed to achieve the required system performance. The NERC transmission planning standards outline certain contingencies where a planned loss of load is allowed, primarily under multiple contingencies occurring at once. However, NERC's transmission

[61] NERC Mandatory Standards Subject to Enforcement: https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States.

planning standard does allow for planned loss of load under certain single contingency events such as a bus section fault or an internal breaker fault on transmission lines that are less than 300 kV.

In addition to the NERC transmission planning standards, TOs each have their own transmission planning criteria that are often more conservative than NERC's transmission standards and are geared toward developing the system in a manner such that a planned loss of load would only be allowable under extreme system conditions, if at all. The TO planning standards also outline items that are not covered thoroughly in NERC standards such as replacement of aging infrastructure.

All planned transmission projects in Michigan, planned for reliability or other purposes such as economics or aging infrastructure replacement, flow into RTO processes like the MTEP and RTEP mentioned above. Both RTOs and TOs are constantly assessing the BES, weighing the need for projects and ensuring compliance with reliability standards. The NERC planning standards, TO planning criteria, and the RTO stakeholder processes are meant to ensure the electric grid is planned to operate under a variety of conditions and stresses, including the loss of a major generator, a summer heat wave, or a polar vortex.

RTO transmission planning could be more robust and incorporate more high impact low probability scenarios into the planning assumptions. RTO planning could examine impacts to the grid under stressful contingency scenarios such as a loss of major gas supply causing gas-fired generation outages during extreme cold temperatures at the same time as a nuclear plant outage. Additionally, long-term planning could consider risks such as cyber-attacks and other impacts that could be broader and more sustained in the changing landscape of the electric grid. The Commission notes there is an opportunity for RTOs to expand scenario planning to encompass high impact, low probability events to enhance awareness for emergency preparedness and inform discussions related to planning criteria.

3.2.2.2 Transmission Siting/Certificate of Public Convenience and Necessity (CPCN) Determinations - Pursuant to PA 30 of 1995, transmission lines longer than five miles and with a voltage of 345 kV or more require a Certificate of Public Convenience and Necessity (CPCN) from the MPSC. Transmission projects under 345 kV do not require MPSC approval but may request it if it is necessary to acquire private property or local ordinances restrict the ability to construct the line. The Commission evaluates the need, costs, and benefits of the line as set forth in a utility's CPCN application through a contested case. The utility must include public comments, potential effects on public health, safety, and the environment, and possible alternate routes in addition to the cost and siting of the lines.

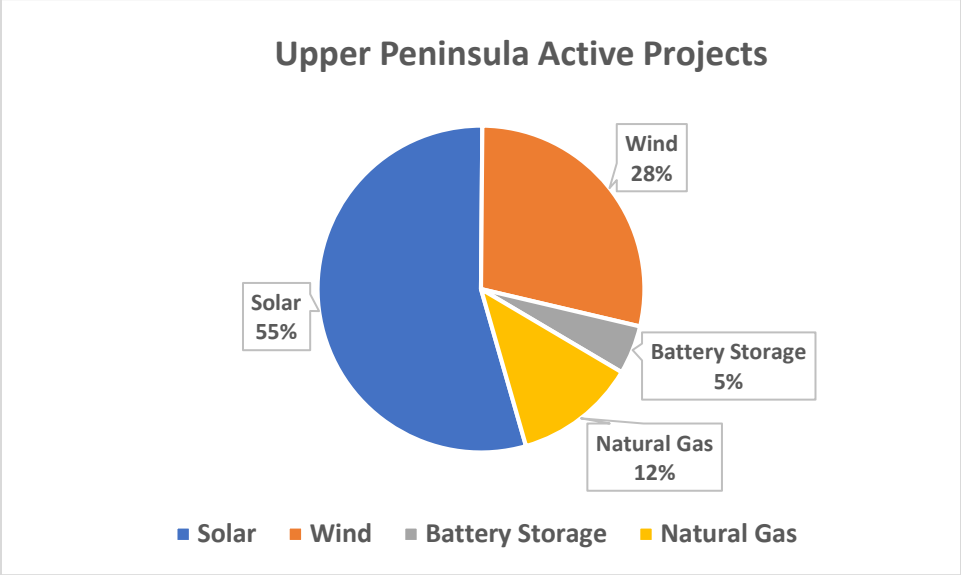
Outside of projects eligible for cost sharing, the MISO process for approving transmission projects between 69 kV and 345 kV is based exclusively upon a review from a reliability perspective rather than a cost perspective. This limited assessment criteria may prevent the consideration of other alternatives such as generation or distribution solutions that could be preferred from a cost, reliability, or resiliency perspective. This is important because transmission projects below 345 kV are not subject to MPSC review and approval under PA 30 of

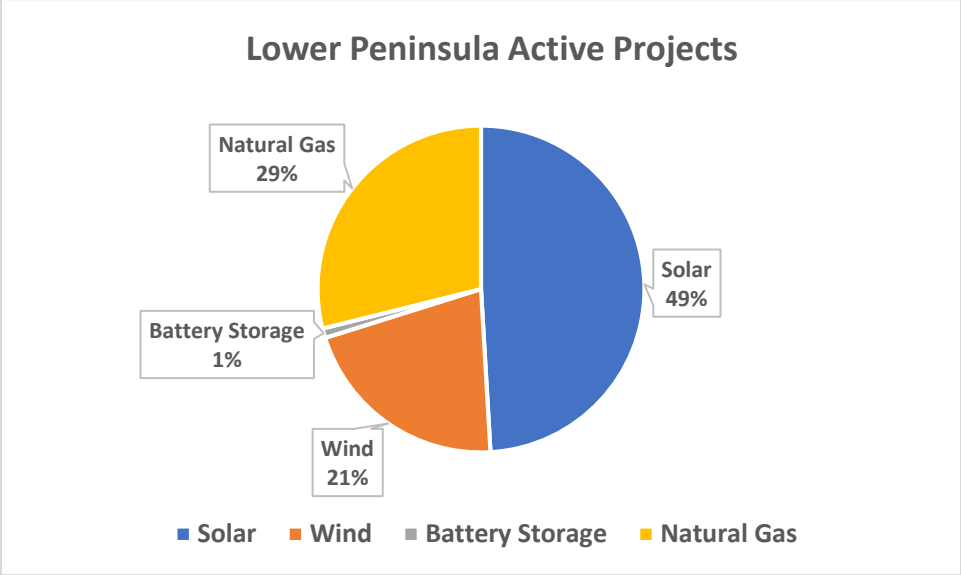
1995. The Commission finds that MISO's process should more carefully consider alternatives to transmission line projects based on cost, reliability, and resiliency prior to approving new transmission.

3.2.2.3 Generator Interconnection - MISO's Generator Interconnection Process (GIP) is the process through which generators can submit requests to be interconnected into the transmission system and MISO examines what the impacts of the project will be on the bulk electric system. Interconnection requests are entered into the Generator Interconnection Queue (GIQ), which is a list of all the projects being studied. The GIP has three Definitive Planning Phases (DPPs) that the generator must go through in order to obtain a Generator Interconnection Agreement (GIA) to interconnect to the transmission system. Additionally, the generator will have to meet two milestones, M1 and M2. For M1, a generator must pay the application fee and pay a DPP study fund deposit.

As of June 2019, there are over 400 MW of active projects in the MISO GIQ in the Upper Peninsula and over 14,000 MW of active projects in the MISO GIQ in the Lower Peninsula. Figure 3-7 identifies the breakdown of active projects in the GIQ by fuel type.

Figure 3-7 Michigan's Active Projects in MISO Generator Interconnection Queue





Source: MISO interconnection queue, June 2019

After the DPP is completed, the generator will sign a GIA with the Transmission Owner to interconnect to the grid and file the GIA with FERC for approval. Many of the projects in the interconnection queue are competing with each other and do not complete the GIQ process. Historically, only a relatively small percentage of generation in the queue at any given time completes the process and interconnects to the system.

The timeline of the GIP is a constraint for generators. From the request to the signing of a GIA, the process takes over 500 days. Stakeholders have raised the concern that the process should be more efficient for generation projects to get interconnected to the transmission grid. MISO has been working with stakeholders to improve the GIQ process and has made several

filings at FERC. PJM's queue has also experienced significant delays and can have impacts with generation interconnections for zone 7.

Despite repeated efforts to improve the process, the MISO generator interconnection queue is cumbersome and cannot keep pace with the level of change in the industry, with generation retiring at an accelerated rate and need to assess/model the best locations for replacement generation from a system reliability perspective. The Commission finds the MISO generator interconnection queue process should be revised to facilitate the timely progression of projects through the process. This enhancement is necessary to ensure safe and reliable electric and natural gas service to customers as it would not only improve system reliability but better reflect the rapid pace of change as the generation mix rapidly evolves. Broader, long-term regional transmission planning is also essential to ensure cost-effective, reliable delivery of power and flexibility to accommodate the changing energy resource mix.

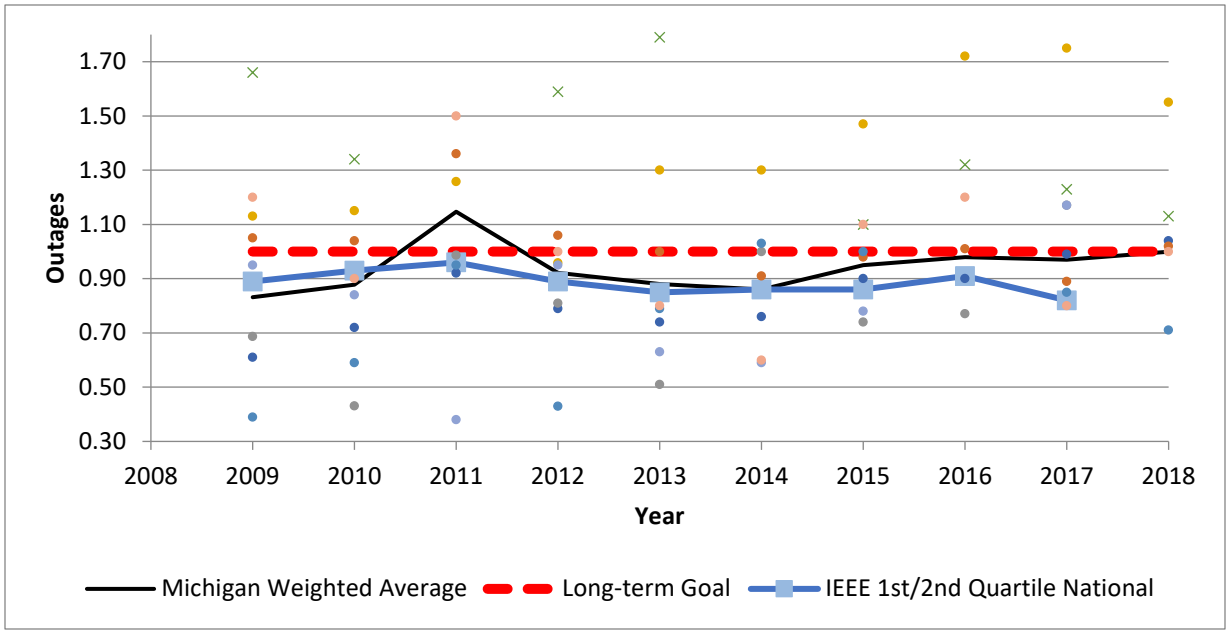
.3.2.3 Distribution

3.2.3.1 Five-year Infrastructure and Maintenance Plans – Over the past several years, efforts to improve electric reliability have been a focus and priority of the MPSC. Damage caused by trees falling on distribution facilities or distribution equipment failures are the top reasons customers experience power outages (outages due to lack of supply are far less common). In 2013 then-Governor Snyder announced reliability goals to reduce the frequency and duration of electric outages (i.e., for Michigan utilities to operate in the first quartile of peers for SAIFI and in the top half among peers for SAIDI). Meeting these goals means the average customer would experience about one power outage per year and the average outage would last about three to four hours.

Figure 3-8 and Figure 3-9 show the average number of power outages per customer (SAIFI) and average duration (SAIDI) for Michigan investor-owned utilities from 2009 through 2018. The data points illustrate the range of individual utility results, compared to the weighted average for all utilities (solid line). This data includes major event days, the more significant outages customers experience, even though the goal contemplated removing such events for benchmarking purposes. With or without including major events, the data shows Michigan has room for improvement, particularly in reducing how long outages last. Michigan has routinely fallen into the fourth quartile in outage duration over the last decade in national reliability benchmarking.[62] With respect to the frequency of outages (SAIFI), Michigan ranks in the second quartile nationally.[63]

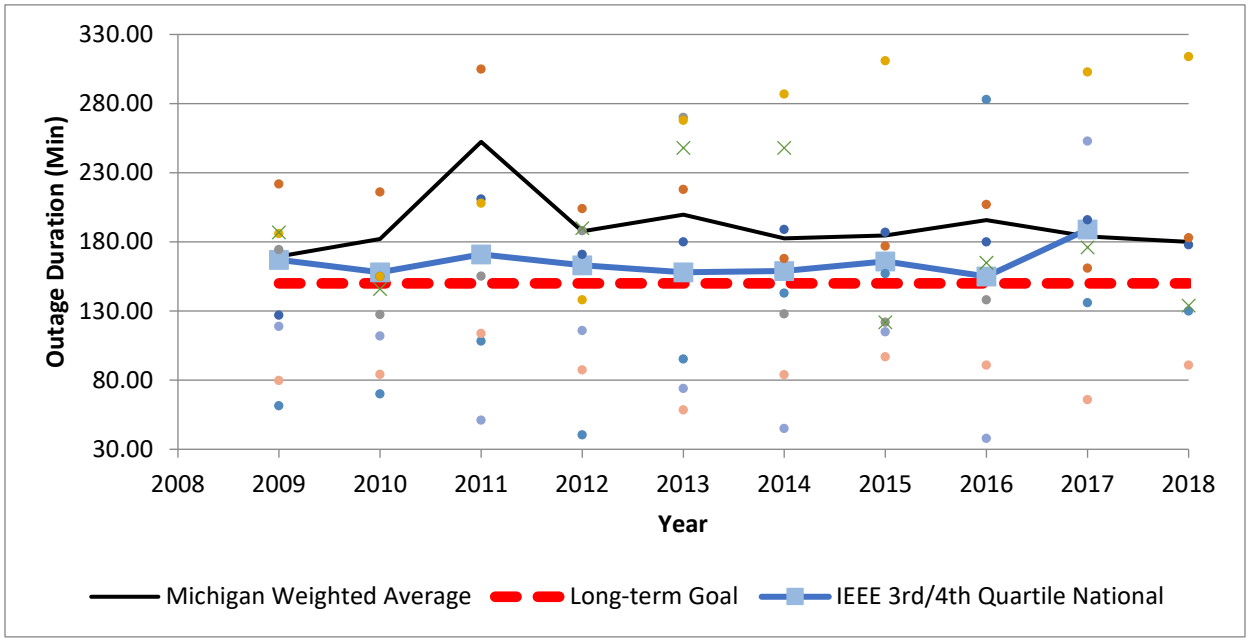
[62] http://grouper.ieee.org/groups/td/dist/sd/doc/Benchmarking-Results-2017.pdf.
[63] http://grouper.ieee.org/groups/td/dist/sd/doc/Benchmarking-Results-2017.pdf.

Figure 3-8 Average Number of Annual Customer Outages Excluding Major Events (SAIFI)



Source: MPSC Commission dockets U-16065, U-16066, U-12270, 2017 IEEE Distribution Reliability Benchmarking Results

Figure 3-9 Average Duration of Annual Customer Outages Excluding Major Events (SAIDI)



Source: MPSC Commission dockets U-16065, U-16066, U-12270, 2017 IEEE Distribution Reliability Benchmarking Results

The SAIDI and SAIFI improvement goals proved to be problematic without significant investment by utilities, as much of Michigan's distribution system assets are near or beyond design lives. Due to the significant investment in distribution assets and the need for more

transparency outside the rigid timeline of a rate case process, the Commission requires the three largest IOUs in the state, DTE Electric Company, Consumers Energy Company and Indiana Michigan Power Company,[64] to file multi-year electric distribution plans to improve reliability by mitigating the greatest causes of distribution outages related to trees and vegetation, weather, and equipment failure, generally in that order.

The leading cause of customer outages and interruptions is tree-related in the transmission[65] and distribution systems. The Commission emphasizes the importance of regular tree trimming and vegetation management cycles.[66] The MPSC's utility line clearance provisions,[67] within the Technical Standards for Electric Service, require vegetation management practices incorporating industry best practices and adherence to the national electric safety code standards.[68] The national electric safety code requires vegetation management practices "as experience has shown to be necessary" demonstrating that the utility needs to know the history and characteristics of the system in order to apply the appropriate frequency and specifications to the vegetation management program. Both sources support the requirement for utility vegetation management programs yet provide flexibility to consider the various unique characteristics within the electric distribution system.

The utilities' distribution plans address vegetation management schedules along with plans to harden the system against weather related outages and equipment failure due to age and wildlife. Much of these hardening measures mitigate outages not just from trees but also for many weather-related events. For example, replacing rotted poles and cross-members provide rigidity against failure due to trees falling on poles but also from excessive ice build-up on conductors resulting in pole failure. Certain equipment failure or replacement in advance of life expectancy is inevitable due to premature failure of the equipment or being operated in areas with load growth beyond expectations. Therefore, the five-year distribution plans provide visibility into the utilities long term solutions to address potential issues, growth and mechanisms to improve reliability (and thereby lower SAIDI and SAIFI metrics).

Before any private, investor-owned utility can include increased O&M and/or capital expenses in rates, the utility must apply for increased rates through a contested rate case which is subject to review by MPSC Staff and other parties. For the past decade, Michigan utilities have included millions of dollars for tree trimming expenses in rate case filings and the

[64] MPSC Case No. U-20147 and its November 21, 2018 Order (November 21 Order).
[65] https://www.ferc.gov/industries/electric/indus-act/reliability/vegetation-mgt.asp.
[66] https://www.ferc.gov/industries/electric/indus-act/reliability/vegetation-mgt.asp.
[67] Rule 460.3505 entitled "Utility line clearance program."
[68] Incorporated by reference in Rule 460.813 entitled "Standards of good practice; adoption by reference."

Commission has increased tree trimming expenses for utilities that have followed through on tree trimming activities. The MPSC reviews the application in the case and all contested filings to ensure the investments are prudent and reasonable prior to allowing the utility to increase rates.

Figure 3-10 provides the authorized and actual tree trim expenses for DTE Electric and Consumers Energy Electric from 2015-2018.

Figure 3-10 Authorized vs Actual Tree Trim Expenses for DTE and CE for 2015-2018

DTE Electric		
Year	**Authorized**	**Actual**
2015	$58.2M	$64.7 M
2016	$65.7 M	$74.2 M
2017	$75.2 M	$84.3 M
2018	$83.8 M	$89.1 M

Consumers Energy		
Year	**Authorized**	**Actual**
2015	$48.5 M	$37 M
2016	$48.5 M	$50.8 M
2017	$51.8 M	$49.8 M
2018	$51.8 M	$52.7 M

Source: MPSC

Note: Authorized tree trim amounts in a given year may have changed due to an approved rate case in the middle of the year. In these instances, the highest authorized amount for the year is displayed.

3.3 Risk Assessment

3.3.1 Infrastructure

3.3.1.1 Asset Conditions and Performance – Extreme weather can have severe and widespread effects on the operation of the electric system; catastrophic storms (>10% of customers interrupted, or a state of emergency declared) are responsible for nearly all recent widespread customer interruptions reported by the utilities. Although extreme cold temperatures, such as those experienced during the PV19, are often of greater concern for the safety of residents, most significant system outages are due to extreme wind and/or ice. These weather conditions put additional strain on utility distribution lines, and can cause poles to break, lines to sag (leading to contact between conductors and a potential short circuit) or cause a tree to fall on the equipment. Utilities identified tree trimming and line clearance programs as critical to mitigate this issue along with applying the NESC design and installation minimum requirements. Figure 3-11 includes statistics on major storms impacting the Lower Peninsula over the past several years.

The five-year electric distribution plans submitted to the MPSC by Consumers Energy, DTE Electric and Indiana Michigan Power illustrated the age and condition of Michigan's electric

distribution systems. As outlined in these reports the infrastructure built to facilitate the rapid population growth in Michigan from 1940-1980 is now reaching the end of its design life. A majority of the buildout of poles, underground wires, switchgear, and circuit breakers placed in service during this growth have been in service over 50 years and are beyond their design life.

Figure 3-11 Lower Peninsula Major Storm Statistics 2013-2019

Date	*Storm Type*	*Customers Interrupted**	*Storm Duration (Days)***	*Storm Restoration (Days)***
11/17/2013	**Wind Storm**	**719,854**	**5.5**	**6**
12/21/2013	**Ice Storm**	**388,950**	**8**	**6.9**
09/05/2014	**Wind Storm**	**414,699**	**7**	**7.2**
12/24/2015	**Wind Storm**	**181,627**	**4**	**4.2**
03/07/2017	**Wind Storm**	**1,103,539**	**7**	**7.1**
07/06/2017	**Wind Storm**	**181,620**	**4**	**4.2**
04/15/2018	**Ice Storm**	**288,976**	**5**	**5.3**
05/04/2018	**Wind Storm**	**254,867**	**4**	**4.5**
08/26/2018	**Wind Storm**	**255,763**	**7**	**6.9**
02/06/2019	**Ice Storm**	**231,891**	**4**	**5**
07/19/2019* **	**Wind Storm**	**825,505**	**3**	**5.0**

* Number of customers interrupted are cumulative when more than one utility reported the same storm.
** Storm duration and storm restoration are reflected as an average when more than one utility reported the same storm.
*** Preliminary numbers at the time of this report.
Source: MPSC

Although exceeding the design life does not necessarily mean failure is imminent, this equipment is at an increased risk of failure that could affect public or worker safety or service to customers. While service to customers can sometimes be fed from another area and actual outages limited or avoided in the case of equipment failures, this is not always the case. For example, aging switchgear equipment at the Apache Substation near Troy, Michigan led to outage of 34 hours for nearly 9,500 customers served by the substation. Mobile generators, portable substations, and the creation of overhead jumping points were used to restore electric service prior to the completion of substation repairs. These emergency assets and procedures provide tools that a utility can leverage to minimize customers impacts during an unanticipated equipment failure. Given the significant customer impact of a substation outage, aging equipment within substations is considered high priority when planning future work. Other low impact assets such as secondary transformers impact fewer customers and can be replaced quickly and are replaced reactively rather than proactively. Customer impact is an important component of the risk models used to prioritize investments.

Aging infrastructure can be susceptible to safety and reliability issues. The 4.8 kV ungrounded system owned and operated by DTE Electric was the first part of the electric

distribution system built in the early 1900s. The 4.8 kV system provides reliable service, but under specific abnormal conditions there may be risks to public safety.

Single-phased downed wires on the ungrounded 4.8 kV system may remain energized since single-phased downed wires may not produce fault currents large enough to engage protective devices (fuses, reclosers, breakers) on the circuit. To improve safety, DTE Electric is piloting a 4.8 kV ground alarm system at some substations which will alert the control room when a live down wire occurs, thereby expediting the response and remediation efforts. This will limit the public's exposure to a potentially dangerous situation.

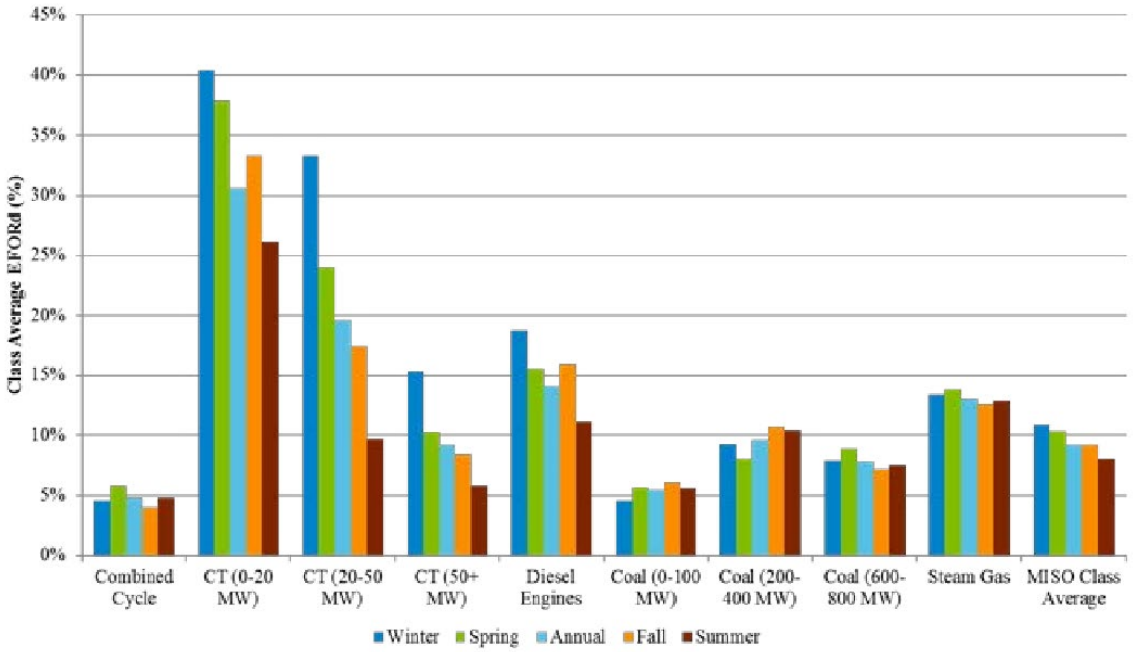
In Detroit and some surrounding communities, the electric distribution system was originally constructed through alleyway easements at the rear of the customer's property, which is known as rear-lot construction. Approximately 80% of the 4.8 kV circuit miles in the City of Detroit are rear-lot construction in alleys no longer maintained by the City, making truck and foot access problematic. Some property owners have extended buildings and fences into the right-of-way, while other parts of the alleys have become extremely overgrown with vegetation and trees and/or littered with garbage and construction debris. These conditions are significant impediments to the operations, maintenance, and restoration work on the DTE electric distribution system.

DTE has established a 4.8 kV System Hardening Program and is beginning a long-term 4.8 kV Conversion and Consolidation Program. The 4.8 kV Hardening Program is designed to improve safety and reliability by strengthening circuit infrastructure before the 4.8 kV circuits are converted. The 4.8 kV Conversion and Consolidation Program will systematically convert aging 4.8 kV circuits to modern 13.2 kV circuits to serve customers in a more reliable and efficient manner. In addition, DTE has begun a tree trimming surge program to reduce tree related hazards, extend right-of-way clearances and improve reliability on a five-year average tree trim cycle. All of these efforts will improve public safety and overall system reliability for DTE customers.

As discussed elsewhere in this report, Michigan's electric generation fleet is also aging and being replaced with new sources of electricity such as natural gas and renewable energy. Outage rates for power plants vary by season, fuel type, and condition of the facility with age and preventative maintenance being important factors. It is not unusual for older power plants to have higher outage rates, particularly given that Michigan utilities have limited expenditures at soon-to-be retiring plants.

A failure at a generating unit that causes it to shut down is called a forced outage. Forced outage rate is the percentage of time that a unit is not in service due to unplanned outages. During normal weather conditions, different types of generating units experience varying levels of forced outage rates. Figure 3-12 depicts the five-year seasonal and annual forced outage rates by generator fuel type in the MISO region during all weather conditions. For example, the figure shows coal plants have forced outage rates between 5% and 10% while very small gas-fired combustion turbines have rates ranging from 10% to 40% depending on season and size.

Figure 3-12 Five-Year Seasonal/Annual EFORd* for MISO from Generator Availability Data System



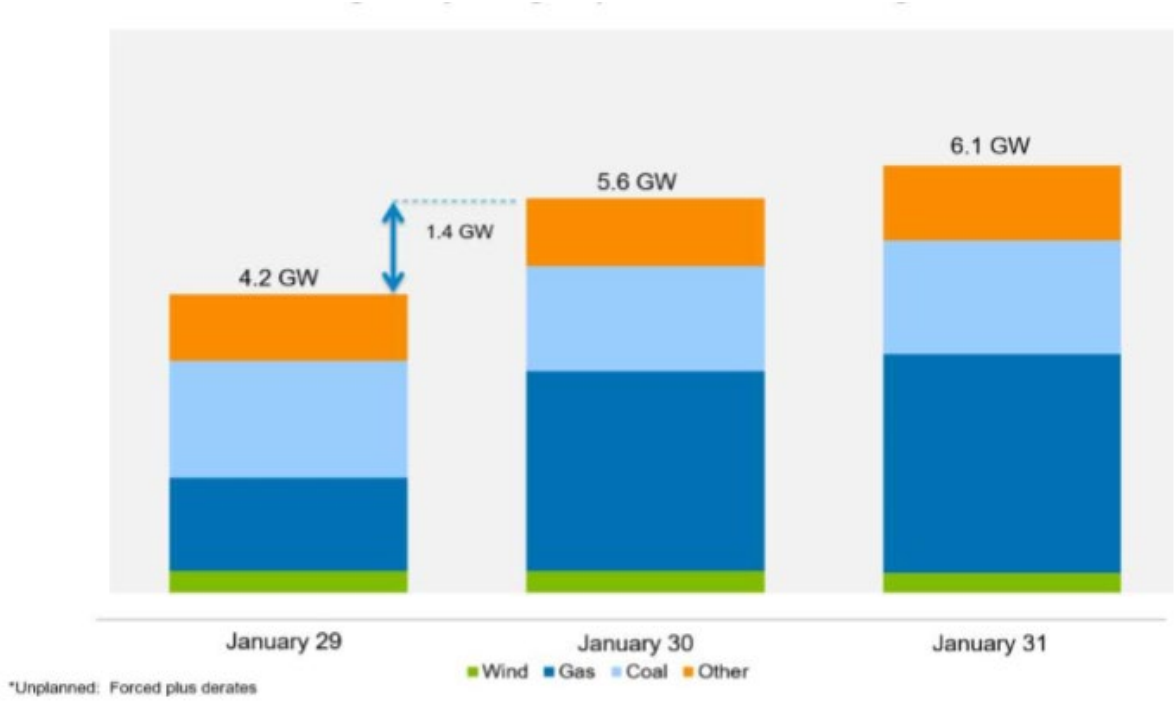
Source: MISO RAN Whitepaper, https://cdn.misoenergy.org/20180405%20RSC%20Item%2007%20RAN%20Issues%20Statement%20White%20Paper164746.pdf

*EFORd is the expected forced outage rate for demand, or a measure of unplanned outages.

Extreme weather events can significantly impact the availability of generation and lead to forced outages. Cold weather, in particular, can cause specific generation issues; components freeze, which leads to mechanical issues, and ultimately fuel supply issues. Natural gas fuel supplies can become scarce during extremely cold weather as fuel that would have otherwise been used for electricity generation is prioritized for heating. Figure 3-13 characterizes the unplanned outages in Michigan during PV19 and shows that the number of unplanned outages increased across most generation sources the longer the cold weather lasted.

In some cases, these unplanned or forced outages prompt the RTO to deploy emergency generating units. The deployment of emergency generating units introduces certain elements of complexity. First, some generating units permitted by the Department of Environment, Great Lakes and Energy (EGLE) may only be used in emergency situations because of air permit constraints or limitations. Second, there are also concerns with the high civil penalties that utilities are subject to for failure to comply with air quality standard requirements for emergency generating units. During electric generation emergencies, the gas-fired electric generator operations may be impacted by other state permit requirements. To improve safety and reliability during energy emergencies, the Commission proposes to discuss with EGLE coordination issues, including scenarios where an electric generator is reaching air emission limitations at the same time an electric emergency declaration by the RTO requires all generators to maximize output.

Figure 3-13 MISO Michigan Daily Average Unplanned Generation Outages



Source: MISO

As of June 2017, MISO had close to 17 gigawatts of wind capacity in its footprint with more coming online every year.[69] In order to prevent damage to wind generators, controls are in place to cut off generation in the event of high winds and extreme cold (generally below negative 20 degrees Fahrenheit). During PV19, approximately 25% of MISO's generating fleet (including, coal, natural gas and wind) was forced out of operation due to the cold, primarily in the northwestern part of the MISO footprint. On the morning of January 29, 2019 approximately 11.4 GW of wind was being generated, but as the day went on and temperatures decreased, wind generation cut off and the output decreased to just 550 MW.[70] Further exacerbating the event, while the wind production fell unexpectedly, thermal generation was unable to ramp up quickly enough to meet the demand as the extreme temperatures caused equipment freeze-offs which required manual thawing with secondary heaters prior to equipment start-up.

Many of Michigan's wind turbines are equipped with cold weather packages that include specially formulated oils, software packages and anti-icing treatments for blades. Operators of thermal units have cold weather protocols that include secondary heaters for thawing frozen components, regular turning of coal piles, and pre-firing of idle generation prior to cold weather events. With appropriate forecasting of temperatures and anticipated load, the impact of events such as PV19 can be greatly reduced. The Commission recommends electric generators continue to provide the RTO with all generator operating characteristics and to incorporate measures to improve generator startup performance when emergency units are called upon**.**

3.3.1.2 Visibility and Controls (e.g., Supervisory Control and Data Acquisition (SCADA)) - Technology offers a variety of potential visibility and control benefits that can affect reliability and resiliency of electricity. Some of these technologies such as ADMS and AMI have been described previously in the report. SCADA is a software system designed to improve system automation that allows each utility to have a "birds eye view" of their system and allows for control processes locally or remotely utilizing this software in order to monitor, gather and process real time data. Utilities in Michigan are in the process of deploying SCADA on additional equipment, such as distribution substations. As with any other software, it can be vulnerable to cyberattacks and is usually part of each utility's Critical Infrastructure Protection plans as discussed Chapter 6 of this report.

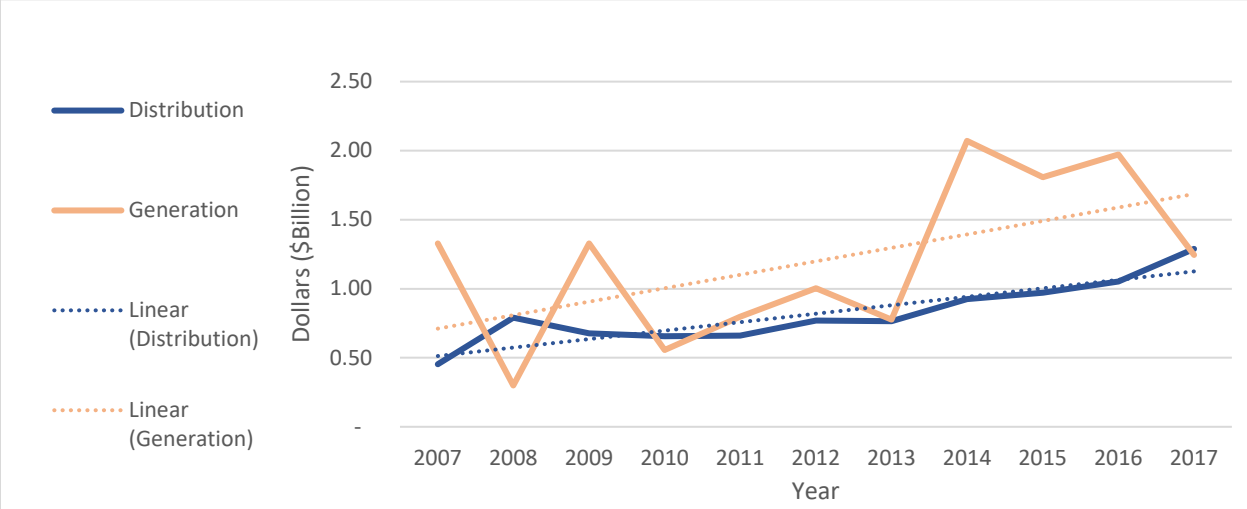
[69] https://cdn.misoenergy.org/2018%20Wind%20Capacity%20Report97278.pdf.
[70] https://www.eenews.net/stories/1060122535.

3.3.2 Investment Trends and Projections

3.3.2.1 Capital Investments

Historical Investments by Type - Figure 3-14[71] represents historical capital expenditures from 2007-2017 for the four largest investor-owned utilities in the state (Consumers Energy, DTE Electric, Indiana Michigan Power and Upper Peninsula Power Company). Capital expenditures is a broad category that includes spending by utilities on fixed assets such as land, plant equipment, or buildings and equipment housing. To provide more detail, Figure 3-14 is broken out in capital expenditures for generation and distribution. The total for these two categories is approximately $2.5B annually. In addition, transmission investments in Michigan have been approximately $8.4B since 2006, or about $419M per year.[72] Thus, electric system investments for generation and distribution in the state are on the order of $3B per year. Overall, capital expenditures have increased substantially over the past 10 years driven by the need to replace aging infrastructure and to comply with new standards and environmental control requirements. This has included a recent effort for utilities in the state to modernize their distribution grids by adopting technology such as advanced metering infrastructure to help improve the responsiveness and performance of the grid.

Figure 3-14 2007-2017 Aggregated Capital Expenditures for Investor-Owned Utilities



Source: P-521 annual reports

Note transmission capital expenditures not reflected.

[71] Information compiled from P-521 annual reports.

[72] Data extracted from MISO MTEP and PJM RTEP annual reports.

Projected Investments by Type - Capital investments in electric infrastructure have increased since 2007, and that trend is expected to continue. While specific expenditures are still subject to approval by the MPSC, the electric distribution plans for Consumers Energy and DTE collectively identified approximately $1.6B per year over the next five years to address aging distribution infrastructure and modernize the grid.[73] Reliability improvements and investments that increased safety and system resilience were areas of emphasis in these plans. In addition, these two utilities have identified approximately $3.5B total from 2019 to 2023 in new generation investments[74] (e.g., wind, solar, natural gas). Transmission companies serving the state have (ITC, ATC, AEP, and Wolverine) also have numerous transmission projects being reviewed through the RTO transmission planning processes.

Investments necessary to ensure safe and reliable operation of the electric system are reviewed by the MPSC in a rate case proceeding for regulated utilities. Utilities can use projected costs and revenues for rate requests, thereby avoiding regulatory lag that may otherwise occur through the regulatory process. Given the cost of new technology and the need to prioritize investments for the benefit of customers and keeping rates affordable, the Commission has required cost-benefit analyses for specific investments such as AMI as well as distribution planning as discussed above. Moreover, pursuant to a recent order in Case No. U-20134, Consumers Energy will hold workgroup sessions with interested stakeholders on performance-based ratemaking and the Commission will continue to evaluate this alternative to traditional cost-of-service ratemaking.[75]

3.3.2.2 Operations and Maintenance - O&M spending for distribution operations has followed a similar increasing trend statewide, with multiple utilities significantly scaling up tree trimming expenses to improve reliability. Tree trimming and line clearance programs were identified by utilities as the most critical O&M program to improve system performance during extreme weather. Preventative maintenance and establishing mutual aid coordination activities were also identified as critical areas to improve system performance.

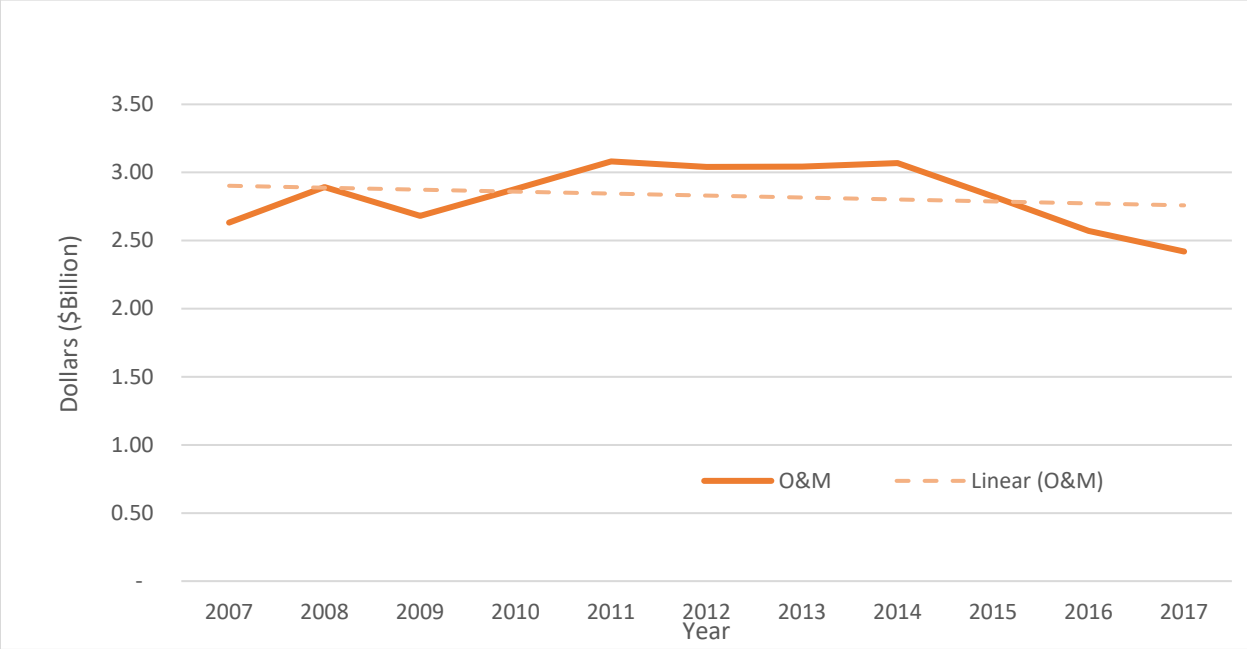
[73] MPSC Case No. U-20147 - https://mi-psc.force.com/s/case/500t0000009gHerAAE/in-the-matter-on-the-commissions-own-motion-to-open-a-docket-for-certain-regulated-electric-utilities-to-file-their-fiveyear-distribution-investment-and-maintenance-plans-and-for-other-related-uncontested-matters.

[74] Consumers Energy 2018 Annual Report https://s2.q4cdn.com/027997281/files/doc_financials/annual_reports/2018/FINAL_AnnualReport2018_Full_web-ready.pdf.

[75] Performance Based Ratemaking report- https://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406274--,00.html.

Electric generation O&M expenditures, on the other hand, have followed a slightly decreasing trend over the past 10-years due in-part to the declining baseload generation and retirement of coal plants. Programs such as energy efficiency, energy waste reduction, and demand response are also recognized programs aimed to reduce the need for added generation, therefore decreasing the O&M generation expenses.

Figure 3-15 2007-2017 Aggregated Generation O&M Expenditures for Investor-Owned Utilities



Source: P-521 annual reports

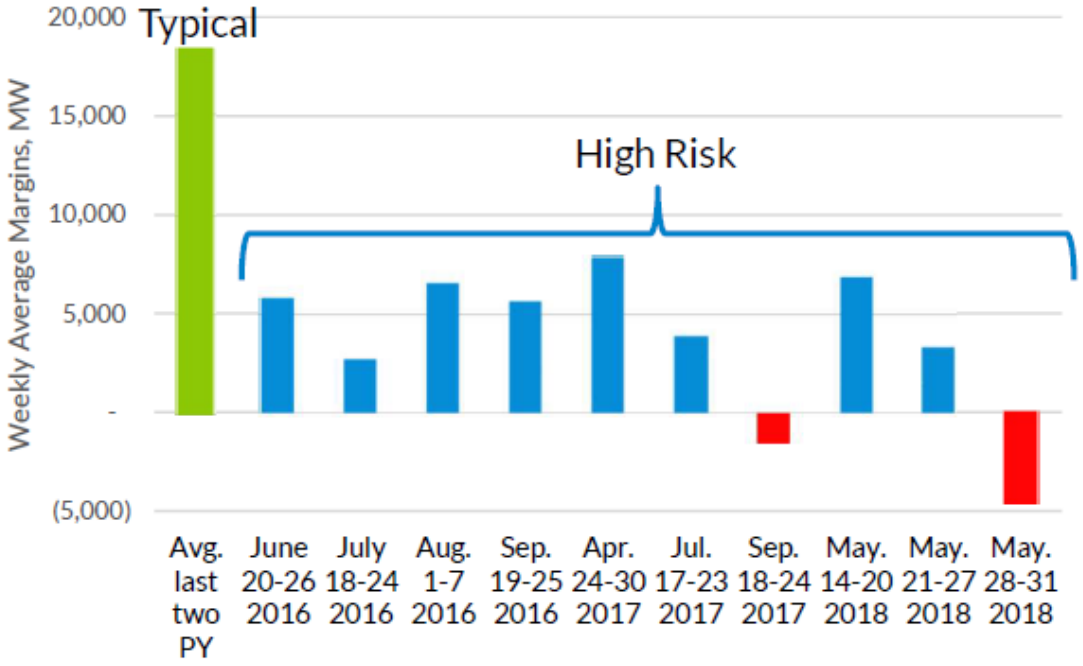
Regarding electric generation, one emerging issue for utility O&M planning is the shrinking of the traditional "shoulder months" particularly, the months of May and September. The spring and fall have historically been the months where most utility maintenance work has been scheduled. Maintenance work that requires outages is usually scheduled in these months due to historically lower demand, allowing for the grid to operate at less than full capacity and still serve the load. However, with increasing extreme weather in these shoulder months, some utilities have shortened the length of time available for maintenance, or shifted from fall to spring maintenance, and MISO has filed with FERC to allow it to incentivize utilities to plan their outages out further in time to allow for improved coordination of planned outages. The charts

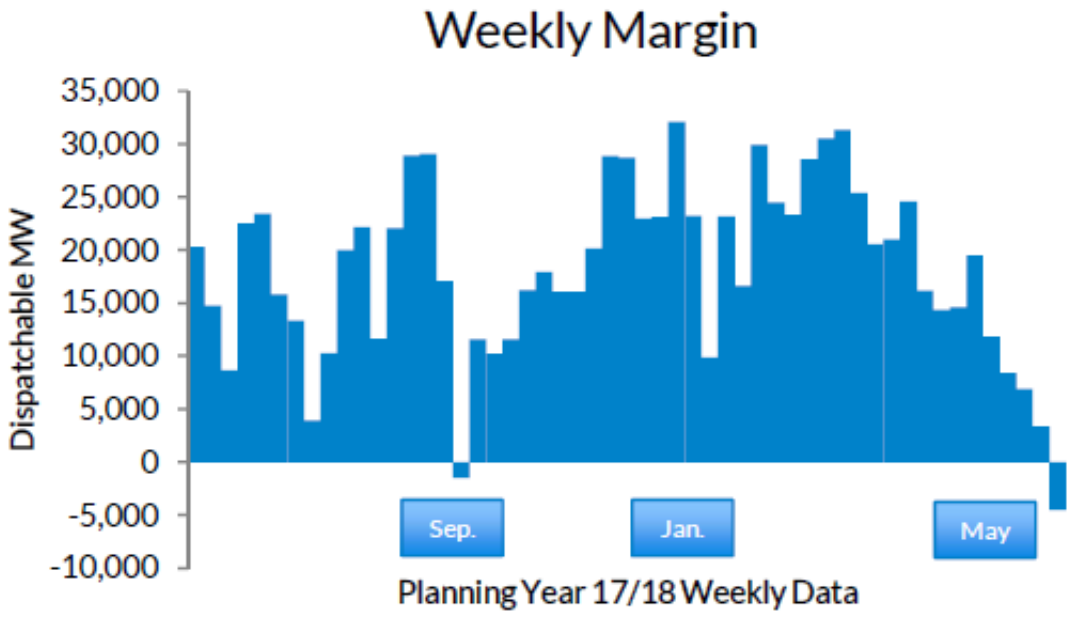
in Figure 3-16 show decreasing weekly margins, or a reduced amount of resources available to meet customer demand, in the MISO region. The dates shown with negative weekly margins in September 2017 and May 2018 correspond with maximum generation events occurring in MISO.[76] When margins are reduced, capacity that is typically only accessed during emergencies such as most DR, happens more frequently. This figure also illustrates that tight operating conditions were occurring in the spring and fall shoulder months, during periods when generating units are typically taken out of service for planned maintenance.

The PV19 event provided the most recent example of an energy emergency occurring during the winter rather that the more traditional summer peak. As the percentage of natural gas fueled electric generation increases throughout the region and other changes to the fuel mix take place that affect operating conditions by season or time of day, the RTO capacity construct must evolve. In the near term, the Commission finds that RTO capacity requirements should provide a seasonal capacity construct at the regional level to better account for different resource characteristics in the capacity accreditation process and to ensure safe and reliable electric and natural gas service to customers during all seasons.

[76] Maximum generation events in MISO occur during times when there are not enough available resources to meet customer demand plus reserve margin. Emergency operating procedures are utilized during maximum generation events.

Figure 3-16 Decreasing Weekly Margins in MISO Region





Source: MISO, https://cdn.misoenergy.org/20181116%20RAN%20Workshop%20Presentation293288.pdf

3.3.2.3 Clean Energy Requirements and Drivers - PA 342 of 2016 increases the required levels of renewable energy as part of a utility's supply portfolio from 10% in 2015 to 15% by 2021. The law also defined a new goal that by 2025, the state would meet 35% of electrical energy needs through renewable energy (RE) and avoided MWhs from energy waste reduction (EWR)[77]. Even before the enactment of this law, there has been a fundamental shift in the generation profiles of major utilities in the state. Consumers, DTE, and UPPCO have all filed integrated resource plans before the Commission with proposals to add significant levels of renewable energy and EWR,[78] in amounts exceeding the requirements of PA 342. Participation by customers in voluntary green pricing programs established pursuant to PA 342 have also driven the shift to renewable energy with customers electing to purchase up to 100% of their electricity from renewable energy resources.

Demand response (DR) resources are another resource option that has become a larger portion of the state's resource portfolio. Energy providers use DR to offset their peak load, either by directly reducing their peak load forecast or by offering it as a resource in the market. Certain types of DR are considered to be load modifying resources in the MISO market and are resources that MISO does not normally rely on to meet load, except in times of capacity shortage to maintain reliability.[79] The amount of DR in the MISO market is growing, which means that energy providers are relying more heavily on resources that are only available during an emergency (MISO must declare a maximum generation emergency in order to dispatch its LMRs). Thus, it is expected that additional emergency events or alerts will be declared given: 1) the increased reliance on DR to meet capacity requirements (in lieu of building more power plants), and 2) the order in which LMRs are called upon in the MISO operating procedures. Some LMRs are only available seasonally, such as interruptible air conditioning load, and MISO has not had testing requirements for DR in its footprint. MISO is working to address these issues through its resource availability and need process and has already made initial filings at FERC. MISO is continuing to study and recommend improvements through its stakeholder process.

[77] As of 2017, the combined RE and EWR contribution to meeting Michigan's electric needs is 19.9% towards the 35% goal.

[78] PA 342 included several provisions to promote additional investment in EWR. For example, it lifted the cost cap on EWR that may have otherwise restricted additional investments in EWR over the long term and the law increased the available financial incentive for utilities exceeding the EWR requirement.

[79] https://cdn.misoenergy.org/20180531%20RSC%20Item%2009%20LMR%20Issues%20Whitepaper206830.pdf.

3.3.2.4 Potential Impacts of Investments and Timing of Recovery on Reliability, Operations, and Energy Supply and Delivery Risks - By law, the rate recovery process allows utilities to file annual rate cases based upon projected expenditures, and to receive a final order within 10 months. Laws also provide for pre-approval of investments made within the first three years of an approved IRP, as well as generation facilities for which a CON is granted as discussed above. Under this regulatory construct and the regularity of utility rate cases before the MPSC, the cost recovery process does not appear to hinder the ability of utilities to make generation or distribution investments to improve reliability, although project costs are not always approved if there is inadequate justification or they are not determined to be reasonable or prudent. Transmission investments are recovered by FERC-jurisdictional transmission companies using formula rates with projected test years; this serves to promote investments in transmission reliability, rather than deter or delay needed investments.

Delays in investments have occurred with the local siting of some renewable energy resources, particularly wind, as some communities are creating zoning restrictions to limit the development.

3.3.3 Adequacy of MPSC Rules and Related to Customer Safety, Reliability, and Resilience; Customer Notification

Michigan last updated its electric reliability performance targets nearly 20 years ago. A recent Staff-conducted survey[80] of other state reliability metrics revealed that while most states required traditional metrics describing the frequency of outages on the system (SAIFI), the duration of outages on the system (SAIDI), and the duration of outages for a typical customer (CAIDI), there were no consistent requirements among states. Regardless of nationwide uniformity in reporting requirements, the Michigan performance targets need to be updated. The MPSC's electric service quality and reliability rules have not been updated recently and could be modified to enhance safety, reliability, and resiliency of the distribution system. The rules address actions to prevent power outages and system restoration. The Commission recommends opening a docket to establish a workgroup to investigate and provide recommendations for updating the Service Quality and Reliability rules and the Technical

[80] Staff conducted a ten-state study and researched the best practices regarding customer safety, reliability, resilience and customer notifications. Currently, the MPSC has detailed standards regarding: how quickly utilities must restore power to their customers, how quickly each utility must relieve first responders that are guarding downed live wires; customer service credits for repetitive outages; and detailed language regarding reportable catastrophic versus normal weather conditions. Examples of areas for improvement include: annual reliability report; reduce the length of time for acceptable customer call answer time; automatic service credits; and reduction in annual same circuit repetitive interruption.

Standards for Electric Service using lessons learned in Michigan and best practices in other states as a guide**.**

3.4 Vulnerabilities

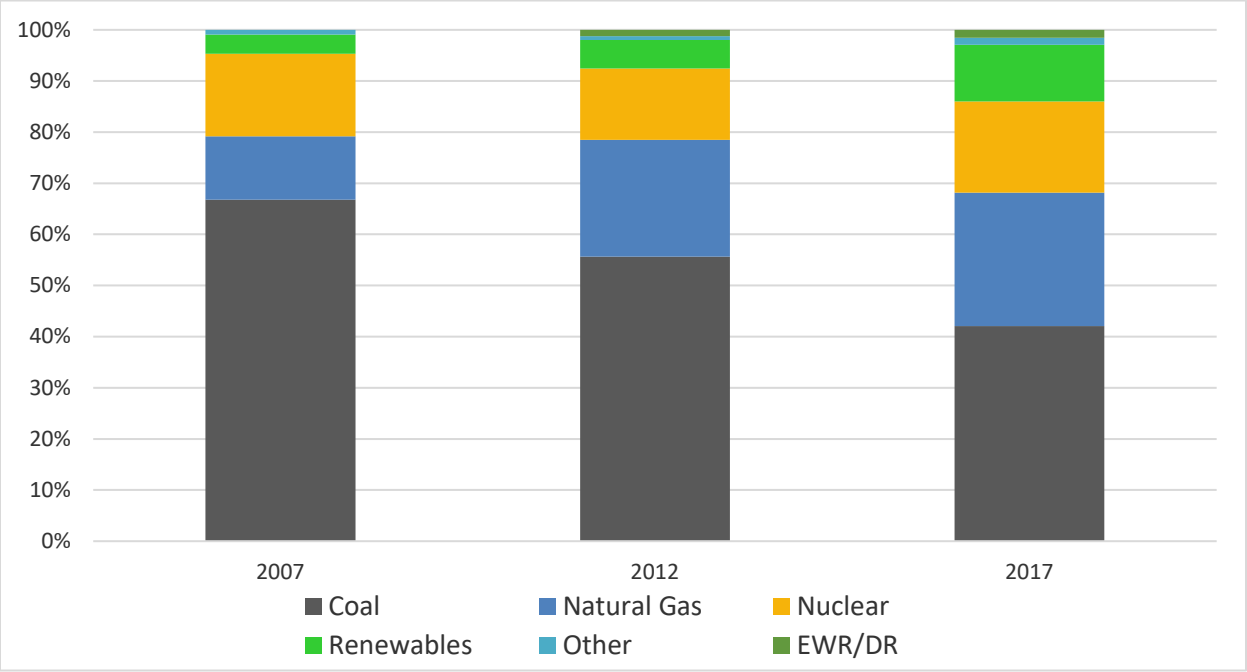
3.4.1 Aging Distribution Infrastructure

Utility risk-based planning models and, in turn, five-year electric distribution plans identified aging distribution infrastructure as one of the leading reliability and safety risks to the electric system, second to poor vegetation management practices. The aging infrastructure may result in increased outages caused by equipment failures. The age of the distribution system makes it extremely important for utilities to implement robust inspection and preventative maintenance procedures to allow the utilities to track the deterioration of these aged assets and replace them before they fail as an effort to improve reliability and ensure safety to workers and the public. There are also various equipment hardening and replacement programs in the state used to update aged assets in need of replacement.

3.4.2 Generation Shift in Supply and Operations Considerations Across Multiple Timeframes and Seasons

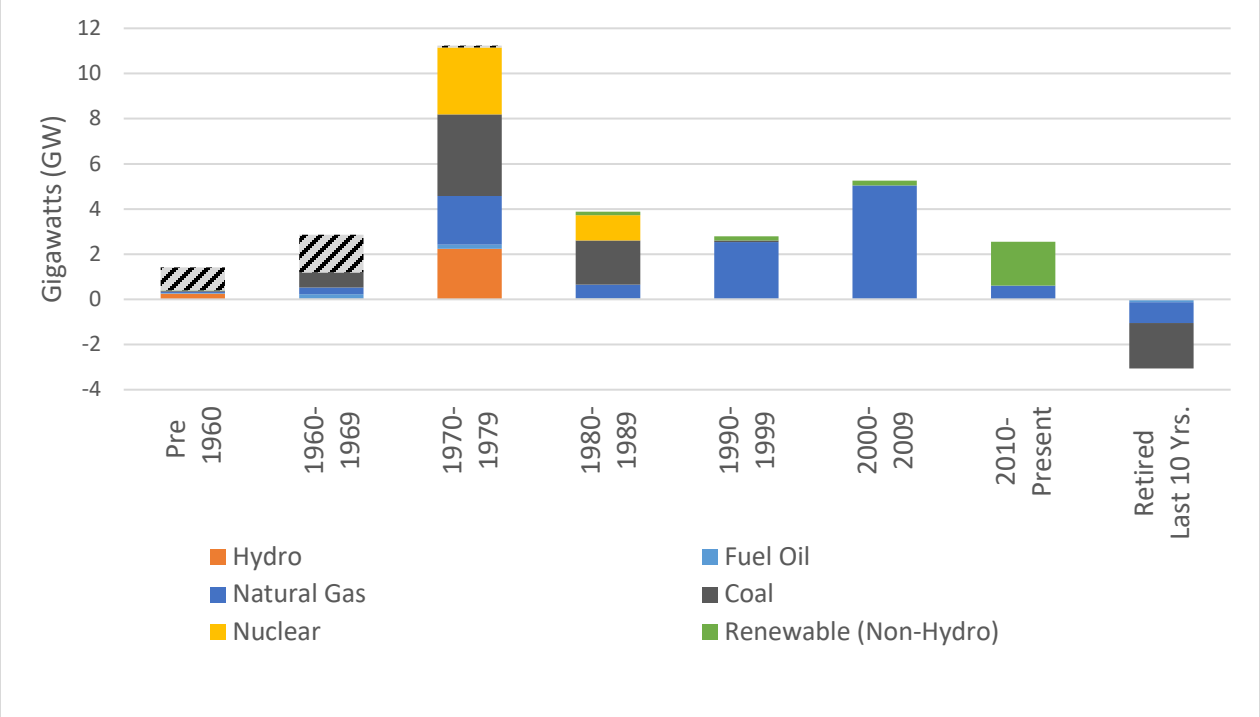
The state's generation asset profile is currently undergoing a significant shift, as are the utilities' metrics for evaluating what technologies should replace aged or uneconomic units. As identified in Figure 3-17 below, the mix of generation technologies in the state has changed over the last 10 years. Since 2007, coal generation is a smaller percentage of the state's overall generation profile as older coal fired generation is replaced by less expensive natural gas and renewable generation assets. This has created a more diverse generation profile for the state, though non-dispatchable resources make up a larger portion of the mix. This shift in generation technology is reinforced by Figure 3-18, which shows the relative age by decade of the generation assets in the state. A significant amount of the coal capacity that is still operating or recently retired was built before 1980. No new coal plants were built after the 1980s. Most units are at or near end of life, and coal units make up nearly all the announced or completed unit retirements over the past decade through the next 5 years.

Figure 3-17 Michigan's Evolving Net Generation Mix from 2007 - 2017



Sources: https://www.eia.gov/electricity/data/state/ and MPSC.

Figure 3-18 Michigan Capacity (GW) Showing When These Resource Types were Built



Sources: https://www.eia.gov/electricity/data/state/, https://www.eia.gov/electricity/data/eia860/, and IRP filings with the Commission as of June 1, 2019.

Standardized interconnection rules for Michigan electric utilities would enable distributed generation to interconnect with the utility system in a safe, reliable, and efficient manner. The Commission recommends that Staff continue to work with stakeholders to update the MPSC's interconnection rules and procedures for generation facilities seeking to connect to the utilities' distribution grids and to better integrate distributed energy resources such as solar, microgrids, and battery storage as part of this process. This effort will inform formal Commission rulemaking activity to commence in the fall of 2019.

3.4.3 Natural Gas and Electric Coordination

The increasing capacity of natural gas-fired electric generation could stress the natural gas system during times of high demand for gas for home heating and normal operating conditions on the electric and/or natural gas systems. Natural gas-fired generators are increasing in the state as natural gas prices make them a cost-effective option to replace retiring coal-fired units. The natural gas need for electric generation dispatched by the RTOs competes with natural gas used for home heating. The size and capability of Michigan's gas storage fields mitigate, but do not eliminate, this risk.

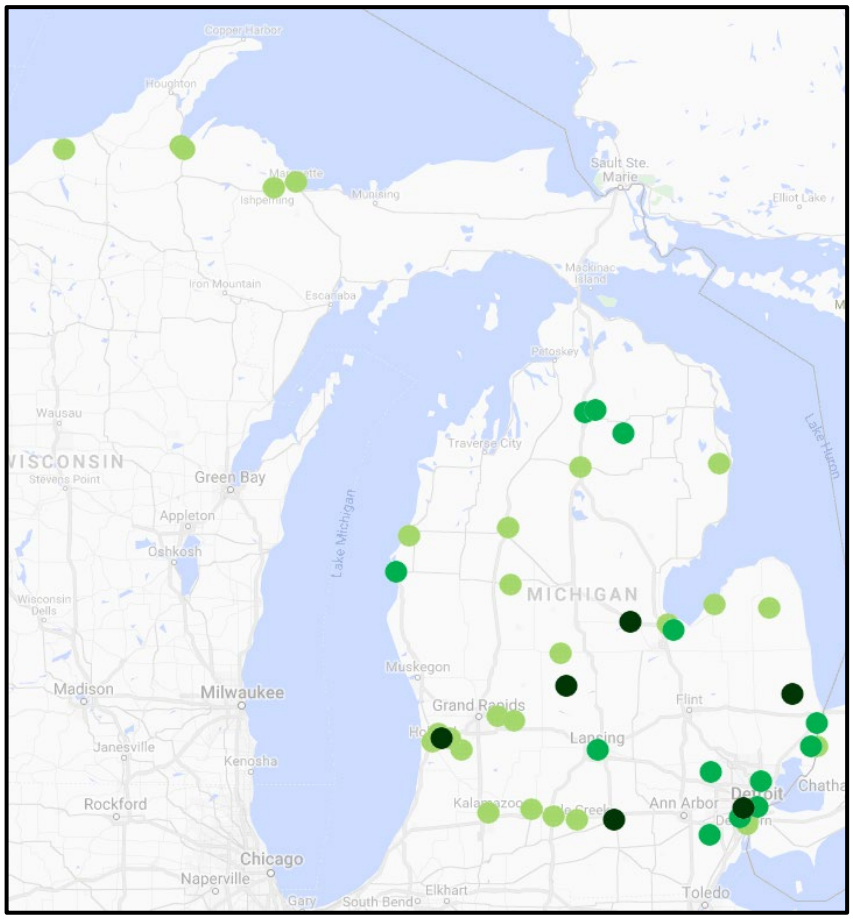
By design, the gas-fired generating units are often located near demand centers to effectively serve customers without having to transport electricity over long distances. As shown in Figure 3-19, existing gas generation and cogeneration plants used to serve local load and the electricity markets are located primarily in the urban areas of the state such as Grand Rapids and Southeast Michigan. More than 65% of the total number of units are in the lower third of the lower peninsula. These areas also have other demands for natural gas including residential home heating, highlighting the potential vulnerability in the cold weather months when demand is high for both electricity and home heating. The increasing gas-fired electric generation capacity also introduces potential constraints in the summer months when gas is being transported for injection into storage fields throughout the state at times where transmission pipelines are also typically taken off-line or restricted for integrity management remediation or inspection work. It should be noted, however, that Michigan gas storage operators have been consistently able to fill storage fields for utilization during the home heating season.

Since natural gas-fired generation naturally competes with natural gas used for home heating, coordination between these two industries is essential to the safety and well-being of customers as well as the reliability of the electric system. Reliability of natural gas pipelines, compressor stations, and storage fields is key to ensuring natural gas reaches generators and home heating customers in a timely fashion and in needed quantities. Gas-electric coordination issues have been a priority for utilities and regulators in the past. The PV14 and PV19 cold weather events highlighted the competition for natural gas-fired electric generation and natural gas-fueled home heating and spurred greater scrutiny leading to improvements at the regional level for better coordination and communication between natural gas and electric systems.

In 2015, (partially in response to PV14), FERC issued Order 809 to better align the scheduling practices of the gas and electric industries and ensure more efficient operations overall. Since that event, RTOs have made scheduling changes per Order 809, coordinate with gas pipelines, and exchange information and winter preparation surveys. Enhanced

communication and awareness between gas and electric operators has better equipped the industry to handle extreme weather events.

Figure 3-19 Michigan Gas Fired Electric Generation and Cogeneration Plants



Notes: The plants with more than one facility per location represent several plants within 10 miles of that location. The black dots indicate the largest plants consuming the most gas (>4,000 Mcf/hr) and the lightest green dots indicate the smallest plants consuming the least gas (<1,000 Mcf/hr) while the dark green dots consume between 1,000 Mcf/hr and 4,000 Mcf/hr.
Source: Information provided following a request from Staff

The RTO is responsible for ensuring reliable electric operations and economic dispatch of generation under established market rules at the regional level. The RTO has authority only during electric emergencies and current standards and procedures in use by RTOs during electric emergencies do not consider natural gas usage for residential home heating. When experiencing an overlapping natural gas and electric energy emergency, loss of natural gas service to residential customers requires house by house pilot "relighting" which is an extensive procedure that could result in customers being without natural gas service for days, depending on the severity of the outage. The Commission recognizes a potential conflict in the operating practices and objectives of the RTO during maximum generation events and natural gas distribution utility curtailment procedures during overlapping gas/electric energy emergencies

and recommends further dialogue to ensure safe and reliable electric and gas service to customers during all seasons**.**

3.4.4 Equipment Damage

American Transmission Company LLC (ATC) operated two 138 kV transmission circuits that electrically connected the Upper Peninsula and Lower Peninsula of Michigan through the Straits of Mackinac. Each of the two circuits consisted of three cables. On April 1, 2018, the lines were taken out of service due to the anchor of a passing vessel severing the electric cables.

ATC was able to restore and place back into service a single circuit by May 1, 2018, maintaining system reliability in the interim while a single circuit was reconfigured from the existing equipment. Customer demand was relatively low during this one-month period of the lines being completely out of service.

Given the age and vulnerability of the single circuit, ATC was granted approval by MISO on December 6, 2018 to construct new 138 KV dual circuit lines in the Straits of Mackinac, subject to approval of permits and regulatory agencies. ATC is proceeding with planning, equipment purchases, and state permitting for this project with an expected in-service date of December 2021. Until this project is completed, there are potential reliability challenges that could occur (e.g., if the single line fails during periods of high consumption or other equipment failures).

As a result of the reliability concerns in the Eastern UP, ATC and Cloverland Electric Cooperative are working on a short-term solution that includes portable generators, emergency operations plans, load management discussions, and more extensive monitoring of the transmission lines in the Eastern UP. Cloverland Electric Cooperative has discussed plans for a long-term generation solution as well.

In addition to the specific anchor strike damage involving ATC electric cables, electric companies are at risk of equipment damages impacting system operations that can present unique restoration challenges, especially when there is a lack of supply for replacement equipment. Lack of inventory and supply may result in long lead times for repair work. Companies typically have the appropriate inventory to replace or restore failed equipment in a timely manner, however, there are instances where it is not practical for the companies to keep new and replacement equipment in local inventory, resulting in potential longer outage durations.

3.4.5 Ability to Import Capacity into the Lower Peninsula

The Lower Peninsula's ability to rely on imported capacity to meet MISO's resource adequacy requirements has recently been reduced, resulting in an increased probability of higher capacity prices and potentially resulting in an increased probability of a loss-of-load event (curtailments) occurring due to a lack of supply. The ability to rely on capacity imports to meet resource adequacy requirements is based upon the local reliability requirement (LRR) and the capacity import limit (CIL). The LRR for a zone, such as the Lower Peninsula, is the amount of zonal resource credits (ZRC) required to yield a 1 day-in-10 years loss of load expectation (LOLE) at peak, without assistance from resources outside the zone (no imports). The PRMR is the total

capacity obligation for all LSEs within the zone. The local clearing requirement (LCR) is the difference between the LRR and the CIL and represents the amount of capacity resources that must be physically located within the zone in order to meet the resource adequacy requirements.

Figure 3-20 MISO Zone 7 (Lower Peninsula) Resource Adequacy 2014 - 2019

Source	PRMR	LRR	CIL	LCR	LCR / PRMR	Total Offers*
PRA Results 2014/2015[81]	22,998	25,177	3,884	21,293	92.6%	23,639
PRA Results 2015/2016[82]	22,678	25,254	3,812	21,442	94.5%	23,559
PRA Results 2016/2017[83]	22,406	24,372	3,521	20,851	93.1%	21,615
PRA Results 2017/2018[84]	22,295	24,429	3,320	21,109	94.7%	22,031
PRA Results 2018/2019[85]	22,121	24,413	3,785	20,628	93.3%	22,036
PRA Results 2019/2020[86]	21,976	25,023	3,211	21,812	99.3%	22,063

*Total Offers is the amount of zonal resource credits offered into the PRA in Zone 7.
Source: MISO Planning Resource Auction Results

For planning year 2019/2020, which runs from June 1, 2019 through May 31, 2020, a decreased CIL and an increased LRR led to over 99% of the resources required to be physically located within the zone, meaning that the Lower Peninsula portion of MISO could only plan to import 0.7% of its resources required at peak. Even though the CIL for the Lower Peninsula was 3,211 MW, the amount of capacity that the Lower Peninsula could plan to import at peak under the MISO resource adequacy requirements was effectively limited to 164 MW, the difference between the PRMR and the LCR. All other things being equal, increasing the CIL would result in a lower LCR, improving the available resource options to meet the resource adequacy requirements. The increased optionality would likely add downward pressure on capacity prices, improve the ability to meet resource adequacy requirements, and reduce the likelihood of loss-of-load events from occurring. An increase in the import capability will increase the resilience of

[81] https://cdn.misoenergy.org/2014-2015%20PRA%20Results89073.pdf
[82] https://cdn.misoenergy.org/2015-2016%20PRA%20Results87078.pdf
[83] https://cdn.misoenergy.org/2016-2017%20PRA%20Results87167.pdf
[84] https://cdn.misoenergy.org/2017-2018%20Planning%20Resource%20Adequacy%20Results87196.pdf
[85] https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf
[86] https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf

the electric system in Michigan and provide assurance that customers will be served as more extreme weather events are experienced as well as in the event of fuel shortages, or to fill in the gaps that may be left by intermittent resources.

3.5 Contingency Planning Methodologies and Assumptions

3.5.1 Electric Distribution Risk-Based Planning Models

Electric utilities have risk-based planning models designed to identify system risks and serve as a first step in mitigating or reducing the potential impacts of the risks. The Commission has asked DTE, Consumers, and I&M to file five-year electric distribution plans which, in most cases, are comprised of the results of the risk-based planning models to reduce safety risks, improve reliability, and manage costs for customers. The risk-based planning models and five-year electric distribution plans are ways for the utility to assess and present areas that are the most susceptible to failure and are prioritized with safety as the highest priority.

3.5.2 Load Forecasting Methodologies and Risks

3.5.2.1 Evaluation of Energy Efficiency Programs on Consumption and Peak Demand - MPSC Staff began assessing Michigan's electric service providers ability to correctly factor in the effects of energy efficiency into their methods for predicting future load requirements.[87] There are multiple ways to handle the effect of energy efficiency and load forecasting, but currently no best practices have been instituted. The utilities are currently producing forecasts at a variance rate that is better than national average variance rates. Staff will continue to work with the utilities to learn more about these potential effects on forecasting from utility energy efficiency programs, and if necessary, provide support or recommendation in future rate case proceedings.

3.5.2.2 Changing Customer Behavior and Technology Adoption (e.g., Electric Vehicles) and Forecasting Risks - As explained above, RTOs manage their systems through day-ahead and real time markets. In order to accurately match generation and load, RTOs must build a load forecast prior to each day. Each RTO relies on many data sources, as well as previous experience, when creating a forecast for the day-ahead. Variables such as the day of the week, upcoming holidays, commercial/industrial activity, and end-use characteristics all come into play when developing an accurate picture of expected load. Often, RTOs look back

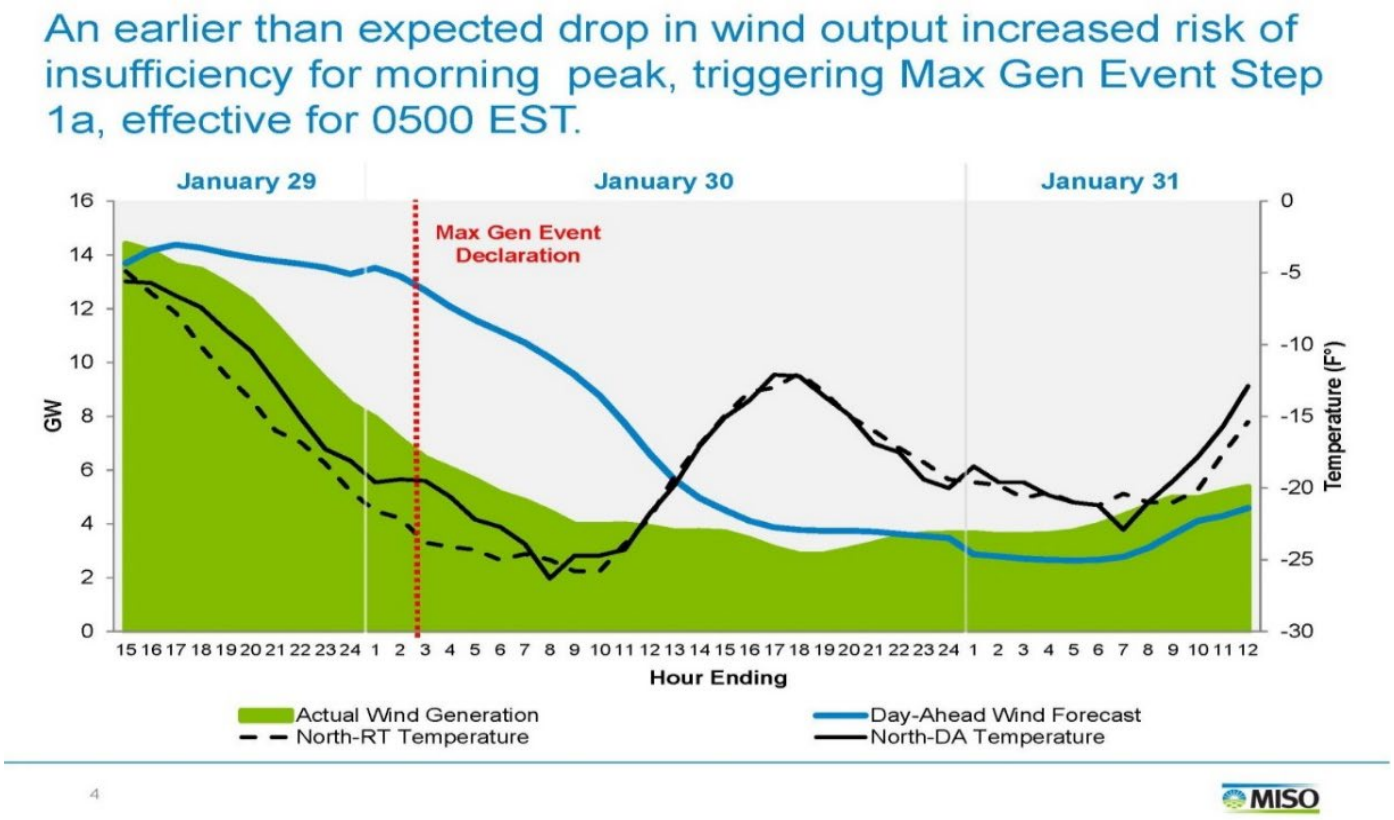
[87] See MPSC Case No. U-18255, April 18, 2018 Order, p. 36, https://mi-psc.force.com/s/filing/a00t0000004rpFnAAI/u182550391. See also MPSC Case No. U-18322, March 29, 2018 Order, p. 50, https://mi-psc.force.com/s/filing/a00t0000004rbALAAY/u183220489.

over the previous day/month/year as a baseline for their forecast and update any variables to meet the expected day-ahead conditions. The laws of physics necessitate that supply must exactly match demand, and any variation from the forecasted load and real time load must be reconciled in the real time market. Therefore, precise forecasting is important to have an accurate representation of the operating conditions throughout the day, which helps keep the system reliable and energy costs down.

One recent example of the impacts from forecasting deviations comes from the MISO footprint during PV19. As shown in Figure 3-21, MISO's day-ahead wind forecast greatly exceeded the actual wind generation in real time due to unexpected generation outages. Wind forecasting capabilities are highly advanced compared to solar forecasting.

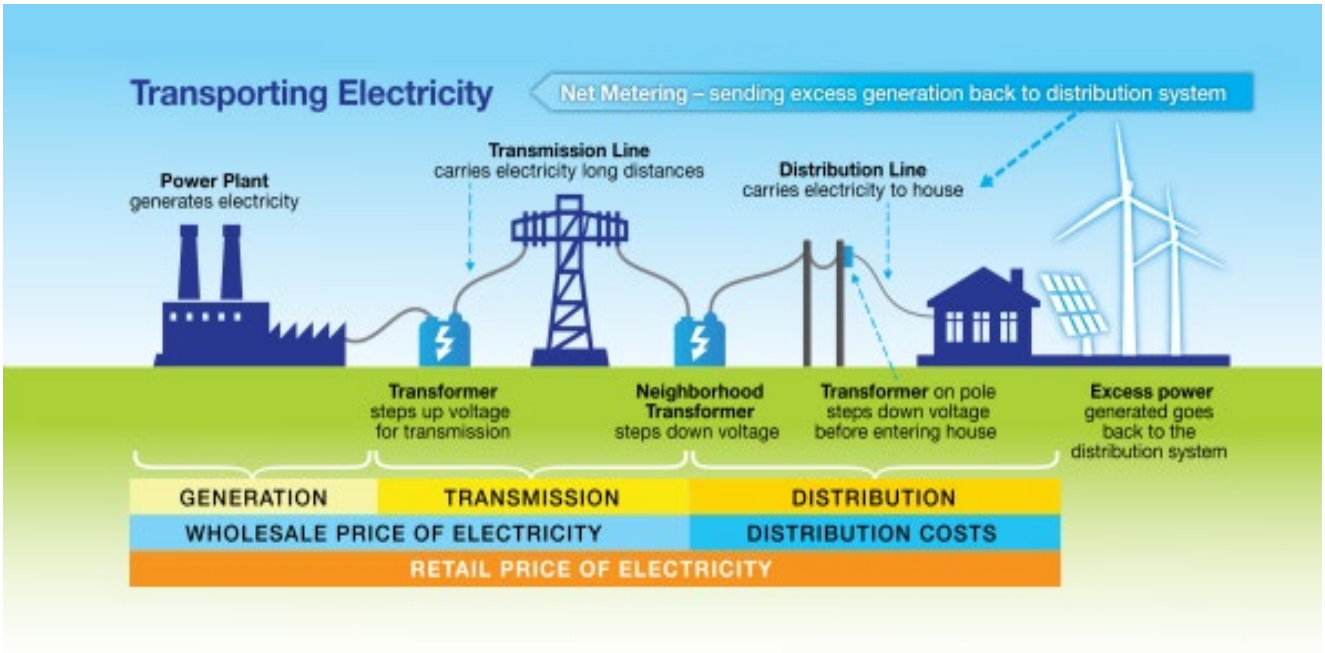
Some other forecasting challenges are accounting for changing consumer behavior, new technologies, and a changing resource mix. As presented in Figure 3-22, the traditional flow of electricity is from the generating station through the transmission system, where voltage is reduced for the distribution system to deliver power to customers. This paradigm is changing as customer-owned generation and other DERs become more prevalent. Customers' ability to generate, store, and push electricity out onto the distribution system presents new challenges for planners and system operators, but also new opportunities to increase reliability and resilience for customers if the customer-owned generation is configured to operate safely in "island mode" during system outages.

Figure 3-21 MISO Day Ahead Wind Forecast During PV19, January 29-31, 2019



Source: MISO

Figure 3-22 Traditional Flow of Electricity



Greater adoption of electric vehicles (EVs) will also bring about new challenges and opportunities for the electric system. US EV sales increased by 81% from 2017 to 2018[88] and adoption rates are expected to continue to climb as major automakers increase production and costs continue to come down (Figure 3-23). The additional demand for electricity from vehicles could be significant and could potentially require significant investment in new resources and infrastructure over time. EPRI study showed without managed charging (promoting charging during off-peak periods), Michigan's power demand could double and the state could move from summer peaking to winter peaking by 2050.[89] However, customers can be incentivized to charge their vehicles during low-cost times, currently overnight, through rates to mitigate the grid impacts. The added off-peak demand would also have the benefit of bringing down overall system costs for customers by more efficiently using the generation fleet designed to meet peak demand. A sudden increased load on the grid would cause adverse effects during peak usage times. Current estimates indicate that there is sufficient generating capacity in Michigan to provide for near-future electric vehicle adoption if the majority of customers utilize nighttime, or off-peak vehicle charging.

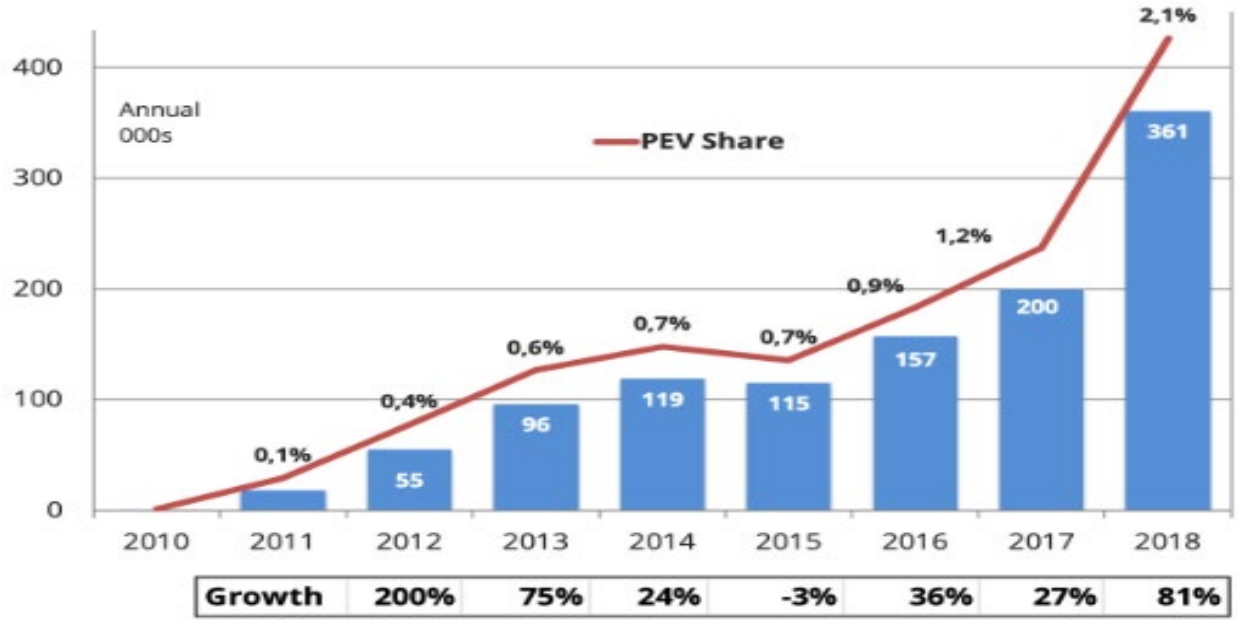
The MPSC began assessing the risks and merits associated with electric vehicle adoption and its impacts on our electric grid in the 2010 timeframe, with additional focus beginning in 2017 through technical conferences and stakeholder input. The state's two largest electric service providers subsequently obtained MPSC approval to implement electric vehicle charging station pilots in their most recent rate cases.[90] These pilots are meant to provide education to customers on the economic and environmental benefits of EVs, promote smart charging or nighttime charging, and gain knowledge as to the effects EVs will have on Michigan's electric infrastructure going forward.

As the transportation sector and other end uses become more electrified and customer behavior evolves, new challenges and opportunities will arise. While electrification will create

[88] Greentech Media, US Electric Vehicle Sales Increased by 81% in 2018, https://www.greentechmedia.com/articles/read/us-electric-vehicle-sales-increase-by-81-in-2018#gs.l8pq94.
[89] Dennis, Deana, "The Role of Electricity in the Future Energy System; A U.S. National Electrification Assessment," February 22, 2019, p. 11.
[90] Consumers Energy electric rate case, MPSC Case No. U-20134, https://mi-psc.force.com/s/case/500t0000009fPPSAA2/in-the-matter-of-the-application-of-consumers-energy-company-for-authority-to-increase-its-rates-for-the-generation-and-distribution-of-electricity-and-for-other-relief. DTE electric rate case, MPSC Case No. U-20162, https://mi-psc.force.com/s/case/500t0000009hEHeAAM/in-the-matter-of-the-application-of-dte-electric-company-for-authority-to-increase-its-rates-amend-its-rate-schedules-and-rules-governing-the-distribution-and-supply-of-electric-energy-and-for-miscellaneous-accounting-authority.

more demand and challenges for the grid, new technologies and demand-side resources are also being developed that may be able to shift this load to off-peak hours if the right incentives are in place. Similarly, DERs such as solar, storage, demand response, and electric vehicles, provide flexibility for grid operators as well as challenges to manage all of these resources and utilize them to their fullest potential. As the U.S. electric grid incorporates higher levels of renewable energy, better management of DERs could be utilized to mitigate operational challenges. To date, both MISO and PJM do not have high enough levels of DERs or renewable energy to see a significant impact on forecasting. However, both RTOs are aware of the potential impact these technologies will have in the future and are actively discussing them in their stakeholder processes. RTO visibility into DERs and their real time performance are critical issues and tie into state efforts to update interconnection processes and standards.[91]

Figure 3-23 United States Plug-In Vehicle Sales & Market Share



Source: http://www.ev-volumes.com/country/usa/

It is essential for the electric utilities to communicate with the RTOs to allow for greater transparency of the system by providing visibility into the electric distribution system for details

[91] See IEEE 1547 interconnection standard, https://standards.ieee.org/standard/1547-2018.html. Also see MPSC interconnection stakeholder process, https://www.michigan.gov/mpsc/0,4639,7-159-91243-482687--,00.html.

including the level of DER and EV penetrations to more effectively forecast in the energy and ancillary services markets.

3.5.3 Available Mutual Aid From Regional/National Utility Resources

When the magnitude of an event is beyond the ability of the local utility to provide needed energy services restore service, or perform repairs in a timely fashion, there are numerous mutual assistance groups to share resources on a regional scale. Edison Electric Institute (EEI) member companies sign a mutual assistance agreement[92] to give and receive assistance during emergencies. Most of Michigan's investor-owned utilities and transmission companies are EEI members and participate in their respective Regional Mutual Assistance Groups (RMAGs).[93] Non-investor-owned utilities, such as the Michigan Municipal Electric Association and the Michigan Electric Cooperative Association, also have their own mutual assistance programs and run exercises to prepare for an event. While every electric utility has a detailed plan in place to repair its system, RMAGs help identify workers and coordinate logistics to help with restoration efforts during significant outage events. RMAGs cover a variety of situations which include storm assistance, wildfires, and cyber/physical attacks. Some well-known examples include Superstorm Sandy and Hurricane Katrina where all seven RMAGs nationwide were called upon to assist. Events of this magnitude often require national coordination, which is accomplished through a variety of entities.

After Superstorm Sandy, a national framework was created to respond to catastrophic storms, now dubbed national response events (NREs). When a NRE is declared, a National Response Executive Committee (NREC), made up of a rotating group of utility executives, allocates resources to the affected area. The utilities communicate with federal government partners like DOE, DOT, DOD, FEMA, and state organizations to direct resources, minimize delays, and provide access to the affected areas. While the RMAG framework is designed to respond to events, other regional and national programs recognize the need to have spare equipment in place to ensure critical electric infrastructure can come back online quickly after an event.

In 2006, DOE and FERC approved the creation of a Spare Transformer Equipment Program (STEP) designed to help the U.S. grid become more resilient and recover quickly from

[92] http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Documents/MAAgreement+GovPrinc_FINAL_090717.pdf.

[93] The RMAG for the Lower Peninsula is the Great Lakes Mutual Assistance Group. The Upper Peninsula's RMAG is the Wisconsin Utilities Association Mutual Assistance Group.

widespread transformer failures.[94] The program recognizes the critical importance of electricity as an essential part of public health, safety, and national security. The STEP is intended to prepare the country in the event of a cyber or physical attack that damages a large portion of the bulk electric system. Building and replacing a large amount of large power transformers would take months, if not years, leaving the safety and security of the nation at risk. Instead, the STEP requires participating companies to maintain spare transformers and sell them to other participating companies in a catastrophic event. Other equipment sharing programs include SpareConnect and the Regional Equipment Sharing for Transmission Outage Restoration (RESTORE) which link companies in need and streamline the ability to share other equipment like step-up transformers, bushings, fans, and auxiliary components. Having spare equipment on hand would help mitigate the worst impacts of an event and improve the resilience of the electric system.

[94] DOE's Strategic Transformer Reserve report, https://www.energy.gov/sites/prod/files/2017/04/f34/Strategic%20Transformer%20Reserve%20Report%20-%20FINAL.pdf.

3.6 Electric Recommendations for Mitigating Risks

3.6.1 Commission's Electric Recommendations

- Michigan continues to expand its reliance on demand response programs to meet reliability needs and avoid the construction of more expensive new electric generation infrastructure. During the PV19 event, some customers participating in "interruptible" tariffs or other demand response programs did not respond as expected and utility tariffs were found to have inconsistent language. System operators need to count on demand response programs to maintain system reliability. **Therefore, the Commission recommends several improvements to demand response programs**:
    - **Staff, utilities, and other stakeholders should review utility demand response tariffs for consistency and clarity when deploying Load Modifying Resources during emergency events, including a review of notification and penalty provisions.**
    - **Utilities should coordinate with Staff, customers, RTOs, and other stakeholders on retail DR tariff offerings to align with wholesale markets and emergency operations.** This should examine the economic and reliability uses of DR and identify updates to DR tariffs to best match customers with performance expectations under applicable tariffs.
    - **Utilities also should review their communications plans with customers that would take place during a demand response event and conduct recurring testing of demand response resources to ensure the ability to respond when called upon.**
- During the PV19 event, MISO discovered it did not have information on all generation facility operating characteristics, such as the wind turbine cold pack installations, which impacted day-ahead and real time generation forecasts. **The Commission recommends electric generators provide the RTO with all generator operating characteristics and to incorporate measures to improve generator startup performance when emergency units are called upon.**
- The MPSC's electric service quality and reliability rules have not been updated recently and could be modified to enhance safety, reliability, and resiliency of the distribution system. The rules address actions to prevent power outages and system restoration. **The Commission recommends opening a docket to establish a workgroup to investigate and provide recommendations for updating the Service Quality and Reliability rules and the Technical Standards for Electric Service using lessons learned in Michigan and best practices in other states as a guide**.
- Standardized interconnection rules for Michigan electric utilities would enable distributed generation to interconnect with the utility system in a safe, reliable, and efficient manner. **The Commission recommends that Staff continue to work with stakeholders to update the MPSC's interconnection rules and procedures for**

generation facilities seeking to connect to the utilities' distribution grids and to better integrate distributed energy resources such as solar, microgrids, and battery storage as part of this process. This effort will inform formal Commission rulemaking activity to commence in the fall of 2019.

3.6.2 Commission's Electric Observations

- During electric generation emergencies, the gas-fired electric generator operations may be impacted by other state permit requirements. **To improve safety and reliability during energy emergencies, the Commission proposes to discuss with EGLE coordination issues, including scenarios where an electric generator is reaching air emission limitations at the same time an electric emergency declaration by the RTO requires all generators to maximize output.**
- The PV19 event provided the most recent example of an energy emergency occurring during the winter rather than the more traditional summer peak. As the percentage of natural gas fueled electric generation increases throughout the region and other changes to the fuel mix take place that affect operating conditions by season or time of day, the RTO capacity construct must evolve. **The Commission finds that RTO capacity requirements should provide a seasonal capacity construct at the regional level to better account for different resource characteristics in the capacity accreditation process and to ensure safe and reliable electric service to customers during all seasons.**
- Despite repeated efforts to improve the process, the MISO generator interconnection queue is cumbersome and cannot keep pace with the level of change in the industry, with generation retiring at an accelerated rate and need to assess/model the best locations for replacement generation from a system reliability perspective. **The Commission finds the MISO generator interconnection queue process should be revised to facilitate the timely progression of projects through the process. This enhancement is necessary to ensure safe and reliable electric and natural gas service to customers as it would not only improve system reliability but better reflect the rapid pace of change as the generation mix rapidly evolves. Broader, long-term regional transmission planning is also essential to ensure cost-effective, reliable delivery of power and flexibility to accommodate changing energy resource mix.**
- Outside projects eligible for cost sharing, the MISO process for approving transmission projects between 69kV and 345 kV is based exclusively upon a review from a reliability perspective rather than a cost perspective. This limited assessment criteria may prevent from consideration other alternatives such as generation or distribution solutions that could be preferred from a cost, reliability, or resiliency perspective. This is important because transmission projects below 345 kV are not subject to MPSC review and approval under Act 30 of 1995. **The Commission finds that MISO's process should more carefully consider alternatives to transmission line projects based on cost, reliability, and resiliency prior to approving new transmission.**

See also: **Chapter 8**, Gaps in Existing Planning, Operational, and Emergency Response Processes, for additional recommendations and observations relevant to the electric sector.

4. Natural Gas

4.1 System Overview and Operational Practices

A recent publication from the Natural Gas Council[95] describes the natural gas resources in the United States as abundant, the sources diverse, the infrastructure robust and able to supply customer demand for natural gas heating as well as providing a fuel source for electric generation.

> "In the United States, there are more than a half million producing gas wells spread across 30 states. The growth of major onshore shale gas production has greatly reduced exposure to the effects of hurricanes to off-shore supplies and spot market prices. Onshore natural gas production accounted for 95 percent of total U.S. gross withdrawals of natural gas in 2016, up from 74 percent in 1990.
>
> The natural gas value chain is extensive and spans from the production well-head to the consumer burner-tip. Mostly underground, America's 2.5 million mile natural gas pipeline network is the safest form of energy delivery in the country – transporting approximately one-fourth of the energy consumed in the U.S. Further, this pipeline and storage network is highly reliable. Production can be accessed from virtually all major North American gas-producing regions and securely delivered via a highly integrated pipeline transportation network. Very rarely, force majeure events such as catastrophic weather have the ability to potentially disrupt localized segments of this network, but typically only at above-ground facilities where the pipeline may be exposed and damaged.
>
> Outages are extremely rare and are localized when they occur due to the interconnected nature of the transportation network."

[95] http://naturalgascouncil.org/wp-content/uploads/2019/04/Natural-Gas-Reliable-and-Resilient.pdf.

4.1.1 Natural Gas Technical and Safety Standards

4.1.1.1 Performance-Based and Prescriptive Standards - The MPSC oversees the safety and reliability of natural gas transmission and distribution systems through a comprehensive set of safety and technical standards and associated compliance inspection and enforcement activities. These regulatory functions are conducted pursuant to state and federal laws and rules with authority delegated by the federal government, specifically the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA).

The MPSC first promulgated Standards of Gas Service in 1926,[96] also known as the Technical Standards, with the most recent amendment to the rules occurring in 1993.[97] This ruleset is being updated, with the request for rulemaking submitted May 29, 2019,[98] in what is expected to be a year-long process. This ruleset pertains to the distribution and service of natural gas to end-users. The rules set standards for: reporting requirements, service installation guidelines, engineering design, meter calibrations and testing for billing accuracy, guidelines for service shutoff, and gas quality standards for safety and efficiency. The rules define and outline requirements regarding these gas service-related categories. A utility's Rate Book for Natural Gas Service contains Standard Rules and Regulations that govern its relations with the customers and includes specific requirements to comply with the Technical Standards for Gas Service.

The MPSC also has separate gas safety rules, which have been in place since 1956, even prior to the federal government becoming involved in 1968 with the passage of the "Natural Gas Pipeline Safety Act," an act which authorized "the Secretary of Transportation to prescribe safety standards for the transportation of natural and other gas by pipeline, and for other purposes." This landmark federal law preempted states in the establishment of the federal safety regulations for the transportation of gas and pipeline facilities, which was contained primarily within 49 CFR Part 191 and 49 CFR Part 192. The majority of states with appropriate laws and rules in place oversee natural gas safety, including Michigan, and administer their own programs with approval and delegated authority by PHMSA. PA 165 of 1969 grants the MPSC authority

[96] Order No. 1982, Standards of Gas Service, Issued by Order of the Commission Effective September 1, 1926. Under the provisions of Act No. 419 of the Public Acts of Michigan for the year 1919.
[97] Technical Standards for Gas Service. By authority conferred on the public service commission by section 6 of Act No. 3 of the Public Acts of 1939, as amended, and section 2 of Act No. 165 of the Public Acts of 1969, being SS460.6 and 483.152 of the Michigan Compiled Laws.
[98] Submitted Request for Rulemaking to ORR on May 29, 2019 for revisions to R 460.2301 through R 460.2383.

for the gas safety rules under state law. Like the Technical Standards governing service to the customer, the gas safety rules are primarily performance-based standards.

Due to the federal-state jurisdictional nature of natural gas safety, it is important to distinguish that there are two separate sets of rules governing gas safety that pipeline operators must adhere to. The first are the Minimum Federal Safety Standards for Transportation of Natural and other Gas by Pipeline (49 CFR Part 192). The second is the Michigan Gas Safety Standards, which are State of Michigan specific regulations. Intrastate pipeline operators must comply with both the Minimum Federal Safety Standards and the Michigan Gas Safety Standards, whereas interstate pipeline operators only have to comply with the Minimum Federal Safety Standards.

While certain operation and maintenance requirements have been present since the state gas safety regulations were first enacted in 1956, none of these operation and maintenance requirements were specifically geared toward a pipeline operator performing additional requirements based on risk assessments and consequences. This changed with the advent of integrity management programs as described below.

In 2003, PHMSA prescribed standards for gas transmission pipeline operators to conduct risk analyses and to adopt and implement a Transmission Integrity Management Program (TIMP). These programs, among other things, require that pipeline operators identify high consequence areas, collect data on the pipelines located in those high consequence areas, and perform ongoing integrity assessments to determine pipeline condition and, where necessary, remediation. The primary assessment methods include in-line tool inspections, direct assessment (above ground surveys) and pressure testing, of which in-line inspections provide the most comprehensive data on the integrity of the pipeline. High consequence areas are places where population density reaches a certain threshold related to the number of structures intended for human occupancy or sites where people congregate. While these regulations include both performance-based and prescriptive requirements, there are significantly more prescriptive requirements than are present in other areas of 49 CFR Part 192.

In 2016, PMHSA published a proposed rulemaking titled "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines"[99] to update 49 CFR Part 192. This proposed rule included significant changes to the transmission integrity management requirements, along with other general changes to transmission and gathering pipelines with enhancements to the following areas:

[99] April 8, 2016, Case No. PHMSA-2011-0023-0136.

1. Re-establishing maximum allowable operating pressure.
2. Verifying material properties.
3. Performing integrity assessments outside of high-consequence areas.
4. Management of change enhancements.
5. Corrosion control enhancements.
6. Modifying the regulation of onshore gas gathering lines.

Due to the significance and breadth of this rulemaking, PHMSA has indicated that this will be split into three separate rulemaking packages that will all be separate final rules. Work on these rulemakings is ongoing and the rules are titled as follows:

- Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments
- Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments
- Safety of Gas Gathering Pipelines

In 2010, PHMSA promulgated rules requiring that pipeline operators develop Distribution Integrity Management Programs (DIMP), which are high-level and performance-based requirements.[100] The distribution integrity management rules were designed to "enhance safety by identifying and reducing pipeline integrity risks. The IM [integrity management] programs required by this rule are similar to those required for gas transmission pipelines but tailored to reflect the differences in and among distribution pipelines. Based on the required risk assessments and enhanced controls, the rule also allows for risk-based adjustment of prescribed intervals for leak detection surveys and other fixed-interval requirements in the agency's existing regulations for gas distribution pipelines."[101]

In 2016, PHMSA promulgated the requirement that pipeline operators develop an underground Storage Integrity Management Program (SIMP), with an effective date of January 18, 2017, that was intended to "address critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities. This interim final rule responds to Section 12 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, which was enacted following the serious natural gas leak at the Aliso Canyon facility in California on October 23, 2015."[102] While the transmission and

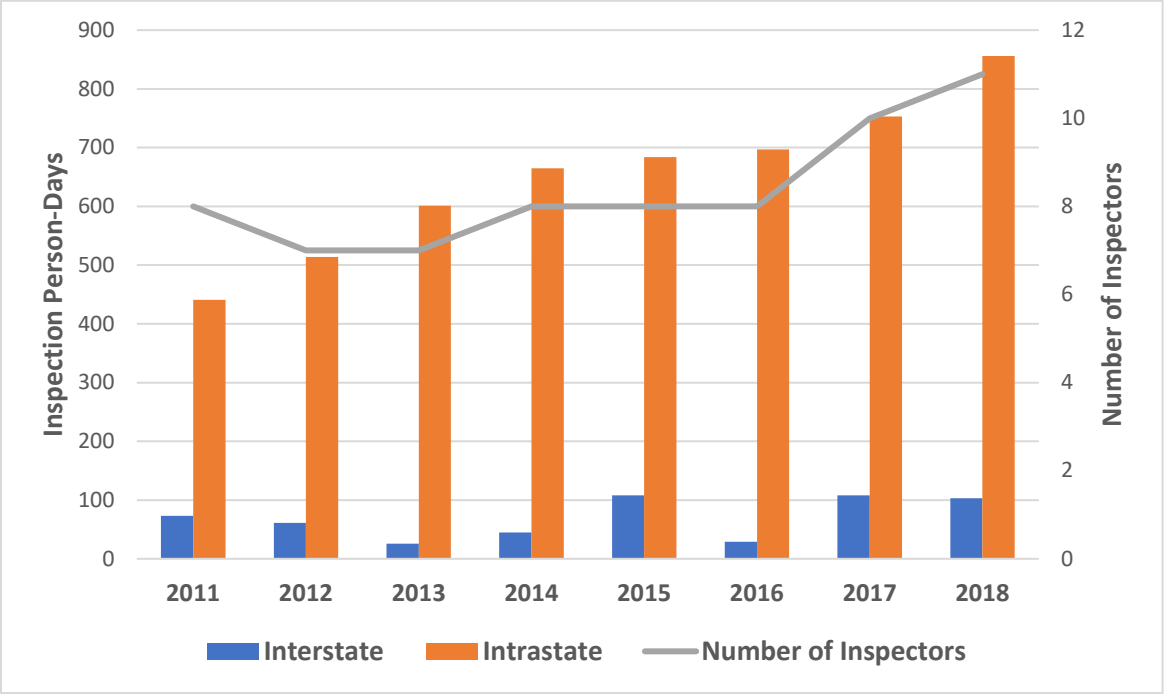
[100] Federal Register: June 25, 2008 (Volume 73, Number 123).
[101] Federal Register: December 4, 2009 (Volume 74, Number 232).
[102] Federal Register: December 19, 2016 (Volume 81, Number 243).

distribution integrity management rules resulted in the creation of additional subparts and associated rules within 49 CFR Part 192, this was not the approach that was adopted for PHMSA-2016-0016 titled "Safety of Underground Natural Gas Storage Facilities." Rather, PHMSA relied on two industry standards that it incorporated into 49 CFR Part 192; American Petroleum Institute (API) Recommended Practice (RP) 1170 titled "Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage" and API RP 1171 titled "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs."

4.1.1.2 Onsite Facility and Operational Inspections - The State of Michigan, through the MPSC, participates in the pipeline safety program acting as an intrastate and interstate agent for and authorized by PHMSA. Intrastate pipeline inspections and enforcement are wholly under the purview of the MPSC. The MPSC Staff are responsible for development of an inspection plan, documentation of inspections, and federal reporting regarding those inspections. The intrastate inspection plan covers the entire set of state and federal regulations and is completed every five years. The inspections cover all aspects of pipeline operations including reporting, procedures, record keeping, design, construction, operation, maintenance, corrosion control, employee qualifications, public education, control room, drug and alcohol testing, and integrity management programs. Inspection types include review of procedures and standards; records reviews; construction inspections; field observations; inspections operations employees performing tasks; and incident investigations. Interstate pipeline inspections are a coordinated effort between the MPSC and PHMSA as described in the previous section. The State of Michigan is not currently certified to inspect underground storage facilities. The MPSC and EGLE have shared responsibility with respect to storage. The MPSC has issued certificates of public convenience and necessity that include monitoring and safety requirements for the facilities and formation. EGLE has requirements for well design and construction. PHMSA is responsible for both the inspections and enforcement on underground storage facilities.

Figure 4-1 provides for the trends in inspection history for both intrastate and interstate pipeline operators from 2011 to 2018, compared to the number of inspectors that were involved in the program.

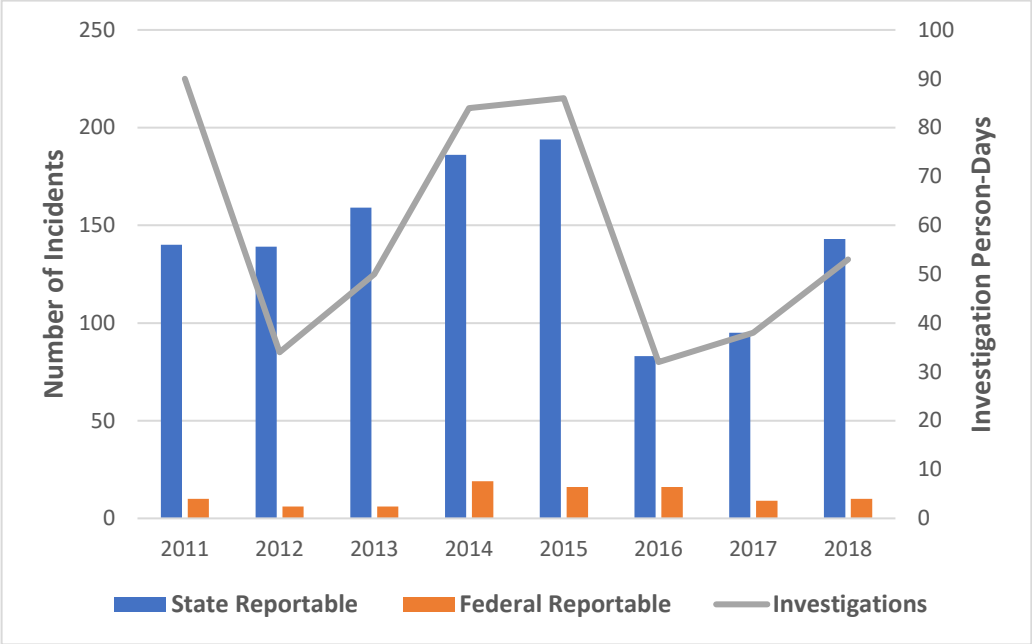
Figure 4-1 Pipeline Safety Inspection Trends 2011-2018



Source: MPSC Gas Safety Database

4.1.1.3 Accident Investigation and Compliance Actions - PHMSA and the MPSC have adopted incident-reporting criteria. The MPSC Staff are responsible for receiving telephonic notice of incidents and responding to the scene of the incident as necessary. The MPSC Staff overseeing the gas safety program are engineers with specialized training and conduct investigations of each significant or reportable incident/accident involving jurisdictional pipeline facilities. The primary objective of the investigation activities is to minimize the possibility of recurrence for the affected pipeline operator and other operators in the state and to institute enforcement action where noncompliance with the safety standards has occurred. In order to conduct an effective incident/accident investigation, the Staff must be familiar with basic investigative procedures and knowledgeable of the design, construction, operation, and maintenance factors involved in pipeline safety. As illustrated in Figure 4-2, the more restrictive incident-reporting criteria in the state of Michigan typically results in over ten times the number of reports received when compared to the federal incident-reporting criteria.

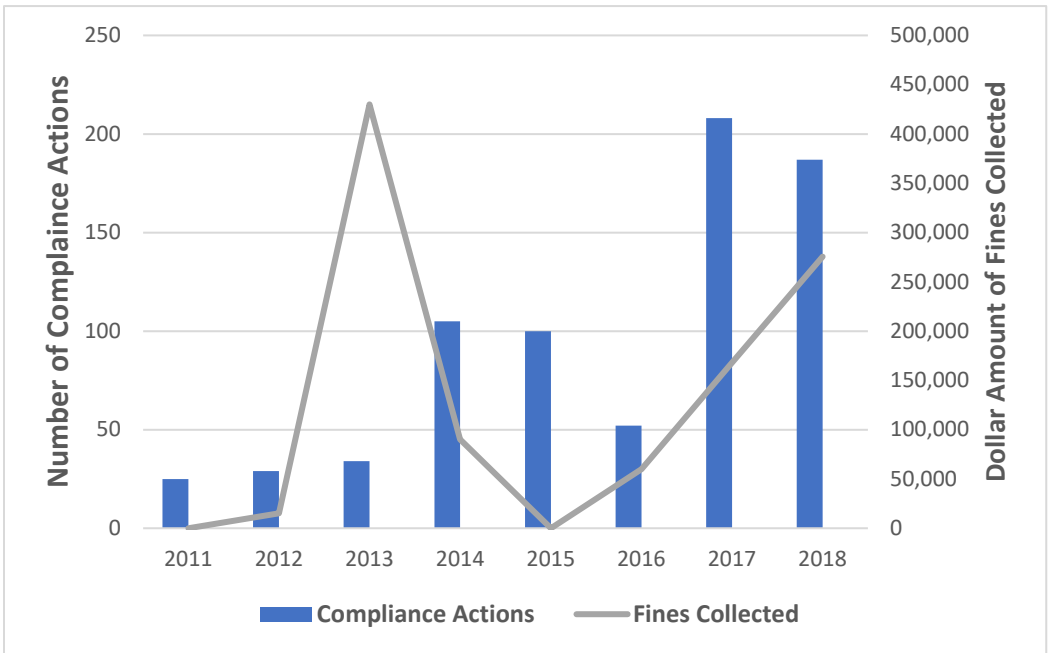
Figure 4-2 State of Michigan Incident Investigations 2011-2018



Source: MPSC Gas Safety Database

Figure 4-3 provides the history of MPSC compliance actions and the fines collected. Compliance actions and penalties are the results of both pipeline safety inspections and incident investigations. The closure of two major investigations involving fatalities were the reason for the spike in fines in 2013.

Figure 4-3 Pipeline Safety Enforcement Actions 2011-2018



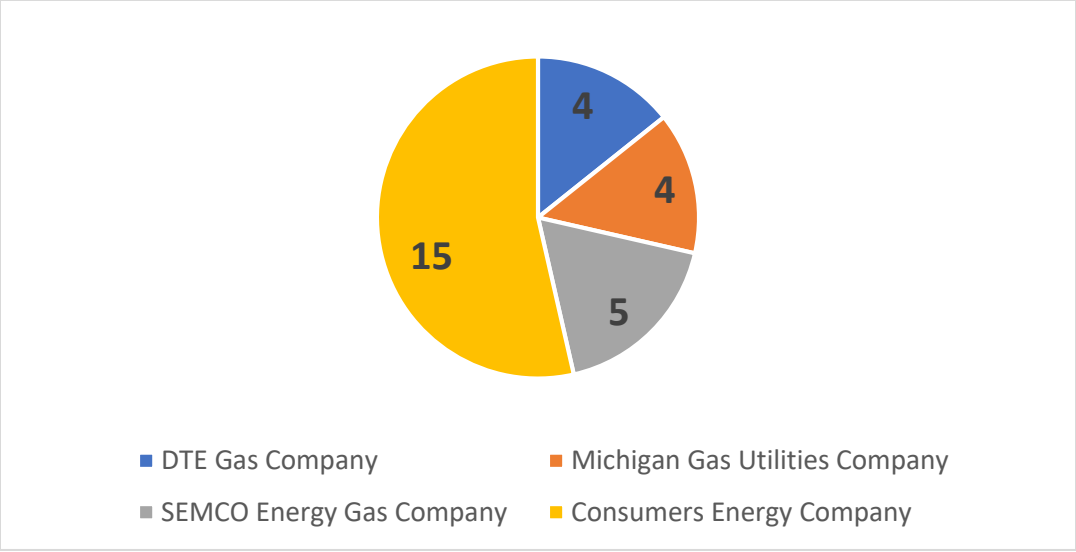
Source: MPSC Gas Safety Database

4.1.1.4 Interstate Inspections - Michigan is one of only eight states that are authorized by PHMSA to act as an interstate agent with the authority to conduct inspections on natural gas interstate pipeline operators. Annually PHMSA provides a preliminary risk-based plan to the MPSC Staff and seeks feedback from the Staff. The two agencies work together to develop the annual interstate inspection plan based on the PHMSA's risk assessment and input from the MPSC. Depending on the nature of the inspection, these can be either integrated (coordinated with PHMSA and other interstate agents) or state-led (coordinated entirely by the interstate agent). All enforcement is conducted by PHMSA after the inspection results have been finalized and communicated. From 2011-2018, the state of Michigan has averaged approximately 70 inspection-person days for interstate pipelines annually.

4.1.2 Storage Facility Operations

As previously discussed, the state of Michigan does not currently perform inspections on the storage facilities located within the state. For the purpose of this report, storage facilities begin at the wellhead. All storage field piping is considered transmission and is inspected by the MPSC Staff. Figure 4-4 shows the number of storage fields in Michigan owned and operated by intrastate pipeline operators. Note that storage facilities in the state are not treated with an odorant as would be natural gas in a distribution system connected to customers.

Figure 4-4 Number of Storage Fields for Michigan's Natural Gas Utilities



Source: MPSC

Figure 4-5 details each of the intrastate utilities' storage fields, the working gas capacity of each, and the associated number of wells that are used for injection and withdrawal. This information was obtained from the Underground Natural Gas Storage Facility Annual Reports for Calendar Year 2018 that are submitted to PHMSA. The Ray storage field is Consumers' single largest storage facility based on working gas capacity; DTE's Belle River site is the largest in the state.[103]

Michigan possesses the most working gas capacity in the nation due to its unique geology, which plays an integral role in gas supply and price stabilization during the winter months. Natural gas can be stored for an indefinite period. The production and transportation of natural gas takes time to reach the market areas, and based on the seasonal needs, when the natural gas that reaches its destination is not always needed right away, so it is injected into underground storage facilities. These storage facilities can be located near market centers that do not have a ready supply of locally produced natural gas or enough pipeline capacity to meet seasonal needs.

[103] Michigan's Natural Gas Storage Field Summary – All Operators: https://www.michigan.gov/mpsc/0,4639,7-159-16385_59482-426107--,00.html#tab=Active.

Figure 4-5 Pipeline Operators' Storage Fields, Capacity (Bcf), and Number of Wells

Operator	Reservoir Name	Working Gas Capacity	Injection Wells
Consumers Energy Company	Ray	47.52	50
	Winterfield	25	268
	Overisel	22.72	150
	Hessen	12.35	15
	Salem	11.46	44
	Cranberry	10.87	146
	Puttygut	9.39	12
	Four Corners	2.36	3
	Ira	1.98	12
	Riverside	1.48	50
	Lyon 29	1.22	3
	Lenox	1.19	7
	Lyon 34	0.69	4
	Northville Reef	0.49	3
	Swan Creek	0.41	1
	Total	149.13	768
DTE Gas Company	Belle River	59.65	30
	W. C. Taggart	39.78	43
	West Columbus	22.38	20
	Columbus	16.17	19
	Total	137.98	112
SEMCO Energy Gas Company	Morton	1.98	6
	Collins	1.46	2
	Lee 11	0.62	1
	Lee 2	0.62	1
	Lacey	0.18	2
	Total	4.86	12
Michigan Gas Utilities Company	Lee 3	0.96	3
	Partello Anderson	0.76	6
	Cortright	0.71	2
	Lee 3A	0.52	2
	Total	2.95	13

Source: MPSC

Traditionally, natural gas has been a seasonal fuel. That is, demand for natural gas is usually higher during the winter, partly because it is used for heat in residential and commercial settings. Stored natural gas plays a vital role in ensuring that any excess supply delivered during the summer months is available to meet the increased demand of the winter months. However, with the recent trend toward natural gas fired electric generation, demand for natural gas during the summer months is now increasing. Natural gas in storage also serves as insurance against any unforeseen accidents, natural disasters, or other occurrences that may affect the production, delivery, or pricing of natural gas.

During a peak flow day in January, Consumers Energy Company relies on their storage fields for approximately 77% of their GCR, gas customer choice, end-use transportation, and large power generation customer demand.[104] Consumers Energy Company's Ray facility is responsible for providing 39% of the natural gas that will be used and delivered on its system during a peak flow day. For a January design day, DTE Gas relies on its owned storage fields for approximately 77% and external storage fields for 7% of the natural gas that will be delivered to all DTE Gas customers, both on and off-system. DTE's plan for a January design day has no more than 32% supply dependence from any one storage facility on a peak day.[105] During a peak flow day in January, SEMCO Energy Gas Company relies on their internal storage fields for approximately 23% and external storage fields for approximately 43% of the natural gas that will be delivered on its system.[106] During a peak flow day in January, Michigan Gas Utilities Corporation relies on their internal storage fields for approximately 13% and external storage fields for approximately 28% of the natural gas that will be delivered on its system.[107] For the purpose of this report, external storage fields are storage fields from other utilities (both interstate and intrastate) that lease space to other utilities for storage and withdrawal purposes.

In general, natural gas is put into storage fields through the summer months and withdrawn during the winter months to offset average consumption on a utility's system or as a way to balance peaks that occur due to increased usage as a result of colder-than-normal temperatures. All storage fields are connected to a compressor station, which is a facility that contains compressor engines that are used to increase the pressure of the natural gas. Also present at compressor stations are meters that are used for measuring gas, gas quality analyzing equipment, and gas processing equipment to remove impurities. Generally speaking, compressor engines are not used to inject gas into a storage field until the pressure in the storage field nears the pressure in the supplying pipeline. At this point, utilities will utilize the compressors to increase the gas pressure on the pipeline to continue injecting into the storage fields. Since natural gas that is being transported on the pipelines already has to meet certain quality criteria, the gas processing equipment that is present at a compressor station is not used when injecting gas into storage.

When gas is being withdrawn from storage during the winter months, the process is reversed. If the storage field pressure is higher than the pressure on the pipeline, the compressor station engines will not be used until the point where the storage pressure is lower.

[104] Source: CE Design Day Supply Plan.
[105] Source: DTE Design Day Supply Plan.
[106] Source: SEMCO Design Day Supply Plan.
[107] Source: MGU Design Day Supply Plan.

However, gas processing equipment is always used upon withdrawal because impurities such as water and hydrocarbons will be present in the gas stream when removed from storage. Because the gas transported on the pipelines has to meet quality specifications, the gas processing equipment is necessary to ensure those conditions are met.

In that sense, storage operations can be likened to a battery: the battery is charged during the summer months and depleted during the winter months.

Also present at compressor stations are emergency shutdown (ESD) systems. If a compressor station meets certain criteria (which the majority in Michigan do), the compressor must have an ESD system that can isolate itself from the attached pipeline system. If there is an incident at the compressor station that resulted in an explosion or fire, valves that are located on the withdrawal and discharge piping would automatically close, removing a source of fuel from the fire. Additionally, the natural gas that would be "trapped" within the compressor station between the closed valves has to have a mechanism to vent at a location away from any potential hazard. These ESD systems are required to be annually tested to ensure proper function.

4.2 Regulatory Oversight of Energy Planning/Infrastructure

4.2.1 Natural Gas System Planning

System planning, which includes aspects such as long-term and outage planning, is an important aspect of the natural gas transportation system as a whole. Planning governs the overall health of the natural gas infrastructure, the reliability of the system to transport gas, both during ideal and extreme peak day weather conditions, and the ability of the utilities to expand upon their infrastructure to support a growing service territory and supply demand. Many aspects of system and outage planning are common to all natural gas utilities and present in each area of a utility's natural gas system, including long-term planning, outage planning, and risk or hazard analysis. Each utility also has its own unique approach to natural gas system planning specifically tailored to its individual needs and design considerations.

4.2.1.1 Natural Gas Storage Field Formation – Pursuant to PA 238 of 1923, the MPSC has the authority for authorize the formation of corporations for the purpose of storing natural gas to public utilities or natural gas utilities. Utilities file an application for a Certificate of Public Convenience and Necessity to acquire, construct, own and operate a natural gas storage facility. The Commission has the authority to authorize actions necessary to develop the storage field including acquiring property, design, safety equipment, and construction requirements. The Commission also has the authority to issue an order in the case of an emergency. EGLE's Oil, Gas, and Minerals Division issues permits for the individual wells and inspects the construction of them.

4.2.1.2 Storage – The SIMP applies to integrity and risk management of underground natural gas storage reservoirs and wells. The goal of the SIMP is to describe, in an inclusive and unambiguous manner, the processes and work tasks that are effective in maintaining functional integrity of storage reservoirs and wells. The SIMP incorporates requirements, programs, plans and procedures in API Recommended Practice 1170 Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage and API Recommended Practice 1171 Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon and Aquifer Reservoirs. The SIMP is the means by which each utility details the processes for incident reporting, risk assessment and management, integrity monitoring, site security and safety, procedures, and training. It is the foundational plan for all storage field related operations, and as guidance for integrity and risk management assessments; for both statewide and site-specific operations.

In addition, the SIMP is the overarching guideline by which each utility develops and operates their individual short and long-term storage reservoir and well programs. Short-term programs include the ongoing operations and maintenance work necessary to conduct storage operations. Long-term programs are the means by which utilities plan for future enhancements to their systems. Such long-term programs include the analysis and creation of a plugging and abandonment schedule for underperforming and temporarily abandoned gas storage wells, the analysis and execution of plans to discontinue operations of underperforming storage fields, development of a drilling program to reinforce the storage field with new and more efficient horizontal wells, the reduction of wellhead encroachment on active gas storage wells by increasing wellpad size and the installation of physical barriers, and the integrity inspection of plugged wells in compliance with storage regulations. One such example of a utility's long-term storage program is Consumers Energy's Well Rehabilitation Program; which is a ten-year program through which Consumers Energy will conduct storage well logging and preventative and mitigative operations in order to ensure storage field integrity and conduct storage field risk assessments.

Each utility, as a component of their system planning, also incorporate planning procedures for required equipment outages for maintenance and inspections. Utilities review their system configurations, individual field capabilities, system constraints, pipeline supply plans and forecasts, seasonal customer demands, and seasonal operating requirements in order to determine the extent of work that must be performed in order to improve the overall health and reliability of their systems. Many utilities update their equipment outage models on a monthly basis, and often more frequently when the volume of new data is received through

enhancement programs. The impacts of the equipment outage events are studied in order to ensure that the utilities can meet customer demand while supporting storage operations and overall health of the system. Optimal times for planned equipment outages, when possible, factor in variables such as storage balances, weather projections, and the availability of related facilities to make up lost supply.

4.2.1.3 Compression - Long-term plans common to all utilities for gas compression facilities include project upgrades, equipment replacements, and capital projects to ensure system integrity, reliability, deliverability, safety, and customer service. Utilities routinely perform analyses of their compression facilities to develop plans for system upgrades, replacements, or retirements. During the compression system analyses it is often the policy of the utilities to extend the review to other gas handling assets at the facility for potential upgrades and replacements concurrent with the planned compression work. This planning ensures that facility equipment is routinely up to date and running efficiently. Compression outage planning utilizes analytical models and tools to balance system and customer requirements with available system capacity. Outage planning considers supply and operations requirements, facility reliability, bottlenecks within the system, and customer impacts while allowing for maintenance and upgrade projects. When facility improvements are identified by the modeling to address reliability risks, the improvements are identified, evaluated, and implemented to provide cost effective and reliable service. As with all outage events, scheduled and unplanned, the impacts are studied to ensure that the utility can meet customer demand while supporting compression operations and system health.

4.2.1.4 Pipeline Siting & Certification – Pursuant to the statutory provisions of 1929 PA 9 (Act 9), the MPSC has the jurisdictional siting authority for intrastate natural gas pipelines regardless of pipeline diameter and length.[108] MPSC approval is required for all Act 9 pipelines before construction may commence. Applications under this statute are subjected to a review of the proposed pipeline route, environmental and landowner impacts, engineering specifications, and the public need of the proposed pipeline. Upon issuance of an Act 9 certificate from the MPSC, the applicant is granted the right of eminent domain and may initiate condemnation proceedings for tracts of land it has not yet acquired. Furthermore, pursuant to the statutory provisions of 1929 PA 69 (Act 69), the MPSC has the authority to regulate public electric and natural gas utilities and to require them to secure a certificate of convenience and necessity. Under Act 69, no public utility shall begin construction or operation of any public utility plant or system, nor render service for the purpose of transacting or carrying on a local

[108] FERC has siting authority for interstate natural gas pipelines such as the recent Nexus and Rover pipelines in southeast Michigan.

business, in any municipality in this state where any other utility or agency is engaged until such public utility first obtain from the Commission a certificate of public convenience and necessity that will allow such construction, operation, service, or extension. In other words, a competing utility cannot build into an area already under a utility franchise. Because there are some areas of the state without natural gas service, utilities seeking to provide service in these areas must first obtain an Act 69 certificate from the MPSC.

4.2.1.5 Transmission – Transmission enhancements for deliverability and integrity are long-term planning programs which ensure continued reliability and safe operation of the transmission infrastructure by performing necessary work such as: pipeline lowerings, valve replacements, pipeline relocation, new pipeline construction, and the efforts to mitigate third party pipeline damage. These future-looking programs allow utilities to meet the needs for Michigan's future capacity demands for continued deliverability and economic growth. Three examples of this type of planning are Consumers Energy's ongoing Saginaw Trail Pipeline and South Oakland Macomb Network projects as well as SEMCO's Marquette connector pipeline. The Saginaw Trail Pipeline project is currently entering its third construction phase and, when complete, will have replaced and rerouted portions of Line 2800 around high-density population areas, such as the City of Flint. The South Oakland Macomb Network project involves the elimination of two transmission pipeline segments in the metropolitan area, and in turn will improve deliverability and resilience, and reduce peak day risks to the system. The Marquette connector will link Northern Natural Gas and Great Lakes pipelines in the Upper Peninsula, providing increased access to natural gas for heating, power generation, and industrial uses, and increasing resiliency by having multiple sources serving the area.

In addition to the system planning procedures that utilities develop for the transmission facilities, outage planning procedures are also developed to allow for the continued maintenance, upgrading, and expansion of the transmission infrastructure. Steady-state and transient modeling software is utilized to plan and assess the capacity of each utility's transmission system so that minimum required inlet pressures to the city-gate stations which feed into the distribution system are met in order to serve existing firm customer demands. The modeling software is also used to indicate when the system is not able to maintain the minimum pressure, and to simulate the impacts of additional new customer demands. When the model indicates the necessity of work in order to maintain minimum inlet pressures, equipment outages are planned in order to upgrade the system. The outage planning considers the required supply to firm capacity customers, while simultaneously allowing the necessary maintenance and upgrade work on the transmission system. As a routine, all outage impacts are studied so that all future outage events can be planned in such a way to ensure customer firm capacity demands are met while supporting transmission operations and system health.

4.2.1.6 Distribution - DIMP regulations require that utilities develop, write, and implement an integrity management program which aims to assure pipeline integrity and improve the safety of pipeline transportation. The regulations require that utilities include in their DIMP rules and procedures for the identification of existing and potential threats to their assets, evaluate the threats and develop a risk ranking system, identify and implement mitigative measures to address the risks, and to understand their program performance and effectiveness in order to continuously improve the DIMP.

In an effort to maintain the safety and reliability of the distribution facilities, utilities employ various system and outage design plans to verify the resilience and robustness of their system. The most prominent system design plans for the distribution infrastructure include: main replacement, service line replacement, and asset relocation projects. All of these system planning measures focus on replacing aging and compromised distribution infrastructure with newer, and more integrally sound, pipeline materials. New pipeline projects may also be needed Including relocating distribution assets to facilitate civic improvement work, mainly road and sewer/water projects. New business connection projects are also included in the system planning process in order to serve the ever-growing expansion of business demands, and the resulting demand for distribution system expansion projects to meet the demand.

To facilitate the review of proposed and new customer loads, the utilities implement distribution system modeling processes, which are routinely rebuilt multiple times annually in order to accurately model current system operations. Scenarios are constructed, either at current design conditions or at proposed conditions for new service installations, to model the impacts on the system due to expansion projects and planned or unplanned system outages. When the models indicate that pressures are becoming too low on the system to meet firm customer demand, outages are planned in order to augment the system to increase capacity. Each utility has their own limits placed on system pressures to trigger when system augmentations are required. For example, Michigan Gas Utilities monitors for a 30% drop in pressure and develops system repair plans when winter surveys indicate a 50% drop in the system, while Consumers Energy identifies risk to the system at 7 pounds per square inch (psig) for a 60 psig system. Some utilities, when necessary outages are identified, remove the facilities to be out of service from their system models to see if the remainder of the infrastructure can adequately serve customers despite the planned outage. Outage planning is a critical component to system planning as it allows the utilities the opportunity to address maintenance issues on the distribution system as well as perform upgrade projects in order to meet a growing consumer supply demand in their service territories.

As an observation, integrity management is an evolving process and some utilities are beginning to explore a different approach to system planning. More than one utility is in the beginning phases of incorporating their individual storage, compression, transmission, and distribution planning programs into one all-encompassing system and outage planning program. While the core aspects of each individual program will remain, allowing the utilities to assess the risks and develop a prioritization for the vulnerabilities present in each particular facility type, the unification into a single program governing the planning for all facilities will

allow for the assessment of all risks enabling the utilities to prioritize the highest risks to their entire system.

4.2.2 Infrastructure and O&M Expense Prudence Reviews Through Rate Proceedings

Pursuant to the statutory provisions of 1909 PA 300, 1909 PA 419, 1939 PA 3, and 1982 PA 304, the MPSC has the authority to regulate the natural gas sales, transportation, storage, and distribution rates for public utilities distributing natural gas in Michigan. Within each natural gas general rate case proceeding, the regulated natural gas utility must provide information related to the O&M expenses and capital expenditures necessary to maintain and improve utility infrastructure in order to provide safe, reliable service and meet customer service quality expectations.

O&M expenses are the ongoing expenditures incurred by the regulated utility to operate its natural gas system and maintain associated utility infrastructure. Typical activities performed under O&M are related to: meter reading and routine exchanges; meter turn-ons and turn-offs; incident response and investigation; leak surveys, patrols, and remediation; corrosion control; pipeline and storage well integrity assessment and remediation; inspection, repair, and maintenance activities on gas storage systems, compression equipment, transmission pipelines, distribution mains, services, regulators, meters and other appurtenances to meet operational and regulatory compliance requirements; underground facility damage prevention activities; storage inventory, deliverability, and reliability; gas control and planning; and lost and unaccounted for gas and company use gas. Significant areas of focus in O&M expense levels in recent general rate case proceedings have been related to:

- Expanded use of inline inspection methods for transmission pipeline integrity assessments and increases in the number of anomalies requiring remediation as a result of increased inline inspection;
- Impact of storage integrity management requirements;
- Compliance with maximum allowable operating pressures for distribution and transmission;
- AMR/AMI initiatives and the impacts on meter reading expenses;
- Leak response, survey, and remediation related to the condition of high-risk distribution main and service materials; and
- Meter move-out from inside homes to the home's exterior.

Capital expenditures represent investments by the regulated utility to replace existing or install new infrastructure. Typical capital investment projects are related to: public improvement and asset relocation of facilities; main extension and customer attachments to serve new customers; installation, replacement, or enhancement of storage wells, compression equipment, transmission pipelines, distribution mains, services, regulators, meters (including meter move-out), and other appurtenances to meet capacity and deliverability demands, address system integrity, and meet regulatory requirements; and fleet, equipment, facility, and information technology necessary to support business needs. Significant areas of focus and drivers for

increases in capital expenditures in recent general rate case proceedings have been major projects related to:

- Distribution main and service line replacement initiatives to accelerate the removal of high-risk, vintage pipe materials that are more prone to leaks (Michigan gas utilities had replacement schedules ranging from 50-100 years until the MPSC approved programs beginning in 2011 to accelerate the replacement under schedules ranging from 20 to 30 years.);
- Replacement of transmission pipeline systems to address system integrity and deliverability requirements;
- Installation of new transmission pipeline systems to enhance system supply, reliability, and redundancy;
- Upgrades to existing compressor station facilities to address system deliverability and reliability;
- Expansion of inline inspection capability on transmission pipeline systems;
- Advanced metering infrastructure.

4.2.3 Review of Supply Arrangements to Meet Customer Demand and Redundancy in Gas Cost Recovery Proceedings

The purpose of the GCR Plan under Act 304 is for the regulated utility to present a proposed plan for gas supply based on expected sales volumes that assume normal weather. This allows the utility to calculate a rate, or "factor," for cost recovery.

Within each annually reviewed GCR plan a regulated utility forecasts a design/peak day that it must be able to serve reliably. It is typically based on the coldest weather experienced in the utility's service territory history on an end-of-January or end-of-February day. Some utilities even provide their supply plan for an end-of-March peak day because it had been the coldest day on the system and because the storage inventories become lower as the heating season progresses. Most will factor in a wind component or other usage contingencies. The utility may also consider the possibility of Colder-Than-Normal (CTN) weather having been experienced up to the design day thereby affecting storage capabilities. The utility then describes how it will meet its system requirements on each peak day. Supply requirements include forecasted usage for customers taking full-service from the utility as well as gas choice customer usage (the utility is the designated Supplier of Last Resort (SOLR) for gas choice and end-use transportation customers).

Each utility provides a thorough explanation of how it will supply a peak day. Most utilities include some sort of buffer above their forecasted design day requirement. This buffer is typically determined using a Commission approved statistical approach. One such example would be Consumers Energy's 4% probability standard which equates to 1 in 25-year risk of colder weather and higher associated demand than the utility's design cold plans. Others employ a standard deviation buffer method such as SEMCO's 2.5 standard deviation requirement. This method projects design day requirements 2.5 standard deviation levels above the estimated design day to provide a more robust level of protection should a design day occur.

A regulated Michigan utility typically plans for approximately 50% of its total winter supply requirements to come from storage. The smaller utilities must lease storage from a third party to achieve this level. The Commission has supported this level of storage because stored gas provides price stability in times of high demand and reliability being that it is stored within the state and therefore readily available. At the same time, it is prudent to have contingency plans if most peak day supply requirements come from one supply source, storage facility, or otherwise.

The supply that comes in via pipeline on a peak day can be procured in different ways. The regulated utility can bring supply in on one of the pipelines with which it has a firm capacity contract. Firm capacity ensures that there will be space on that pipeline for the utility to transport its supply. The utility then needs to contract for supply with a supplier. There is the possibility that due to a pipeline incident, sometimes known as a "Force Majeure," the supply may not be delivered to the utility's city-gate, due to the intended delivery route being unavailable. Procuring all peak day supply requirements in this manner is unnecessarily costly because the utility would have to hold redundant, and for the most part unused, capacity just to protect for its peak day requirements.

The utility can also enter into a contract with a supplier or gas marketer to bring supply directly to its city-gate. This eliminates the transportation aspect of the procurement for the utility. It is the supplier's responsibility to get the gas to one of the utility's city-gates. Under this arrangement the transportation component of the cost of gas is worked into the price. Unless the utility fixes the commodity portion of the cost, it will be assigned the market price at the time the gas is needed. This can lead to price risk, but in general it lowers the total cost of gas (especially in periods of low commodity prices and adequate pipeline capacity) because it reduces the amount of unnecessary pipeline capacity the utility must procure. Despite the more "as needed" nature of this supply procurement method, its reliability has been proven over the recent years. The city-gates of Michigan's major utilities have enough liquidity to ensure that supply has been available on peak days. Since the utilities have multiple city-gates, the possible delivery points available to the supplier are numerous, which reduces the probability that a Force Majeure event will affect the delivery. This procurement method may be costlier for short periods during times of high demand, but with the Midwestern hubs now having ample supply due to shale production, actual lack of gas supply has not and most likely will not be an issue in the future.

A resilient system has facilities, systems, controls, and procedures in place that will provide capacity for peak design days by utilizing diversity in gas supplies, multiple interconnections, redundancies or bypasses in flow paths at critical facilities, and gas supply reserve margins. This past winter's polar vortex experience highlighted the importance of a resilient peak day supply plan. A resilient peak day portfolio ensures that if something were to happen to a major supply source on a peak day, the impact to customers would be minimized to the best extent possible. This diversity should apply to the storage fields as well as the pipeline supply. Storage diversity would imply that not all the utilities' storage sourced peak day supply is coming from one or two fields. Diversity of pipeline supply means relying on multiple pipelines for transportation, multiple marketers for supply, and multiple city-gates for delivery. Diversity in both areas ensures the robustness of the utility's peak day plan and minimizes the likelihood the utility will

be unable to serve. Any changes that come about as a result of this report may add cost. Minimizing cost has always been one of the primary priorities of the Commission with regards to the GCR plans. Reliability has been a priority as well, but contingencies related to worst-case scenarios now must be given more consideration than they have been in the past. The imprudence of a minimally diversified portfolio had not been seriously questioned if the supply was shown to be available at a reasonable cost. In future GCR plan cases, the Commission clarifies that: 1) the utilities must consider contingencies related to resilience at key facilities and 2) the Commission Staff must consider more resilient peak day plans and make recommendations that give a higher priority to this issue.[109]

4.3 Vulnerabilities

4.3.1 System Limitations

Vulnerabilities vary from utility to utility and even within a utility from system to system. This section will specifically discuss the following vulnerabilities: bottlenecks; seasonal restrictions; required outages for maintenance; and worst-case scenarios/consequences on peak summer and winter days. As discussed, and outlined in previous sections of this report, the Commission's authority with regards to these issues is broad and well founded in statutory authority. The Commission's authority rests in many different areas including rate case proceedings; GCR plan and reconciliation cases; gas safety and technical standards; depreciation rate cases; and pipeline and gas storage siting. The recommendations contained within this section are based on the Commission knowledge of the infrastructure through the cases that are related to these different statutory proceedings and the investigation done as part of the information gathering for this report.

4.3.1.1 Bottlenecks are constraints on the system that prohibit current requests for service or future expansion or growth to both existing and new customers. Bottlenecks can exist in either the distribution or transmission portions of the system and can be related to other existing vulnerabilities or past growth that has removed any redundant system capacities. Bottlenecks can be remediated in many ways depending on the type of infrastructure and why the bottleneck exists. Bottlenecks within the distribution system can be remediated by adding connections between existing systems, replacing existing pipeline restrictions with larger

[109] For a breakdown of each utility's peak day supply plan, see the peak day exhibits in the following dockets: Consumers Energy Company U-20233, DTE Gas U-20235, Michigan Gas Utilities U-20239, and SEMCO Energy Gas Company U-20245.

diameter pipelines, upgrading regulator stations, and constructing new pipelines. Transmission bottlenecks can include similar solutions but may also include adding interconnects with other transmission pipelines or upgrading storage field capacity. The utilities use different design day parameters for both distribution and transmission. Bottlenecks for transmission systems are vetted in many different types of cases before the Commission including GCR plan and reconciliation cases, rate cases, and pipeline siting cases. The Commission Staff would be a party to those cases and make recommendation to the Commission on the need of any proposed system enhancements. Distribution bottlenecks are typically vetted in rate cases in which the Commission Staff would be a party and would make recommendations on the need of any proposed system enhancements.

4.3.1.2 Seasonal Restrictions include the need for storage gas processing in the winter, compression for summer storage injection, compression for end-of-season storage withdrawal, and summer grid interdependencies related to increased reliance on natural gas-powered generation. Similar to bottlenecks, any issues related to seasonal restrictions can be remediated in different ways depending on existing infrastructure. Redundant processing can be added at compressor stations associated with storage, additional compression horsepower can be added to increase redundancy, and additional pipelines can be built to add capacity for summer peaks related to generation. The utilities have a responsibility to recognize the need and propose projects related to these restrictions and the Commission's authority resides in the applications filed in the rate cases, GCR plan and reconciliation cases, and pipeline siting cases. Commission Staff would be a party to those cases and can make recommendation to the Commission on the need of any proposed projects related to seasonal restrictions.

4.3.1.3 Required Outages for Maintenance can be required for different parts of the system. In most situations the infrastructure is designed to be able to accommodate necessary maintenance. Increasing reliance on in-line inspection tools for integrity management assessments on transmission pipelines and the associated remediations cause outages that impact the capacity of the system during shoulder and summer months. These outages can restrict electric generation loads and storage injections. The assessments are necessary to ensure the safety and reliability of the system and the utilities have a responsibility to recognize and plan for the necessary outage windows to accommodate this system maintenance. The Commission's authority resides in the applications filed in the rate cases, GCR plan and reconciliation cases, pipeline siting cases and pipeline safety. Commission Staff is a party to those cases and can make recommendation to the Commission on the pipeline safety standards; necessity of the outages for assessments and remediation; gas supply issues; and proposed projects related to system enhancements to accommodate in-line inspection tools or increase capacity.

4.3.1.4 Worst Case Scenarios on Peak Summer or Winter Days can impact both the distribution and transmission systems. Summer peak day issues include pipeline ruptures. A specific example of this would be a rupture related to third-party damage. Winter peak day issues include many more and different issues across both distribution and transmission systems. These issues include pipeline ruptures, but additionally, equipment failures at critical regulator stations, compressor stations, or storage fields. The design criteria vary between

utilities and reliance on any one piece of the utility's system to meet that peak design day also varies. Similar to the other vulnerabilities, the Commission's authority is broad, and issues related to the design, resiliency, and redundancies built into the systems can be addressed through proceedings related to rate cases, GCR plan and reconciliation cases, pipeline siting cases and pipeline safety. Contingencies related to worst-case scenarios must be given more consideration than they have been in past cases before the Commission. The utilities should strive for resiliency at key assets and should consider options including, but not limited to, diversity in supplies, redundancies in key assets, and limited dependency on any one facility. In future rate and GCR plan and reconciliation cases the Commission clarifies that: 1) the utilities should consider contingency options for resiliency at key facilities and 2) the Commission Staff should consider these issues and make recommendations to further the safety and reliability of the state's natural gas system, including, but not limited to, consideration of more diversified peak day plans.

4.3.2 Infrastructure Failures

An infrastructure failure is the inability of the system to handle an event related to an outside force or improper maintenance. Outside force can include natural causes, vehicle damage, or third-party excavation damage. Improper maintenance can include human factors, construction defects, material / equipment defects, or corrosion. Thus, the utilities are aware of the necessity to prevent failures, and to be able to withstand failures due to outside force or improper maintenance. Many of the design, construction, operations, maintenance, corrosion control, employee qualifications, and integrity management regulations found in the MGSS and the 49 CFR Part 192 are in place because of previous pipeline failures and were codified to prevent similar incidents in the future. The utilities must be diligent in design, construction, and maintenance of pipeline facilities and infrastructure to ensure that the system remains resilient in its ability to prevent and withstand failures. The Commission Staff recognizes the potential for unchecked events to later result in significant failures. On a day-to-day basis, the utilities should be performing maintenance to the system that minimizes the possibility of future failures and recognizes the need for future enhancements that are included and vetted in rate cases. During pipeline safety inspections and the review of maintenance expenditures in rate cases, the Commission Staff must consider the necessity of projects that will advance the reliability of the system and aid the utilities in the prevention of future failures. The Commission addresses issues related to failures in rate case proceedings and pipeline safety inspections / reports.

4.3.3 Interconnections

Interconnection vulnerability relates to the physical connection of pipelines within the natural gas grid. Within the distribution grid, these connections add capacity and redundancy that allows flexibility for maintenance or unforeseen outages. Interconnections also exist between utilities within distribution systems. These connections are typically borne out of a necessity because there are no other viable alternatives to provide gas to these markets. Within the transmission system, interconnections allow for redundancy by having multiple sources of supply. They accommodate maintenance, increase the ability to deal with failures, and provide flexibility in getting gas into the utility's system. The utilities are cognizant of the redundancy

and flexibility created in having additional interconnections and study the necessity of connections during ongoing system planning and system design work. Distribution interconnections within a utility's own system are often cost effective and easily constructed, so the standard practice is to make these connections where feasible. As opportunities arise, new transmission interconnections are studied and consideration is given to the benefits related to the cost of gas, system redundancy, and reliability. Additionally, transmission interconnections may exist that are unused or underutilized, which typically occurs because the utility can negotiate more cost-effective rates through other connections. The need for new system interconnections and the use of existing connections must be better understood and vetted in future cases before the Commission. Natural gas distribution utilities should have diversity in supplies and limit dependency on any one interconnection. The Commission recommends the utilities consider the necessity and cost of new transmission interconnections including the diversity in supply sources available and propose prudent investments to increase the reliability of the natural gas system. Similarly, the utilities should consider diversification of supply sources in the portfolio, providing for redundancy and reliability through the use of all the existing interconnections available in GCR plan and reconciliation cases.

4.3.4 System Redundancy

System redundancy is the overall capacity of the system to deal with planned or unplanned events. Capacity constraints can exist within a system because of customer growth, maintenance activities that restrict flows, outages related to failures or some combination of these events or prolonged cold weather. The utilities are aware of the need to have system redundancy and study the necessity during ongoing system planning and design work taking into consideration future growth, maintenance requirements, and different scenarios that could potentially cause a partial outage. Like other vulnerabilities, the necessity for redundancy in a system has to consider the cost for that benefit and the potential number of customer outages that could occur if that system does not have sufficient redundancy. Seasonal redundancy constraints may also exist on a system when an event occurs. The utilities should be diligent in their system modeling / planning work to identify the necessity of system redundancy and the Commission recommends the utilities look for opportunities to develop solutions that mitigate risk of outages, improve operational flexibility, and accommodate future growth in demand.

4.3.5 Single Source Supplies

Single source supply is the dependency on only one source of gas to provide service to residential and / or commercial customers. Single source vulnerability exists both in the transmission and distribution systems. To create a system that has 100% redundancy, so no customer is only provided service from one source, is cost prohibitive. Cost-effectively creating redundancy in systems that provide service to tens of thousands of customers is a desirable goal.

It is important to understand that natural gas outages can be much more labor intensive than electric outages. The process of restoring natural gas service to customers involves physically shutting off the natural gas to every customer at their meter; reestablishing service to the system; and then reestablishing service to every individual customer including a leak test of

the customers piping and relighting appliances. Developing resources and qualified individuals to perform this work can take time. Restoration work in systems that contain thousands of customers could take days and possibly weeks, which in winter conditions, may risk lives and cost millions of dollars in property damage because of freezing temperatures in customers' buildings.

Depending on the circumstances of the outage, the amount of time that it would take to physically visit each meter for the initial turn-off and final turn-on varies. One Michigan utility has established a target time of performing six shutoffs an hour and four turn-ons an hour per technician. Turn-ons require more time because customer relights are involved. An outage of just 1,000 customers would involve over 400 labor hours just to perform the work necessary at each meter. Therefore, bringing in additional crews to assist with restoration can drastically reduce the outage time. It is for this reason that mutual-assistance programs are vital to ensuring an effective response; however, not all utilities have established these agreements. While there are different entities offering mutual-assistance programs in different parts of the nation, the one most pertinent to the state of Michigan is through the American Gas Association (AGA). Refer to Appendix C for the current list of signatories.

The vulnerability of single source supplies varies from utility to utility and within a utility, from system to system. The utilities need to be diligent in their system modeling work to identify the most vulnerable systems and develop long term plans to cost-effectively construct a second gas source for single source systems that provides service to a large quantity of customers. The Commission has dealt with issues related to single source supplies in rate case proceedings and pipeline citing cases based on Staff recommendations and utility proposals. The Commission's broad authority resides in many different areas including rate case proceedings; GCR plan and reconciliation cases; gas safety and technical standards; and pipeline and natural gas storage siting.

4.4 Risk Assessment

4.4.1 Infrastructure

4.4.1.1 Asset Conditions and Performance - PHMSA has mandated that a utility must have a mechanism for measuring risk on distribution, transmission, and storage fields, depending on what facilities a utility possesses. These risk tools are required as part of each asset's integrity management program. Appendix D is a May 2019 MPSC summary document describing risk assessment methodologies for natural gas utilities.

Integrity Management Rule Highlights

transmission integrity management program: An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, Section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§ § 192.919, 192.921, 192.937), and to determine what additional preventative and mitigative measures are needed (§ 192.935) for the covered segment.

Per 49 CFR 192.917

distribution integrity management program: An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services, and other appurtenances; areas with common materials or environmental factors), for which similar actions would likely be effective in reducing physical and cyber risk.

Per 49 CFR 192.1007

Identification and assessment of risks to functional integrity: The operator shall develop, implement, and document a program to manage risk that includes data collection, identification of potential threats and hazards to the storage operation. Risk analysis should include estimation of the likelihood of occurrence of events related to each threat, the likelihood of occurrence and potential severity of the consequences of such events, and the preventive, mitigative, and monitoring processes to reduce the likelihood of occurrence and/or the likelihood and severity of consequences, and a periodic review and reassessment of the processes. [API Recommended Practice 1171]

Per 49 CFR 192.12, which incorporates by reference API Recommended Practice 1170 & 1171

Cathodically unprotected steel, ductile iron, cast/wrought iron, and copper are generally considered poor performing. In the context of this report, "poor-performing" is based on the material type having higher leaks-per-mile than others. Cathodic protection is an electrochemical process where direct current is applied to a buried metallic structure to slow or stop corrosion.

Figure 4-6 illustrates the mileage of each of these poor-performing material types per 1,000 miles in Michigan and nationally. Note that this breakout is only for distribution pipe materials. The analysis was performed in this fashion to normalize the data. A straight number of miles of each material type does not provide a suitable comparison as to how Michigan's natural gas infrastructure is comprised when compared to other states.

Figure 4-6 Miles of Cathodically Unprotected Pipe per 1,000 Miles

Material Type	National	Michigan
Unprotected Steel	38.921	36.895
Ductile Iron	0.231	0.009
Cast/Wrought Iron	10.263	20.804
Copper	4.201	32.834

Source: PHMSA Annual Reports (PHMSA F7100.1-1

From analyzing this data, Michigan performs comparably with the national average regarding the amount of unprotected steel pipe, and has significantly less ductile iron than the national average, but approximately twice as much cast and wrought iron pipe per 1,000 miles than the national average, and eight times more copper per 1,000 miles than the national average.

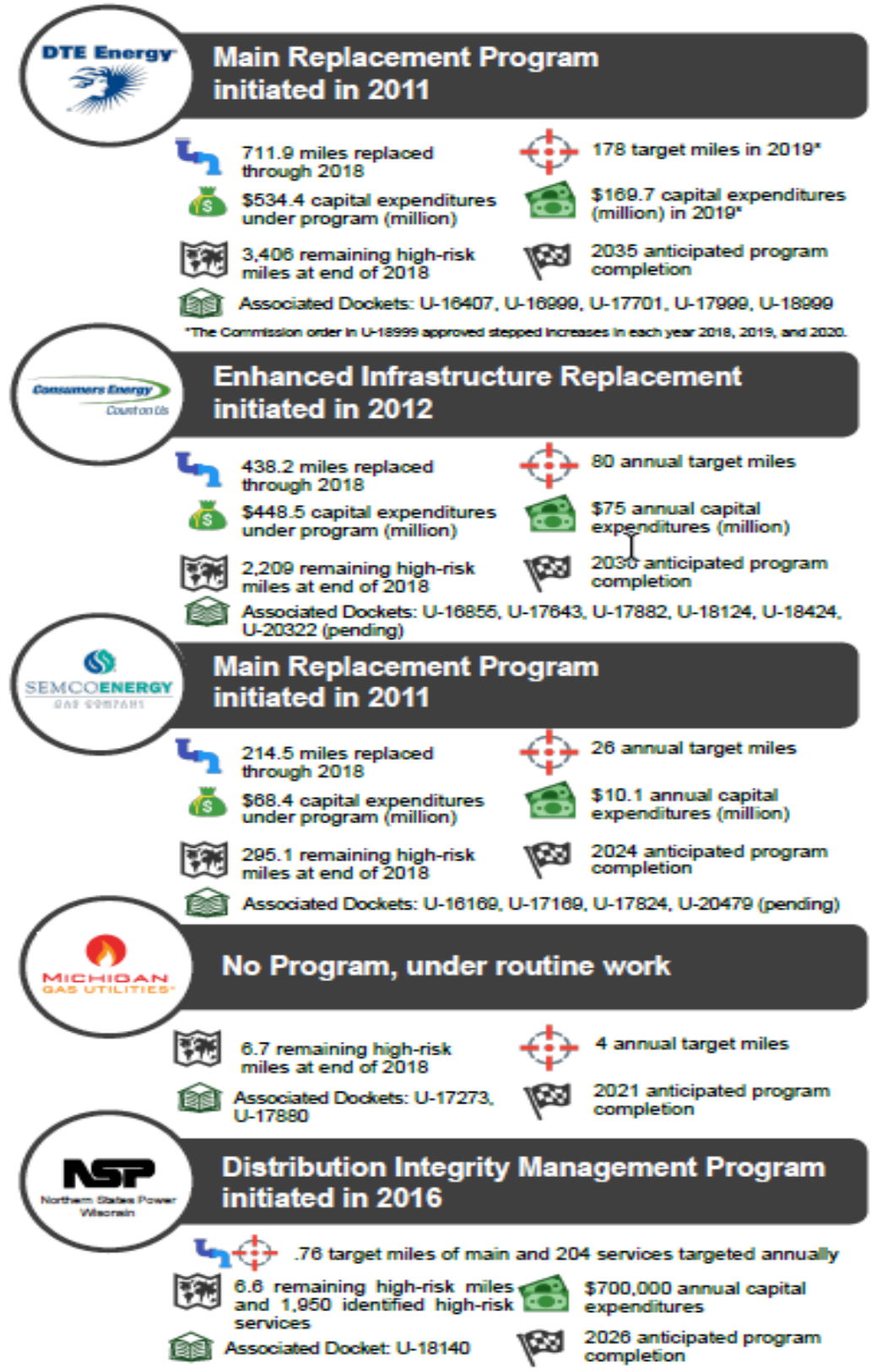
The MPSC has supported replacement programs of these material types in rate cases, as illustrated in Figure 4-7.

Such efforts primarily address distribution pipelines. Transmission pipelines, due to operating at a significantly higher pressure, have typically been constructed using steel pipe with cathodic protection applied to it. As such, there has not been the same level of utility investments in replacing transmission pipe. However, as these assets continue to age, and as growth in different parts of Michigan occurs, additional replacement may be necessary.

4.4.1.2 Interconnection Limitations or Constraints - The risk assessments that are covered by the regulations in 49 CFR Part 192 do not place an emphasis on sources of supply or potential outages should the sources of supply become unavailable. The risk models stress the importance of protecting the public and property from the hazards associated with natural gas, not the hazards associated with the lack of natural gas.

Currently, Consumers Energy, DTE Gas, MGU and SEMCO have flow-modelling capabilities that can analyze different scenarios, such as loss of supply at an interconnection or storage supply, lack of delivery at a receipt point, the number of potential outages associated with supply interruption, etc. Lacking in these modeling capabilities is the functionality to calculate risk. While the flow models can analyze the outcomes of a supply interruption, such as determining the potential and extent of a customer outage, they are not rigorous enough to determine the likelihood of such an event or the consequences.

Figure 4-7 Natural Gas Distribution Main Replacement Programs



In many cases, where a utility may receive natural gas directly from another utility, an effective risk calculation that considered the impacts of a lack of supply would be unattainable without knowing the infrastructure of the other utility that provides their gas. This data is necessary to determine the likelihood of an outage, but in many cases would be confidential to the utility.

Additionally, the complexity of the variables that could be used to determine the consequences of a lack of natural gas supply are staggering. Such variables include the location of the outage (which could have different impacts even if the number of outages were the same), the time of year the outage occurred, the dependency (or lack thereof) of natural gas fired electricity generating plants, the availability of warming centers and the American Red Cross, etc.

The need for new interconnections and the use of existing connections must be better understood and vetted in future cases before the Commission, specifically GCR plan cases. The utilities must have diversity in supplies and limited dependency on any one interconnection. The utilities should consider diversification of supply sources in the portfolio by providing for redundancy and reliability using all the existing interconnections available to the utility. In the GCR plan cases, the Commission Staff must consider diversification of existing supply sources and make recommendations to the Commission to further reliability of the natural gas system.

4.4.1.3 Visibility and Controls - Pipeline utilities in the state have Supervisory Control and Data Acquisition (SCADA) systems, which allow for remote monitoring of their pipeline systems from a central control room. The operators of these system are called controllers. Controllers can monitor and, in some cases control, pipeline flows, pressures, temperatures, valve statuses, and more, depending on the robustness of the utility's system.

The more monitoring and controlling actions that a controller can take on a pipeline system, generally the quicker the system can respond to unforeseen events. For example, if pressure unexpectedly drops on a segment of pipeline, a controller can be made aware of the situation in seconds and respond as appropriate. The corrective actions may be initiated directly after an incident occurs, rather than having to dispatch an employee to the location of the event.

One of the most significant actions a controller can take is remotely controlling valves that have the appropriate equipment installed to facilitate such control. Such actions can reduce the consequences of a pipeline failure by being able to effectively isolate the pipeline segment moments after the failure has occurred and being able to open valves to permit an alternative flow of gas to enter the system thereby continuing to serve the market. Currently, regulations in place require that utilities install either remote or automatic control valves only in the locations where a utility's risk analysis has determined that they are necessary. This performance-based approach has led to different levels of remote-control valve installation by various pipeline utilities within the state.

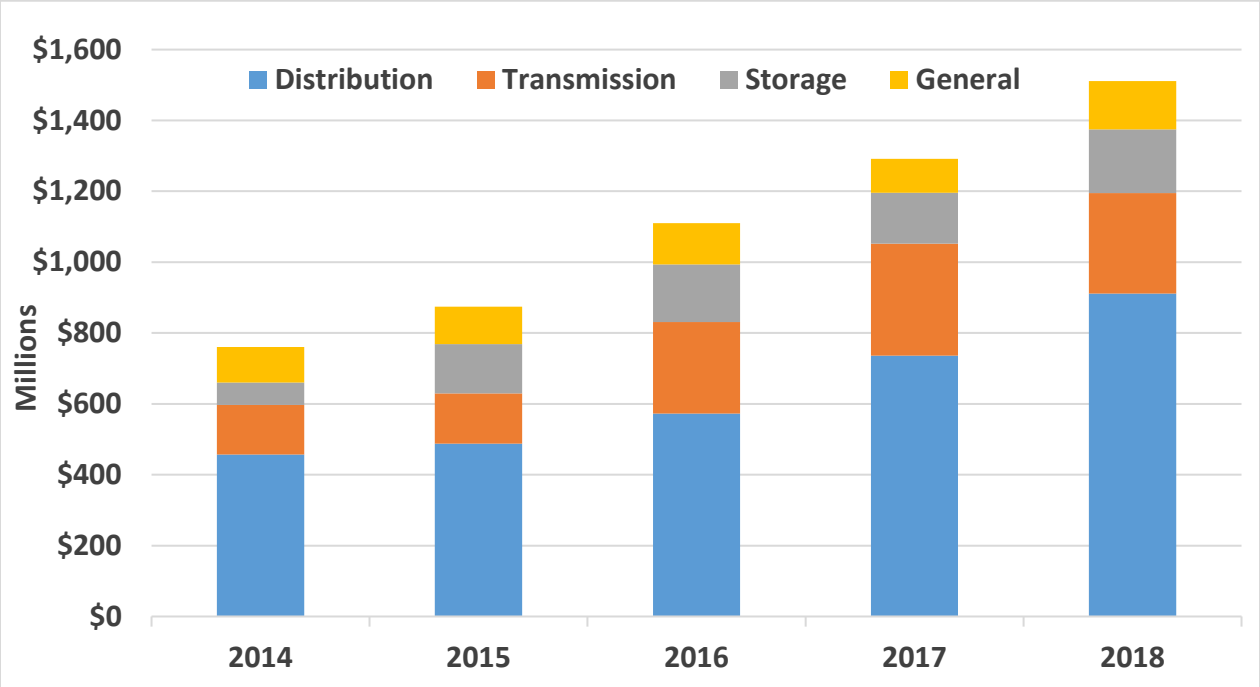
49 CFR 192.935(c) requires the utilities to complete a risk analysis of their pipelines in high consequence areas to determine if automatic shut-off valves or remote-control valves would add protection to these areas. DTE Gas and Consumers Energy have done the risk analysis and have added valves as a result of the analyses.

4.4.2 Investment Trends and Projections

4.4.2.1 Capital Investments and Operations and Maintenance Expenditures

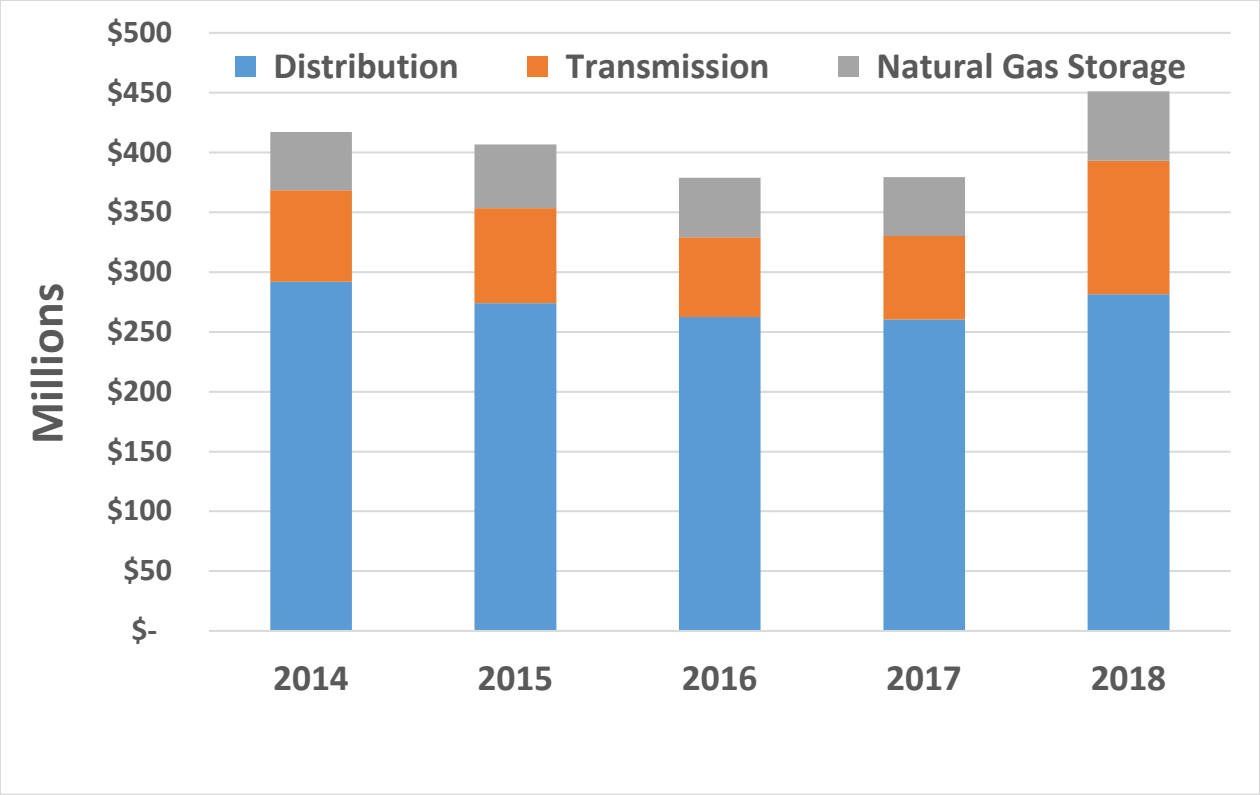
A review of historical capital and O&M expenditures by major natural gas utilities in Michigan indicates an increasing trend in investment in natural gas infrastructure. Historical capital expenditures are shown in Figure 4-8 and historical operations and maintenance expenditures are shown in Figure 4-9. The primary drivers for increased expenditures are related to replacement and increased capacity and deliverability of existing infrastructure related to distribution, transmission and compression, and storage systems necessary to safely and reliably deliver natural gas throughout the state.

Figure 4-8 Historical Capital Expenditures by Plant Type



Source: MPSC Utility Rate Cases

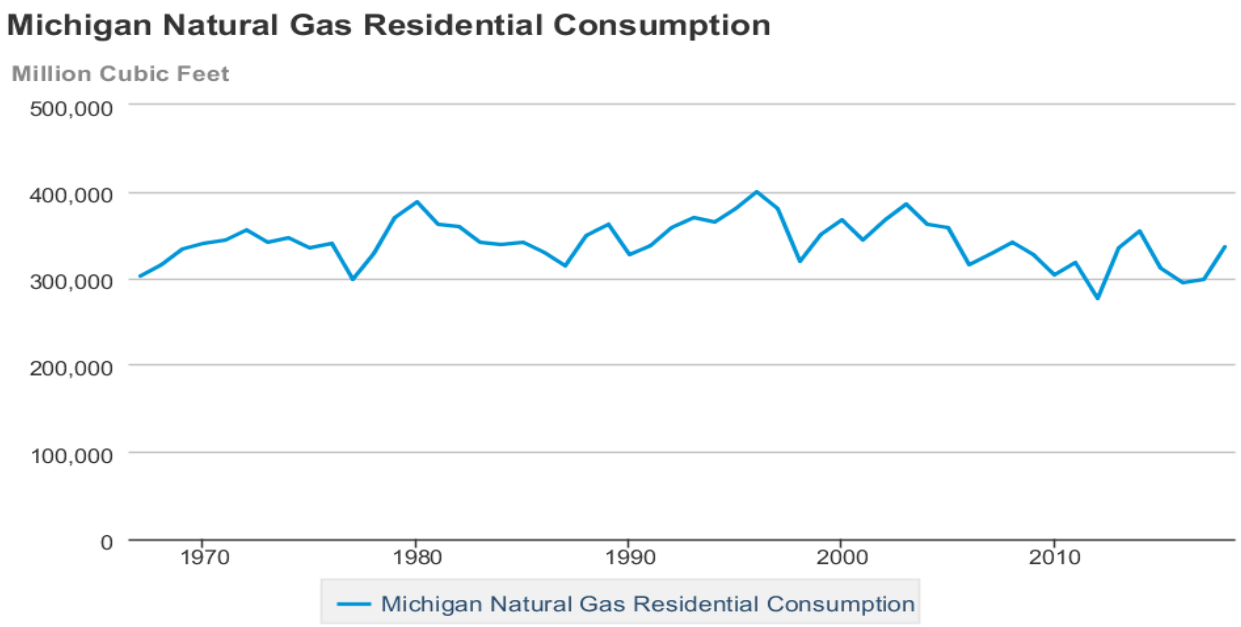
Figure 4-9 Historical Operations and Maintenance Expenditures by Plant Type



Source: MPSC

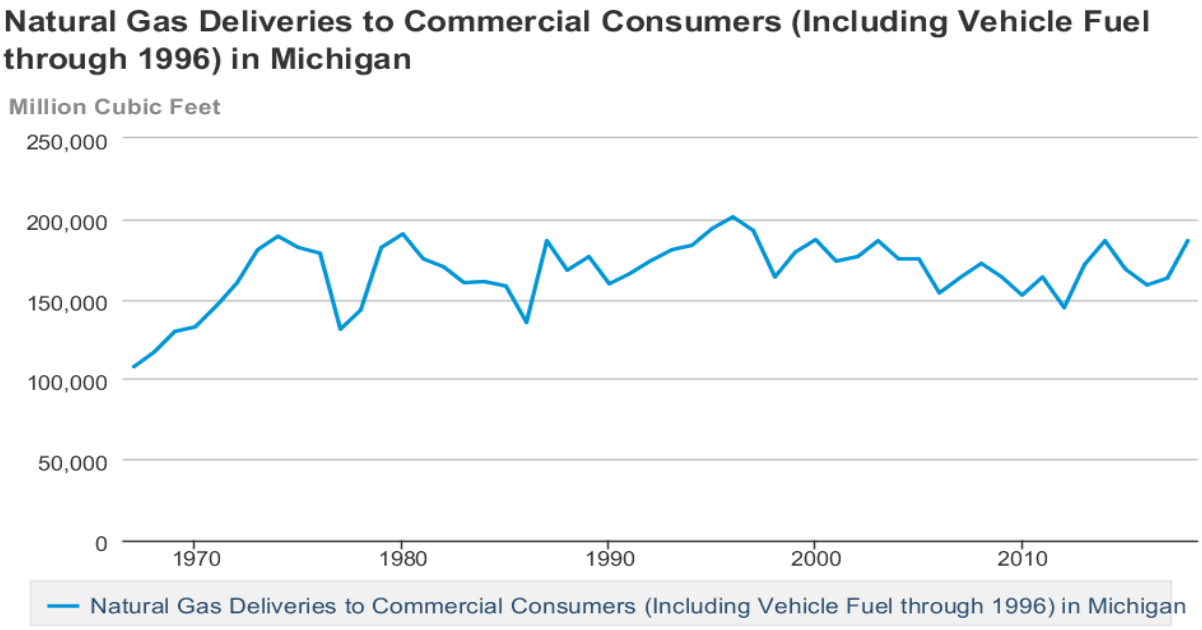
4.4.2.2 Clean Energy Requirements and Drivers; Emerging Technologies - The AGA has stated that "The average American home consumes 40 percent less natural gas than it did 40 years ago. Since 1970, the decrease in natural gas use per residential and commercial customer has averaged one percentage point per year." The decrease in natural gas for each individual customer is offset by new customer loads continuing to be attached to the system. This is illustrated in Figure 4-10, which shows that despite the natural gas efficiencies being realized, the overall consumption for the residential customer class has remained relatively consistent since 1970. The same trend appears for the commercial customer class as well, illustrated in Figure 4-11. The increase in efficiencies is offset by new customers, creating a relatively stable trend in natural gas usage.

Figure 4-10 Michigan Natural Gas Residential Consumption



eia Source: U.S. Energy Information Administration

Figure 4-11 Michigan Natural Gas Commercial Customer Consumption



eia Source: U.S. Energy Information Administration

4.4.2.3 Potential Impacts of Investments and Timing of Recovery on Reliability, Operations, and Energy Supply and Delivery Risks - In order for the regulated utility to proceed with significant investments that are necessary to ensure safe and reliable operation of its natural gas system, there must be a reasonable level of regulatory certainty that such investments will be deemed approved for recovery in general rate case proceedings after prudency review. To reduce the regulatory lag for recovery of such investments, PA 3 of 1939, as amended, MCL 460.1 et seq., allows a utility to use projected costs and revenues for a future 12-month period in developing its requested rates. Further, it requires that natural gas rate applications filed complete and in compliance with application filing forms and instructions be processed in a 10-month timeframe from the date of application, and allows a utility to file a new general rate case 12 months following the date of the filing of its previous general rate case application. Although a regulated utility is permitted to file general rate case applications annually, the prudency review in such a regulatory proceeding is time consuming and burdensome on the utility, the Commission, and interested parties. To mitigate the burden of frequent general rate case proceedings, the Commission has been supportive of alternative mechanisms that allow regulated utilities to delay general rate case applications while maintaining certainty and reducing regulatory lag of recovery of such investments. Specifically, the Commission has approved investment recovery mechanisms for SEMCO Energy Gas Company, DTE Gas Company, and Consumers Energy Company that allow for monthly surcharge assessments to offset ongoing capital investments until the investments are included in rate base in the next general rate case proceeding. These recovery mechanisms provide the regulated utility a level of confidence in recovery of long-term capital projects necessary to mitigate system risk and avoid delay in recovering costs of such programs in between general rate case proceedings. The Commission has currently approved recovery mechanisms related to accelerated distribution main replacement, meter move out initiatives, and pipeline integrity.

4.4.3 Adequacy of MPSC Rules and Best Practices Related to Customer Safety, Reliability, and Resilience; Customer Notification

The MPSC has rules governing pipeline safety, such as the Michigan Gas Safety Standards (which incorporate by reference the Federal Pipeline Safety Regulations) and has adopted additional rules governing the Production and Transmission of Natural Gas and Technical Standards for Gas Service. These rules are more stringent than the Federal Pipeline Safety Regulations.

One place where Michigan's statutory requirements are less than the federal requirements is the Commission's ability to issue penalties for violations of the Michigan Gas Safety Standards. This issue has been a raised as part of PHMSA's annual audits and has resulted in a finding that impacts the federal funding available to the state. The current penalty authority is found in MCL 483.161 and allows for "not more than $10,000.00 for each violation for each day that the violation persists, except that the maximum civil penalty shall not exceed $500,000.00 for any related series of violations." Current statutory federal penalty authority is found in 49 USC 60122, which states:

> A person that the Secretary of Transportation decides, after written notice and an opportunity for a hearing, has violated section 60114(b), 60114(d), or 60118(a) of this title or a regulation prescribed or order issued under this chapter is liable to the United States Government for a civil penalty of not more than $200,000 for each violation. A separate violation occurs for each day the violation continues. The maximum civil penalty under this paragraph for a related series of violations is $2,000,000.

Additionally, the federal law allows for the pipeline safety regulations for these penalties to be inflation adjusted.[110] Michigan's penalties do not adjust automatically for inflation.

An additional area that the pipeline safety regulations do not specifically address is safety management systems (SMS). A safety management system is a holistic approach to managing pipeline risk that involves comprehensive planning, ensuring that the proper controls to mitigate risks are in place, continuously evaluating the controls, and taking actions to make improvements to those elements. The industry has developed and is generally supportive of API RP 1173, which is a "framework to reveal and manage risk, promote a learning environment, and continuously improve pipeline safety and integrity."[111] The Commission has also been supportive of the development of SMS within the utilities to promote management engagement in putting controls in place that will further mitigate risk within all aspects of the operation of pipeline facilities. Consumers Energy and DTE Gas have begun the process of developing SMS programs. The process of developing a mature SMS program takes years and the Commission expects that the natural gas utilities to continue to evaluate and improve their SMS programs over time.

The pipeline safety regulations are generally silent regarding system reliability from the standpoint of ensuring there is adequate natural gas supply. The regulations do cover system reliability in ensuring that the supply of natural gas in the pipeline will arrive safely to its destination, but do not address the consequences of an inadequate supply. The regulations minimize the hazard of transporting natural gas, not the hazards of the lack of natural gas.

[110] These adjusted penalties are found in 49 CFR 190.223, which currently states that "Any person found to have violated a provision of 49 U.S.C. 60101, et seq., or any regulation or order issued thereunder, is subject to an administrative civil penalty not to exceed $213,268 for each violation for each day the violation continues, with a maximum administrative civil penalty not to exceed $2,132,679 for any related series of violations."

[111] American Petroleum Institute, ANSI/API Recommended Practice 1173, Pipeline Safety Management Systems, First Edition, July 2015.

4.5 Contingency Planning Methodologies and Assumptions

4.5.1 Transmission

4.5.1.1 Distribution Interconnections - Connections between the transmission systems and the distribution systems are where gas being transported at high pressures, typically in large diameter pipelines, for long distances, and from production areas and storage fields, is delivered at lower pressures into pipelines that supply the distribution grid. The delivery pressures and system configurations in distribution systems vary, ranging from higher pressures that supply multiple stations within the distribution grid to one station that regulates pressure of gas delivered directly to the customer. If there is a change of ownership at the delivery point, there is typically a series of valves, metering, and regulators that are used to measure the gas and regulate the gas pressure. If there is no change in ownership, a similar regulator station would exist, but metering may not be present. Gas heaters, filters, and odorizers are additional equipment that can exist at these regulator / meter stations. Odorizers are devices that add odorant, such as mercaptan, to the gas so that leaks can be readily detected with a normal sense of smell. Critical and large volume stations will have on-line monitoring and alarms that communicate information related to the gas flow back to gas control is continuously monitored. Gas-control where the gas controllers can take a variety of actions depending on the system and the amount of automation that exists within a pipeline or station. The actions that can be taken include dispatching a technician to a site; changing flow settings within predetermined parameters to deal with changing demand; or shutting down a pipeline segment or station in an emergency.

The components and equipment at these stations have built in redundancy and equipment to be able to deal with failures and emergency situations. When regulators are used to control the pressures in a distribution system, there are standby regulators that will be sensing for a low-pressure situation (below a certain threshold) and mechanically open if that pressure is experienced. The redundancy in regulators monitoring for low-pressure issues allows the system to automatically maintain adequate pressure in a situation where the primary regulator fails or there is an extremely high demand on the system. Typically, when a standby regulator is in operation, the gas controller will receive an alarm and dispatch a technician to the site to determine the cause and take necessary remedial action. Like low-pressure monitoring, regulator stations have equipment that is monitoring for high-pressure situations. Equipment can either be redundant regulators that will take over the operations when a high-pressure (above a certain threshold) situation is experienced or relief valves that will open and vent the high-pressure gas to the atmosphere. Similar to low-pressure situations, the gas controller will receive a high-pressure alarm and dispatch a technician to the site to determine the cause and take necessary remedial action. Within the metering / regulating stations, there is typically bypass piping that can bypass a piece of equipment and / or the entire station. Bypass piping allows for the continued operation of the of the station during maintenance or in an emergency. Large or complex stations have emergency procedures that are unique for that station and include different scenarios such as equipment bypass, entire station bypass, or isolation of the

station.

The design, operation, maintenance, gas control, and emergency procedures required to operate these interconnections are regulated per the MGSS and 49 CFR Part 192. Specifically regulated is the design of the stations; requirements to have overpressure protection and the pressure set points of that equipment; maintenance of the regulators and overpressure protection equipment; control room operations, and emergency procedures. Not required by regulations are redundant standby low-pressure regulators, on-line system monitoring, and remote operations capability. Although this equipment is not specifically required, the distribution pipeline utilities recognize the value of this equipment in their ability to provide reliable service to their customers. Stations that provide service to a significant number of customers have redundant standby low-pressure regulators. As technology has advanced and become more cost effective, the utilities have recognized the value of having additional monitoring equipment and remote operations equipment within the distribution grids. The utilities have added monitoring equipment and alarms to stations and updated mechanical pressure monitoring equipment in the distribution grid to enhance monitoring. The utilities have requested funding for these types of system upgrades in their rate cases and the Commission has been supportive of these initiatives.

4.5.1.2 Intrastate Interconnections - Intrastate interconnections were typically established out of need because no other viable or cost-effective solution existed. Connections exist where one gas utility's only source of supply is from anther gas utility; these are typically smaller adjacent systems where the customer would not have service if it was not for these connections. As the transmission infrastructure has grown, the dependency on these interconnections has in some situations become more a point for supply redundancy in case of an emergency or for maintenance. Equipment at these interconnections would consist of the same types as would be found at any typical distribution connection. Michigan natural gas production and landfill gas being brought to the market through intrastate connections would also typically have equipment to monitor the gas quality.

Contingencies for these supply points can vary depending on the construction of the system. Single feed systems do not have any alternatives but are typically smaller with regards to the number of customers they serve. Larger interconnects typically have multiple feeds with communications between companies that would address any loss of service. Communications would typically start with the gas controllers from the two companies and escalate within management as needed.

4.5.1.3 Interstate Interconnections - Connections between the utilities and interstate natural gas transmission companies exist throughout the state and consist of many different types of facilities. Connections can be similar to those outlined in the section on distribution interconnections where the interstate company does the metering and regulation and will connect directly into the utility's distribution grid. Other connections exist where the interstate company meters the gas and the utility will lower the gas pressure to serve customers. Other interconnections exist where the interstate companies provide the gas directly into the utility's transmission system where only metering takes place and the utility can accept the gas at the full pipeline pressure**.**

Michigan has eight interstate gas transmission operators that have varying degrees of interconnections between each other, intrastate transmission, and distribution systems. These connections bring gas to Michigan from many different producing regions across the nation and from Canada. The reliance on each connection can range from being the sole source of supply for that distribution system to a redundant and unused connection to a transmission system. The transmission interconnections that exist that are unused or underutilized are a result of gas being available from different connections at a lower cost. With the number of interstate transmission companies serving Michigan, the different regions where the gas can originate from, and because there are interconnections that are unused or underutilized, Michigan has redundancy built into the transmission system.

During an emergency, the control rooms of interconnected pipeline utilities would immediately begin discussions about the ability to provide assistance. Interstate transmission operators would aid each other as much as possible and they would also provide the same aid to the utilities. The utilities can dispatch personnel to those unused or underutilized interconnections and provide additional gas supplies during those emergencies. Depending on the severity of the emergency, the utility with the supply restriction could also begin making inter-day nominations for additional gas, and if the restriction persists, make additional nominations for subsequent days.

4.5.1.4 Peak Design Day - The utilities have contingency planning methodologies, assumptions regarding peak design day determination and modeling which enables the utility to adequately forecast their peak design day demand. The annual GCR plan cases the utilities file with the Commission must take into consideration the peak day forecast, number of customers, and anticipated system demand. The GCR plan cases are an appropriate mechanism to annually review reasonableness of each natural gas utility's ability to provide service to its customers in a reliable and cost-effective way. As previously stated, the Commission expects utilities to focus on contingencies related to worst-case scenarios in future GCR plan cases.

4.5.1.5 Contingency Considerations - The infrastructure is designed by the utilities with safeguards in place to ensure continued operation when there is a mechanical failure. Critical assets are continuously monitored, and issues are responded to by remote operations where possible and physical response to a site as needed. The utilities have control systems and emergency operations procedures in place to deal with shutting down facilities and / or pipelines. The utilities also have emergency bypass procedures to enable continued operation

of critical assets when a mechanical issue exists within that facility. When an emergency does exist at a facility, the utilities would use their procedures to work with local, state, and federal officials to control the situation and as necessary use an Incident Command System (ICS) and communicate with Emergency Operation Centers (EOC).

The utilities have contingency planning methodologies and assumptions as part of the modeling process and peak day design. The annual GCR plan cases the utilities file with the Commission take into consideration the seasonal weather and anticipated system demand. The GCR plan cases are an appropriate mechanism to review the reasonableness of each natural gas utility's ability to provide reliable service to its customers and consider contingencies related to worst-case scenarios.

If a capacity restriction exists and the utility cannot provide service to its customers, curtailment procedures provide an orderly process to curtail gas load until such time when adequate supply can be obtained. The rules contained in the utilities' Rate Book for Natural Gas Service provide the detail for the curtailment procedures including the required communications with customers and the priority in which curtailments would take place. The curtailment procedures are comprehensive and contain requirements to address issues related to capacity restrictions. The Commission has approved the rules contained in the rate books and has the authority to require changes as it deems necessary.

4.5.1.6 Effectiveness of Modeling - The utilities use steady state and static modeling programs for system overview and analysis, monitoring for system health, planning for outages, maintenance and growth, as well as assessment and performance review of their load forecast modeling for verification and adjustments. Data inputs come from a variety of different sources including on-line monitoring, pressure recording charts, customer usage data, Geographical Information System (GIS), and weather data. The utilities analyze the effectiveness of modeling by comparing deviations in actual demand to their model forecast. Learnings from that work are incorporated in future modeling. New customer loads are considered and analyzed using the same system modeling.

4.5.2 Distribution

4.5.2.1 Planning and Modeling - Like the transmission modeling, the utilities use steady state and static modeling programs for system analysis, maintenance, growth, and load forecasting. Data for the modeling comes from a variety of different sources including pressure monitoring; customer usage data; pipeline configuration, regulator station design and upstream pressures; and weather data.

4.5.2.2 Contingency Considerations - The contingencies within the distribution grid revolve around the resiliency in the design of the system. As discussed in the section regarding distribution connections to transmission systems, they are safeguarded by having pipes and valves in place to isolate and bypass in an emergency. Constant monitoring, alarms, and gas control keep watch for conditions that need intervention. Emergency procedures are in place to use the controls and isolate or bypass facilities as necessary. If the physical intervention is not

adequate and a capacity restriction exists, the utility can begin communications with customers and begin curtailment per the rules in the utilities' Rate Book for Natural Gas Service.

Single source distribution systems are the most vulnerable to outages, because a single outage could impact up to 50,000 customers. Third-party damage to a pipeline or damage from outside force can cause outages to these systems. In situations where there is some lead time, the utilities can provide temporary facilities to bypass or maintain service or use liquified natural gas brought in by truck to maintain service.

4.5.2.3 Effectiveness of Modeling - The utilities are continuously using the models to analyze growth, evaluate the impact of maintenance, and study the effectiveness of forecasted design days.

4.5.3 Load Forecasting Methodologies and Risks

Evaluation of energy efficiency programs on consumption and peak demand is important but does not currently have a significant impact on mitigating risks. Several of the utilities are in the evaluation stages of considering a gas demand response program for residential and smaller business customers to augment the existing gas curtailment provisions applicable to participating large customers. The main benefit, aside from conservation of our natural resources, would be reducing the peak hourly demand; however, proactively reducing customer load could potentially offset some future investments that would have been needed for maintained system resilience.

Given the pivotal role DR can play during energy emergencies, the development or expansion of natural gas DR programs should be analyzed. The Commission recommends convening a utility and stakeholder workgroup to review the potential for natural gas DR programs and develop recommendations to encourage the development or expansion of natural gas DR programs.

4.6 Natural Gas Recommendations for Mitigating Risk

4.6.1. Commission's Natural Gas Recommendations

- Natural gas infrastructure incidents carry the potential for significant impacts to health, safety and welfare of Michigan residents and utility workers. Utility safety management systems must reflect the leadership of executives to support a culture of safety. Safety Management Systems are management tools that help natural gas utilities comprehensively and holistically manage all aspects of pipeline safety. **The Commission recommends natural gas utilities continue to develop and enhance Safety Management Systems to support and prioritize safety programs**.
- Currently, natural gas infrastructure investments are prioritized separately for storage, transmission and distribution projects rather than in a holistic manner. To maximize efficiencies, a comprehensive risk model must be developed inclusive of storage, compression, transmission, and distribution assets and which considers a long-term risk mitigation as part of a multi-year plan. **The Commission recommends utilities work towards incorporating the use of probabilistic risk models to prioritize system investments, including the development of long-term risk mitigation plans covering infrastructure investment, operations, and maintenance**.
- Risk models for natural gas utilities do not adequately incorporate the risk of equipment and facility outages. Incorporating this type of assessment – either within or outside of the natural gas safety regulations – could provide insights to system vulnerabilities. This should include a consideration of the appropriate percent of peak day supply from any single source. **The Commission recommends natural gas utilities incorporate equipment and facility outages in risk models**.
- The utilities should have diversity in supplies, redundancies in key assets, and limited dependency on any one facility. In future rate and GCR plan and reconciliation cases the **Commission clarifies that: 1) the utilities should consider contingency options for resilience at key facilities and 2) the Commission Staff should consider these issues and make recommendations to further the safety and reliability of the state's natural gas system, including consideration of more resilient design day plans.**
- The need for new system interconnections and the use of existing connections must be better understood and vetted in future cases before the Commission. Natural gas distribution utilities should have diversity in supplies and limit dependency on any one interconnection. **The Commission recommends the utilities consider the necessity and cost of new transmission interconnections including the diversity in supply sources available and propose prudent investments to increase the reliability of the natural gas system. Similarly, the utilities should consider diversification of supply sources in the portfolio, providing for redundancy and reliability through the use of all the existing interconnections available in GCR plan and reconciliation cases**.

- The utilities must be diligent in their system modeling / planning work to identify the necessity of system redundancy and **the Commission recommends the utilities look for opportunities to develop solutions that mitigate risk of outages, improve operational flexibility, and accommodate future growth in demand**.
- Given the pivotal roles that DR can play during energy emergencies, the development or expansion of natural gas DR programs should be analyzed. **The Commission recommends the utilities work with Staff and stakeholders to review the potential for natural gas DR programs and develop recommendations to encourage the development or expansion of natural gas DR programs.**
- During the PV19 event, impacted natural gas utilities did not have mutual assistance agreements in place which could have provided process efficiencies and better communication during the event. Natural gas utilities could provide safer and more reliable service by developing mutual assistance agreements similar to those used by electric utilities during electric outages. **The Commission recommends convening a utility workgroup to facilitate the development of**:
  - **mutual assistant agreements to be in place for all natural gas distribution utilities; and**
  - **transmission contingency planning.**
- Remote shutoff valves are tools that can reduce the number of customers affected by disruptions. **The Commission recommends the utilities continue to conduct analyses to evaluate increasing the number of remote shutoff valve systems in high consequence areas to minimize the impact during emergency events**.

4.6.2. Commission's Natural Gas Observations

- The ability of the Commission to impose meaningful fines for non-compliance is statutorily limited and not on par with the levels in federal statute required by PHMSA. In PHMSA's annual federal audit of the MPSC's federal grant implementation, the State of Michigan's limited fine structure results in a loss of points and reduces the maximum amount of federal funding available to Michigan to administer the federal gas safety program. **The Commission finds that Michigan statute limits the ability of the Commission to assess meaningful penalties for non-compliance with the Michigan Gas Safety Standards, and this may impact the health, safety and welfare of Michigan residents.**

See also: **Chapter 8**, Gaps in Existing Planning, Operational, and Emergency Response Processes, for additional recommendations and observations relevant to the gas sector.

5. Propane

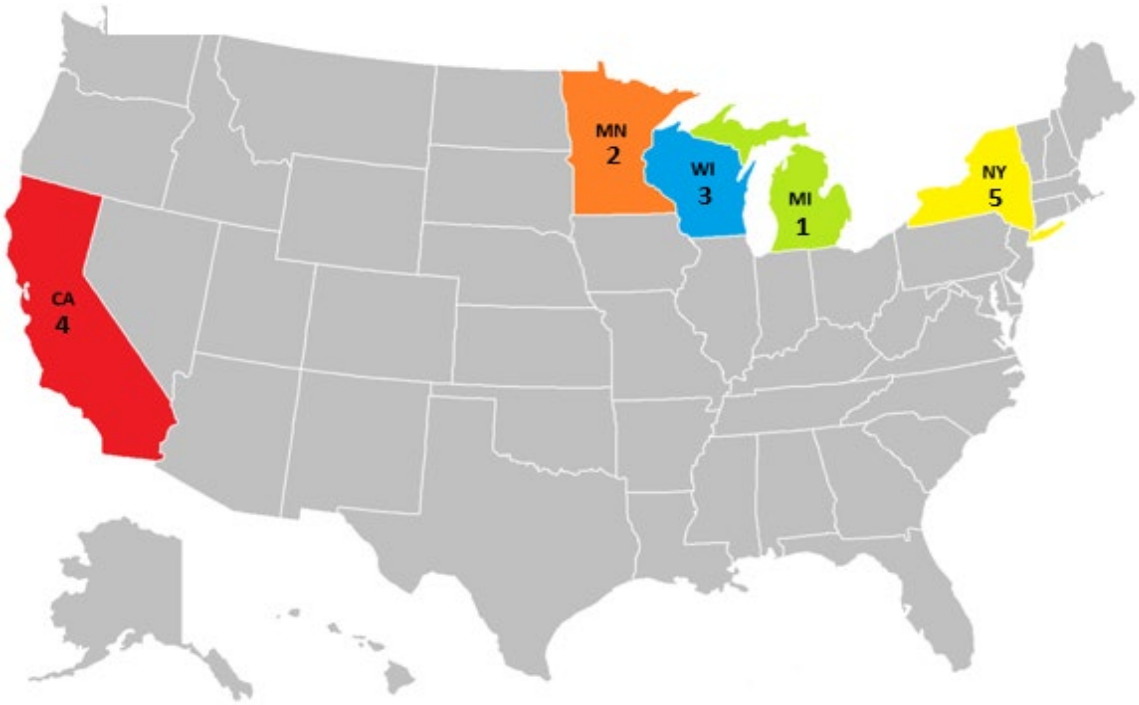
5.1 System Overview and Operational Structure

While Michigan's propane market is not regulated, meeting demand and ensuring adequate supply availability is essential to public safety and of great interest to the state of Michigan.[112] Propane belongs to a group of hydrocarbon gases commonly referred to as liquified petroleum gases (LPGs),[113] which also includes normal butane and isobutane. Propane is a colorless, flammable hydrocarbon gas that is extracted from natural gas or refinery gas streams and commonly used for home heating and cooking, grain drying, transportation fuel, and as a petrochemical feedstock in the production of various plastics. In Michigan, 8% of households (320,000) use propane as their primary home heating fuel – consuming an estimated 1,189 gallons per year.[114] According to the Energy Information Administration (EIA), Michigan's residential sector consumption ranked first in volume consumed in 2017, totaling a little more than 380 million gallons (Figure 5-1).

[113] Liquified Petroleum Gases (LPGs) are a group of hydrocarbon gases consisting of propane, normal butane, and isobutane derived from crude oil refining or natural gas processing. LPGs are considered a subset of natural gas liquids (NGLs). Furthermore, LPGs and NGLs are a subset of hydrocarbon gas liquids (HGLs), which include all NGLs and their associated olefins.

[114] 1,189 gallons per year sourced from the U.S. Energy Information Administration. Residential consumption includes all forms of consumption and is not limited to home heating.

Figure 5-1 Top Five Residential Sector Propane Consuming States



Source: Energy Information Administration

5.1.1 Production

A unique feature of propane is that it is not produced independently, but rather as a byproduct of natural gas processing and crude oil refinement. Therefore, production volumes cannot be adjusted when prices and/or demand for propane fluctuates. When produced from wells, raw natural gas (methane) is often mixed with water, carbon dioxide, and other hydrocarbons – which need to be removed to satisfy product quality standards. The heavier hydrocarbons that are removed are sent to a facility called a fractionator, where individual products are separated out into purer forms like ethane, propane, and butane. Concentrations of propane present in raw natural gas and crude oil can vary, but typically 4 to 6% (2 to 3 gallons) of the 45 gallons of petroleum product produced from a barrel of crude oil are LPGs such as propane. Michigan has one crude oil refinery and two fractionators in-state that help to meet the needs of propane consumers.

5.1.2 Transportation

Once produced, propane is typically transported to large wholesale market storage locations. In North America, these locations include Conway, Kansas; Mt. Belvieu, Texas; Edmonton, Alberta; and Sarnia, Ontario. From these larger storage locations, propane can then be transported to regional or local storage locations for final distribution to the end consumer. Propane is compressed/cooled to a liquid state before being transported – primarily by rail, pipeline, or truck. This is done because propane is 270 times more compact as a liquid than as a gas.

5.1.2.1 Rail - Michigan's railroad network is commonly used for the transport of propane to larger regional storage facilities, as well as local storage areas in places such as Marysville, Kalkaska, Alto, and Kincheloe. Major railroad owners and/or operators in Michigan include Canadian National Railway, CSX Transportation, Norfolk Southern Railway, Amtrak, and the State of Michigan.[115] Railcars used to transport propane typically have a capacity of about 33,000 gallons.

5.1.2.2 Pipeline - Pipelines are also utilized to transport propane. However, they are primarily used at the wholesale storage and distribution level and not for delivering propane to residential consumers. Michigan has several pipelines that transport propane from storage areas in Sarnia and Windsor, Ontario to the Marysville and St. Clair, Michigan storage caverns, as well as the Kalkaska fractionator. For a comprehensive list of LPG pipeline connections between Michigan and Ontario, see Appendix E.

5.1.2.3 Truck - Trucks are most often used to deliver propane from wholesale storage facilities to individual retail locations and residential homes. Trucks hauling propane to retail storage tanks hold approximately 13,000 gallons, while the trucks that deliver to homeowners may only hold between 2,500 and 3,000 gallons.

5.1.3 Storage

Propane in Michigan is stored either underground in repurposed salt caverns, or in above ground pressurized tanks, often called bullet tanks. Large underground cavern storage facilities are often connected to pipelines and can receive and load-out supply by both rail and truck. Storage capacity varies greatly in Michigan, from a homeowner's tank holding 500 gallons, to an aboveground bullet tank holding 30,000 gallons, to an underground cavern storing millions of gallons.

[115] https://www.michigan.gov/documents/mdot/Michigan_Rail_430289_7.pdf.

5.2 Regulatory Oversight of Propane Market

Residential users tend to think of propane as a "utility" service based on its use as a heating fuel. However, as an unregulated, open market commodity, propane providers do not have the same obligation to serve customers like a regulated utility does. Propane providers are different from a utility in that they do not typically deliver propane to customers by permanent physical connections, they do not have an exclusive service territory, their rates are not regulated, they do not have monopolized market power, and generally do not have the power of eminent domain. In addition, because of its unregulated status, propane customers in Michigan do not have access to the same weatherization and efficiency improvements offered by regulated electric and natural gas distribution utilities.

Given the unregulated nature of the propane market, consumers are also more susceptible to supply chain risks than they would be with a regulated utility, like those providing natural gas or electricity. Regardless of propane's status as an open market, meeting demand and ensuring adequate supply availability is essential to public safety and of great interest to the State of Michigan. Various activities within the supply chain – such as transportation and storage – are, to an extent, regulated to support the safe delivery of propane to Michigan consumers.

5.2.1 Pipeline Siting

New propane pipelines would be subject to Act 16 of 1929 (Act 16). Act 16 grants the MPSC siting authority for petroleum product pipelines and MPSC approval is required before construction can commence. Applications under this statute are subjected to a review of the proposed route, environmental and landowner impacts, engineering specifications, and the public need of the proposed pipeline.

5.2.2 Safety Oversight of Hazardous Liquid Pipelines

In Michigan, safety oversight of hazardous liquid pipelines, including propane pipelines, belongs to the federal government through the US DOT's PHMSA. This includes the inspection and regulatory enforcement of both intrastate and interstate hazardous liquid pipelines. PHMSA categorizes hazardous liquid pipelines into five categories which include:

- Crude Oil
- Refined Petroleum Products
- Highly Volatile Liquids or Other Flammable or Toxic Fluids
- Carbon Dioxide
- Biofuel

Pipelines transporting propane fall under the highly volatile liquid or other flammable or toxic fluids category of hazardous liquid pipelines. Michigan does not have an extensive pipeline network for the exclusive transport of propane. However, pipelines transporting crude oil and natural gas liquids (NGLs), from which propane is derived, supply the refineries and fractionators that ultimately produce the propane consumed by residents. These pipelines also fall under PHMSA's safety oversight responsibilities. There are also several small pipeline segments connecting propane production and storage in Sarnia, ON to storage facilities near St. Clair and Marysville, MI.

5.2.3 Non-Pipeline Transportation Regulations

As previously discussed, railcars and trucks are commonly used to transport propane into and throughout the state. For example, this might include long-haul rail transports originating in Alberta or Kansas, but also a truck delivering propane from storage in Marysville, Michigan to an individual retail location. Regardless of the origin of the shipment, regulations are in place to ensure the safe delivery of propane to end consumers in Michigan.

5.2.3.1 Truck - Commercial motor vehicles transporting hazardous materials must comply with the Motor Carrier Safety Act, Act No. 181 of 1963 MCL 480.11-25 of the Michigan Compiled Laws.[116] Section 480.11a. adopts provisions of title 49 of the Code of Federal Regulations which include hazardous materials regulations (49 CFR parts 105 – 180) and motor carrier safety regulations (49 CFR parts 40, 356, 365, 368, 371-373, 375, 376, 379, 382, 383, 385, 387, 390-393, 395-399).[117]

5.2.3.2 Rail - The transportation of propane by rail is regulated by the Federal Railroad Administration and PHMSA within the Department of Transportation. Like truck transport, railroad transports must also adhere to hazardous materials regulations (49 CFR 105-110, 171-174,179,180) and carrier safety regulations (49 CFR 200-299). Various economic aspects of rail transport, such as rates and service disputes, are regulated (49 CFR Parts 1000-1399) by the Surface Transportation Board.

5.2.4 Storage

Propane's designation as a hazardous material (Class 2 Flammable Gas) requires that it be stored safely at all points of the supply chain. Depending on the type of storage, various

[116] http://legislature.mi.gov/doc.aspx?mcl-Act-181-of-1963.
[117] http://legislature.mi.gov/doc.aspx?mcl-480-11a.

regulations have been put in place to ensure the safe storage of propane. Below are the common ways in which propane is stored and the applicable regulations that apply to each.

5.2.4.1 Underground Cavern Storage

The Oil, Gas, and Minerals Division of the Michigan Department of Environment, Great Lakes, and Energy (EGLE) is responsible for administering the statute[118] and rules[119] subject to Part 615 of the Natural Resources and Environmental Protection Act of 1994 (PA 451). Rule 204 of Part 615 states the following:

> **R 324.204 Permits for oil and gas storage by conversion of operation.**
> Rule 204. If a well or underground operation developed for a non-oil and gas use is converted for the storage of oil or gas or any of the natural hydrocarbons produced from oil or gas, then the well or underground operation shall be classified as an oil or gas storage operation and shall be subject to the provisions of these rules.

The underground storage caverns utilized in Michigan were originally solution mined salt caverns that were repurposed for the storage of various hydrocarbon gas liquids (HGLs)[120], including propane, and therefore are subject to the statute and rules of Part 615. Operators of underground storage caverns must also comply with 40 CFR Part 68 of the U.S. Environmental Protection Agency's chemical accident prevention provisions.[121] These provisions require owners or operators of a stationary source having more than a threshold quantity of a regulated substance in a process to submit a risk management plan to the U.S. Environmental Protection Agency (EPA), among other hazard assessment requirements. Propane is a regulated substance with the EPA and has a threshold quantity of 10,000 pounds (approx. 2,400 gallons).

5.2.4.2 Aboveground Bulk Storage - LPG storage containers where individual capacity is over 2,000 gallons, or aggregate capacity over 4,000 gallons, are subject to the Department of Licensing and Regulatory Affairs (LARA), Bureau of Fire Services storage and handling of LPG Rules.[122] These rules were revised in 2008 to incorporate provisions of the National Fire Protection Association Pamphlet No. 58, 2004. Aboveground bulk storage locations may also have to adhere to the requirements of CFR 40 Part 68 mentioned above,

[118] http://legislature.mi.gov/doc.aspx?mcl-451-1994-III-3-2-615.
[119] http://dmbinternet.state.mi.us/DMB/ORRDocs/AdminCode/1693_2017-017EQ_AdminCode.pdf.
[120] Hydrocarbon gas liquids (HGLs) include natural gas liquids (ethane, propane, normal butane, isobutane, and pentane) as well as their associated olefins (ethylene, propylene, butylene, and isobutylene).
[121] https://www.law.cornell.edu/cfr/text/40/part-68.
[122] https://www.michigan.gov/lara/0,4601,7-154-89334_42271_4115_4237-9578--,00.html.

unless they meet the definition of a retail facility.[123] Certain propane distribution systems that distribute propane to end users by pipeline are subject to MPSC jurisdiction for rates and safety pursuant to Act 165 of 1969 and the gas safety standards and technical standards as discussed in more detail in section 4.1.1.1.

5.2.4.3 Residential Customer Tanks - Residential propane customers typically do not own large enough tanks to be regulated by LARA's Bureau of Fire Services. However, tank safety is still very important, and many retailers will not fill a customer's tank without first inspecting it. Michigan's current Container Law also prohibits a propane marketer from filling a container that is not their own without first receiving the authority of the owner of the tank.[124]

5.2.5 Pricing

The price of propane is not regulated by the MPSC. However, the retail price of propane is closely monitored during the winter heating season (October to March) to identify potential supply constraints and risks. Under a cooperative agreement with the U.S. Department of Energy's (DOE) Energy Information Administration, MPSC Staff make weekly phone calls to a sample of propane and heating oil retailers for the State Heating Oil and Propane Program (SHOPP).[125] The price data that is collected each week is sent to the EIA and aggregated before being published as a statewide average price metric.[126] The weekly phone calls provide an opportunity to build relationships with industry participants and learn of emerging supply issues.

The Michigan Attorney General's Office provides consumer alerts to inform the public of unfair, misleading, or deceptive business practices, and to provide information and guidance on issues regarding propane pricing. These consumer alerts often include information on different pricing options offered by propane retailers as well as tips for becoming more energy efficient.[127] There are also some protections against price gouging by propane retailers under the Michigan Consumer Protection Act, and the Michigan Attorney General was able to obtain approximately $600,000 in reimbursements and credits from two propane retailers following the 2013-14 polar vortex.

[123] https://www.epa.gov/sites/production/files/2013-10/documents/chap-01-final.pdf.
[124] 1910.110(b)(14)(ii) in Part 56 of LARA's General Industry Safety Standards, https://www.michigan.gov/documents/CIS_WSH_part56_35462_7.pdf.
[125] https://www.michigan.gov/energy/0,4580,7-364-85452_86924_86926_87100_87101_88659---,00.html.
[126] https://www.eia.gov/dnav/pet/PET_PRI_WFR_DCUS_SMI_W.htm.
[127] https://www.michigan.gov/ag/0,4534,7-359-81903_20942-252787--,00.html.

5.3 Unique Strengths

Michigan's propane energy system has several unique strengths which help to insulate consumers from potential supply and price shocks. These strengths include an abundance of storage capacity for HGLs, key infrastructure for the transportation of refinery and fractionator feedstocks, market access diversity, and market size.

5.3.1 In-State Storage Capacity

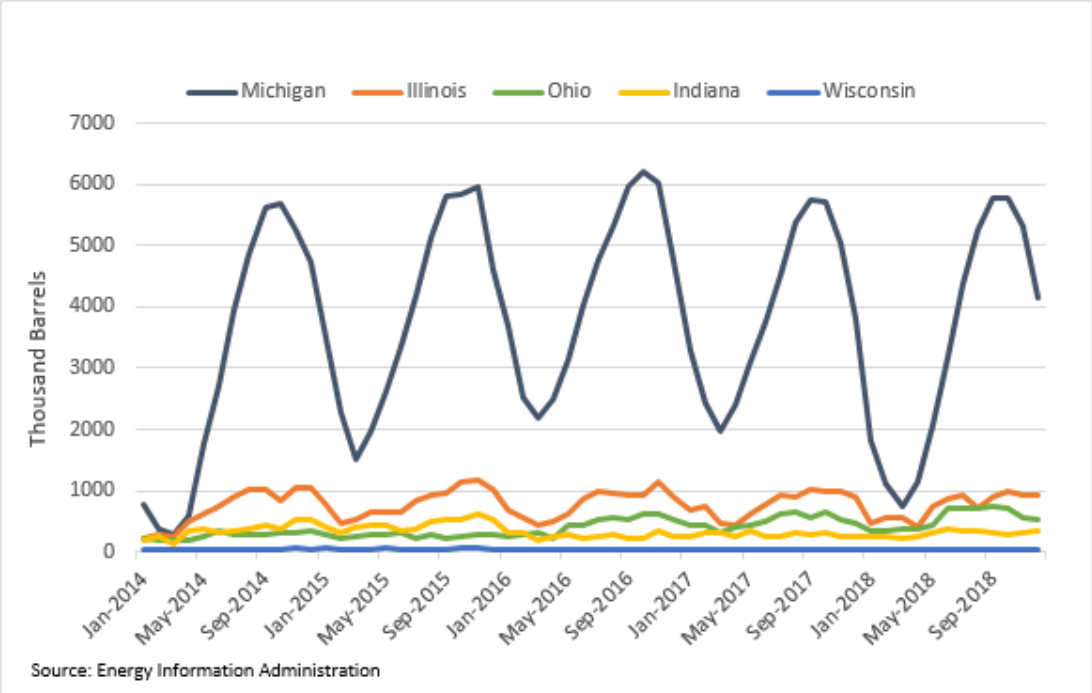
Michigan is unique in its ability to safely store large quantities of propane underground in repurposed salt caverns. There is an estimated 13.8 million barrels (580 million gallons) of underground storage capacity for HGLs – such as propane – in Michigan. A significant amount of this storage capacity is located near St. Clair and Marysville, with additional cavern space near Woodhaven, Inkster, and Alto. However, it should be noted that not all of this storage capacity is used strictly for propane, but also for other products such as butane and ethane. In addition to underground cavern storage, these locations also have significant aboveground storage capacity of approximately 30,000 barrels (1.2 million gallons).

These storage figures represent a significant portion of capacity available in Michigan to meet the needs of propane consumers. However, there are many other smaller storage locations around the state that play a vital role in supplying fuel. For a more comprehensive list of storage locations, see Appendix F.

Figure 5-2 displays propane stocks for various Midwest states between January 2014 and December 2018. Although this figure does not show storage capacity, it clearly shows Michigan's distinct advantage in propane storage when compared to other midwestern states. Michigan's pre-heating season storage peak at bulk storage facilities (50,000 barrels or greater storage capacity), natural gas plants, and refineries has historically been near 6 million barrels (252 million gallons), equivalent to about 65% of Michigan's annual residential propane consumption.[128] Other neighboring states reliant on propane for heating needs typically peak at less than 1 million barrels.

[128] Michigan 5-year (2013-2017) residential sector average annual propane consumption equal to 391,356,000 gallons, based on EIA's State Energy Data System estimates.

Figure 5-2 Bulk Storage, Natural Gas Plant, and Refinery Propane Stocks



5.3.2 Infrastructure

Michigan's two fractionators play an important role in meeting in-state, and to some extent, out-of-state propane demand. One fractionator is located in Rapid River in the Upper Peninsula and receives supplies of NGLs from Line 5 of Enbridge's Lakehead Pipeline System. The Rapid River fractionator produces approximately 2,000 bpd[129] of propane, and with its associated storage capacity, is an important source of propane for the residents of the Upper Peninsula and Wisconsin who rely on propane. Additionally, Line 5 also supplies a fractionator and several refineries in Sarnia, Ontario. This Sarnia fractionator is the largest in eastern Canada and has a fractionation capacity of 120,000 bpd,[130] producing primarily propane and butanes, some of

[129] MPSC Staff calculation from Dynamic Risk's "*Alternatives Analysis for the Straits Pipelines*", Appendix: Tables C-1 and C-2. https://mipetroleumpipelines.com/files/user/documents/AlternativesAnalysisFinal-Appendices.pdf.

[130] Canadian Energy Research Institute (CERI), https://ceri.ca/assets/files/CERI%20Study%20139%20Part%20II%20-%20Final.pdf. Note: Assuming an overall plant capacity factor of 95% and a similar NGL input stream as to what is received in Rapid River, Staff estimates average daily propane production would be approximately 78,660 bpd (3,303,720 gallons).

which is transported by truck, rail, or pipeline to storage facilities and eventually to consumers in Michigan. In order for these fractionators to continue accessing NGLs from Line 5, the pipeline must operate as an integrated whole.

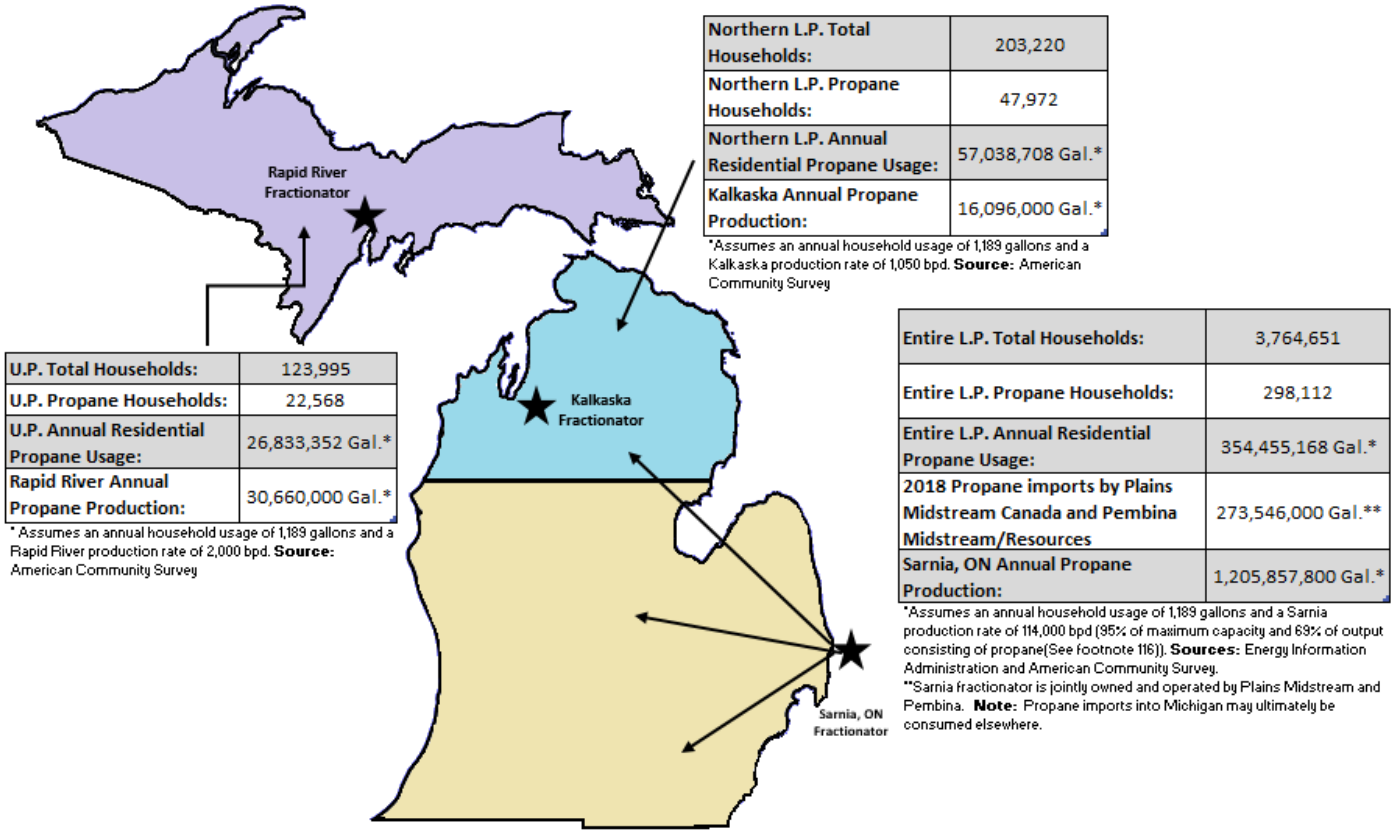
Michigan's second fractionator is near Kalkaska in the northern Lower Peninsula and receives its feedstocks primarily by pipeline from natural gas production facilities in the area, but also by rail from out-of-state sources, and by truck from in-state oil production operations. On average, this fractionation facility produces 1,050 bpd of propane, supplying approximately 28 retail propane providers with operations in Michigan. The northern Lower Peninsula is an area of the state that relies heavily on propane for household heating, placing the facility in a strategic location. Annual production from the Kalkaska fractionator is equivalent to 28% of northern Lower Peninsula demand,[131] defined as the region shaded in blue below.

In addition to the fractionators in Michigan, Marathon's Detroit Refinery also produces propane as a byproduct of its operations, estimated by MPSC Staff to be approximately 2,300 bpd.[132] One significant source of crude oil for the refinery is Line 78 of the Lakehead Pipeline System connecting Pontiac, Illinois to Sarnia, Ontario.

[131] Assumes an annual household usage of 1,189 gallons.

[132] According to Marathon Petroleum Corporation's (MPC) 2018 Securities and Exchange Commission (SEC) 10-K filling, Mid-Continent refinery yields of propane were 14,000 bpd from the processing of 839,000 bpd of crude oil, equating to a 1.66% average propane refinery yield rate. MPC's Detroit Refinery has the capacity to refine 140,000 bpd of crude oil. Applying the Mid-Continent average propane refinery yield rate to MPC's Detroit Refinery capacity equates to 2,324 bpd of propane production.

Figure 5-3 Fractionators Located in Michigan



Northern L.P. Total Households:	203,220
Northern L.P. Propane Households:	47,972
Northern L.P. Annual Residential Propane Usage:	57,038,708 Gal.*
Kalkaska Annual Propane Production:	16,096,000 Gal.*

*Assumes an annual household usage of 1,189 gallons and a Kalkaska production rate of 1,050 bpd. **Source:** American Community Survey

U.P. Total Households:	123,995
U.P. Propane Households:	22,568
U.P. Annual Residential Propane Usage:	26,833,352 Gal.*
Rapid River Annual Propane Production:	30,660,000 Gal.*

* Assumes an annual household usage of 1,189 gallons and a Rapid River production rate of 2,000 bpd. **Source:** American Community Survey

Entire L.P. Total Households:	3,764,651
Entire L.P. Propane Households:	298,112
Entire L.P. Annual Residential Propane Usage:	354,455,168 Gal.*
2018 Propane imports by Plains Midstream Canada and Pembina Midstream/Resources	273,546,000 Gal.**
Sarnia, ON Annual Propane Production:	1,205,857,800 Gal.*

*Assumes an annual household usage of 1,189 gallons and a Sarnia production rate of 114,000 bpd (95% of maximum capacity and 69% of output consisting of propane(See footnote 116)). **Sources:** Energy Information Administration and American Community Survey.
Sarnia fractionator is jointly owned and operated by Plains Midstream and Pembina. **Note: Propane imports into Michigan may ultimately be consumed elsewhere.

5.3.3 Market Access Diversity

Michigan's central location relative to various supply sources creates a resilience advantage when compared to other states, particularly along the East Coast, where supplemental shipments often must arrive from overseas. NGLs, the raw material for propane, can be accessed via pipeline, and consumer grade propane can be transported into Michigan by rail from several different locations including western Canada, Chicago, Toledo, as well as Sarnia and Windsor, Ontario. Transporting propane by truck is common from these locations (excluding western Canada), but also provides the option to source product from the TEPPCO Pipeline (originating near the Gulf Coast) at points in Indiana and Ohio. This diverse access to consumer grade propane helps to provide energy security and can help alleviate price spikes during periods of high demand.

5.3.4 Market Size

Michigan ranks first in the nation for residential propane usage by volume, followed by neighboring states Minnesota and Wisconsin. Although states such as Vermont, South Dakota, and New Hampshire have a higher proportion of households utilizing propane for primary home heating, Michigan's large population relative to these states requires a more robust propane

infrastructure system to handle greater consumption volumes. Below in Figure 5-4 is a propane market size comparison between various propane consuming states.

Figure 5-4 State Propane Market Sizes, 2017

	Percent of Households	Number of Households	Total Residential Consumption (Gallons)	Average Household Consumption (Gallons)
Michigan	8.2%	320,680	381,444,000	1,189
Illinois	4.1%	198,002	198,156,000	1,000
Ohio	5.2%	241,227	187,950,000	779
Indiana	7.1%	180,475	117,684,000	652
Wisconsin	11.2%	260,306	243,600,000	935
Vermont	15.8%	40,879	70,266,000	1,718
South Dakota	15.6%	53,053	44,268,000	834
New Hampshire	15.4%	81,344	105,000,000	1,290

Sources: Energy Information Administration and U.S. Census Bureau - American Community Survey.
Note: Residential consumption includes all forms of consumption and is not limited to home heating. Although residential propane usage is primarily for home heating, average consumption statistics are likely inflated due to uses other than for home heating (clothing dryers, water heating, pool heating, etc.)

5.4 Vulnerabilities

As is the case for all energy systems, Michigan's propane energy system can be susceptible to vulnerabilities that could disrupt the availability and reliability of supplies for consumers. Awareness and understanding of these vulnerabilities are paramount to contingency planning and ultimately the response to an energy emergency event. As part of the efforts to develop this assessment, Staff developed and conducted an anonymous survey to propane industry partners to better understand the system and potential vulnerabilities. The results of the survey, consisting of 20 questions, were incorporated into this report and a summary of key findings is included as Appendix G.

5.4.1 Driver Shortages

One of the primary methods in which propane is moved from large storage hubs to retail locations is by transport truck. Industries across the U.S. that rely on truck transports are finding it difficult to maintain an adequate amount of truck drivers. According to a report by the American Transportation Research Institute, driver shortages ranked as the trucking industry's top concern in 2018, and the U.S. driver shortage was estimated to be over 50,000.[133] Michigan's propane industry is vulnerable to this shortage during the winter when the demand for propane increases. In the survey of Michigan propane retailers, 28% of respondents indicated that they had experienced difficulty in receiving or distributing propane due to the availability of properly trained and qualified transport drivers. However, 67% of respondents had a moderate concern and 22% had a major concern regarding the availability of properly trained and qualified transport drivers.

5.4.2 Infrastructure Availability

Although Michigan is fortunate to have a significant amount of propane storage capacity and two in-state fractionators, the availability of heavily relied upon infrastructure is still a vulnerability to the propane energy system. If given enough time and advanced notice, open markets can and will adjust to create an alternative economic solution to meet consumer demand. However, when key pieces of infrastructure are suddenly taken off-line, such as a catastrophic equipment failure, prices will often become volatile until the market has an adequate amount of time to adjust. For example, if a sudden loss of Line 5 (which supplies multiple refineries and fractionators) or DTE's northern Michigan "wet header" (which supplies feedstock to the Kalkaska fractionator) experienced a major outage without advance planning, the system would require significant changes to replace those supply sources. At least in the short term, these alternate sources and transportation methods are likely to be less reliable and more costly. In the long-term, migrating away from pipeline supply will remove a layer of redundancy to the system, thus decreasing our resilience to future supply issues or infrastructure outages.

A sudden failure of Line 5 without warning to arrange alternative supplies and delivery could have widespread implications, starting with the loss of NGL supply to the Rapid River and Sarnia fractionators. Enbridge has stated that Line 5 serves approximately 55 percent of Michigan's propane needs and about 65 percent of the U.P. and northern Michigan's propane needs. Rapid

[133] American Transportation Research Institute, "Critical Issues in the Trucking Industry - 2018". https://atri-online.org/wp-content/uploads/2018/10/ATRI-Top-Industry-Issues-2018.pdf.

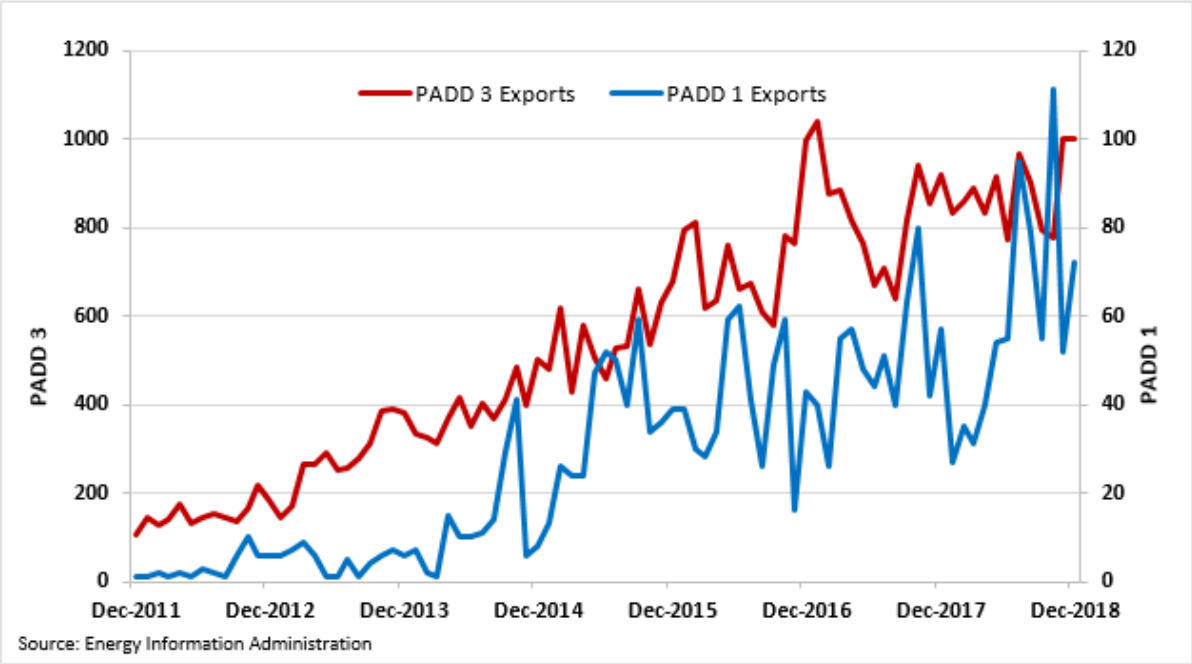
River has no other available short-term supply options and without identifying an alternative source for NGLs, would essentially become a stranded asset. The Sarnia fractionator, given its relative size and location, may have the opportunity to secure additional NGL supply by rail or alternative pipelines. However, it is unclear whether this additional rail or pipeline capacity is available to supplant volumes lost from Line 5. Without the Rapid River propane fractionator operating in the U.P., trucking would likely be used as the next alternative. Truck transports would have to travel further distances either downstate, or out of state to locations like Superior or Janesville, WI. Southern Michigan is fortunate to have an abundance of underground storage capacity, which may help to insulate supply disruptions for a short period of time. However, without the flow of propane from the Sarnia fractionator, this supply would be depleted within one winter season. As a result, lines and wait times at terminals would likely increase, forcing distributors in the Lower Peninsula to travel further distances for supplies. During the PV14, it was not uncommon for trucks to travel as far as Kansas or the Gulf Coast for supplies of propane.

The most recent supply shock to Michigan's propane energy system was in 2014, with the combination of a wet drying season that depleted propane reserves, the polar vortex, the reversal of the Cochin pipeline, and sudden loss of fractionator feedstock at Rapid River. Residential propane prices to begin the 2013/14 heating season averaged $2.06/gallon, but later peaked at $3.76/gallon the first week of February as supplies became tight.

5.4.3 Exports

U.S. propane exports have increased considerably in the past decade – primarily from the Gulf Coast and to a lesser extent the East Coast. Gulf Coast exports of propane for the month of December 2018 averaged 998 thousand bpd compared to only 23 thousand bpd in December 2008. Top destinations for propane leaving the Gulf Coast in 2018 included Japan, China, and Mexico. An increase in drilling activity and infrastructure buildout in the Appalachian Basin has also made more propane available for export from the East Coast, rising from nearly zero in 2008 to an average of 59 thousand bpd in 2018.

Figure 5-5 Propane Exports



In 2017, annual propane exports surpassed domestic demand for the first time on record. Increased exports are a strong indication that domestic heating market end-users are now a secondary player in the U.S. propane market to export demand – where propane is also used for heating and as a petrochemical feedstock in the production of synthetic plastics and rubbers.

5.4.4 Unregulated Marketplace

The propane energy system being an unregulated marketplace is not a vulnerability per se but gathering information and data can sometimes prove difficult. Unlike with utilities where individual plant-level data is often available, specific information about propane infrastructure is closely guarded, rightfully so given the competitive nature of the industry. However, filling data gaps such as demand estimates, product movement patterns, production and storage capacities, and plant level contingency plans can be extremely helpful in preparing for and responding to an energy emergency. In addition, as unregulated entities, actions taken during an emergency event may be solely at the discretion of industry stakeholders, without state consultation or notification. Emergencies can impact residents on a statewide or regional scale – not only at the company level – emphasizing the need to maintain state-industry relationships and effective communication during emergency response. Finally, because propane suppliers have no obligation to serve, and because propane rates are unregulated, customers relying on propane for heating are more exposed to price fluctuations and supply disruptions.

5.4.5 Extreme Weather

While the exact consequences of climate change are unknown, it is anticipated that more extreme weather patterns are a likely consequence. For Michigan, this may mean increased temperature swings and precipitation, which could become a vulnerability for the propane

industry and their customers. Extreme cold events, such as those experienced in 2014 and 2019, cause unexpected spikes in demand and can strain the system in the short term and potentially throughout a heating season. Increased precipitation in the form of snow fall could further complicate propane distribution which is heavily dependent on trucking and access to rural areas of the state. Additionally, increased efforts to thwart climate change and shift away from fossil fuels may affect existing and proposed infrastructure that impacts the availability of propane supplies.

5.5 Contingency Planning

5.5.1 National and Regional Coordination of Supply Monitoring and Waiver Requests

In emergency situations, declarations can be issued by the President, Governors of states, or the Federal Motor Carrier Safety Administration (FMCSA) to help provide supplies and transportation services to the affected area(s). These declarations temporarily suspend certain Federal safety regulations, including Hours of Service, for motor carriers and drivers involved in the emergency relief effort. Communication between affected states and coordinated waiver requests demonstrate situational awareness and can be helpful for the granting authority to understand the need for such a declaration.

5.5.2 Public Education and Awareness

Educating the public and making consumers aware of the potential events that could impact them is a crucial part of contingency planning. Much like with markets, when consumers have an adequate amount of time to prepare, the implications of an event disrupting supply can often be mitigated.

The MPSC – in an effort to promote consumer awareness – has in the past released announcements urging consumers to consider participating in pre-buy propane programs.[134] Pre-buy programs act as a type of insurance against upside price risk. These announcements are not for fear that an event will severely disrupt supply, but rather to make the consumer aware that as the heating season and demand for propane nears, prices could rise and become more volatile.

[134] https://www.michigan.gov/energy/0,4580,7-364-85452_72070-473015--,00.html.

5.5.3 Access to Appalachian Basin Resources

The Appalachian Basin presents a unique opportunity to secure additional propane supplies. As previously mentioned, an increase in drilling activity in this natural gas rich region has increased the supply of NGLs that can be fractionated into purity products like propane. Some of these resources are already supplementing the feedstocks for Ontario refineries. For example, the recently constructed Utopia pipeline transports NGLs from the Marcellus shale formation in eastern Ohio for refining in Windsor, Ontario. This region's resources should be examined closely as it could potentially become an important source of supply for Michigan propane consumers and ensure additional energy security.

5.5.4 UP Energy Task Force

On June 7, 2019, Governor Whitmer issued Executive Order 2019-14, which created the UP Energy Task Force as an advisory board within EGLE charged with assessing the UP's overall energy needs, formulating alternative solutions for meeting UP energy demands, and identifying and evaluating potential plans in the event of supply disruptions. Chairman Sally Talberg was appointed to the Task Force and Commissioner Dan Scripps was designated to serve on behalf of the MPSC.

A Task Force organizational meeting, which included member introductions and discussion of the Task Force's mission, was held on July 9, 2019 in Marquette, Michigan. The first few Task Force meetings focused on propane supply options for the UP, including contingency plans, with a March 31, 2020 report due to the Governor, as outlined in the Executive Order. The second meeting took place in St. Ignace, Michigan on August 5, 2019 and included presentations from Dr. Richelle Winkler of Michigan Technological University, the Michigan Propane Gas Association, and Michigan Public Service Commission Staff. Future Task Force meetings in 2019 will be held on September 20, October 1, November 13, and December 10 (tentatively). Following the March 31, 2020 report, the Task Force will shift its focus to broader energy issues in the UP, with a final report due to the Governor on March 31, 2021.

5.6 Propane Recommendations for Mitigating Risks

5.6.1 Commission's Propane Recommendations

- As part of the SEA, Staff created a retail propane survey to monitor market trends and gain additional market insights. While roughly 20% of propane suppliers participated in this anonymous survey, it nevertheless provided statewide propane provider information never before collected. **The Commission recommends Staff continue to solicit market information from propane suppliers and create an annual retail propane survey to monitor market trends and gain additional market insights, similar to the survey completed for this report.**
- It is not uncommon for propane customers to forgo options to mitigate exposure to market price fluctuations. **The Commission recommends the MPSC continue public education efforts to promote the use of pre-buy and price lock-in purchase strategies to enhance consumers' resilience to market price fluctuations**.

5.6.2 Commission's Propane Observations

- The future of Line 5 is uncertain and could be impacted by anchor strikes or other actions that cause significant damage to the pipeline, emergency shutdowns of the pipeline, or legal action to shut down, temporarily or permanently, the existing pipeline or arrangements to construct a tunnel in which to house a new pipeline crossing the Straits of Mackinac. The line, which transports NGLs for propane production, could also be affected by physical damage, equipment failure or legal action. **The MPSC finds that a formal contingency plan for the continued supply and delivery of propane or other energy alternatives for Michigan residents is needed in the event of supply disruptions, including a shutdown (permanent or temporary) of Line 5.**
- The UP Task Force is charged with identifying alternatives to both supplying the energy by sources currently used by UP residents and alternatives to those energy sources under the timelines established in Executive Order 2019-14. **The MPSC finds that a comprehensive alternatives analysis as called for by Governor Whitmer in Executive Order 2019-14 is needed, and that such an analysis should consider the use of rail and trucks to supply the Rapid River fractionator, options for importing propane into the UP from other areas, the extension of natural gas infrastructure for home heating, the use of electric heat sources, including heat pumps, and targeted energy waste reduction programs for residential propane customers. The MPSC is currently participating in, and providing personnel and other support for the UP Energy Task Force as set forth in the executive order.**
- There is a benefit to developing working relationships with propane suppliers prior to potential shortage conditions. **The Commission finds that the State of Michigan should work with owners and operators of critical petroleum assets to ensure the availability of NGLs and propane supplies for Michigan residents.**

- Currently there is not an accurate source of information for propane supply and storage information which would provide staff with a valuable data resource to inform summer and winter energy appraisals. **The Commission finds that it would be beneficial for Michigan petroleum prime suppliers to provide the Energy Security Section with a copy of form EIA – 782C to more accurately account for inflow and outflows of propane supply/storage**.
- Currently there is a lack of trained and qualified transport drivers for propane deliveries. **The Commission finds that the State of Michigan should support the development of a HAZMAT Driver Training Program to help supply the propane market with properly trained and qualified transport drivers, potentially in partnership with the Michigan Propane Gas Association.**
- There are opportunities to improve the resiliency of the propane market by adding diversity to the source and building additional infrastructure. **The Commission finds that the State of Michigan should study the feasibility of:**
    - **increased utilization of Appalachian Basin natural gas liquids (NGLs) and purity propane supplies in conjunction with additional in-state geological storage and fractionation capacity to diversify fuel sourcing; and**
    - **additional rail and storage infrastructure buildout near the Rapid River, Michigan fractionation facility to enhance resilience, including the potential use of the existing Michigan Economic Development Corporation's Freight Economic Development Program to offset 50% of the cost of a rail spur to serve the Rapid River facility.**

6. Cyber and Physical Security

6.1 Today's Infrastructure Security Landscape

6.1.1 Cybersecurity

Cybersecurity is the practice of protecting systems from cyber attacks. Cyber attacks can be extremely expensive to remedy and any attack on utility infrastructure could interrupt the supply of energy to Michigan customers. With attacks becoming more commonplace, utilities need to implement cybersecurity controls that will help them detect and respond to malicious activity before it causes damage or disruption.

Technological advancement and evolving societal demands are facilitating the growing digitalization of our everyday lives. For many of us, this shift has fundamentally transformed how we find information, work, communicate, shop, entertain ourselves, and perform other life tasks. For owners and operators of energy infrastructure, it has helped create efficiencies, reduce costs, provide additional functionality, and improve the reliability of energy operations.

Across the energy industry, this digital shift has manifested itself somewhat differently across two complementary technological domains:

- **Information Technology (IT)** – which centers on the use of electronic equipment and software to perform data or information processing, transmission, and storage, and
- **Operational Technology (OT)** – which centers on the use of electronic equipment and software to monitor and control physical equipment and processes.[135]

In the context of the energy industry, traditional IT pertains to the hardware and software that enables familiar enterprise functions such as email, word processing, billing, and human resources. OT, on the other hand, operates physical devices such as valves, pumps, and relays and provides telemetry to help inform and control energy operations.

The differing use cases between IT and OT have several important cybersecurity ramifications. First, IT and OT environments have historically been heterogeneous; OT environments routinely feature hardware, software, and communication protocols not typically seen in IT. Accordingly, many "off-the-shelf" cybersecurity tools and appliances are not designed for use in OT environments. Second, the need for energy systems to operate roughly 24/7 – and the fact that OT devices are often located on isolated networks scattered across a

[135] https://ics.sans.org/media/IT-OT-Convergence-NexDefense-Whitepaper.pdf.

large geographic footprint – makes conducting routine monitoring, maintenance, and patching a significant challenge. Lastly, the consequences of a cyber attack could be markedly different. An intrusion into an IT environment is more apt to result in exposed customer or employee data, render organizational data inaccessible, or cause the loss of trade secrets or other confidential information. On the other hand, an intrusion into an energy provider's OT environment could directly lead to electrical outages, a pipeline explosion, environmental contamination, or other significant physical consequences.

In keeping with the Governor's request to explore security threats which could disrupt energy "supply and/or delivery,"[136] this section of the Statewide Energy Assessment will focus less on traditional IT and more on the OT systems which manage energy operations. We note, however, that a disruption to email and voice communications, payroll, scheduling, or other enterprise IT functions would unquestionably hinder a utility or other energy organization's overall energy supply and delivery mission. Additionally, vulnerabilities in IT environments can provide valuable footholds which can be used by malicious actors who seek to compromise OT systems. For these and other reasons, and despite it being discussed less extensively here, we emphasize how integral traditional IT security remains to ensuring safe and reliable energy production, transmission, and distribution.

Despite the unique challenges in securing OT systems, the potential benefits to be captured by further deploying "smart" OT devices and increasing their connectivity to other enterprise systems are hard to ignore. Among other things, expanded OT deployment could enable energy infrastructure owners and operators to:

1. Detect and respond more quickly to events such as electrical outages and pipeline leaks;
2. Conduct smarter preventative maintenance of energy infrastructure;
3. Foster energy efficiency by providing near real time energy consumption and pricing information;
4. Further integrate distributed and renewable energy resources;
5. Automate various operational functions to reduce costs and add resilience; and
6. Improve data collection and tracking to help meet regulatory requirements

By and large, stakeholders are choosing to accept this tradeoff while simultaneously working to mitigate the accompanying cyber risks. The EIA estimates that nearly 79 million two-way communication-enabled advanced electric utility meters and over 5 million direct load control devices were installed in the U.S. at the end of 2017, nearly all of which were installed in the last

[136] https://www.michigan.gov/documents/mpsc/Energy_Study_Request_645612_7.pdf.

decade.[137] In Michigan, roughly 89% of all installed electric meters are two-way communication-enabled meters, which is among the highest percentages in the country.[138] Energy stakeholders have also detailed to MPSC Staff an array of plans to add bandwidth to OT networks, install additional devices to monitor infrastructure operations and improve site security, expand OT networks to connect previously islanded facilities, and implement other upgrades.

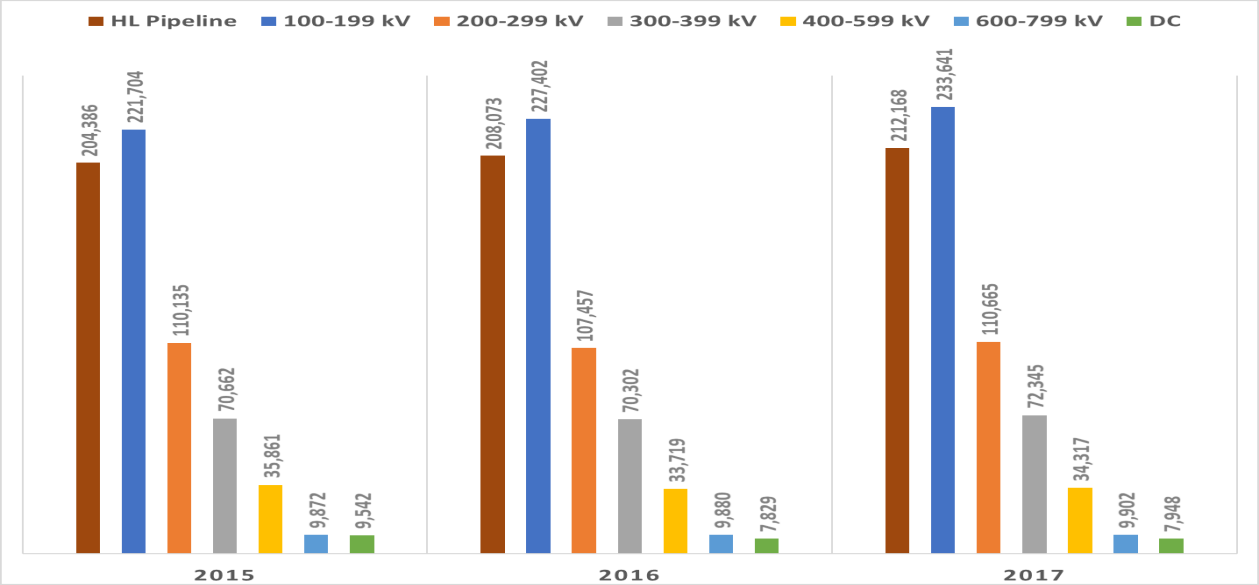
6.1.2 Physical Security

Physically securing the nation's energy infrastructure is quite literally a growing problem. The development of new solar, wind, oil, gas, and other energy resources, along with an expanding and shifting population, is fueling the continued buildout of electric infrastructure such as power lines, pipelines, and the physical stations needed to operate them. Between 2015 and 2017, more than 11,000 circuit miles of electric transmission and nearly 7,800 miles of hazardous liquids transmission pipeline were added nationally (Figure 6-1).[139] When this growth is viewed in conjunction with continued changes to other energy infrastructure such as generation, distribution, and storage facilities, it becomes clear how daunting the task to physically secure all of these assets can be.

Further complicating this mission is the fact that much of our energy infrastructure is not designed exclusively to minimize physical security risks; physical security considerations must contend with other organizational objectives such as limiting capital and O&M costs, minimizing environmental disturbance, and ensuring equipment is configured for reliable performance and is accessible for observation and maintenance.

[137] https://www.eia.gov/electricity/data/eia861/.
[138] Ibid.
[139] https://www.nerc.com/pa/RAPA/tads/Pages/ElementInventory.aspx.

Figure 6-1 Miles of U.S. Hazardous Liquid Transmission Pipeline and Electric Transmission, 2015-2017



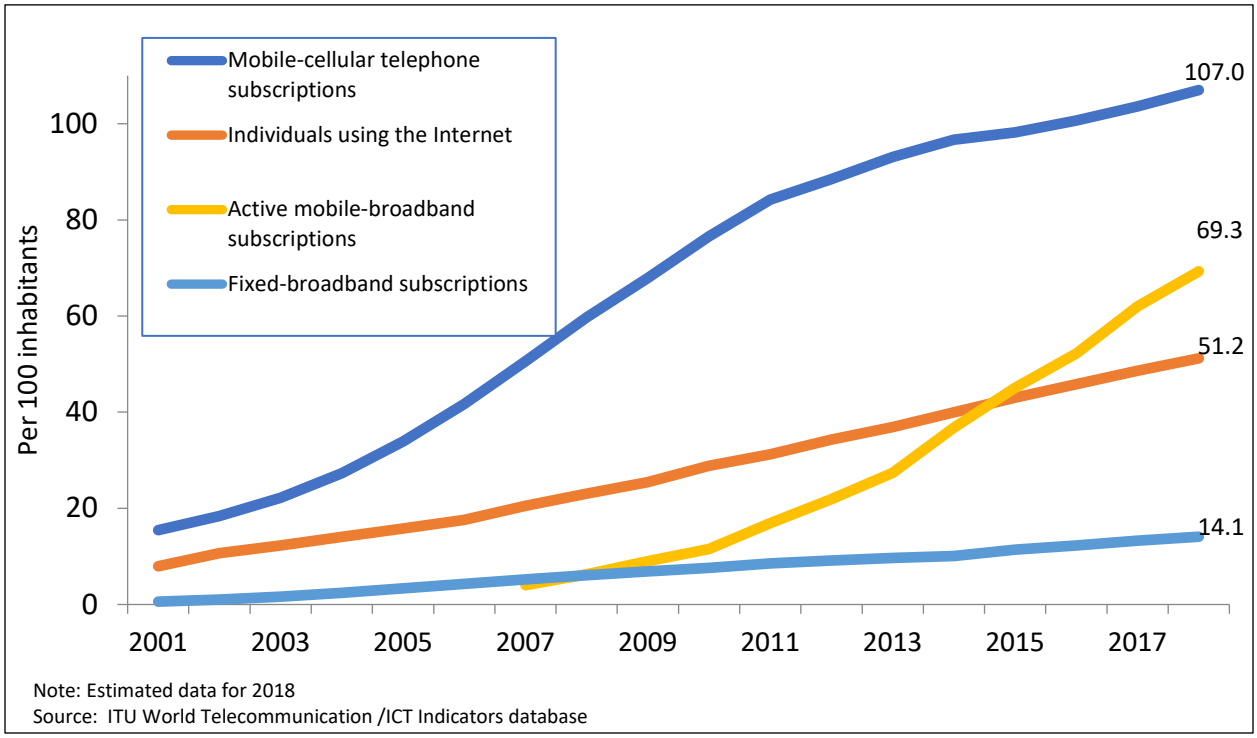
6.2 An Evolving Threat Environment

6.2.1 Cybersecurity

As our energy infrastructure becomes increasingly connected, so too is the world's population. The International Telecommunications Union estimates that 51% of the global population were internet users at the end of 2018, up from about 8% in 2001 (Figure 6-2). In the United States, the Pew Research Center estimates that nearly 90% of adults are internet users.[140] Further, numerous studies have shown that the amount of time U.S. individuals are spending online has also grown substantially over the same period, with one finding that weekly time spent online has more than doubled since 2000.[141]

[140] https://www.pewinternet.org/chart/internet-use/.
[141] https://www.digitalcenter.org/wp-content/uploads/2018/12/2018-Digital-Future-Report.pdf.

Figure 6-2 Global Information and Communication Technologies Developments, 2001-2017



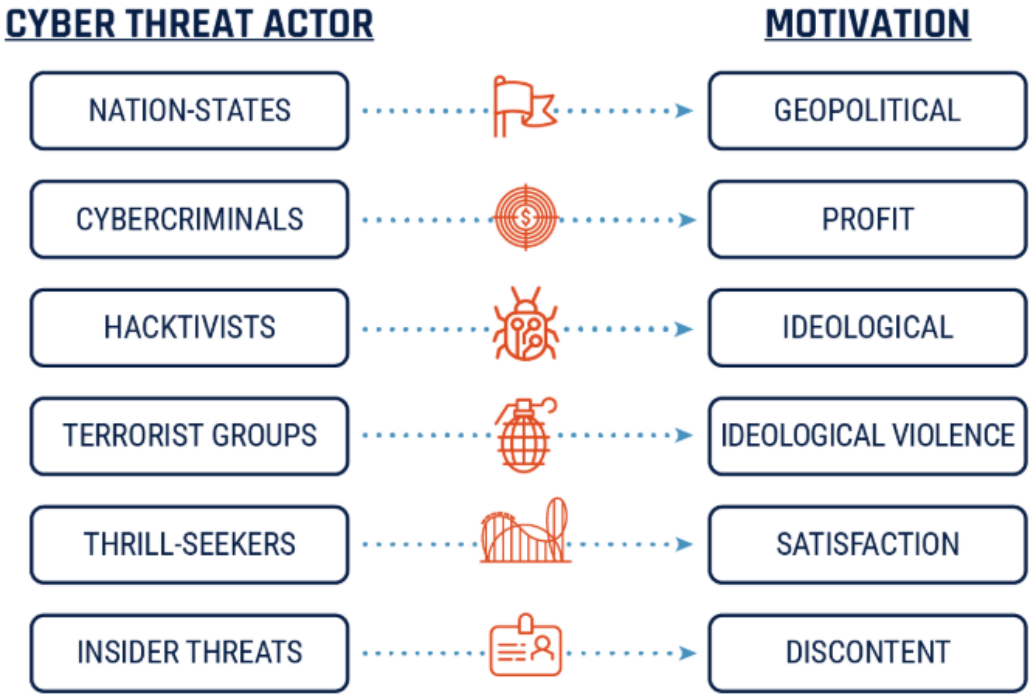
With each passing year, new devices become connected to new people and systems in never before seen ways. From the perspective of those tasked with defending the nation's energy infrastructure from cyberattacks, this means that the pool of actors who could remotely disrupt these systems is also continuing to grow. The cyber threat posed by such actors was cited by the Obama Administration as being "one of the most serious economic and national security challenges we face as a nation."[142] Figure 6-3 describes different types of cyber threat actors and their motivation.

Though categorizations vary somewhat from source to source, organizations have identified several types of cyber threat actors to help conceptualize the threat environment. These actor types are categorized primarily by the actor's principal motivation, but also in part by the actor's

[142] https://obamawhitehouse.archives.gov/the-press-office/2015/01/13/remarks-president-national-cybersecurity-communications-integration-cent.

level of sophistication. The figure below shows one example, from the Canadian Centre for Cyber Security[143].

Figure 6-3 Cyber Threat Actors



Each threat actor type is noted for its capacity and track record of intentionally causing or seeking to cause cyber disruptions. An overlooked aspect, however, is that these actors can also inadvertently cause disruptions or, as is common with insiders, take actions which unwittingly jeopardize the security of an organization.

While it is an oft-repeated consensus that the cyber threat is growing, less frequently discussed are some of the drivers of this trend. Increased interconnectedness, as noted above, undoubtedly provides new vulnerabilities and an improved means by which malicious actors may carry out their cyber activities. But industry cybersecurity personnel have also highlighted several other troubling trends to MPSC Staff:

[143] https://cyber.gc.ca/en/guidance/cyber-threat-and-cyber-threat-actors.

- **Specialization –** malicious actors are continuing to coalesce around specific areas of cyber expertise, which is fostering levels of sophistication beyond earlier "one-stop-shop" hacking models.
- **Off-the-Shelf Tools –** allow actors with limited expertise to conduct cyberattacks and helps expedite the attack development cycles for all actors.
- **Cryptocurrencies –** facilitate illicit transactions in underground marketplaces and provide a means to monetize malware such as cryptominers or ransomware.
- **Nation-State Activity –** is increasing in frequency and sophistication and is doing so in an environment without well-established global offensive and defensive cyber norms.

6.2.2 Physical Security

This section focuses principally on man-made physical security threats. However, energy infrastructure also faces an array of natural physical threats, such as extreme weather and wildlife activity, that may ultimately pose a greater risk than the man-made threats discussed more thoroughly here.

Like the discussion about cyber threat actors, energy infrastructure is subject to a similar collection of physical security threat actors with differing motivations and capabilities. The Electricity Information Sharing and Analysis Center, E-ISAC, in 2018 assessed that an increase in incidents of theft was likely, fueled in part by continued socio-economic issues and, perhaps, by rising copper prices.[144] They further anticipated an uptick of suspicious activity, such as individuals probing physical defenses or making inquiries about specific facility information that may be useful to a malicious actor.[145] With respect to pipelines, individuals have closed valves,[146] damaged pipeline construction equipment,[147] and taken other actions in protest of the pipeline operator, the pipeline's route, its impact on the environment or other reason.

6.2.3 Cyber and Physical Security Incidents

In today's age, few weeks go by without the media's reporting of a troubling new physical or cybersecurity incident, campaign, or plot. In many cases, particularly for reports involving critical infrastructure, key details are often kept confidential and information in the public domain regularly goes uncorroborated by authoritative sources. The net result is that the details of such incidents tend to be murky. Nonetheless, what has been publicly reported makes very clear that

[144] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_2018_SOR_06202018_Final.pdf.
[145] Ibid.
[146] https://www.detroitnews.com/story/news/local/michigan/2019/03/09/valve-turners-enbridge/39172951/.
[147] https://www.desmoinesregister.com/story/news/politics/2018/07/23/dakota-access-pipeline-iowa-sabotage-no-federal-charges-jessica-reznicek-ruby-montoya/801287002/.

the world's energy infrastructure is in the crosshairs of various threat actors. What follows is a brief overview of some widely reported, relatively recent incidents which directly threatened critical energy infrastructure or the operation thereof.

Notable Cybersecurity Incidents:

- **Iranian Nuclear Facility –** In 2010, sophisticated malware was discovered at a uranium enrichment facility in Natanz, Iran.[148] The malware was later reported to be designed to compromise specific OT devices that control the spin rate of the facility's centrifuges and alter their settings. By one estimate,[149] the malware may have caused up to 1,000 centrifuges at the facility to fail prematurely.
- **Ukrainian Power Grid –** On December 23, 2015, attackers remotely accessed the control centers of three Ukrainian electric distribution utilities, opened breakers at approximately 30 distribution substations, and caused an estimated 225,000 customers to lose power.[150] The attackers also took steps to overwhelm the telephone systems of the utilities' call centers, disable two of the three control centers' backup power supplies, and took other measures to hinder the utilities' efforts to quickly restore power.[151] Approximately one year later, on December 17, 2016, a 330-kV substation in northern Kiev was knocked offline, which was later reported as being instigated by a cyberattack.[152]
- **Saudi Arabian Petrochemical Complex –** Petro Rabigh operates a 400,000 b/d refinery and petrochemicals complex in Rabigh, Saudi Arabia.[153] In August 2017, the facility's safety systems triggered an emergency shutdown of the facility, though operators did not notice anything out of the ordinary at the time. Subsequent investigation determined that the safety systems – which are designed to act if unsafe conditions are detected to avert a catastrophic facility failure – had been compromised.[154] Observers have since hypothesized that the adversary had likely unintentionally knocked the plant offline, and that the ultimate goal was to trigger an

[148] https://www.wired.com/2014/11/countdown-to-zero-day-stuxnet/.
[149] http://isis-online.org/uploads/isis-reports/documents/stuxnet_FEP_22Dec2010.pdf.
[150] https://ics.sans.org/media/E-ISAC_SANS_Ukraine_DUC_5.pdf.
[151] https://www.wired.com/2016/03/inside-cunning-unprecedented-hack-ukraines-power-grid/.
[152] https://www.reuters.com/article/us-ukraine-cyber-attack-energy/ukraines-power-outage-was-a-cyber-attack-ukrenergo-idUSKBN1521BA.
[153] https://www.ogj.com/articles/2019/02/petro-rabigh-s-refinery-due-fuel-oil-upgrading-project.html.
[154] https://www.eenews.net/stories/1060123327.

explosion or accident in which the compromised safety systems would be prevented from intervening.[155]

Notable Physical Security Incidents:

- **British Columbia Natural Gas Facilities –** Between October 2008 and July 2009, a series of six bombings targeted natural gas wells and pipelines owned by the Encana Corporation. No one was injured as a result of the explosions, though damage at some of the facilities caused a loss of containment and the release of natural gas.[156] Across the border in the U.S., similar pipeline bombing plots were reported in Oklahoma in 2011[157] and Texas in 2012.[158]
- **Metcalf Substation –** Shortly before 1:00 a.m. on April 16, 2013, an unknown number of individuals arrived at Pacific Gas and Electric Company's Metcalf Substation near San Jose, California. The attackers cut fiber optic communications cables adjacent to the facility and spent nearly 20 minutes firing over 100 rounds of ammunition into the radiators of the substation's transformers. By 2:00 a.m. the attackers had left the area, and 17 of the facility's 20 transformers had been damaged from overheating. Grid operators were able to reroute power to avoid end-user electrical outages, but the damage kept the Metcalf facility out of service for 27 days while repairs were made.[159]
- **East-West Crude Oil Pipeline –** In May 2019, explosive-laden drones attacked pumping stations on Saudi Aramco's 48-inch East-West Crude Oil Pipeline, causing a fire and a one-day stoppage of the pipeline.[160] Though the damage was relatively minor, observers have noted an uptick in the use of civilian drone technology to conduct malicious activity, underscoring the need to reevaluate physical security measures to protect infrastructure from this emerging threat.[161]

Though the root causes may be very different, one can see that the consequences of a physical attack, a cyberattack on OT infrastructure, a natural disaster, or an equipment

[155] https://www.nytimes.com/2018/03/15/technology/saudi-arabia-hacks-cyberattacks.html.
[156] https://www.theglobeandmail.com/news/british-columbia/questions-linger-about-encana-bombings/article16109812/.
[157] http://www.cnn.com/2011/CRIME/08/12/oklahoma.pipe.bomb/index.html.
[158] https://www.justice.gov/usao-edtx/pr/plano-man-guilty-pipeline-bombing-incident.
[159] https://www.wsj.com/articles/assault-on-california-power-station-raises-alarm-on-potential-for-terrorism-1391570879.
[160] https://oilprice.com/Latest-Energy-News/World-News/Saudi-Aramco-Restarts-Oil-Pipeline-After-Drone-Attack.html.
[161] https://www.nbcnews.com/politics/national-security/terrorists-likely-attack-u-s-drones-says-fbi-director-n918586.

malfunction may be quite similar. Accordingly, mitigation strategies such as adding redundant infrastructure, hardening facilities, and conducting emergency response planning and exercises serve to reduce the risks associated with many types of infrastructure failures, regardless of the failure's root cause.

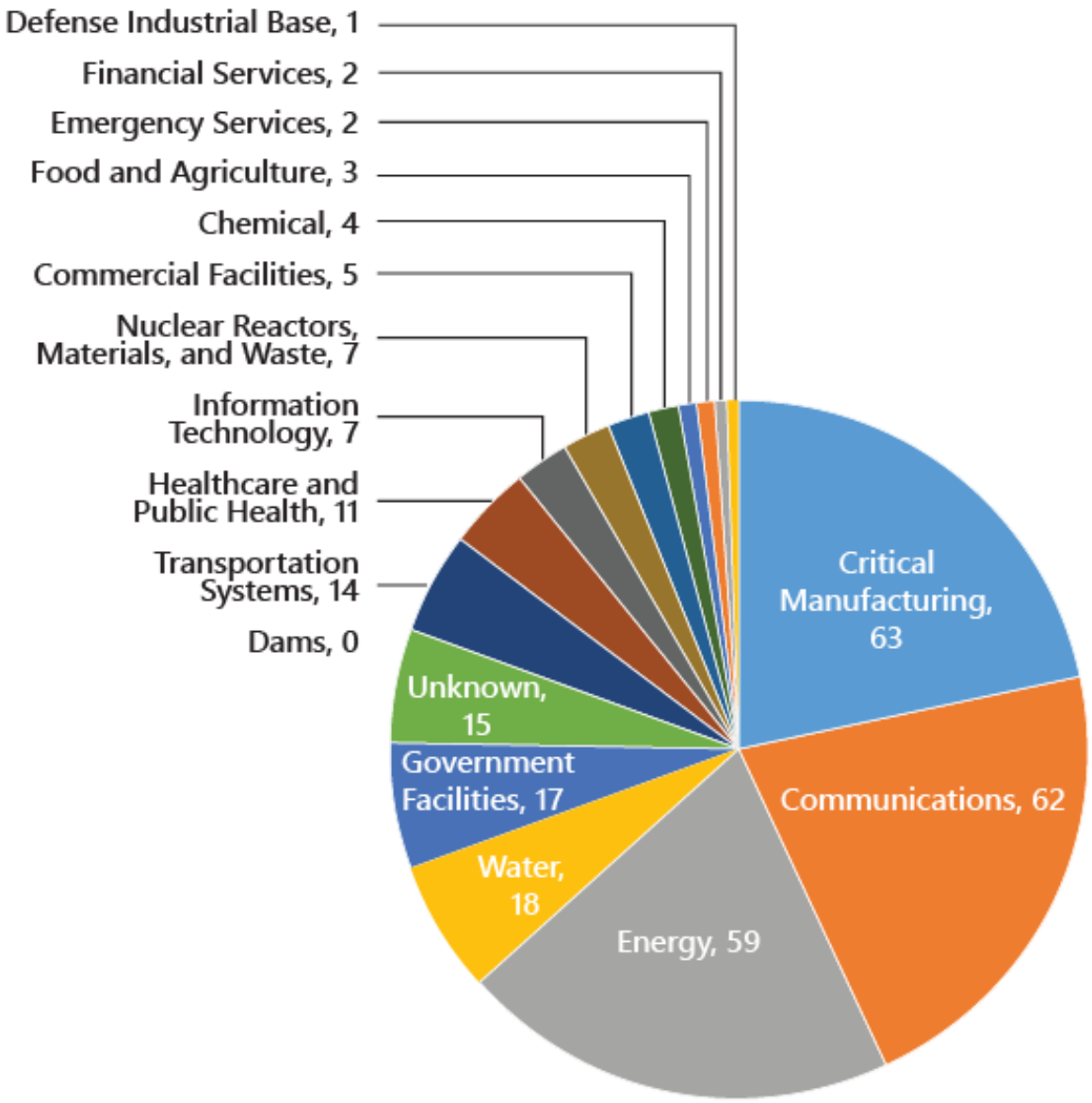
While some authoritative public statistics about physical and cyber incidents involving critical infrastructure exist, these figures are rare. Several factors likely contribute to this, including the need to keep certain incident information confidential, the under-detection or underreporting of incidents, the relative infrequency of such incidents, or simply that few mechanisms exist to collect this information in any broad-based, systematic way. Nonetheless, the following figures are intended to help contextualize this discussion by providing a sense of the types and frequency of physical and cybersecurity incidents occurring in the critical infrastructure space.

In fiscal year 2018, the DHS's National Cybersecurity and Communications Integration Center responded to 59 cyber incidents originating in the energy sector.[162] A review of incident data from DHS reveals that the number of reported incidents attributed to the energy sector consistently rivals that of any other critical infrastructure sector. A breakdown of cyber incidents reported to DHS's control systems unit, by critical infrastructure sector during fiscal year 2016, is shown in Figure 6-4.[163]

[162] Email correspondence from DHS to MPSC staff, July 3, 2019.

[163] https://www.us-cert.gov/sites/default/files/Annual_Reports/Year_in_Review_FY2016_IR_Pie_Chart_S508C.pdf.

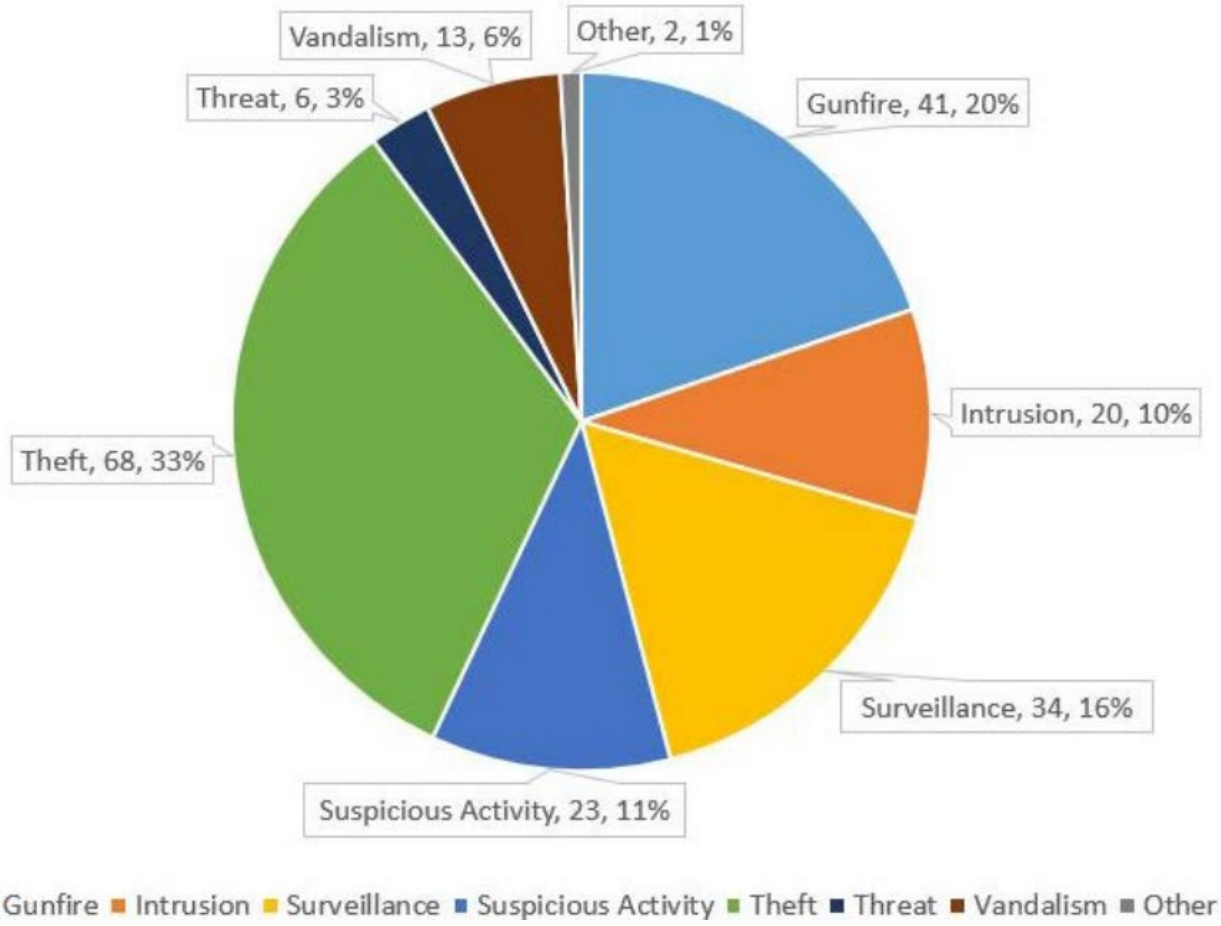
Figure 6-4 Incidents by Sector, Fiscal Year 2016



Source: National Cybersecurity and Communications Integration Center

According to NERC, electric sector entities reported over 200 physical security incidents to the E-ISAC in 2018.[164] These incidents, broken down by category, are shown in Figure (6-5).

Figure 6-5 Physical Security Incidents by Category



Source: North American Electric Reliability Corporation

6.3 Sector Response

As the latest *National Infrastructure Protection Plan* (NIPP) notes, our national well-being relies upon secure and resilient critical infrastructure – those assets, systems, and networks that

[164] https://www.wecc.org/Administrative/TLP%20Green%20E-ISAC%20End%20of%20Year%20Report.pdf.

underpin American society.[165] The tactics, techniques, and procedures of malicious adversaries continue to evolve, and stakeholders tasked with protecting critical infrastructure must continue taking strides to stay one step ahead. Thankfully, stakeholders are working to do just that. Below are a few security-centric areas that have seen substantial stakeholder engagement over the past decade or so.

6.3.1 Strategies, Goals, and Principles

A fundamental component of an effective security program is a high-level strategy which sets overarching cybersecurity goals and principles. From the physical security standpoint, the NIPP continues to serve as the national strategy for the security of critical infrastructure. In terms of cybersecurity, in April 2018, NIST released version 1.1 of its Cybersecurity Framework. The Framework is a template, geared toward critical infrastructure owners and operators, that articulates cybersecurity objectives and practices and that users can customize and adopt to help guide their cybersecurity programs.[166] The U.S. government followed by releasing its National Cyber Strategy[167] in September 2018, which highlights key national cybersecurity objectives and corresponding actions. In October 2018 NARUC released guidance to help state utility commissions develop their own cyber strategies.[168]

A review of these documents and other literature reveals a few common guiding principles. Perhaps most notably are that:

- Physical and cybersecurity programs should be based on risk management principles.
- Information security should be based on the core objectives of confidentiality, integrity, and availability.
- No single control is perfectly effective, and therefore defense-in-depth approaches should be employed.
- Security involves people, processes, and technology, and effective programs must consider how all can work in tandem securely.

[165] https://www.dhs.gov/sites/default/files/publications/NIPP%202013_Partnering%20for%20Critical%20Infrastructure%20Security%20and%20Resilience_508_0.pdf.
[166] https://nvlpubs.nist.gov/nistpubs/CSWP/NIST.CSWP.04162018.pdf.
[167] https://www.whitehouse.gov/wp-content/uploads/2018/09/National-Cyber-Strategy.pdf.
[168] https://pubs.naruc.org/pub/8C1D5CDD-A2C8-DA11-6DF8-FCC89B5A3204.

6.3.2 Standards and Controls

Effectuating high-level security goals and polices requires the application of security controls, including safeguards or countermeasures tailored to help meet specific security objectives or formal requirements.[169]

In the context of the energy sector, many resources exist to help guide the implementation of security controls and other cyber policies and practices. Figure 6-6 highlights a few security resources that MPSC Staff is aware are being used or have been wholly adopted by Michigan utilities, either because doing so is mandatory or because they have done so voluntarily. In a forthcoming revision to the Technical Standards for Gas Service, the MPSC will seek to require all natural gas utilities covered by the technical standards to adhere to API Standard 1164.

Figure 6-6 – Security Resources

Issuing Entity	Security Reference	Description
NERC	Critical Infrastructure Protection (NERC-CIP)[170]	A set of standards that set minimum security requirements for bulk power systems
TSA	Pipeline Security Guidelines[171]	A set of recommended security practices for gas and liquid pipeline systems
CIS	CIS Controls[172]	A prioritized list of 20 cybersecurity actions that can be implemented to reduce cyber risk
DOE	Cybersecurity Capability Maturity Model (C2M2)[173]	A tool to evaluate one's implementation of defined cybersecurity practices and to assess one's overall cybersecurity capabilities
API	Standard 1164: Pipeline SCADA Security[174]	A standard that provides guidance to pipeline operators to help manage SCADA system integrity and security

[169] https://csrc.nist.gov/glossary/term/security-control.
[170] https://www.nerc.com/pa/Stand/pages/cipstandards.aspx.
[171] https://www.tsa.gov/sites/default/files/pipeline_security_guidelines.pdf.
[172] https://www.cisecurity.org/controls/cis-controls-list/.
[173] https://www.energy.gov/ceser/activities/cybersecurity-critical-energy-infrastructure/energy-sector-cybersecurity-0.
[174] American Petroleum Institute. Standard 1164, Pipeline SCADA Security, Second Edition, June 2009; Reaffirmed October 2016.

6.3.3 Information Sharing and Partnerships

Arguably the space which has evolved most significantly in recent years is security information sharing. Each state maintains at least one "fusion center" – Michigan has two – which centralizes the collection and dissemination of security-related intelligence. The U.S. energy sector also operates three subsector-based ISACs (e.g. E-ISAC, for electricity) to allow stakeholders to share security information within their subsector. Federal agencies also provide classified intelligence briefings to selected utility personnel in Michigan and elsewhere, and various informal utility-to-utility sharing practices also exist.

Supporting these burgeoning information-sharing apparatuses are an array of partnerships. One such partnership is Infragard, a partnership between the Federal Bureau of Investigation and members of the private sector to support the protection of critical infrastructure. Trade associations and other industry groups also play a key role, as they participate on councils and in working groups that engage with government and help guide industry security practices.

6.3.4 Cyber Mutual Assistance

For decades, utilities have been sending personnel and equipment to assist other utilities in their electric or natural gas restoration efforts following a major storm, natural disaster, or other significant event. Building off this successful arrangement, the industry is working to expand this relationship to assist utilities preparing for or recovering from a significant cyber incident. The Cyber Mutual Assistance program provides a legal framework to facilitate the sharing of personnel, services, and equipment, which is accompanied by a non-disclosure agreement to protect confidentiality. Participation in the program is voluntary, and the fulfilment of any requests for assistance is made at the assisting utility's sole discretion. As of January 2018, 140 entities, including Michigan utilities, are now participating in the recently formed cyber mutual assistance program. Collectively, these entities serve approximately 80% of all U.S. electric customers and 75% of all U.S. natural gas customers.[175]

6.3.5 Exercises

Exercises provide an opportunity to test incident response plans, clarify roles and responsibilities, identify gaps in resources, and identify opportunities for improvement. Flagship biennial national exercises like DOE's Clear Path and NERC's GridEx are increasing in overall stakeholder participation and quality; participation in the latest GridEx increased by 47% and

[175] http://www.electricitysubsector.org/CMA/Cyber%20Mutual%20Assistance%20Program%20One-Pager.pdf?v=1.2.

24%, for individuals and organizations respectively, from its previous iteration. Michigan also boasts the Michigan Cyber Range, the nation's largest unclassified, network-accessible cybersecurity training platform.[176] The range allows users to exercise their offensive and defensive cyber skills in a simulated environment containing, among other things, virtualized critical infrastructure systems.[177]

6.4 MPSC Response

As the sector continues to take steps to mitigate its cyber risk, MPSC staff actively works to support these efforts by, among other things, participating in exercises, receiving cyber training, and sharing information with Michigan's energy stakeholders. In recent years, the MPSC has also endeavored to supplement ongoing sector efforts with its own initiatives. Two such efforts, the Annual Cybersecurity Reporting initiative and the Cybersecurity Incident Reporting initiative, warrant particular mention and are discussed more fully below.

6.4.1 Annual Cybersecurity Reporting

In late 2015, the Commission issued orders directing Consumers Energy[178] and DTE Electric[179] to each provide MPSC staff with an annual report about their respective cybersecurity programs. The initial reports from the companies, and the overall practice itself, were viewed favorably by MPSC staff. To expand the practice to the remaining investor-owned and cooperative electric utilities in Michigan, the Commission updated the Technical Standards for Electric Service, effective January 2019.[180] Under the terms of the new rule, electric providers subject to the rule must report the following to MPSC staff about their cybersecurity programs:

- An overview of the provider's program
- A diagram of the provider's cybersecurity organization, including contact information for select personnel
- A description of the provider's participation in cybersecurity training and emergency preparedness exercises.
- A description of the provider's communications plan in the event of a significant cybersecurity incident

[176] https://www.merit.edu/cyberrange/.
[177] Ibid.
[178] Commission order in U-17735, November 19, 2015.
[179] Commission order in U-17767, December 11, 2015.
[180] Commission order in U-18203, November 22, 2016.

- A summary of any significant cybersecurity incidents experienced by the provider and any remedial actions taken
- A description of the risk assessment tools and methods used by the provider to evaluate, prioritize, and improve its cybersecurity capabilities
- General information about the provider's incident response plans, preparedness strategies, threat assessments, and vulnerability assessments

In addition to the above, investor-owned electric utilities must also provide MPSC staff with a description of, and a rationale for, any recent or forthcoming major cybersecurity investments.

By and large, Michigan's electric utilities have opted to provide their annual reports orally, during in-person meetings with MPSC staff. Since the rule's inception in January 2019, MPSC staff has completed annual reports with 10 of the 18 electric providers covered by the rule. The remaining reports will be scheduled and completed in 2019.

6.4.2 Cybersecurity Incident Reporting

In 2017, while language was being drafted for the above-noted Annual Reporting rule, MPSC staff and Michigan's energy stakeholders began jointly working on additional language that would require electric providers to notify MPSC staff and the Michigan Intelligence Operations Center (MIOC) in the event the provider experiences a significant cybersecurity incident. The Technical Standards for Electric Service, effective January 2019, include mandatory incident reporting requirements for investor-owned utilities and cooperatives. The rule requires that electric providers make notifications to MPSC staff and to the MIOC if any of the following occur:

- A person intentionally interrupted the production, transmission, or distribution of electricity.
- A person extorted money or other thing of value from the electric provider through a cybersecurity attack.
- A person caused a denial of service in excess of 12 hours.
- An unauthorized person accessed or acquired data that compromises the security or confidentiality of personal information maintained by the electric provider, as defined by section 3(r) of the Identity Theft Protection Act.
- Any other cybersecurity incident, attack, or threat which the electric provider deems notable, unusual, or significant.

6.5 Vulnerabilities

Infrastructure owners are increasingly making use of technologies which blur the traditional lines between OT, IT and physical security. As OT systems become better connected, the prospect of leaving OT systems unpatched or unmonitored for long periods of time, as was common historically, is increasingly untenable. These concerns and other business objectives are fueling a drive toward more IT-style technologies being deployed in OT environments.

Further, as infrastructure owners seek to "buy down" physical security risk across their asset footprint, they continue to turn to IT/OT solutions such as camera systems, physical intrusion detection systems, and electronic facility access controls. The net result is that the physical, OT, and IT security missions are becoming increasingly intertwined, and a breach in any of these domains can serve to directly subvert another. With the foregoing in mind, we look now at a few areas of existing or emerging vulnerability and note the relative costs to implement some corresponding enhancements.[181]

6.5.1 Security Governance

A pillar of any security program is an overarching policy that establishes a process to regularly set tangible organizational physical and cybersecurity objectives, assigns ownership of these objectives, assesses the degree to which those objectives were ultimately met, and then endeavors to establish new objectives. This process occurs inconsistently across Michigan's utilities, and in some cases, in disparate ways within an organization.

Enhancement Cost: Low

6.5.2 Implementation of Basic Cybersecurity Controls

A 2017 analysis found that implementing just the top 5 Center for Internet Security (CIS) security controls could have prevented 85% of the most common cyberattacks. Implementing all 20 would have boosted that number to 97%.[182] It is not clear to MPSC Staff that all of Michigan's utilities have the necessary policies, procedures, and tools in place to accomplish the following basic cyber hygiene objectives:

a. Hardware and Software Asset Management
b. Change and Configuration Management
c. Identity and Access Management
d. Threat and Vulnerability Management

Enhancement Cost: Varies

[181] Costs designated as "Low" are assessed to be implementable within existing IT security budgets or with a small increase (<10%). Costs designated as "Medium" are assessed to require a larger increase (>10%). Actual costs depend on many factors and will vary by utility.

[182] https://www.tripwire.com/state-of-security/featured/foundational-controls-work-a-2017-dbir-review/.

6.5.3 Phishing Vigilance

Around 90% of cyberattacks begin with a phishing email, and around 1% of all emails are malicious, according to a 2018 report from FireEye.[183] The Lansing Board of Water and Light was the victim of a ransomware attack in 2016 that stemmed from a phishing email. A utility employee reportedly opened an email containing a malicious attachment effectively shutting down the utility's information systems for a full week.[184] The attack on the Lansing Board of Water and Light, while unfortunate, provides a relevant example of the risks associated with phishing. In meetings with MPSC Staff, utility representatives all appeared to recognize the seriousness of the threat, but the measures their respective organizations were taking to mitigate the threat varied considerably.

Enhancement Cost: Low

6.5.4 Third-Party Risk

Third-party risk is a broad category of risks that stem from the actions of outside parties with which one conducts business. Examples include contractors who have unmanaged physical access to sensitive facility areas, inauthentic or insecure hardware or software procured from suppliers, or uncontrolled vendor access to IT or OT systems. In 2018, DOE and DHS issued advisories concerning a nation-state actor engaged in an ongoing campaign to compromise third parties to subvert others' cybersecurity defenses.[185] Utilities should evaluate and make appropriate changes to current badging and access control policies, network configurations, methods to validate software, and other polices to further reduce third-party risk.

Enhancement Cost: Medium

6.5.5 Human Capital

The world is estimated to be short nearly 3 million cybersecurity professionals, with nearly half a million of the shortfall coming in North America.[186] Utilities will have to be creative in finding and developing physical and cybersecurity personnel and take care to foster an environment conducive to retention. To avert an organizational talent shortage, utilities should

[183] https://mms.businesswire.com/media/20180912005256/en/677559/1/ig-it-only-takes-one-email.pdf?download=1.
[184] https://www.govtech.com/security/Ransomware-Attack-on-Michigan-Utility-Provider-Highlights-Organizational-Vulnerabilities.html.
[185] https://www.energy.gov/articles/department-energy-statement-chinese-hacking-global-managed-service-providers.
[186] https://blog.isc2.org/isc2_blog/2018/10/cybersecurity-skills-shortage-soars-nearing-3-million.html.

consider ways to maximize available talent and resources through partnerships with peer institutions, government agencies, academia or other entities.

Enhancement Cost: Medium

6.5.6 Insider Threats

A 2019 analysis reported by Verizon of more than 2,000 data breaches found that approximately 34% involved internal actors.[187] While some breaches are perpetrated by rogue insiders, far more are caused by the inadvertent errors of system administrators or other employees. These errors can take various forms, including misconfigured servers, improper permissions, or the accidental publication of sensitive data. As with all cyber risks, no single approach can effectively neutralize all insider threats. As such, utilities should seek to promote a culture that encourages the reporting of suspicious behaviors, employ network tools to detect suspected data leakage events and anomalous user activities, evaluate existing hiring and screening procedures, revisit access and configuration management policies, and pursue other avenues to reduce insider risk.

Enhancement Cost: Varies

[187] https://enterprise.verizon.com/resources/reports/2019-data-breach-investigations-report.pdf.

6.6 Cyber and Physical Security Recommendations for Mitigating Risk

6.6.1 Commission's Cyber and Physical Security Recommendations

- **The Commission instructs Staff to include cybersecurity standards and reporting for natural gas distribution systems under MPSC jurisdiction through proposed amendments to the Gas Technical Standards. The Commission recommends that the Technical Standards for Gas Service be updated to incorporate by reference API Standard 1164 to enhance the cybersecurity of natural gas infrastructure.**
- **The Commission instructs Staff to continue to evaluate existing Commission rules and utility data privacy tariffs for opportunities to enhance the protection of customer data and the cybersecurity of electric distribution infrastructure.**
- **The Commission recommends electric and natural gas utilities conduct annual self-assessments of cyber capabilities using the C2M2 self-assessment tool utilized by the U.S. DOE, or similar tool.**
- **The Commission recommends electric and natural gas utilities pursue the close coordination of OT, IT, and physical security operations, and centralize security functions under the auspices of a high-ranking security leader.**
- **The Commission recommends utilities work to develop metrics to assess cybersecurity performance and to track their performance against these metrics.**
- **The Commission recommends the utilities categorize anticipated physical and cybersecurity incident types and severities and make clear the internal and external notifications that will occur based on these categorizations.**
- **The Commission recommends the utilities regularly audit operational technology environments for internet-facing systems and remediate to limit the organizational attack surface.**
- **The Commission recommends the utilities run simulated phishing campaigns at least quarterly and include all employee levels.**
- **The Commission recommends the utilities require multifactor authentication to remotely access OT assets.**
- **The Commission recommends utilities adopt industry best practices in mitigating threats from phishing and other IT threats, perform a cost-benefit analysis for top CIS security controls, and take appropriate steps to implement additional controls.**

7. Energy Emergency Management

7.1 Nature of Energy Emergencies

During any given year, states, including Michigan, face a variety of energy disruptions in both supply and distribution. Where these disruptions are limited in scope and the energy sector resolves them quickly, they are barely noted. However, if these disruptions extend over wide areas and last more than several hours or days, they may become "energy emergencies" and may require assistance by government. It is for these energy emergencies that fully developed and well-thought-out energy emergency plans are necessary.

An energy emergency is an actual or potential loss of energy supply that may significantly impact the health and welfare of citizens, the economic stability of a region, emergency services, and/or government operations. An energy emergency can be caused by natural or man-made disasters, geopolitical events, or market unrest. While each situation is unique, and it is impossible to envision every potential event or combination of events that might precipitate an energy emergency, the most common causes of energy emergencies can generally be categorized as the following:

- **Severe Weather –** Extreme cold and heat waves can stress the energy system when unusual surges in demand overwhelm available system capacities. Ice and windstorms in Michigan have the potential to disrupt electric distribution.
- **Natural Disasters –** Tornadoes, floods, wildfires or other natural disasters can cause disruptions to energy systems by affecting distribution, transmission, generation or other system components.
- **Infrastructure Failures –** Unanticipated events resulting from transmission congestion, electric generation interruption, refinery shutdowns, pipeline breaks, and equipment or system failures could result in the reduction of supply and/or disrupt distribution.
- **Commodity Market Volatility –** Price volatility or extreme increases in price can impact available supply or inventories of energy fuels. Destabilized market conditions can also affect demand by influencing consumer behavior.
- **National Security Events –** Sabotage, war, acts of terrorism, or cyber-attacks can impact supply availability or result in the physical destruction of energy systems. Large scale military operations may also place undue pressure on energy supplies.

In the early stages of an energy emergency, the primary role of government is fact finding, monitoring, and information exchange, rather than direct intervention in industry efforts to restore services. The MPSC serves as a clearing house of information regarding statewide electric, natural gas, and petroleum outages and emergency impacts.

7.2 Statutory Authorities Addressing Energy Emergencies

7.2.1 Declaration of State of Energy Emergency, PA 191 of 1982[188]

Pursuant to the Declarations of State of Emergency Act, PA 191 of 1982, MCL 10.81 et seq., the Governor may declare a State of Energy Emergency to address emergency conditions concentrated in the energy sector, including but not limited to supply, distribution, transportation, or pricing issues that affect the health and welfare of Michigan citizens. The declaration may be used to direct energy supplies to meet essential services or restrict the use and sales of energy resources if necessary.

> "Critical infrastructure owners and operators are uniquely positioned to manage risks to their individual operations and assets, and to determine effective strategies to make them more secure and resilient."
>
> *-Presidential Policy Directive 21, 2013*

7.2.2 Emergency Management Act, PA 390 of 1976[189]

Public Act 390 of 1976, as amended, is the basic state emergency management enabling legislation. This Act prescribes the power and duties of the Governor and certain state and local agencies and officials related to preparing for, responding to, recovering from, and mitigating disasters and emergencies; prescribes immunities and liabilities related to disaster relief work; and establishes the organizational framework for the emergency management system used in the state.

[188] PA 191 of 1982 - http://www.legislature.mi.gov/documents/mcl/pdf/mcl-act-191-of-1982.pdf.
[189] PA 390 of 1976 - http://legislature.mi.gov/doc.aspx?mcl-act-390-of-1976.

7.2.3 Federal Motor Carrier Safety Administration (FMCSA) 49 CFR Parts 300-399[190]

Federal regulations (49 CFR Part 390.23) allow for temporary relief from Parts 390 through 399 of the safety regulations, to any motor carrier or driver operating a commercial motor vehicle to provide direct emergency assistance during an emergency.

7.2.4 Clean Air Act - US Environmental Protection Agency (EPA)[191]

The EPA enforces regulations under the Clean Air Act that limit the Reid vapor pressure (RVP) of motor fuels during warmer months. This helps reduce evaporation of volatile organic compounds, which contribute to urban air pollution. In instances where shortages of summer or winter blend fuel occurs, air quality waivers may be sought from EPA to temporarily alleviate the supply imbalances.

7.2.5 Motor Fuels Quality Act, PA 44 of 1984

At the state level, vapor pressure requirements fall under Michigan's Motor Fuels Quality Act and are enforced by the Michigan Department of Agriculture and Rural Development (MDARD). Michigan has chosen to adopt more stringent requirements in Southeast Michigan and has received EPA approval for a State Implementation Plan (SIP)[192] that further restricts RVP levels in Livingston, Washtenaw, Oakland, Macomb, Wayne, St. Clair, Lenawee and Monroe counties.

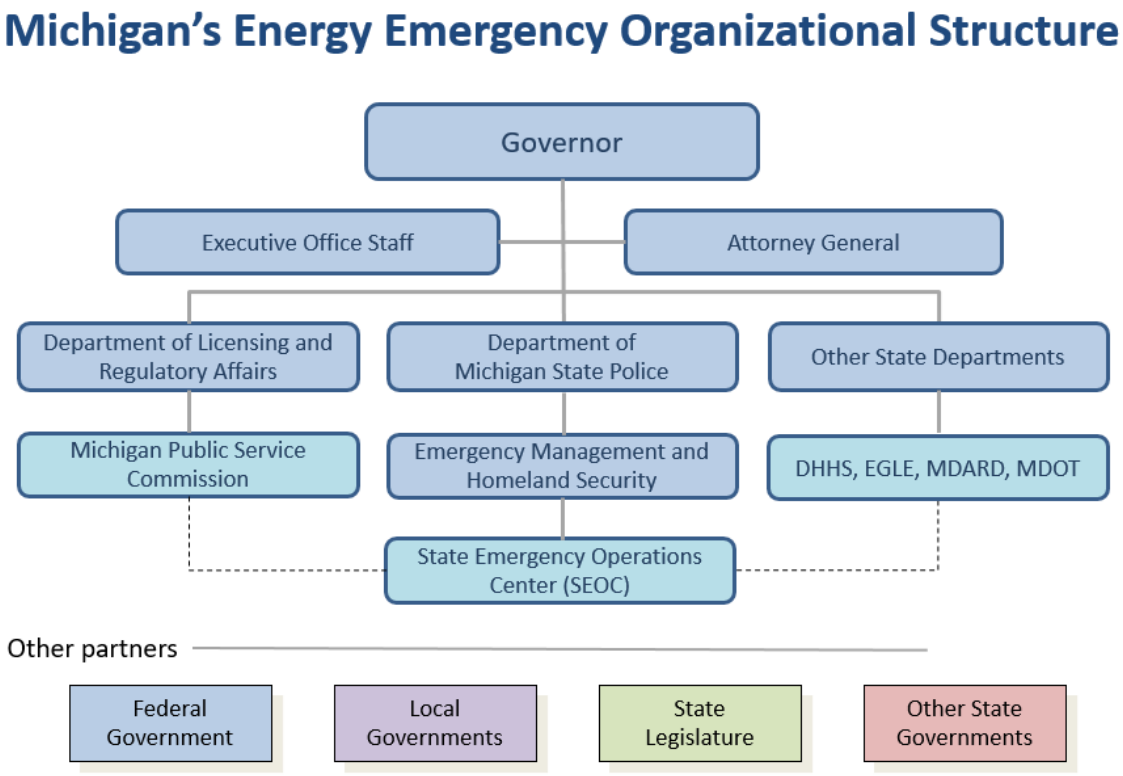
7.3 Roles and Responsibilities

7.3.1 Overview

Several federal, state and local government agencies share a part in energy emergency management. Working together, these agencies serve as crucial coordination hubs bringing together prevention, protection, response and recovery authorities, capacities and resources among local jurisdictions, across sectors and between regional entities. In concert with the private sector owners of much of Michigan's energy infrastructure, Michigan agencies play a significant role in preventing an energy supply crisis, mitigating a potential emergency's impacts, and responding to energy emergencies.

[190] 49 CFR Parts 300-399 - https://www.fmcsa.dot.gov/regulations/title49/b/5/3?reg=390.23.
[191] Clean Air Act 211(C)(4)(C)(ii) - https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapII-partA-sec7545.htm.
[192] EGLE – SIP Information: https://www.michigan.gov/egle/0,9429,7-135-3310_70940-90599--,00.html.

Figure 7-1 Michigan's Energy Emergency Organizational Structure



7.3.1.1 Governor - If an energy emergency requires mandatory state action, the Governor may declare a State of Energy Emergency under 1982 PA 191. Following such a declaration, the Governor may enact waivers to better cope with petroleum supply issues or under extreme circumstances order mandatory actions to alleviate the emergency. The Governor's powers to respond under a declaration of a State of Energy Emergency include:

- Ordering restrictions on the use and sale of energy resources
- Directing energy suppliers to provide energy resources to any person or facility which provides essential services for the health, safety and welfare of Michigan residents (i.e. medical/health facilities, schools, fire and law enforcement, etc.)
- Suspending statutes, orders or rules of state agencies if compliance with the statute, order or rule will prevent, hinder, or delay necessary action in coping with the energy emergency.

The Governor's State of Energy Emergency declaration remains in effect for the duration of the emergency or 90 days, whichever is shorter. If the situation worsens, the Governor can declare a State of Disaster. In this case, the primary responsibility of response efforts shifts to the Emergency Management and Homeland Security Division (EMHSD) of the State Police. In this instance, the MPSC Staff would support statewide activities and response regarding energy issues or concerns until the disaster has passed.

7.3.1.2 MPSC - The MPSC is the primary liaison to the electric and natural gas industry operating within the state and deals with issues related to service disruptions and restoration, system damage, and impacts affecting (or potentially affecting) incident response and recovery, and emergency services. The MPSC investigates significant service/supply disruptions in these sectors that may negatively impact public health and safety, and coordinates efforts to reduce the impact on critical facilities, services and populations. As part of the MPSC's day-to-day activities, Staff continuously monitor and gather data relating to energy supply, demand, infrastructure, and utility operations. The MPSC is generally successful in working with the utilities to obtain this information, however, certain sensitive information is often withheld by industry due to concerns about data confidentiality and the lack of disclosure protection under Michigan Freedom of Information Act (FOIA).

The energy emergency responsibilities of the MPSC can be grouped into five broad categories:

Figure 7-2 Emergency Responsibilities of the MPSC

Monitoring	Monitor Michigan's energy supply to detect unusual imbalances that may indicate the potential for an energy emergency and advise the appropriate state officials.
Development	Develop, administer, and/or coordinate energy emergency, response, and contingency plans.
Coordination	Act as the communication focal point for federal, state and local activities related to energy emergency preparedness, planning, and management.
Communication	Maintain ongoing contact with the electric, natural gas, and petroleum industries and other state, local and federal agencies concerning Michigan's energy supply and recovery efforts.
Support	Provide situation reports in the event of an emergency or disaster; support the State Police and SEOC as needed.

Emergency Response Roles – Depending on the severity and type of energy emergency, different sections of the Commission have different responsibilities as follows:

- **Energy Emergency Assurance Coordinators (EEAC) –** are the first-line responders to an energy incident or emergency and will evaluate the information received, coordinate monitoring, liaison with industry, and recommend response efforts and activities.
- **Energy Emergency Response Team (EERT) –** is comprised of subject matter experts serving the MPSC Chairman in the event of an impending or ongoing energy emergency. Select EERT members have received training in the Incident Command System in preparation for SEOC activation.
- **Emergency Management Coordinator (EMC) –** the manager of the MPSC's Energy Security section serves as the emergency management coordinator for energy and is the primary representative at the SEOC. The EMC coordinates monitoring efforts and communicates with the appropriate partner agencies (LARA, MSP, EGLE, DHHS, MDARD, MDOT, and private sector, etc.) or management as needed.
- **MPSC Chairman –** In the case of an impending or actual energy emergency, the Chair may make recommendations to the Governor regarding declarations of energy emergency or potential actions to alleviate or reduce the negative impacts of the emergency.[193] The Chair may also convene other state department directors to review the status of the developing energy disruption and make appropriate recommendations to the Governor.

Emergency Communications Plans – The MPSC maintains Energy Emergency Communication Procedures (Appendix H) which outline both the intake and sharing of pertinent energy infrastructure and supply information, roles and responsibilities of emergency response personnel, and response actions for local, state, or national energy emergencies. These procedures are updated twice annually.

Emergency Alert and Warnings – The MSP/EMHSD will work the MPSC to notify the public of energy emergencies, if necessary, through the Emergency Alert System and/or Wireless Emergency Alerts.

[193] Authority is granted via EO 2019-06, 4(b)(1) where the energy emergency lead is transferred from the MAE director to the MPSC chair. https://www.michigan.gov/whitmer/0,9309,7-387-90499_90705-490039--,00.html. Authority was previously established by EO-2015-10.

Emergency Management Training and Exercises – Following the August 2003 blackout, MPSC emergency plans were updated to accommodate a more active presence at the SEOC should the energy emergency require coordination with additional state agencies and local jurisdictions.

Training – Select members of the MPSC's EERT have received specialized training in the areas of emergency management and homeland security. Collectively the EERT will exhibit the following capabilities:

- The ability to operate within the Incident Command System as outlined in the National Incident Management System;
- Have knowledge of the state's critical energy infrastructure systems, including their location, function, general vulnerabilities, and consequences of loss;
- The ability to communicate with other local and state agencies utilizing Michigan Critical Incident Management System (MI CIMS), the MSP/EMHSD incident management software.

Exercises – Periodically, members of MPSC's EERT are involved with exercises and drills related to energy supply disruptions or critical infrastructure protection. The goal is to participate in at least one tabletop exercise each year involving a significant event scenario that would require the collective effort of emergency response Staff. Historically, these exercises are focused on roles specific to emergency response and restoration rather than curtailment and demand response procedures. Increased involvement in joint exercises between the State and industry could enhance emergency preparedness in this regard.

Staff Preparedness – It is important that attention be paid to individual emergency preparedness for the MPSC Staff assigned these roles. Personnel who are well-prepared are better able to focus on the task at hand, rather than worrying about their homes or family. MPSC Staff planning or expected to work during a catastrophic emergency should:

- Have an emergency supply kit and family emergency plan.
- Discuss with their families what type of emergencies they may be called upon to respond to and what they should do when a disaster occurs.
- Prepare for special considerations for family members with access or functional needs.

7.3.1.3 Michigan State Police – Similar to all natural disasters or acts of terrorism, MSP/EMHSD provides oversight and tactical assistance with the declaration of an Energy Emergency or a State Disaster. MSP/EMHSD supports preparedness, mitigation, response, and recovery from all hazards. Specific to an energy emergency, MSP/EMHSD coordinates with local emergency management and public safety authorities to prepare for energy emergencies. During an energy emergency, the MSP will activate the SEOC and solicit support from state agencies as appropriate. According to the State Emergency Management Act the State Police is responsible for:

- Making recommendations to the Governor and implementing the orders and directives of the Governor in the event of a disaster.

- Coordinating all federal, state, county, and municipal disaster prevention, mitigation, relief, and recovery operations within the state.
- Administering state and federal disaster relief funds.
- Assigning general missions to the National Guard or state defense force to assist disaster relief operations.
- Maintaining a division within the department to coordinate the pre-disaster emergency service activities of federal, state, county, and municipal governments.
- Preparing and updating the Michigan Emergency Management Plan that outlines how the State will respond to emergencies.

7.3.1.4 Other Departments

Motor Fuels Quality Program, Dept. of Agriculture and Rural Development (MDARD)

The Motor Fuels Quality Program establishes and regulates the sale and quality of motor fuels through licensing, investigation, inspection, and sampling to ensure the fuels that consumers buy contain the proper materials and abide by legal standards. If a gasoline or diesel shortage prompted the need for a Waiver of Air Quality Specifications, MPSC Staff coordinates with Staff from the Motor Fuels Quality Program and EGLE to obtain the needed waiver from the Environmental Protection Agency (EPA).

Air Quality Division, Department of Environment, Great Lakes, and Energy (EGLE)

The Air Quality Division of the EGLE ensures that Michigan's air remains clean by regulating sources of air pollutants to minimize adverse impact on human health and the environment. If a gasoline or diesel shortage prompted the need for a Waiver of Air Quality Specifications, MPSC Staff coordinates with Staff from the Air Quality Division and MDARD to obtain a waiver from the Environmental Protection Agency (EPA).

Michigan Department of Transportation (MDOT)

MDOT is primarily responsible for specific emergency support functions related to transportation (ESF-1), which includes coordinating the use of necessary transportation resources and services to support emergency response or recovery operations. The MDOT also has responsibilities in Michigan's Petroleum Shortage Response Plan (i.e., public information, ride-sharing, etc.).

7.3.2 Federal

7.3.2.1 U.S. Department of Energy – If a Michigan emergency or disaster reaches the level of a national emergency, coordination with federal and other state authorities will then occur. Within the U.S. Department of Energy (DOE), the Office of Cybersecurity, Energy Security, and Emergency Response and the Infrastructure Security and Energy Restoration Division coordinates the DOE's response to energy emergencies and helps all levels of government and the private sector recover from energy supply disruptions.

7.3.2.2 Department of Homeland Security (DHS)/Federal Emergency Management Agency (FEMA) – Emergency Support Function #12 (ESF 12) sets forth the policies and procedures for the DHS and DOE to facilitate the restoration of significant

disruptions in energy supplies including the restoration of damaged energy systems. ESF 12 provides for appropriate supplemental federal assistance and resources to enable restoration of energy supplies in a timely manner while acknowledging that restoration of normal operations at energy facilities is the responsibility of facility owners.

7.3.2.3 Environmental Protection Agency – The EPA enforces regulations under the Clean Air Act that limit the vapor pressure of motor fuels during warmer months. The EPA may grant a waiver for these requirements but requires a strong demonstration of need and/or a declaration of emergency in order to do so. In general, a waiver would be allowed to address only a temporary emergency fuel supply shortage caused by an unusual situation and be unavoidable through prudent planning.

7.3.2.4 Federal Motor Carrier Safety Administration (FMCSA) – Petroleum emergencies can result in or contribute to distribution issues for fuel transportation and delivery. When this occurs, states will work with FMCSA to determine if there is adequate justification for temporary relief from safety waivers in order to alleviate the crisis.

7.3.2.5 North American Electric Reliability Corporation (NERC) – NERC has mandatory standards for electric utilities specifically related to emergency procedures.

7.4 Energy Emergency Procedures

7.4.1 General Info

Michigan's Energy Assurance Plan outlines the roles and responsibilities of local, federal, and state governments during an emergency. Typically, state involvement occurs when a local government's capacity to address the emergency is exceeded, and federal government involvement occurs when a state's capacity is exceeded. In these latter two instances, an Energy Emergency or a Disaster is declared and the agency leading response and recovery efforts changes.

Figure 7-3 Energy Emergency Phases

LEVEL 1 – Monitoring / Stand-By
Conditions: Routine monitoring uncovers current or potential impacts to Michigan's energy supply and/or systems. Although an impact to Michigan's communities has been observed, it is relatively low and likely in the initial stages.
Lead Agency: MPSC
LEVEL 2 – EERT Activation
Conditions: The impact on Michigan is moderate/limited compared to a more catastrophic event, however conditions are unstable or likely to worsen and additional information is required.
Lead Agency: MPSC
LEVEL 3 – State Energy Emergency Declaration
Conditions: The anticipated impact within the State of Michigan is moderate to high. Conditions have sufficiently deteriorated to the degree that the state has declared, or is considering declaring, an Energy Emergency under PA 191. The emergency is limited in scope to energy issues.
Lead Agency: MPSC / LARA
LEVEL 4 – State Disaster Declaration
Conditions: It is determined that the event involves more than an energy supply disruption, and that the impacts within Michigan are so severe that the governor has declared a State Disaster under PA 390. Governor directs necessary response actions led by Michigan State Police.
Lead Agency: MSP / EMHSD
LEVEL 5 – Federal Disaster Declaration
Conditions: The consequences of the event are extreme, the governor has requested, and/or the president has declared a National Disaster under the Robert T. Stafford Disaster Relief and Emergency Assistance Act.
Lead Agency: FEMA /DOE

7.4.1.1 Energy Emergency Phases – Significant energy disruptions may escalate gradually over time or may come about with little warning. In the above figure, five response levels are established with a description of conditions and lead agency.

7.4.1.2 Utility Incident Notification Procedures – Incident notification and information sharing are integral to developing situational awareness leading up to and during emergencies. At both the local and state level, this information helps emergency response personnel determine where resources may be needed and where future problems may arise.

Electric Incident Reporting

Michigan investor-owned distribution utilities and electric cooperatives are required to notify the MPSC when certain outage thresholds are met. This information is shared with the Electric Operations section and depending on the severity of the event, may be shared

with the MSP/EMHSD and/or Governor's office. The MPSC requires notification from these utilities when:

- Severe conditions result in outages of 5% or more of a provider's total customers. Stricter guidelines exist for:
  - Consumers Energy – any outage over 50,000 customers
  - DTE – any outage over 75,000 customers
- Events of significant magnitude result in issuances of an official state of emergency declaration by the local, state, or federal government.
- Serious injury or fatality after contact with utility facilities as required by MPSC rule R460.3804,

The utility experiences a cyber incident that disrupts electric operations, involves extortion, impairs certain computer systems for more than 12 hours, or requires public notification under state law. Additionally, the two largest utilities in Michigan, Consumers Energy and DTE, have established notification procedures for the following circumstances:

- Intentional load shed or curtailment action,
- System-wide blackout event or condition, and
- Outage at a large generation unit, such as a nuclear facility.

Greater consistency in reporting details and timing has been identified as an area for improvement, as has the lack of outage information from unregulated entities.

Natural Gas Incident Reporting

Certain incidents on the natural gas system require urgent notification to MPSC Staff. The specific criteria for incidents requiring notification are described in the Michigan Gas Safety Standards and under PHMSA's 49 CFR Part 191. Some examples are any release of gas that results in:

- Property damage of $10,000 or more;
- Loss of service to more than 100 customers;
- Injury, fatality, or explosion;
- Other operational triggers as defined in the regulations.

Typically, the incident notification must include details such as:

- Names of the operator and reporting person;
- Suspected cause, location, and time of the incident;
- Nature and extent of any injuries or fatalities;
- Any other notable information.

7.4.2 Utility Mitigative Measures

The contingency plans for investor-owned electric or natural gas utilities regulated by the MPSC are similar in nature and typically deem the following types of facilities as high priority:

- Any facility known to be necessary for the support of human life,
- Public safety,

- Food and medicine refrigeration,
- Transportation navigation controls and traffic signals/lighting,
- Communication services,
- Water and sanitation services, and
- Energy power generation or refinery facilities.

Disruption of petroleum, electricity, and natural gas supplies will require particular actions unique to each. The MPSC does not regulate municipal electric and natural gas utilities, nor industries producing or transporting petroleum products.

7.4.2.1 Electric Emergency and Curtailment Procedures – Emergency electrical procedures are used by regional transmission operators and electric utilities in case of significant mismatches between the supply and demand of electricity. Their purpose is to limit problems within a utility's system and to keep problems from spreading to neighboring systems. A mismatch in supply and demand can be caused by immediate outages in the generation or transmission networks and/or by demand that outstrips available capacity. The procedures are designed for system-threatening situations; they are not meant for localized disruptions, such as distribution power lines being out of service.

As described in Chapter 3, the North American Electric Reliability Council (NERC) publishes mandatory standards for the electric system that are approved by FERC. NERC Standard EOP-002-0 – Capacity and Energy Emergencies[194] outlines the mandatory procedure for RTOs to ensure that they are prepared for capacity and energy emergencies. The standard outlines remedies that the RTO may implement in a capacity or energy emergency to keep the electric system within prescribed operating limits including:

- Loading all available generating capacity;
- Deploying all available operating reserve;
- Interrupting interruptible load and exports;
- Requesting emergency assistance from neighboring regions;
- Declaring an energy emergency; and
- Reducing load, through procedures such as public appeals, voltage reductions, and curtailing interruptible and firm loads.

MISO and PJM have implemented emergency operating procedures for their regions to comply with the NERC standard, which are included in Appendix N. The emergency procedures have three stages which show an increase in severity: alerts, warning, and events. The Alert level

[194] https://www.nerc.com/files/EOP-002-0.pdf.

informs all stakeholders within the RTO of the weather conditions to expect, to begin enhanced communications among market participants and system operators, and to take preventative measures like cancelling maintenance and ensuring equipment is able to function. The Warning level signals worsening system conditions and allows the RTOs to access additional resources though emergency pricing, scheduling imports, calling on reserves, and determining emergency demand response availability. The Event level takes steps to preserve the reliability of the electric system by deploying emergency resources and issuing public appeals to conserve energy. For more details on MISO[195] and PJM's[196] Electrical Emergency Curtailment plans, please see Appendix I.

7.4.2.2 Natural Gas Curtailment Procedures – The MPSC-approved rate book (Appendix J) for each natural gas utility contains procedures the utility will implement if there is a shortage in the natural gas supply to meet the demands of customers. Typically, a short-term deficiency would be addressed by curtailment of natural gas service while a long-term deficiency may be mitigated by the implementation of Controlled Service Programs which limit the addition of new load on the system. This section focuses on the general procedures that utilities will follow for curtailment of natural gas service during an emergency.

Emergency curtailment procedures provide an orderly process to shed existing natural gas load when the total demand for natural gas exceeds available supplies due to supply shortages or capacity restrictions. Utilities may also implement an Operational Flow Order (OFO) which allows the utility to limit daily storage withdrawal volumes to an authorized level. When implementing an OFO or curtailment, the utility must provide notice to the MPSC and all affected customers of the nature and probable duration of the event. Curtailment plans typically include sections such as: Steps Prior to Curtailment, Notice of Curtailment, Method of Curtailment, Curtailment Priorities, Rate Adjustment, Enforcement, and Penalties. The MPSC may order the implementation of additional procedures or the termination of the procedures previously employed when circumstances so warrant. It is important to note that most pipeline failures (such as third-party damage to pipeline facilities, fire/rupture involving gas facilities or rupture of a transmission or distribution line) will not require curtailment under these provisions.

Each utility's curtailment procedure differs in its details but is similar in overall objectives. There are three fundamental objectives to the curtailment procedures.

[195] MISO Emergency Curtailment Plans - https://cdn.misoenergy.org/SO-P-EOP-00-002%20Rev%207%20MISO%20Market%20Capacity%20Emergency333797.pdf.
[196] PJM Emergency Curtailment Plans - https://www.pjm.com/~/media/documents/manuals/m13.ashx.

- **To provide the utility with a relatively immediate response to a supply emergency through a significant reduction in customer demand.**

  The goal is to shed the largest amount of load with the smallest possible number of customer contacts, because the time period associated with an initial response to an emergency is directly related to the number of customer contacts that need to be made. Because system safety depends on maintaining certain minimum pressures, time is of the essence to avoid widespread system outages. Large volume commercial and industrial customers are classified in the lowest priorities for this purpose and are the first to be curtailed, while residential customers, loads involving public health and safety, or plant protection loads are in the highest priority and the last to be curtailed.

- **To implement pre-curtailment steps that will reduce the severity of curtailment and that could eliminate the need to curtail high-priority customers.**

  These steps involve public service announcements for voluntary dial-down actions, to seek out emergency gas supply contracts, to encourage fuel switching where possible, to curtail excess volumes allowed under customer contracts, and to limit transportation customer access to transportation balancing services and gas storage injection or withdrawal services. These actions may take some time to fully implement and may occur subsequent to the actual curtailment of lowest priorities but would in any event precede high priority (residential) curtailment during long-term supply emergencies.

- **To provide a rational/equitable allocation of available supply or capacity during the course of an energy emergency. Importantly, curtailment procedures do not provide for the confiscation of natural gas supplies owned by transportation customers of the utility.**

  Utilities may purchase, borrow, or divert transportation gas only if the owner of such gas voluntarily agrees. Reallocation of transportation gas could only take place by an Executive Order of the Governor once a Declaration of Energy Emergency was issued and compensation issues would need to be addressed.

Curtailment is based on prioritized customer classifications; for most utilities there are five prioritized categories. Below is an example from one of the major natural gas utilities in Michigan that is generally applicable to other natural gas utilities. The utility will apply these priorities throughout its system to the extent necessary, considering such factors as system capacity and the extent to which curtailment of customers in a specific portion of the system may remedy the emergency.

- **Priority Five (curtailed first) –** All non-residential customers that have alternative fuel capability for the portion of their load covered by the alternative fuel, and all sales of system supply gas to non-system supply customers.

- **Priority Four –** Commercial and industrial customers that used more than 41,667 Mcf in the same month one year earlier.

- **Priority Three –** Commercial and industrial customers that used between 8,334 – 41,667 Mcf in the same month one year earlier.

- **Priority Two –** Commercial customers that used between 1,250 – 8,334 Mcf in the same month one year earlier, and industrial customers that used 8,334 Mcf or less in the same month one year earlier.

- **Priority One (curtailed last) –** Residential customers, commercial customers using 1,250 Mcf or less in same month one year earlier, customers that need gas to protect their plants and machinery, and customers that need gas to provide services essential for public health and safety that are not capable of using an alternative fuel.

7.4.2.3 Natural Gas Curtailment for Electric Generation - During an emergency curtailment of natural gas service, electric utilities that generate and distribute electricity are granted Priority One classification, which ensures that gas supply for natural gas-fired electric generation to essential services will not be interrupted unless all other options fail. This classification is contingent upon the electric utility taking reasonable steps to minimize load during the course of the natural gas emergency. Such actions may include:

- Utilizing non-natural gas reserve capacity.
- Switch natural gas-fired dual fuel generating plans to an alternate fuel.
- Attempt to procure incremental purchased power.
- Curtail all non-firm off-system electric sales.

Existing natural gas curtailment procedures recognize residential customers as the highest priority customer in addition to natural gas-fueled electric generation. These procedures were developed prior to the creation of RTOs, however, and should be reviewed to reflect current market conditions in Michigan. The Commission recommends utilities and Staff convene a workgroup to review whether natural gas curtailment procedures need to be updated to reflect current RTO market structure where natural gas-fueled electric generation is dispatched by an RTO and may not consider impacts from local natural gas emergencies.

7.4.3 Petroleum Shortage Response Plan

Energy emergencies involving shortages of petroleum products are quite different from emergencies involving electricity or natural gas. While electricity outages tend to occur in regions within the state, petroleum problems can be caused by multi-state, national or international events. Therefore, state government may need to become involved earlier in petroleum shortages than for electric or natural gas emergencies. A government response to a petroleum emergency would be largely coordinated through the MPSC.

In the face of a petroleum shortage, the government's role is to ensure a steady supply of fuel to essential services, manage demand to reduce consumer fear/panic, moderate price spikes, and assist businesses in their efforts to provide adequate supply. The measures included in the plan represent a series of options designed both to manage limited supplies and to reduce overall demand. These measures can be found in greater detail in the Michigan Petroleum Shortage Response Plan.

7.4.3.1 Supply Management Measures - Supply management measures are intended to ensure that essential needs are met and to reduce the impact of localized fuel shortages. The efficacy of supply-side measures is limited and therefore should only be employed in response to particular problems they are designed to prevent or solve. If in a severe shortage, essential public services such as police and fire had their supply sharply reduced or cut off because of their inability to compete for limited supplies, some of these programs would be considered:

- State Set-Aside Program for Bulk Purchasers
- Release of State Set-Aside
- Priority End-User Plan for Essential Services
- Minimum Purchase & Odd/Even Purchase Plan

7.4.3.2 Demand Restraint Measures - The demand restraint measures are intended to help the public cope with a shortage by reducing the demand for petroleum fuels, which often has an ancillary benefit of moderating price increases. These measures focus primarily on encouraging the public to conserve during a supply shortage and require only voluntary participation with varying levels of commitment/effort. Many conservation measures are already in place and require only a quick ramp up in the event of an energy emergency.

- Public Information Program
- Expansion of Ridesharing Programs
- Increased Enforcement of Freeway Speed Limits
- State Department Travel Budget Reductions

7.4.3.3 Emergency Waivers - In addition to supply and demand measures, further actions can and have been initiated in coordination with the federal government. These measures ease state and/or federal regulatory mandates which would inhibit petroleum product distribution during a shortage. First is a temporary waiver of driver safety regulations under rules promulgated by the FMCSA, and second are environmental fuel waivers under the Clean Air Act issued by the EPA for motor gasoline or distillate (diesel) fuel. Granting waivers requires a strong demonstration of need and/or a declaration of energy emergency. While they can be enacted at no cost, they do require collaboration between state agencies (MPSC, EGLE, MDARD, MSP) and the federal government (EPA, USDOT) and require a state declared energy emergency.

In recent years, driver safety and air quality waivers have been issued during the propane shortage of the 2013/2014 winter and the motor fuel disruptions caused by the West Shore pipeline outage in 2016. In these events the Governor declared an Energy Emergency under Public Act 191 and issued executive orders to initiate further actions.

- Emergency Relief from FMCSA Safety Regulations
- Environmental Fuel Waivers

7.5 Public Information and Communication

One of the key crisis management actions the state should take during an energy emergency is to organize a strong public information program. Timely and accurate information can help prevent confusion and uncertainty as well as enlist the support and cooperation of the public. An effective emergency response plan involves continuous coordination and two-way communication with all levels of government, private industry, and the public. Providing these groups with information about the nature, severity, and possible duration of the emergency is essential.

Care should be taken to be sure that the public understands the cause of the emergency and what actions will be necessary to mitigate and eventually resolve it. It is also important that the public does not take any actions that are counter-productive to recovery efforts and that actions taken have a positive effect and do not cause unintended consequences.

Experience reveals two major risks due to poor public information programs: 1) multiple authorities may inadvertently release information that appears to be contradictory because they use different technical terms or are less timely in their delivery; and 2) some groups will take advantage of a shortage by characterizing it in ways that further their own self-interest. It is critical to work closely with media outlets and trade associations to ensure that a consistent, concise and well-informed message is distributed by all parties. Objectives include:

- **To provide information to the public** regarding state government programs providing energy emergency information and assistance.
- **To establish a clear channel of communication** between the MPSC and the following entities:
  - **Other state agencies** that have support responsibilities during an energy emergency (EGLE, MDOT, MDAARD, MHHS, MSP, etc.);
  - **The energy industry**, to collect detailed information on the emergency, its duration and scope, planned remedies, and to confirm that the State's and industry's interpretation of the situation are consistent;
  - **Local governments** within Michigan that have the task of implementing programs and providing information at the local level as may be provided for by various contingency plans;
  - **Midwest states** that share an energy interdependency and whose actions may directly impact each other; and
  - **Federal agencies** such as the DOE's Office of Cybersecurity, Energy Security, and Emergency Response and the Infrastructure Security and Energy Restoration Division that can provide information to assist in evaluating the crisis.

Observations from PV19

The fire at the Ray Compressor Station and ensuing natural gas incident provides a useful opportunity to reflect on the effectiveness of public information and crisis communication between the State and private industry, as well as the general public and media. While this specific incident serves as an example, the lessons learned are universal and should be considered during future emergency situations regardless of utility partner.

- Greater efforts should have been made to ensure the public understood not only the cause of the incident, but realistic potential impacts and actions taken by government and industry to remedy the situation. Public information staff should work more closely with outside media to ensure accurate information is available and publicized widely.
- The need for a public request to conserve natural gas usage should have been anticipated and prepared sooner, so that communication materials were drafted and vetted prior to usage, thus saving valuable time. By delivering this messaging sooner, greater participation and cooperation by the public was likely to have occurred.
- As is typical of other emergency events, the utility, in this case Consumers Energy, held briefings with numerous state partners, including: the Governor's office, Legislature, MPSC Staff and Commissioners, Staff at SEOC, and local emergency managers. This responsiveness and flexibility resulted in the unintentional consequences of confusing narratives, timelines, and wasted resources. The State should streamline and consolidate these communication paths for future emergency events.

7.6 Ongoing Projects

After multiple Dark Sky exercises, in which the State would evaluate capabilities to respond to an energy emergency, in 2016 the Legislature appropriated $750,000 to MSP to identify strategies to prepare and mitigate against energy disruptions. In 2017, an independent Energy Assurance Assessment was conducted. Based on that assessment, MSP, in conjunction with MPSC, established discrete projects aimed at mitigating known vulnerabilities.

7.6.1 Local Energy Assurance Planning (LEAP)[197]

Local emergency management agencies and first responders prepare for and respond to all emergencies, including those involving energy supplies or infrastructure. Local governments represent the front lines for critical infrastructure protection and drive emergency preparedness efforts in the communities they serve.

> "A secure and resilient nation with the capabilities required across the whole community to prevent, protect against, mitigate, respond to and recover from the threats and hazards that pose the greatest risk."[198]

While the State of Michigan maintains a Michigan Energy Assurance Plan to provide guidance for energy emergency preparedness and response planning, it does not fully address the needs at the local level. With the development of a more localized plan, communities will be able to achieve several objectives including:

- Building long-term relationships with key energy providers and users,
- Increased awareness of key energy systems and potential vulnerabilities associated with those systems,
- Identification and prioritization of critical energy end-users, and
- Understanding the roles and prioritization of government and private industry given the legal framework.

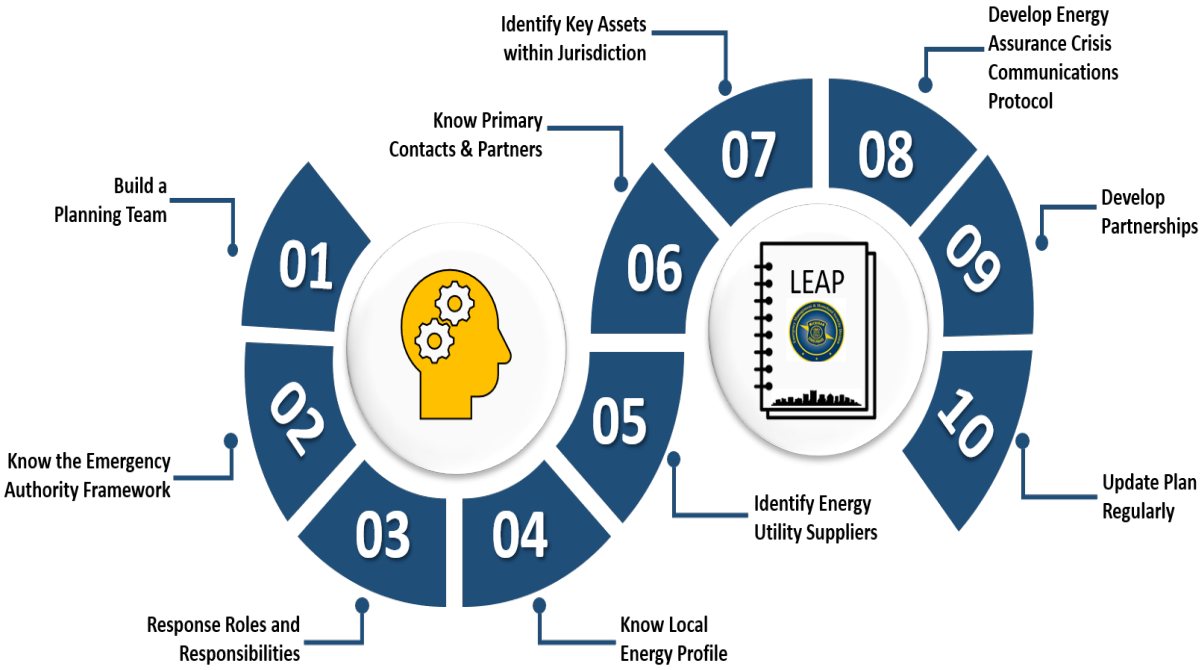
In order to build capacity to respond to energy disruptions at the local level, MSP/EMHSD with assistance from the MPSC and an outside contractor has launched a LEAP initiative with the following program goals:

- Implement 8 regional LEAP workshops
- Establish a web-based toolkit to support LEAP planning
- Develop regionally specific planning templates

At the conclusion of this year, Staff form MSP/EMHSD and MPSC hope to continue this initiative. Figure 7-4 outlines the steps necessary to develop a robust emergency preparedness plan.

[197] A plan to respond and recover from an energy disruption based on a complete understanding of the local jurisdiction's energy system.
[198] National Preparedness Goal – DHS, https://www.fema.gov/pdf/prepared/npg.pdf.

Figure 7-4 Steps to Achieve Emergency Preparedness



7.6.2 Critical Infrastructure Generator Assessment

MSP/EMHSD and MIOC is currently implementing the critical infrastructure generator assessment program. This program is designed to reduce the impact and recovery time for critical infrastructure[199] affected by an extended electric outage by assembling data on backup power needs ahead of time. After major disasters it can take days to assess impacted facilities to determine generator requirements and update electrical connections. Therefore, utilizing a process and database provided by the United States Army Corps of

[199] PPD-21 identifies 16 critical infrastructure sectors: Chemical, Commercial Facilities, Communications, Critical Manufacturing, Dams, Defense Industrial Base, Emergency Services, Energy, Financial Services, Food and Agriculture, Government Facilities, Healthcare and Public Health, Information Technology, Nuclear, Transportation Systems, Water and Wastewater Systems. Michigan has added Education to the list of critical sectors.

Engineers, the State is assessing and collecting generator requirements and electrical connections. This data will be stored in a secure Federal database called the Emergency Power Facility Assessment Tool as well as within the State's GIS and MICIMS account.

7.6.3 Petroleum Backup Readiness

7.6.3.1 Fueling Stations – Reduced availability of operable fueling stations is an often-identified consequence of long-term electric outages and has the potential to disrupt recovery efforts across many sectors. One way to combat this vulnerability and ensure that essential services continue operation is to support back-up generation readiness at petroleum fueling stations. With this in mind, a grant program has been developed and MSP will provide funding (up to $3,000) to selected retail fuel stations and municipal fuel depots that are interested in wiring their facility to be generator ready. The goal of this program is to identify at least two fueling facilities in each county (as appropriate). The notice of funds availability was issued over the summer of 2019.

7.6.3.2 Terminals – Petroleum terminals are dependent on electrical service to transfer fuel to trucks and railcars for delivery elsewhere. Mixing of additives and oxygenates also occur at the terminal. Most Michigan terminals do not have backup generation nor are they pre-wired to accept generators during an extended outage. This poses a threat to our ability to distribute important transportation fuels (i.e., gasoline, diesel, jet fuel, etc.) during electrical outages. Other states such as Wisconsin have begun to address this vulnerability through grants for transfer switch installation (often cost-shared by the asset owner). Michigan would be well served to address this recognized vulnerability and work with industry to help reduce the fuel shortage risk associated with electrical outages.

7.6.4 Statewide Energy Sector Sub-Committee

To support continued collaboration and coordination with the energy sector, the State Police will assemble a Statewide Energy Sector Sub-Committee. This committee will be comprised of utility representatives, critical infrastructure representatives and public safety officials to share best practices, collaborate on initiatives and sustain coordination efforts pre-and-post disaster.

7.6.5 Lifeline Sector Restoration Prioritization

Lifeline sectors are generally defined to include communications, energy, hazardous material, health and medical, safety and security (emergency services), transportation, and water/wastewater. These sectors are fundamental to lessening the impact of emergencies and protecting human health and welfare, and thus many facilities are eligible to be considered for priority restoration during electric outages. Michigan's electric service providers do a good job of identifying these facilities and expediting service restoration when possible, but invariably some fall through the cracks. The MPSC plans to facilitate

> "A lifeline provides indispensable service that enables the continuous operation of critical business and government functions, and is critical to human health and safety, or economic security."
>
> -Community Lifeline Info Sheet, FEMA

the identification and documentation of these facilities by holding monthly or quarterly meetings with the MSP, associated state agencies (EGLE, DHHS, MDOT, etc.), facility owners, and electric providers. Each meeting would target a different lifeline sector.

7.7 Emergency Management Recommendations to Mitigate Risk

7.7.1 Commission's Emergency Management Recommendations

- During PV19, communications during the event were confusing, inconsistent, and erratic. **The Commission recommends Staff:**
    - **Provide timely and consistent energy emergency communication to the public via the MPSC website, social media, and other outlets to provide contextual understanding of event cause, remediation, and duration, as well as important safety tips.**
    - **Develop drafts of energy emergency messaging to be used in traditional and social media, so that initial review and approval can occur well in advance of potential need as part of a comprehensive emergency communications plan.**
    - **Annually provide an emergency contact list to energy providers in electric, natural gas, petroleum and regional transmission organizations.**
- When utilities are reporting outages to the MPSC's emergency contact list, the information provided is not consistent among utilities. **The Commission recommends developing standardized communications to the MPSC regarding electric and natural gas emergency events among IOUs and cooperatives.**
- Energy emergency exercises and drills with industry should provide a wide range of scenarios besides just outage management and restoration. **The Commission recommends that utilities expand upon traditional drills to include emergency drills that also focus on curtailment and demand response procedures rather than just outage management and restoration.**
- Existing natural gas curtailment procedures recognize residential usage and natural gas-fueled electric generation as the highest priority customers. These procedures were developed prior to the ongoing shift towards natural gas dominated generation and should be reviewed to reflect current market conditions in Michigan. **The Commission recommends utilities and Staff convene a workgroup to review whether natural gas curtailment procedures need to be updated to prioritize natural gas use for residential heating above natural gas use for electric generation when appropriate during emergencies.**
- The ability to restore natural gas service after an outage can be a time consuming, resource-intense endeavor, whereas electric outages can be more targeted and short term if managed properly. **The MPSC should work with State Police, RTOs, gas and electric utilities, and the Governor's office to exercise critical decision making during catastrophic energy events where sustaining natural gas and electricity service may be in conflict. After action reports and lessons learned from these exercises may help develop guidelines to inform the State (e.g., Governor, MSP, MPSC, etc.) in the execution of their respective emergency management roles**

under state law. Factors to consider may include, for example, extent and severity of safety and public health risks, outage duration and customers affected, types of customers affected including critical facilities, time of year, economic disruption, and the collective ability to mitigate customer impacts with timely communications, available shelter, and necessary supplies..

- **The Commission recommends the Staff plan workforce development activities for Commissioners and Staff to better enable the Commission to continue to fulfill its duties related to ensuring energy emergency preparedness, given turnover due in part to the aging workforce in the energy industry.**
- **The Commission directs the Staff to update the Michigan Energy Assurance Plan and the Petroleum Shortage Response Plan bi-annually, with appropriate utility and energy sector collaboration.**
- **The Commission recommends the Staff facilitate a workgroup to address potential gaps in petroleum fuel supply and delivery with the Michigan State Police, terminal owners, as well as other stakeholders.**

7.7.2 Commission's Emergency Management Observations

- During the data gathering phase of the SEA, Staff became aware that some utilities do not use the Incident Command System to manage and respond to emergencies. **The Commission recommends the adoption of the Incident Command System at larger utilities and cooperatives to better align with federal and state emergency responders. Additional training and use of ICS across all utilities and industries would better prepare the State of Michigan in handling energy emergencies.**
- During the data gathering phase of the SEA, Staff outreach to the MMEA indicated a need for a representative to contact during energy emergencies. **The Commission finds that it would be beneficial for municipal electric providers or a representative association to follow the same outage reporting standard to ensure situational awareness for MPSC and Michigan State Police emergency management personnel during energy emergencies.**
- During the data gathering phase of the SEA, concerns about protecting confidential critical infrastructure information created time-consuming delays to create a work-around which would protect the data while Staff reviewed the information. Currently there is no law providing protection. **The Commission finds that legislation is needed to provide protection of critical energy infrastructure information to enhance information sharing with state agencies for emergency response preparedness efforts.**

8. Gaps in Existing Planning, Operational, and Emergency Response Processes

The basic methods for producing and delivering electricity have gone largely unchanged for the past century but are on the cusp of major transformation. As discussed in this report, the energy industry is undergoing significant change driven by aging infrastructure, public polices, technological advancements, and customer preferences. Older power plants are retiring and being replaced by a mix of natural gas-fueled generation and renewable energy. The increased adoption of energy storage, electric vehicles, microgrids, and other distributed energy resources could lead to profound change in how energy is produced, transmitted, and used. While the pace of change is unknown, it is important to adapt energy planning, markets, and operations in order to maintain energy security and reliability under a variety of system conditions.

Recognizing the need to prepare for this industry change, MISO recently completed a forward-looking report[200] outlining three key trends that are transforming the electric industry, referred to as the "3Ds": de-marginalization, decentralization and digitalization. De-marginalization refers to the impact of zero-/very low variable cost generation resulting in declining market prices and inadequate pricing signals to incentivize complimentary ramping products or storage. Decentralization refers to the increase in both utility-scale and customer-owned behind-the-meter generation. Digitalization refers to advances in technology allowing customers greater control over their energy usage. The report identified three major opportunities and challenges: 1) increased variability and uncertainty of both generation and demand; 2) more coordination required with transmission seams partners (including PJM and the Southwest Power Pool), stakeholders, advanced technology providers and distribution system operators; and 3) market products, incentive structures, and planning processes that are increasingly misaligned with efficiency and future reliability needs.

To address these opportunities and challenges, MISO has identified three key needs:

1. Availability, which is the ability of transmission and energy resources to meet requirements at all hours;

[200] https://www.misoenergy.org/forward/.

2. Flexibility, which is the ability to anticipate and adapt to frequent, significant changes in generation output and demand; and enable new sources of flexibility; and
3. Visibility, which is the ability to see and coordinate relevant resource, demand, and power flow attributes in operations and planning horizons.

MISO is working with stakeholders in the region to develop action plans to address the challenges and opportunities existing in its region. Those same challenges and opportunities exist in Michigan. Additionally, other gaps exist in planning, operational and emergency response processes, that warrant further consideration and action to improve the reliability, resiliency and safety of Michigan's energy infrastructure and delivery systems as discussed in this section.

8.1 Gaps in Existing Planning, Operational, and Emergency Response Processes That Highlight Opportunities to Improve Safety, Reliability, and Resilience

8.1.1 Better Integration of Gas and Electric Planning Functions Recognizing Interdependencies

In the PV19 period, the natural gas supply in Michigan was jeopardized by the incident at the Ray Compressor Station at a time when demand for natural gas for home heating purposes was at an all-time high due to extreme weather. In the future, increases in natural gas-fired electric generation may increase the likelihood of natural gas supply shortages occurring, if the natural gas-fired generation is competing for a limited supply of gas with gas distribution utilities, particularly during extreme weather events. In order to ameliorate this risk, an investigation should be commenced to examine the value of diversity in electric generation portfolios, acknowledging that there are additional options for new electric generation sources that would not compete for natural gas with home heating.

One of the factors considered by the Commission in the evaluation of electric utility integrated resource plans (IRP) is the diversity of supply. A diverse mix of resources offers many benefits, including a reduced reliance on any single type of fuel or technology which could in turn improve resilience. While diversity of supply is one consideration in an IRP, there are not currently any methods to quantify the value of diversity, nor are there goals with respect to the diversity of supply.

The changing electric generation fleet in Michigan and the Midwest due to increasing retirements of coal and nuclear plants could lead to reliability and resiliency problems especially if new replacement resources such as energy waste reduction, demand response, and wind and solar energy projects are delayed. Understanding the value of resource diversity could also better inform power plant retrofitting and retirement decisions beyond traditional net present value and market price comparisons.[201] [202] [203] **The Commission recommends utilities work with Staff and stakeholders to propose a methodology to quantify the value of generation diversity in integrated resource plans.**

Likewise, understanding the value of resilience improvements will better inform future Commission decisions on investments targeting resilience improvements. Resilience, or the robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event, is a broad

[201] For example, the Palisades nuclear power plant, owned by merchant generator Entergy, is licensed through 2031 but the plant owner has said it will close in 2022 at the expiration of its power purchase agreement (PPA) with Consumers Energy. Consumers previously sought approval from the MPSC in 2017 to pay Entergy to terminate their agreement early in 2018 based on a comparison of the PPA payments to Entergy with wholesale market prices as well as new options to supply the energy and capacity (e.g., gas, solar, wind generation and energy waste reduction). While the Palisades cost under the PPA may have been higher than forecasted wholesale market prices and some new resource options, the value of this nuclear plant supplying baseload power is not fully recognized in these comparisons. That is, attributes such as reliability, resilience, commodity risk, resource diversity, and environmental impact are not fully considered, let alone quantified. The Commission did not approve the proposed buyout and Entergy plans to continue to operate the plant under the original PPA with Consumers until April 2022. The plant has performed well in terms of availability, was found to be profitable under the existing PPA with Consumers (during the MPSC proceeding in 2017) and is licensed by the NRC through 2031. Entergy is proceeding with the closure and decommissioning of the plant as part of its strategic business plan to close all its merchant nuclear plants. A rough estimate to keep Palisades running past the spring of 2022 is $32.6M per year at a contract price of $58 per MWh. This estimate does not include any additional capital investments that may be necessary in order to keep the plant running beyond 2022. Importantly, such an option would depend on Entergy's willingness to continue to operate or sell the plant and the negotiation, execution, and approval of a new PPA (if the plant is not purchased by a regulated utility). This option was not considered in the recently approved integrated resource plan for Consumers Energy but highlights the issue of resource diversity and reliability. The consideration of diversity of generation supply in integrated resource plans is required by MCL 460.6t(8)(a).

[202] Cook Nuclear Plant Unit 1 is licensed through 2034 and Unit 2 is licensed through 2037. Fermi Unit 2 is licensed through 2045. While 2034-2045 is still more than a decade away, both Cook and Fermi provide significant amounts of carbon-free baseload generation that may be retired at some point in the future and may be challenging to replace.

[203] Several biomass facilities in Michigan provide baseload power and the economics of those biomass plants have been challenged in recent years. A framework to capture the value of diversity in generation resources should also consider the value provided by Michigan biomass facilities, as well as other emerging technologies such as battery storage.

concept. Many different types of investments across the electricity system may provide some level of improvement to resilience qualitatively, however, improvements to resilience may be difficult to quantify. Unlike reliability standards, there are not currently any resilience standards identifying acceptable levels of resilience.

Also, there are not currently any widely accepted methods to quantify the value of resilience. While quantifying the value of resilience provided by any single electricity system investment may be difficult, identifying and quantifying the value that could be provided by different combinations of networked investments is even more challenging. NARUC recently published a report on the value of resilience for distributed energy resources and acknowledged the challenge of quantifying the value of energy resilience, stating "At present, there are no standardized approaches for policy makers or energy project developers to identify and value energy resilience investments at the state, local, or individual facility levels."[204] Targeting and valuing resilience and resource diversity could result in providing economic signals for resources such as energy storage to address MISO's and Michigan's needs for available, flexible and visible resources to maintain, and even improve, the operation of the grid in our changing energy landscape.

As utilities and regulators focus on resilience improvements, evaluating expenditures proposed for resilience improvements to ensure they are just and reasonable will be important. Developing a methodology to evaluate the benefits of resilience improvements will better enable the Commission and stakeholders to ensure that expenditures made to capture resilience improvements are reasonable and prudent.

Evaluating the system resilience benefits provided by DERs, including combinations of DERs such as solar plus storage, will enable informed decisions regarding proposed investments going forward. As outlined by NARUC, "Although it is clear that DERs offer resilience benefits, it is unclear how to determine the value of those benefits. Identifying appropriate methodologies to calculate the value of resilience will be an important step toward ensuring that resilient DERs are considered alongside alternatives and integrated into future energy infrastructure and investment planning efforts."[205] The Regulatory Assistance Project, in a recent paper titled "Capturing More Value From Combinations of PV and Other Distributed Energy Resources," notes that quantifying the value of DERs or combinations of DERs can be "difficult, inexact, and controversial.[206] Types of value streams that may be considered to capture the value of DERs as

[204] https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198, p. 7.
[205] https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198, p. 4.
[206] https://www.raponline.org/wp-content/uploads/2019/08/rap_shenot_linvill_dupuy_combinations_pv_other_ders_2019_august.pdf, p. 5.

resilience improvements are outlined by RAP in Figure 8-1. These include societal benefits that are not typically considered, at least explicitly, when evaluating utility investments.

Figure 8-1 Illustrative List of DER Value Streams

Beneficiary	Value Streams
Utility system	Avoided energy costs
	Avoided generation capacity costs
	Avoided reserves or other ancillary services
	Avoided transmission & distribution system investment
	Avoided transmission & distribution line losses
	Avoided operations & maintenance costs
	Wholesale market price suppression
	Avoided renewable portfolio standard (RPS) compliance costs
	Avoided environmental compliance costs
	Avoided credit and collection costs
	Reduced risk
Participants	Electricity bill savings, credits, or revenues
	Participant health, comfort, and safety
	Participant resource savings (non-electric fuels, water)
	Increased resilience
Low-income customers	Reduced low-income energy burden[11]
Public	Public health benefits
	Energy security
	Jobs and economic development benefits
Environment	Environmental benefits

Source: https://www.raponline.org/wp-content/uploads/2019/08/rap_shenot_linvill_dupuy_combinations_pv_other_ders_2019_august.pdf, p. 17.

While attempting to quantify the value provided by any one type of DER technology may be difficult, capturing the value of combinations of DERs is even more challenging. For example, "Any PV system, installed in isolation without other DERs, is limited in the services and value streams it can provide. But when PV is combined with other DERs, new synergistic opportunities arise such that the total value of a combination of PV and other DERs can be greater than the sum of the values of each component in isolation."[207]

The Commission recommends utilities work with Staff and stakeholders to propose a methodology to quantify the value of resilience, particularly related to DERs. In addition, the value of resilience should be considered in future investment decisions related to energy infrastructure in future cases. As major investments in energy resources, distribution, and transmission are considered through various processes, diversity and resilience should be evaluated even if costs and benefits are challenging to quantify.

8.1.2 Better Integration of Electric Resource, Distribution and Transmission Planning

Several Michigan utilities submit to the MPSC, approximately every two years, electric distribution plans that identify and prioritize capital investments and operations and maintenance activities over a five-year period. In addition, all regulated utilities submit to the MPSC at least every five years integrated resource plans that identify options for meeting customer demand over the next five, ten, and fifteen years. The IRPs and distribution plans are developed separately but there is considerable opportunity to better align assumptions, data, and review of alternatives through a more holistic approach. The National Association of Regulatory Utility Commissioners and the National Association of State Energy Officials recently launched a joint task force on comprehensive electricity planning focusing on the following needs:

> "With growing customer installation of DERs and evolving non-utility energy services, electricity generation and resource planning needs to account for the quantity, location, and load shapes of resources added to the distribution system. With utilities making annual capital expenditures of over $100 billion, ensuring distribution system investments are right-sized and consider approaches such as non-wires alternatives can lower costs and offset supply-side needs."[208]

[207] https://www.raponline.org/wp-content/uploads/2019/08/rap_shenot_linvill_dupuy_combinations_pv_other_ders_2019_august.pdf, p. 20.
[208] https://pubs.naruc.org/pub/0AB39B39-90A0-06B0-5973-A0A320AF3159.

Michigan is participating in this joint task force, which seeks to better align resource and distribution system planning to improve grid reliability and resilience. The changing energy landscape and the transition to an increasing number of distributed energy resources provides Michigan with an opportunity to better integrate distributed energy resources and five-year electric distribution plans into integrated resource plans. Five-year electric distribution plans are developed separately from electric integrated resource plans that plan how the utility will meet its future customer demand. With increased adoption of electric vehicles and distributed energy resources such as solar and energy storage, **the Commission recommends utilities better align electric distribution plans with integrated resource plans to develop a cohesive, holistic plan and optimize investments considering cost, reliability, resiliency, and risk. As part of this effort, Staff, utilities, and other stakeholders should identify refinements to IRP modeling parameters related to forecasts of distributed energy resources (e.g., electric vehicles, on-site solar), reliability needs with increased adoption of intermittent resources, and the value of fuel security and diversity of resources in IRPs.[209] A framework should also be developed to evaluate non-wires alternatives such as targeted energy waste reduction and demand response in IRPs and distribution plans**.

Transmission planning also occurs in a separate venue, led by stand-alone transmission companies with participation from stakeholders, under processes overseen by the RTOs. While PA 341 section 6t contains provisions to consider transmission alternatives in utility-filed IRPs, this task has proven difficult. Transmission project costs and benefits are typically shared by customers in a zone larger than a single utility's service territory and project approval takes place at the RTO, which only has jurisdiction over transmission, not options under state regulation such as distribution, generation, or demand-side options. Transmission affecting Michigan may be physically located outside of Michigan and subject to state and local siting requirements outside of Michigan's control. The cost recovery for a transmission project may impact customers of several utilities, both inside and possibly outside of Michigan, making the direct comparison of transmission alternatives to generation projects difficult. Moreover, the analysis of transmission alternatives often includes an assumption that excess generation in another service territory will be available for use in Michigan, which may introduce risk given the resources may be outside of the utility's control.

Transmission planning takes place separately from generation and distribution planning making the consideration of transmission options in integrated resource plans limited.

[209] The MPSC intends the concept of fuel security, as recommended, to include the assurance of fuel delivery as opposed to onsite fuel.

The Commission recommends the MPSC Staff work with Michigan utilities and stakeholders to propose revisions to the Commission-approved IRP modeling parameters and filing requirements to better accommodate the consideration of transmission alternatives in IRPs. In addition, the Commission observes that MPSC Staff should work with RTOs and stakeholders to ensure non-transmission alternatives are considered in a fair and equitable manner through the RTO transmission planning processes.

8.1.3 Quantifying the Benefits of an Increased Capacity Import Limit as an Opportunity for Increased Resilience and Diversity in Supply

Michigan utilities participate in RTO markets, which should result in the efficient use of both local and imported energy and capacity resources. On a daily and annual basis, there are significant imports of energy into Michigan based on the RTO's least-cost dispatch of generation across the region and available transmission capacity. However, the ability to rely on imported generation to meet MISO resource adequacy requirements is limited by MISO's tariff requiring a certain amount of generation to be physically within the local area and related to this, the transmission system's ability to import resources from outside the area. Thus, given power plant retirements and other factors, Michigan is faced with having to build additional local generation or expand transmission interconnections (or some combination) to continue to meet these resource adequacy requirements. As outlined in the Staff's report on capacity demonstrations filed in March of 2019, the effective capacity import limit into the lower peninsula (zone 7) is only 164 MW,[210] decreased from approximately 1,500 MW one year ago based on MISO's assumptions, calculations and system modeling.

The effective capacity import limit has recently been much lower than the amounts of actual imports coming into the Lower Peninsula. On average, Michigan's Lower Peninsula imported approximately 16.3% of the energy needed to serve load in Zone 7 for 2017 and 2018 which totals over 32 Million megawatt hours for the two-year period. During that same two-year period, Zone 7 imported more than 5,000 MW for 115 hours.[211]

Improving the MISO effective capacity import limit would allow more imports of capacity into Michigan during the peak, as well as other times throughout the year, thereby improving system resiliency and allowing customers to more fully realize the benefits of participation in

[210] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000004PmgNAAS, p. 7; (Effective capacity import limit = PRMR 21,976 MW – LCR 21,812 MW = 164 MW).
[211] Data provided by ITC.

RTO markets. CIL improvements have been proposed,[212] but do not neatly fit MISO's definition of a reliability project, nor do they neatly fit MISO's definition for a market efficiency project.

To address this gap in planning, utilities, electric transmission companies, Staff, RTOs, and stakeholders, should further investigate opportunities to expand Michigan's capability to import additional electricity to address short- and long-term reliability and resource adequacy needs in a more holistic manner as Michigan experiences additional power plant retirements. This effort should also consider a methodology to quantify the value of such projects and related cost allocation, as appropriate.

[212] In MPSC Case No. U-20165, ITC transmission proposed transmission alternatives, installing static var compensators to increase the capacity import limit into the Lower Peninsula. Specifically, "in various future scenarios including known unit retirements – the deployment of approximately 1000 MVAR can increase the Michigan CIL by 1000 MW or more." The cost estimate provided by ITC Transmission to increase the CIL by 1,000 MW is approximately $150M. ITC has submitted a project for review under MISO's MTEP19, ITCT-15923 SVC for import near the Fermi nuclear plant. This is a 300 MVAR project for $2M with a projected in-service date of June 31, 2023. See also: MPSC Case No. U-20165, Exhibit A-97; and https://cdn.misoenergy.org/20190604%20ESPM%20Item%203d%20MTEP19%20Project%20Justification%20ITCT%20rev1350778.pdf.

9. Conclusions and Recommendations

9.1 System Adequacy to Account for Changing Conditions and Extreme Weather Events

In response to a request by the Governor following the PV19 energy emergency event, the Commission conducted a review of the energy supply and delivery systems for electric, natural gas and propane and assessed the adequacy of these systems. The result of that assessment is a determination that Michigan energy systems are adequate, particularly due to the diversity in fuel supply and generation resources and access to natural gas storage, which can accommodate evolving conditions and extreme weather events. Market structures, laws, and regulatory processes in Michigan for infrastructure planning, review, and cost recovery are conducive to ensuring investments needed for safe, reliable electric and natural gas service are made. There are opportunities for improvement which incorporate lessons learned from the PV19 event. Insights gleaned from event and system analyses provide short- and long-term opportunities to improve reliability and resilience, and to consider the related costs and benefits. The costs to build 100% redundancy into every system would be an unreasonable expectation for ratepayers and a mismatch in the benefits realized. The next section provides key recommendations and observations for further action.

9.2 Recommendations to Mitigate Risk and Ensure Safety

During the course of this assessment, there were distinctions made between recommendations within and outside the Commission's jurisdiction. This report reflects this distinction by providing two distinct categories of conclusions: 1) Recommendations, and 2) Observations.

Recommendations - concepts, actions, programs, initiatives, or projects which ***fall within the Commission's jurisdiction***, and may be considered as potential opportunities for utilities to improve the reliability and resilience to future energy emergencies should they occur.

Observations - concepts, actions, programs, initiatives, or projects which ***fall outside the Commission's jurisdiction,*** but which may be considered as potential opportunities for discussion with stakeholders in other venues.

Following is a compilation by Sector of the Recommendations and Observations developed as a result of the Statewide Energy Assessment.

9.3 Compiled Recommendations and Observations for Mitigating Risks

9.3.1 Recommendations for Mitigating Risks

9.3.1.1 Electric

Electric Recommendations

- **E-1:** Michigan continues to expand its reliance on demand response programs to meet reliability needs and avoid the construction of more expensive new electric generation infrastructure. During the PV19 event, some customers participating in "interruptible" tariffs or other demand response programs did not respond as expected and utility tariffs were found to have inconsistent language. System operators need to count on demand response programs to maintain system reliability. **Therefore, the Commission recommends several improvements to demand response programs**:
    - **E-1.1: Staff, utilities, and other stakeholders should review utility demand response tariffs for consistency and clarity when deploying Load Modifying Resources during emergency events, including a review of notification and penalty provisions.**
    - **E-1.2: Utilities should coordinate with Staff, customers, RTOs, and other stakeholders on retail DR tariff offerings to align with wholesale markets and emergency operations.** This should examine the economic and reliability uses of DR and identify updates to DR tariffs to best match customers with performance expectations under applicable tariffs.
    - **E-1.3: Utilities also should review their communications plans with customers that would take place during a demand response event and conduct recurring testing of demand response resources to ensure the ability to respond when called upon.**
- **E-2:** During the PV19 event, MISO discovered it did not have information on all generation facility operating characteristics, such as the wind turbine cold pack installations, which impacted day-ahead and real time generation forecasts. **The Commission recommends electric generators provide the RTO with all generator operating characteristics and to incorporate measures to improve generator startup performance when emergency units are called upon.**
- **E-3:** The MPSC's electric service quality and reliability rules have not been updated recently and could be modified to enhance safety, reliability, and resiliency of the distribution system. The rules address actions to prevent power outages and system restoration. **The Commission recommends opening a docket to establish a workgroup to investigate and provide recommendations for updating the Service Quality and Reliability rules and the Technical Standards for Electric Service using lessons learned in Michigan and best practices in other states as a guide**.

- **E-4:** Standardized interconnection rules for Michigan electric utilities would enable distributed generation to interconnect with the utility system in a safe, reliable, and efficient manner. **The Commission recommends that Staff continue to work with stakeholders to update the MPSC's interconnection rules and procedures for generation facilities seeking to connect to the utilities' distribution grids and to better integrate distributed energy resources such as solar, microgrids, and battery storage as part of this process. This effort will inform formal Commission rulemaking activity to commence in the fall of 2019**.
- **E-5:** Five-year electric distribution plans are developed separately from electric integrated resource plans that plan how the utility will meet its future customer demand. With increased adoption of electric vehicles and distributed energy resources such as solar and energy storage, **the Commission recommends utilities better align electric distribution plans with integrated resource plans to develop a cohesive, holistic plan and optimize investments considering cost, reliability, resiliency, and risk. As part of this effort, Staff, utilities, and other stakeholders should identify refinements to IRP modeling parameters related to forecasts of distributed energy resources (e.g., electric vehicles, on-site solar) reliability needs with increased adoption of intermittent resources, and the value of fuel security and diversity of resources in IRPs. A framework should also be developed to evaluate non-wires alternatives such as targeted energy waste reduction and demand response in IRPs and distribution plans.**
- **E-6:** The changing electric generation fleet in Michigan and the Midwest due to increasing retirements of coal and nuclear plants could lead to reliability and resiliency problems especially if new replacement resources such as energy waste reduction, demand response, and wind and solar energy projects are delayed. Understanding the value of resource diversity could also better inform power plant retrofitting and retirement decisions beyond traditional net present value and market price comparisons. **The Commission recommends utilities work with Staff and stakeholders to propose a methodology to quantify the value of generation diversity in integrated resource plans.**
- **E-7:** Developing a methodology to evaluate the benefits of resilience improvements will better enable the Commission and stakeholders to ensure that expenditures made to capture resilience improvements are reasonable and prudent. **The Commission recommends utilities work with Staff and stakeholders to propose a methodology to quantify the value of resilience, particularly related to DERs. In addition, the value of resilience should be considered in future investment decisions related to energy infrastructure in future cases.**
- **E-8:** Transmission planning takes place separately from generation and distribution planning making the consideration of transmission options in integrated resource plans limited. **The Commission recommends:**
    - **E-8.1: MPSC Staff should work with Michigan utilities and stakeholders to propose revisions to the Commission-approved IRP modeling parameters and**

filing requirements to better accommodate the consideration of transmission alternatives in IRPs. In addition, the Commission observes that MPSC Staff should work with RTOs and stakeholders to ensure non-transmission alternatives are considered in a fair and equitable manner through the RTO transmission planning processes.

- **E-8.2: Utilities, electric transmission companies, Staff, RTOs, and stakeholders, should further investigate opportunities to expand Michigan's capability to import additional electricity to address short- and long-term reliability and resource adequacy needs in a more holistic manner as Michigan experiences additional power plant retirements. This effort should also consider a methodology to quantify the value of such projects and related cost allocation, as appropriate.**

Electric Observations

- **E-9:** Planning and coordination efforts between electric utilities and RTOs could be improved to allow greater transparency of utility distribution systems for more accurate forecasting, as outlined in the MISO Forward Report. **The Commission finds improved communications and data sharing between electric utilities, the MPSC Staff, other market participants and the RTOs could ensure that the RTOs will have the information needed to plan and operate the electric system to accommodate an increasing amount of distributed energy resources.**
- **E-10:** During electric generation emergencies, the gas-fired electric generator operations may be impacted by other state permit requirements. **To improve safety and reliability during energy emergencies, the Commission proposes to discuss with EGLE coordination issues, including scenarios where an electric generator is reaching air emission limitations at the same time an electric emergency declaration by the RTO requires all generators to maximize output.**
- **E-11:** The PV19 event provided the most recent example of an energy emergency occurring during the winter rather than the more traditional summer peak. As the percentage of natural gas fueled electric generation increases throughout the region and other changes to the fuel mix take place that affect operating conditions by season or time of day, the RTO capacity construct must evolve. **The Commission finds that RTO capacity requirements should provide a seasonal capacity construct at the regional level to better account for different resource characteristics in the capacity accreditation process and to ensure safe and reliable electric service to customers during all seasons.**
- **E-12:** Despite repeated efforts to improve the process, the MISO generator interconnection queue is cumbersome and cannot keep pace with the level of change in the industry, with generation retiring at an accelerated rate and need to assess/model the best locations for replacement generation from a system reliability perspective. **The Commission finds the MISO generator interconnection queue process should be revised to facilitate the timely progression of projects through the process. This**

enhancement is necessary to ensure safe and reliable electric and natural gas service to customers as it would not only improve system reliability but better reflect the rapid pace of change as the generation mix rapidly evolves. Broader, long-term regional transmission planning is also essential to ensure cost-effective, reliable delivery of power and flexibility to accommodate changing energy resource mix.

- **E-13:** Outside projects eligible for cost sharing, the MISO process for approving transmission projects between 69kV and 345 kV is based exclusively upon a review from a reliability perspective rather than a cost perspective. This limited assessment criteria may prevent from consideration other alternatives such as generation or distribution solutions that could be preferred from a cost, reliability, or resiliency perspective. This is important because transmission projects below 345 kV are not subject to MPSC review and approval under Act 30 of 1995. **The Commission finds that MISO's process should more carefully consider alternatives to transmission line projects based on cost, reliability, and resiliency prior to approving new transmission.**

9.3.1.2 Natural Gas

Natural Gas Recommendations

- **G-1:** Natural gas infrastructure incidents carry the potential for significant impacts to health, safety and welfare of Michigan residents and utility workers. Utility safety management systems must reflect the leadership of executives to support a culture of safety. Safety Management Systems are management tools that help natural gas utilities comprehensively and holistically manage all aspects of pipeline safety. **The Commission recommends natural gas utilities continue to develop and enhance Safety Management Systems to support and prioritize safety programs**.
- **G-2:** Currently, natural gas infrastructure investments are prioritized separately for storage, transmission and distribution projects rather than in a holistic manner. To maximize efficiencies, a comprehensive risk model must be developed inclusive of storage, compression, transmission, and distribution assets and which considers a long-term risk mitigation as part of a multi-year plan. **The Commission recommends utilities work towards incorporating the use of probabilistic risk models to prioritize system investments, including the development of long-term risk mitigation plans covering infrastructure investment, operations, and maintenance**.
- **G-3:** Risk models for natural gas utilities do not adequately incorporate the risk of equipment and facility outages. Incorporating this type of assessment – either within or outside of the natural gas safety regulations – could provide insights to system vulnerabilities. This should include a consideration of the appropriate percent of peak day supply from any single source. **The Commission recommends natural gas utilities incorporate equipment and facility outages in risk models**.
- **G-4:** The utilities should have diversity in supplies, redundancies in key assets, and limited dependency on any one facility. In future rate and GCR plan and reconciliation cases the **Commission clarifies that: 1) the utilities should consider contingency options for resilience at key facilities and 2) the Commission Staff should consider these issues and make recommendations to further the safety and reliability of the state's natural gas system, including consideration of more resilient design day plans.**
- **G-5:** The need for new system interconnections and the use of existing connections must be better understood and vetted in future cases before the Commission. Natural gas distribution utilities should have diversity in supplies and limit dependency on any one interconnection. **The Commission recommends the utilities consider the necessity and cost of new transmission interconnections including the diversity in supply sources available and propose prudent investments to increase the reliability of the natural gas system. Similarly, the utilities should consider diversification of supply sources in the portfolio, providing for redundancy and reliability through the use of all the existing interconnections available in GCR plan and reconciliation cases**.

- **G-6:** The utilities must be diligent in their system modeling / planning work to identify the necessity of system redundancy and **the Commission recommends the utilities look for opportunities to develop solutions that mitigate risk of outages, improve operational flexibility, and accommodate future growth in demand**.
- **G-7:** Given the pivotal roles that DR can play during energy emergencies, the development or expansion of natural gas DR programs should be analyzed. **The Commission recommends the utilities work with Staff and stakeholders to review the potential for natural gas DR programs and develop recommendations to encourage the development or expansion of natural gas DR programs.**
- **G-8:** During the PV19 event, impacted natural gas utilities did not have mutual assistance agreements in place which could have provided process efficiencies and better communication during the event. Natural gas utilities could provide safer and more reliable service by developing mutual assistance agreements similar to those used by electric utilities during electric outages. **The Commission recommends convening a utility workgroup to facilitate the development of**:
  - **G-8.1: mutual assistant agreements to be in place for all natural gas distribution utilities; and**
  - **G-8.2: transmission contingency planning.**
- **G-9:** Remote shutoff valves are tools that can reduce the number of customers affected by disruptions. **The Commission recommends the utilities continue to conduct analyses to evaluate increasing the number of remote shutoff valve systems in high consequence areas to minimize the impact during emergency events**.

See also: **Chapter 8**, Gaps in Existing Planning, Operational, and Emergency Response Processes, for additional recommendations and observations relevant to the gas sector.

Natural Gas Observations

- **G-10:** The ability of the Commission to impose meaningful fines for non-compliance is statutorily limited and not on par with the levels in federal statute required by PHMSA. In PHMSA's annual federal audit of the MPSC's federal grant implementation, the State of Michigan's limited fine structure results in a loss of points and reduces the maximum amount of federal funding available to Michigan to administer the federal gas safety program. **The Commission finds that Michigan statute limits the ability of the Commission to assess meaningful penalties for non-compliance with the Michigan Gas Safety Standards, and this may impact the health, safety and welfare of Michigan residents.**

9.3.1.3 Propane

Propane Recommendations

- **P-1:** As part of the SEA, Staff created a retail propane survey to monitor market trends and gain additional market insights. While roughly 20% of propane suppliers participated in this anonymous survey, it nevertheless provided statewide propane provider information never before collected. **The Commission recommends Staff continue to solicit market information from propane suppliers and create an annual retail propane survey to monitor market trends and gain additional market insights, similar to the survey completed for this report.**
- **P-2:** It is not uncommon for propane customers to forgo options to mitigate exposure to market price fluctuations. **The Commission recommends the MPSC continue public education efforts to promote the use of pre-buy and price lock-in purchase strategies to enhance consumers' resilience to market price fluctuations**.

Propane Observations

- **P-3:** The future of Line 5 is uncertain and could be impacted by anchor strikes or other actions that cause significant damage to the pipeline, emergency shutdowns of the pipeline, or legal action to shut down, temporarily or permanently, the existing pipeline or arrangements to construct a tunnel in which to house a new pipeline crossing the Straits of Mackinac. The line, which transports NGLs for propane production, could also be affected by physical damage, equipment failure or legal action. **The MPSC finds that a formal contingency plan for the continued supply and delivery of propane or other energy alternatives for Michigan residents is needed in the event of supply disruptions, including a shutdown (permanent or temporary) of Line 5.**
- **P-4:** The UP Task Force is charged with identifying alternatives to both supplying the energy by sources currently used by UP residents and alternatives to those energy sources under the timelines established in Executive Order 2019-14. **The MPSC finds that a comprehensive alternatives analysis as called for by Governor Whitmer in Executive Order 2019-14 is needed, and that such an analysis should consider the use of rail and trucks to supply the Rapid River fractionator, options for importing propane into the UP from other areas, the extension of natural gas infrastructure for home heating, the use of electric heat sources, including heat pumps, and targeted energy waste reduction programs for residential propane customers. The MPSC is currently participating in, and providing personnel and other support for the UP Energy Task Force as set forth in the executive order.**
- **P-5:** There is a benefit to developing working relationships with propane suppliers prior to potential shortage conditions. **The Commission finds that the State of Michigan should work with owners and operators of critical petroleum assets to ensure the availability of NGLs and propane supplies for Michigan residents.**
- **P-6:** Currently there is not an accurate source of information for propane supply and storage information which would provide staff with a valuable data resource to inform

summer and winter energy appraisals. **The Commission finds that it would be beneficial for Michigan petroleum prime suppliers to provide the Energy Security Section with a copy of form EIA – 782C to more accurately account for inflow and outflows of propane supply/storage**.

- **P-7:** Currently there is a lack of trained and qualified transport drivers for propane deliveries. **The Commission finds that the State of Michigan should support the development of a HAZMAT Driver Training Program to help supply the propane market with properly trained and qualified transport drivers, potentially in partnership with the Michigan Propane Gas Association.**
- **P-8:** There are opportunities to improve the resiliency of the propane market by adding diversity to the source and building additional infrastructure. **The Commission finds that the State of Michigan should study the feasibility of:**
    - **P-8.1: increased utilization of Appalachian Basin natural gas liquids (NGLs) and purity propane supplies in conjunction with additional in-state geological storage and fractionation capacity to diversify fuel sourcing; and**
    - **P-8.2: additional rail and storage infrastructure buildout near the Rapid River, Michigan fractionation facility to enhance resilience, including the potential use of the existing Michigan Economic Development Corporation's Freight Economic Development Program to offset 50% of the cost of a rail spur to serve the Rapid River facility.**

9.3.1.4 Cyber and Physical Security Recommendations

- **S-1: The Commission instructs Staff to include cybersecurity standards and reporting for natural gas distribution systems under MPSC jurisdiction through proposed amendments to the Gas Technical Standards. The Commission recommends that the Technical Standards for Gas Service be updated to incorporate by reference API Standard 1164 to enhance the cybersecurity of natural gas infrastructure.**
- **S-2: The Commission instructs Staff to continue to evaluate existing Commission rules and utility data privacy tariffs for opportunities to enhance the protection of customer data and the cybersecurity of electric distribution infrastructure.**
- **S-3: The Commission recommends electric and natural gas utilities conduct annual self-assessments of cyber capabilities using the C2M2 self-assessment tool utilized by the U.S. DOE, or similar tool.**
- **S-4: The Commission recommends electric and natural gas utilities pursue the close coordination of OT, IT, and physical security operations, and centralize security functions under the auspices of a high-ranking security leader.**
- **S-5: The Commission recommends utilities work to develop metrics to assess cybersecurity performance and to track their performance against these metrics.**
- **S-6: The Commission recommends the utilities categorize anticipated physical and cybersecurity incident types and severities and make clear the internal and external notifications that will occur based on these categorizations.**
- **S-7: The Commission recommends the utilities regularly audit operational technology environments for internet-facing systems and remediate to limit the organizational attack surface.**
- **S-8: The Commission recommends the utilities run simulated phishing campaigns at least quarterly and include all employee levels.**
- **S-9: The Commission recommends the utilities require multifactor authentication to remotely access OT assets.**
- **S-10: The Commission recommends utilities adopt industry best practices in mitigating threats from phishing and other IT threats, perform a cost-benefit analysis for top CIS security controls, and take appropriate steps to implement additional controls.**

9.3.1.5 Emergency Management

Emergency Management Recommendations

- **EM-1: D**uring PV19, communications during the event were confusing, inconsistent, and erratic. **The Commission recommends Staff:**
  - **EM-1.1: Provide timely and consistent energy emergency communication to the public via the MPSC website, social media, and other outlets to provide contextual understanding of event cause, remediation, and duration, as well as important safety tips.**
  - **EM-1.2: Develop drafts of energy emergency messaging to be used in traditional and social media, so that initial review and approval can occur well in advance of potential need as part of a comprehensive emergency communications plan.**
  - **EM-1.3: Annually provide an emergency contact list to energy providers in electric, natural gas, petroleum and regional transmission organizations.**
- **EM-2:** When utilities are reporting outages to the MPSC's emergency contact list, the information provided is not consistent among utilities. **The Commission recommends developing standardized communications to the MPSC regarding electric and natural gas emergency events among IOUs and cooperatives.**
- **EM-3:** Energy emergency exercises and drills with industry should provide a wide range of scenarios besides just outage management and restoration. **The Commission recommends that utilities expand upon traditional drills to include emergency drills that also focus on curtailment and demand response procedures rather than just outage management and restoration.**
- **EM-4:** Existing natural gas curtailment procedures recognize residential usage and natural gas-fueled electric generation as the highest priority customers. These procedures were developed prior to the ongoing shift towards natural gas dominated generation and should be reviewed to reflect current market conditions in Michigan. **The Commission recommends utilities and Staff convene a workgroup to review whether natural gas curtailment procedures need to be updated to prioritize natural gas use for residential heating above natural gas use for electric generation when appropriate during emergencies.**
- **EM-5:** The ability to restore natural gas service after an outage can be a time consuming, resource-intense endeavor, whereas electric outages can be more targeted and short term if managed properly. **The MPSC should work with State Police, RTOs, gas and electric utilities, and the Governor's office to exercise critical decision making during catastrophic energy events where sustaining natural gas and electricity service may be in conflict. After action reports and lessons learned from these exercises may help develop guidelines to inform the State (e.g., Governor, MSP, MPSC, etc.) in the execution of their respective emergency management roles under state law. Factors to consider may include, for example, extent and severity**

of safety and public health risks, outage duration and customers affected, types of customers affected including critical facilities, time of year, economic disruption, and the collective ability to mitigate customer impacts with timely communications, available shelter, and necessary supplies..

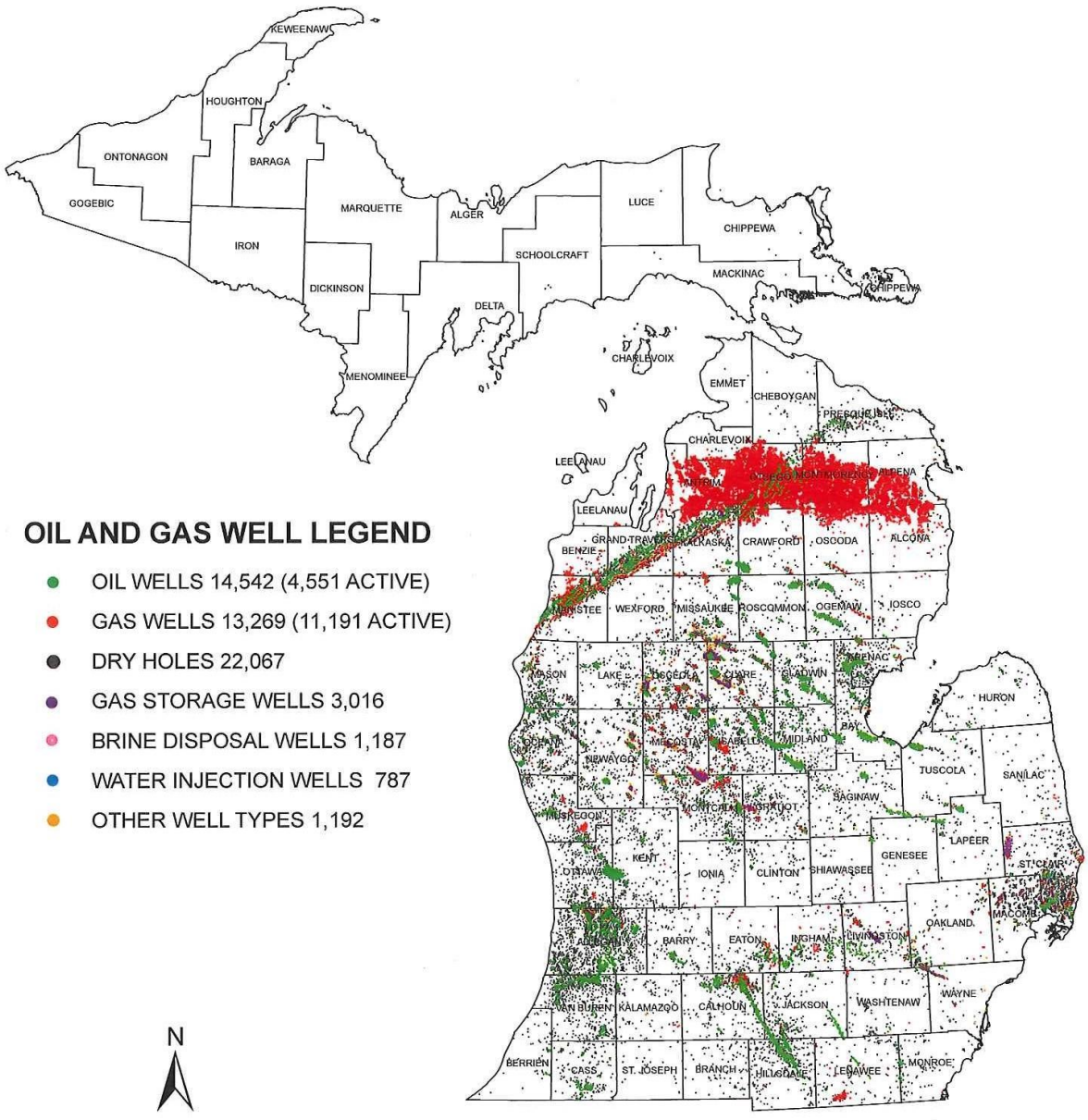
- **EM-6: The Commission recommends the Staff plan workforce development activities for Commissioners and Staff to better enable the Commission to continue to fulfill its duties related to ensuring energy emergency preparedness, given turnover due in part to the aging workforce in the energy industry.**
- **EM-7: The Commission directs the Staff to update the Michigan Energy Assurance Plan and the Petroleum Shortage Response Plan bi-annually, with appropriate utility and energy sector collaboration.**
- **EM-8: The Commission recommends the Staff facilitate a workgroup to address potential gaps in petroleum fuel supply and delivery with the Michigan State Police, terminal owners, as well as other stakeholders.**

Emergency Management Observations

- **EM-9:** During the data gathering phase of the SEA, Staff became aware that some utilities do not use the Incident Command System to manage and respond to emergencies. **The Commission recommends the adoption of the Incident Command System at larger utilities and cooperatives to better align with federal and state emergency responders. Additional training and use of ICS across all utilities and industries would better prepare the State of Michigan in handling energy emergencies.**
- **EM-10:** During the data gathering phase of the SEA, Staff outreach to the MMEA indicated a need for a representative to contact during energy emergencies. **The Commission finds that it would be beneficial for municipal electric providers or a representative association to follow the same outage reporting standard to ensure situational awareness for MPSC and Michigan State Police emergency management personnel during energy emergencies.**
- **EM-11:** During the data gathering phase of the SEA, concerns about protecting confidential critical infrastructure information created time-consuming delays to create a work-around which would protect the data while Staff reviewed the information. Currently there is no law providing protection. **The Commission finds that legislation is needed to provide protection of critical energy infrastructure information to enhance information sharing with state agencies for emergency response preparedness efforts.**

Appendices

OIL AND GAS WELLS IN MICHIGAN



OIL AND GAS WELL LEGEND

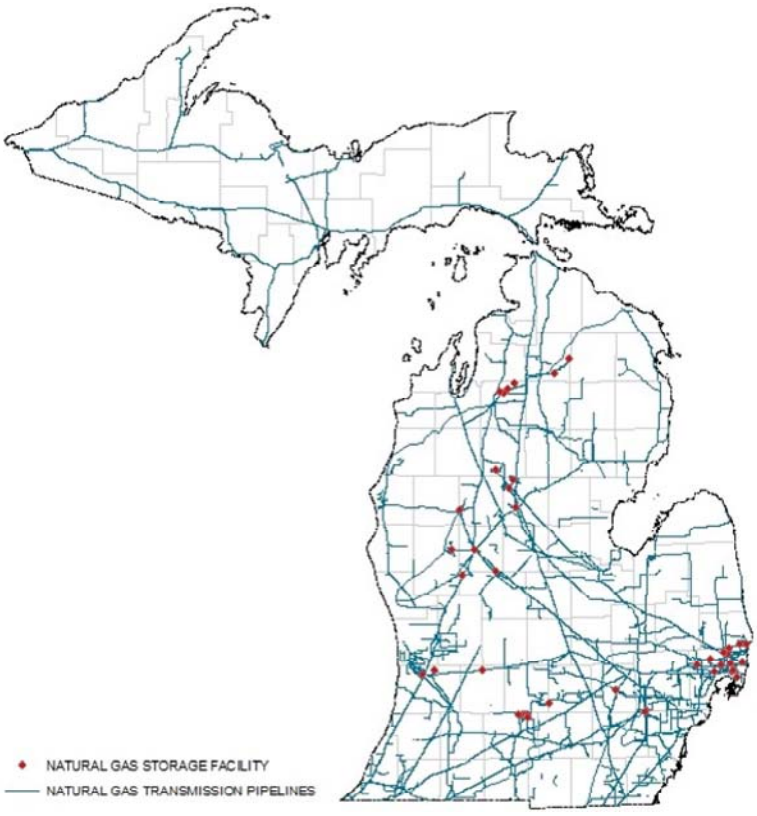
- OIL WELLS 14,542 (4,551 ACTIVE)
- GAS WELLS 13,269 (11,191 ACTIVE)
- DRY HOLES 22,067
- GAS STORAGE WELLS 3,016
- BRINE DISPOSAL WELLS 1,187
- WATER INJECTION WELLS 787
- OTHER WELL TYPES 1,192

N

0 12.5 25 50 75 100 Miles

Michigan Department of Environmental Quality
Office of Oil, Gas, and Minerals
September 2012

DEQ


NATURAL GAS STORAGE FACILITY
NATURAL GAS TRANSMISSION PIPELINES

Current Michigan Natural Gas Companies listed on the Mutual Assistance database through the American Gas Association, June 2019

Consumers Energy Company
DTE Energy
DTE Gas Company
SEMCO Energy Gas Company
We Energies
WEC Energy Group
Xcel Energy Inc.

Michigan Public Service Commission

Natural Gas Operator Risk Assessment Methodologies

Michigan Public Service Commission Staff

May 30, 2019

49 CFR Part 192 and the Michigan Gas Safety Standards have requirements that an operator has to have a mechanism for measuring risk on distribution pipelines, transmission pipelines, and storage fields, depending on what facilities an operator possesses. These risk tools are required as part of each assets' integrity management program.

The requirements for risk assessments on transmission pipelines are located in 49 CFR 192.917:

> An operator mush conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§ 192.919, 192.921, 192.937), and to determine what additional preventative and mitigative measures are needed (§ 192.935) for the covered segment.

The requirements for risk assessments on distribution pipelines are located in 49 CFR 192.1007:

> An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services, and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

The requirements for risk assessments on storage fields are located in 49 CFR 192.12, which provides references to one of two API RP documents depending on the nature of the storage field.

> Therefore, each operator shall take a holistic and comprehensive approach to monitoring cavern integrity, which includes the following aspects of design, monitoring, and engineering evaluation.
> * * *
> — Identification and assessment of risks to functional integrity.
>
> [API Recommended Practice 1170]
>
> The operator shall develop, implement, and document a program to manage risk that includes data collection, identification of potential threats and hazards to the storage operation, risk analysis including estimation of the likelihood of occurrence of events related to each threat, the likelihood of occurrence and potential severity of the consequences of such events, and the preventive, mitigative, and monitoring processes to reduce the likelihood of occurrence and/or the likelihood and severity of consequences, and a periodic review and reassessment of the processes.
>
> [API Recommended Practice 1171]

There are generally four different types of risk assessments that are used in the pipeline industry, listed in the increasing order of sophistication:

1. Qualitative or Subject Matter Expert (SME) Assessment
2. Relative Risk Assessment
3. Quantitative Assessment
4. Probabilistic Assessment

The majority of natural gas operators in the State of Michigan utilize a relative risk assessment. Smaller operators may rely on a qualitative or SME assessment, but these approaches do not yield meaningful results when an operator's system reaches a certain complexity. Through these risk assessments and other mechanisms available to operators, an understanding of asset condition and performance can be generated. However, because most operators utilize a relative risk assessment, these calculations become largely meaningless when taken outside of the operator's organization, and the results certainly cannot be benchmarked against other operators. A quantitative or probabilistic risk model would need to be developed and adopted by pipeline operators in order to be able to have valid comparisons amongst each operator's systems.

Pipeline and Hazardous Materials Safety Administration (PHMSA) has recognized that the current regulations may have shortcomings based on the findings from standard pipeline inspections and failure investigations. In Docket PHMSA-2018-0050, PHMSA published a draft report titled "Pipeline Risk Modeling; Overview of Methods and Tools for Improved Implementation." The Executive Summary of this report states in part:

> Pipeline risk models are a foundational part of the assessment of operational pipeline risk. Federal pipeline safety integrity management (IM) regulations require pipeline operators to use risk assessments. Based on the results of pipeline inspections and failure investigation findings, both the Department of Transportation's PHMSA and the National Transportation Safety Board (NTSB) have identified general weaknesses in the risk models used by pipeline operators in performing risk assessments for their IM programs.
>
> To help address the varying levels of risk model implementation, PHMSA organized a Risk Modeling Work Group (RMWG) composed of representatives of state and federal pipeline regulators, pipeline operators, industry organizations, national laboratory personnel, and other stakeholders. The purpose of the RMWG was to gather information regarding state-of-the-art pipeline risk modeling methods and tools, the use of those methods and tools, and the resulting data in operator IM programs. This document provides an overview of methods and tools for improved implementation based on the results of the RMWG.

This report provided the following conclusions:

1. The overriding principle in employing any type of risk model/assessment is that it supports risk management decisions to reduce risks.

2. While different risk models have different capabilities for evaluating risk reduction actions, Quantitative System model or Probabilistic models are more versatile and provide greater

capabilities to provide risk insights and support decision making. Such models are not necessarily more complex or need more data than other types of risk models.

- Small pipeline operators with limited (but highly knowledgeable) personnel resources will likely continue to use relative assessment/index models.
- Pipeline operators who continue to use relative assessment/index models should seek to supplement personnel judgment with as much physical data as can reasonably be acquired over time.
- Use of the most complete and accurate available data is needed for the application of all risk model types.

3. Pipeline operators should take on-going actions to improve and update data quality and completeness over time. However, the type of risk model to employ in pipeline risk analysis should not depend primarily on the perceived initial quality and completeness of input data, because all models utilize the available data. Instead, operators should select the best model approach and then populate the model with the best information currently available on risk factors or threats for each pipeline segment and improve that data over time.

4. It is important for risk models to include modeling of incorrect operations, which includes human interactions and human performance that are significant to the likelihood of failure or have a significant effect on the consequences of a failure (e.g., inappropriate controller restart of pumps, realistic emergency response time scenarios).

5. It is important for pipeline risk models to include the potential for threat interactions in ways that can increase risk. Therefore, when risk analysis involves multiple threats, the effect of "interactive threats" or dependencies on likelihood of failure should be clearly evaluated.

6. Varying levels of sophistication are possible in the analysis of the consequences of a failure. However, it is important to consider a full range of scenarios (even if they do not have a high probability of occurrence) to capture the full spectrum of possible consequences, including the high consequence outlier.

7. The characteristics of pipeline facilities that affect risk may be significantly different than those of line pipe, although the same basic risk assessment principles apply.

It can be clearly seen that there is room for improvement in regards to how operators are measuring risk on their systems. Without a rigorous methodology that is capable of accurately assessing system risk, risk management decisions may not be targeting the appropriate threat, reducing confidence in the methodology. Such errors are inherently more prevalent in qualitative or relative risk models, as the quantitative and probabilistic models contain algorithms that more accurately categorize the likelihood of a threat being realized, and concurrently, how the threats can be reduced through appropriate preventative and mitigative measures. It should be noted that currently, some of the pipeline operators within the State of Michigan are currently vetting out a

transition to a probabilistic risk model. However, such transitions, due the amount of data required to populate a rigorous model, would likely be years in evolution before the model would be ready to supplant the existing relative risk methodology.

An important part of a mature risk management model is the ability to convey to senior officials within a company how a financial investment can alter the operator's risk profile. For example, if a model is capable of modeling a failure and correlating this with a financial impact, then this can be contrasted with the costs of mitigating the failure to determine the effectiveness of such an investment. Obviously financial impacts are secondary to system safety, but the costs to improve system integrity inevitably becomes part of any risk-mitigation strategy. Note that even the Federal Department of Transportation uses an economic value of a statistical life in determining the most prudent investments to prevent injury or illness:

> The benefit of preventing a fatality is measured by what is conventionally called the Value of a Statistical Life (VSL), defined as the additional cost that individuals would be willing to bear for improvements in safety (that is, reductions in risks) that, in the aggregate, reduce the expected number of fatalities by one. This conventional terminology has often provoked misunderstanding on the part of both the public and decision-makers. What is involved is not the valuation of life as such, but the valuation of reductions in risks. While new terms have been proposed to avoid misunderstanding, we will maintain the common usage of the research literature and OMB Circular A-4 in referring to VSL.
>
> Most regulatory actions involve the reduction of risks of low probability (as in, for example, a one-in-10,000 annual chance of dying in an automobile crash). For these low-probability risks, we shall assume that the willingness to pay to avoid the risk of a fatal injury increases proportionately with growing risk. That is, when an individual is willing to pay $1,000 to reduce the annual risk of death by one in 10,000, she is said to have a VSL of $10 million. The assumption of a linear relationship between risk and willingness to pay therefore implies that she would be willing to pay $2,000 to reduce risk by two in 10,000 or $5,000 to reduce risk by five in 10,000. The assumption of a linear relationship between risk and willingness to pay (WTP) breaks down when the annual WTP becomes a substantial portion of annual income, so the assumption of a constant VSL is not appropriate for substantially larger risks.[1]

With the understanding that that the correlation between the transportation industry and the natural gas industry is not one-to-one, it does serve to provide an example of risk can be prioritized to determine what investments will have the largest impact.

[1] U.S. Department of Transportation, Office of the Secretary Of Transportation, Revised Departmental Guidance 2016: Treatment of the Value of Preventing Fatalities and Injuries in Preparing Economic Analyses

Natural Gas Liquids Pipelines Connecting Michigan and Ontario

System Name	Operator	Diameter (in.)	Product Type	Status
Sarnia Downstream Pipeline – Marysville to Sarnia	Plains Marketing, L.P.	8	LPG	Active (Filled)
Sarnia Downstream Pipeline – Sarnia to St. Clair	Plains Marketing, L.P.	8	LPG	Active (Filled)
Sarnia Downstream Pipeline	Plains Marketing, L.P.	5	LPG	Active (Unfilled)
Sarnia Downstream Pipeline	Plains Marketing, L.P.	8	LPG	Active (Unfilled)
Eastern Delivery LPG	Plains Pipeline, L.P.	12	LPG	Active (Filled)
Lakehead	Enbridge Energy, L.P.	30	NGL	Active (Filled)
NOVA	Nova Chemicals LTD.	8	NGL	Active (Filled)
NOVA	Nova Chemical LTD.	6	NGL	Active (Unfilled)
NOVA	Nova Chemical LTD.	6	NGL	Active (Unfilled)
NOVA	Nova Chemical LTD.	12	NGL	Active (Filled)
R0255-A	Buckeye Development & Logistics, LLC	6	Butane	Active (Filled)
District 03 – Great Lakes: Inkster to Sarnia	Sunoco Pipeline L.P.	8	Propane, Butane, Ethane**	Active (Filled)
Utopia	Kinder Morgan LLC.	12	Ethane	Active (Filled)

Source: National Pipeline Mapping System

** https://eastgoshen.org/wp-content/uploads/2015/01/Mariner-East-FAQs.pdf

Hydrocarbon Gas Liquids (HGL) Storage Capacity*

Location	Owner/Operator	Storage Capacity (Barrels)	
		Underground	Aboveground
St. Clair, MI	Plains GP Holdings	2,000,000	3,864
Marysville, MI	DCP Midstream	8,000,000	8,570
Woodhaven, MI	MPLX/MPC	1,755,000	3,570
Alto, MI	Plains LPG Services	1,300,000	10,714
Inkster, MI	Sunoco Logistics	800,000	2,857
Kincheloe, MI	Plains Midstream	N/A	2,857
Rapid River, MI	Plains Midstream	N/A	8,570
Kalkaska, MI	Lambda Energy Resources	4,050	36,430
Total		**13,859,050**	**77,432**
Windsor, ON	Plains Midstream	4,700,000	-
Sarnia, ON	Plains Midstream	5,800,000	-
Corunna, ON	Alberta Ltd.	5,200,000	-
Sarnia, ON	Suncor Energy Products	1,180,000	-
Sarnia, ON	Imperial Oil	1,820,000	-
Total		**18,700,000**	-

* HGLs include propane, butane, ethane, isobutane, natural gasoline, and their associated olefins, including ethylene, propylene, butylene, and isobutylene. Storage capacities based on MPSC Staff research and calculations. Capacities could also include brine storage. List only shows known major storage locations and should not be considered exhaustive. Aboveground storage capacities in Ontario are not known.

Key Findings of the Statewide Energy Assessment Propane Survey

Background:

In February 2019, Michigan Governor Gretchen Whitmer sent a letter requesting that the Michigan Public Service Commission (MPSC) undertake a statewide review of the supply, engineering, and deliverability of natural gas, electric, and propane. This request was in response to the extreme cold weather event that affected much of the Midwest – including Michigan.

The team tasked with completing the propane portion of the assessment created a short survey for propane industry participants to voluntarily and anonymously complete in order to gather market insights and data. Survey questions were primarily related to propane retail company operations and the information gathered was aggregated and used to report industry-wide trends and statistics. This type of information was extremely helpful for the team to better understand Michigan's propane industry and may also be of value to industry participants.

Below are the key findings from the Statewide Energy Assessment Propane Survey.[1] The propane team would like to thank the Michigan Propane Gas Association (MPGA) for the assistance they provided with the survey.

Key Findings:

Question: What percentage of your residential customers participate in keep-full/courtesy fill programs?

- **Findings:** The median response was 55.5 percent, with a maximum of 90 percent and minimum of 10 percent.

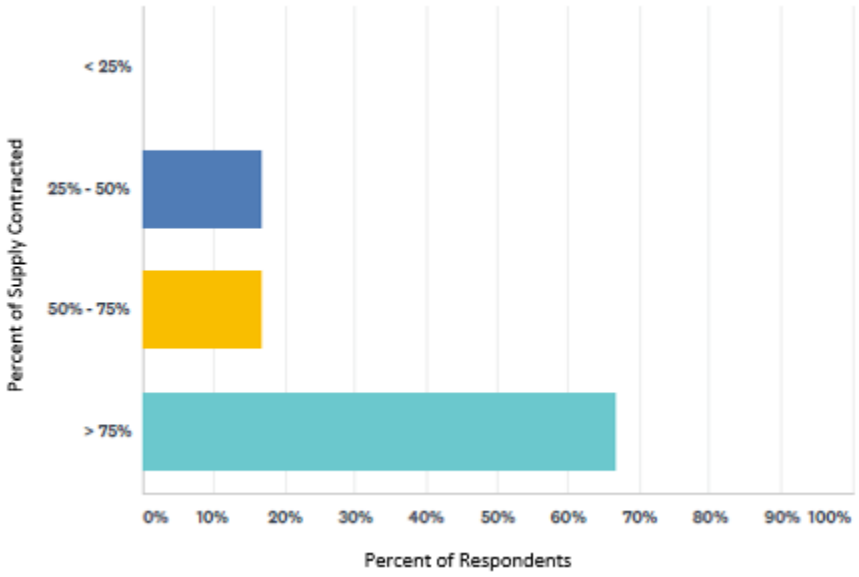
Question: What percentage of your residential customers participate in each program? (In reference to pre-buy and lock-in price programs)

- **Findings:** The median responses for pre-buy and lock-in price programs were 20 percent and 60.5 percent, respectively.

[1] A complete list of survey questions can be found at: https://www.michigan.gov/documents/mpsc/U-20464_Propane_Survey_Questions_4-9-19_651935_7.pdf

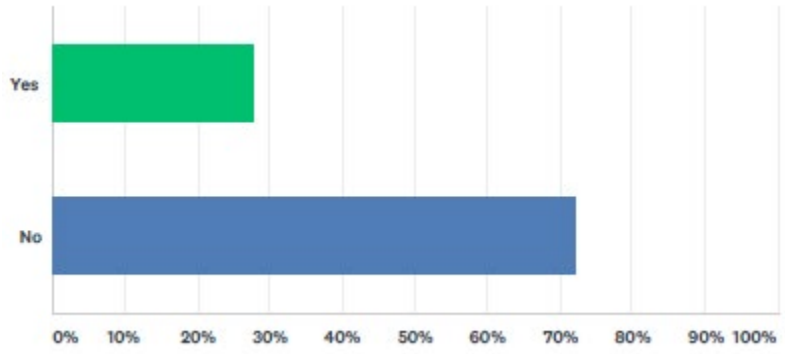
Question: What percentage of your retail company's annual supply is contracted versus spot purchased?

- **Findings:** 67 percent of the survey respondents contract more than 75 percent of their annual supply.



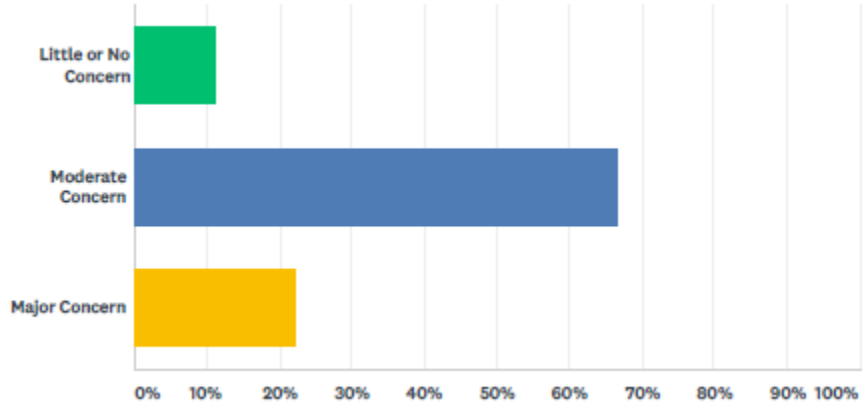
Question: Has your retail company had difficulty in receiving or distributing propane due to the availability of properly trained and qualified transport drivers?

- **Findings:**



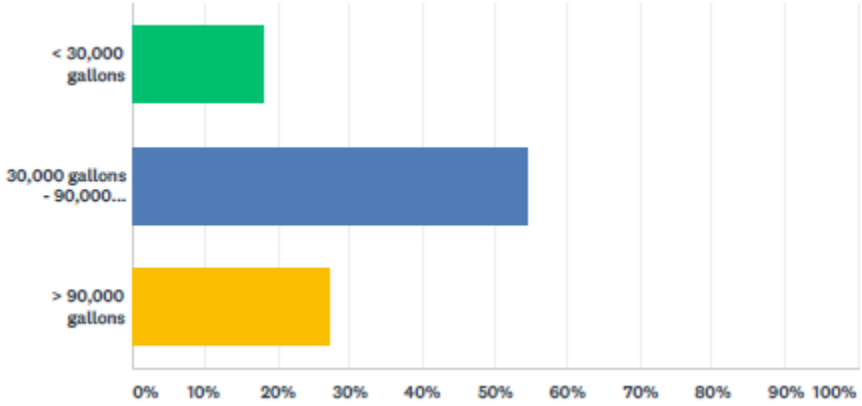
Question: What is your company's level of concern regarding the availability of properly trained and qualified transport drivers?

- **Findings:**



Question: Has your retail company increased on-site storage capacity due to the polar vortex of 2013/14?

- **Findings:** 61 percent of respondents answered yes, that they have increased storage capacity due to the polar vortex of 2013/14. Additionally, of the respondents who did answer yes to the question, 54 percent added between 30,000 and 90,000 gallons of storage capacity.



Question: Do you have established contingency plans for severe supply interruptions?

- **Findings:** 67 percent of respondents have contingency plans in place for severe supply disruptions.

Question: Including seasonal users, please calculate your retail company's average annual residential customer usage in gallons.

- **Findings:** The average of the survey responses was 777 gallons, with a maximum of 971 gallons and minimum of 650 gallons.

Energy Emergency Communication Procedures

MPSC

(Updated: May 2019)

Table of Contents

- Overview
- Reporting Criteria
- Receiving Emergency Information
- Roles and Responsibilities
- Response Actions
  - Initial Incident
  - Statewide
  - Multi-state or National
  - Severe or Catastrophic
  - Ongoing and Follow-up

Incident Contact Information

	Electric *	1) Don Mazuchowski, [redacted] 2) Pat Poli, 517- [redacted]
	Natural Gas *	1) Dave Chislea, [redacted] 2) Pat Poli, [redacted]
	Petroleum *	1) Alex Morese, [redacted] 2) Travis Warner, [redacted]
	MSP, Field Operations	1) Operations Lt, [redacted]

* EEAC: Energy Emergency Assurance Coordinators are the first-line responders to an energy incident or emergency.

Initial Incident Communication Process

- Monitor: observation of significant event(s) affecting energy supply, infrastructure, or markets
- Inform: bring to the attention of energy emergency assurance coordinators (EEAC), above
- Liaison: confirm and gather additional information from federal, state, and industry contacts
- Communicate: if determined to be of significant consequence or have lasting effect, EEAC will provide comprehensive information to [redacted]
- Ongoing: EERT will increase monitoring and investigate potential mitigation options

***** If you believe issues are of an urgent nature, immediately call MPSC Chair and/or the Michigan State Police *****

Attachments

A. Energy Emergency Response Team (Red Sheet)
B. MPSC - Emergency Distribution list
C. Statewide Emergency Contacts
D. Energy Emergency Assurance Coordinators (EEAC) -- Midwest Contacts
E. SEOC After-Hours/On-call Calendar

Overview

This document contains the procedures for communicating information that the Michigan Public Service Commission (MPSC) receives in the event of an energy[1] incident or emergency. This document will be updated every six months (October 1 and May 1).

Reporting Criteria

An energy incident or emergency is any instance in which the energy supply, critical energy infrastructure, or prices in the state or region have been or are likely to be significantly disrupted. Examples of emergencies would include the following:

- Extensive power outages due to storms, infrastructure damage, etc.
- Instability of the electric grid,
- Curtailment of power deliveries to meet high demand conditions,
- Declaration of emergency electrical conditions,
- Major oil/gas infrastructure outages or incidents,
- Petroleum price volatility,
- Petroleum supply disruptions (i.e., low winter inventories of home heating fuels),
- Requests for petroleum related waivers (Reid Vapor Pressure (RVP) or driver hour),
- Significant disruptions in interstate natural gas pipeline deliveries,
- Damage to gas storage wells or pipeline systems affecting deliveries or forcing emergency actions, or
- Other incidents (natural disasters, terrorists action, or cyber event) that materially affects energy supply or distribution.

Receiving Energy Incident or Emergency Information

In response to an energy incident or emergency conditions, MPSC personnel may receive information from the following:

- Utilities,
- Other energy suppliers, owners, or operators,
- State and federal agencies, or
- Media and other sources.

Provided that the information comes from a reliable source, or is independently confirmed, the information should be reported to the corresponding sector Energy Emergency Assurance Coordinator.

Roles and Responsibilities

The **Energy Emergency Assurance Coordinators** (EEAC) are the first-line responders to an energy incident or emergency and will evaluate the information received, coordinate monitoring, liaison with industry, and recommend response efforts and activities. The Coordinators should be the first point of contact when there is information regarding an incident or emergency. They should be contacted immediately and directly via email or phone, even during non-business hours.

[1] Telecommunications falls under the MiC3 in the Michigan Cyber Response Plan (Michigan State Police and the Department of Management and Budget)

Electric	1) Don Mazuchowski, [redacted] 2) Pat Poli, [redacted]
Natural Gas	1) Dave Chislea, [redacted] 2) Pat Poli, [redacted]
Petroleum	1) Alex Morese, [redacted] 2) Travis Warner, [redacted]

The **Energy Emergency Response Team** (EERT) is comprised of subject matter experts serving the MPSC Chair in the event of an impending or ongoing energy emergency. Select EERT members have received training in the incident command system and MiCIMS (WebEOC) in preparation for SEOC activation. Members of the EERT represent all energy disciplines (electric, natural gas, and petroleum). Five members of the EERT have keyed access to the SEOC and represent these agency roles:

Emergency Management Coordinator	Alex Morese
First Alternate	Paul Proudfoot
Second Alternate	Brian Sheldon
Third Alternate	Travis Warner
Public Information Officer	Judy Palnau

Contact information for the Energy Emergency Assurance Coordinators and Energy Emergency Response Team are provided in *Attachment A*.

Responding to a Report of a Potential Energy Incident or Emergency

1. Initial Incident or Emergency

Energy-related incident or emergency information on a potential electric, natural gas, or petroleum incident or emergency should immediately be reported as follows:

- Contact an Energy Emergency Assurance Coordinator (table above).
  - Explain the nature of the problem, and describe any response efforts, if known,
  - Provide any other information deemed relevant, and
  - Report only public information (*confidential information should not be included*).

- The EEAC will confirm and gather additional information from federal, state, and industry partners, and if warranted, send a brief email to the MPSC Emergency Distribution List.
  - Includes staff from MPSC, LARA, and MSP
  - Email address (*Attachment B*)

- Members of the EERT will ramp up monitoring to determine severity and potential resolutions.

Note: If the incident or emergency notification occurs after normal business hours, direct calls should be made to the individual home or cell phone number of the Energy Emergency Assurance Coordinators until one of them is reached successfully for assessment of the situation and further instructions.

2. Statewide Emergency

If information is received that the emergency has statewide impact, the MPSC Chair will consult with appropriate members of the Energy Emergency Response Team and/or other senior staff and technical experts, to assess the severity of the incident or emergency and provide recommendations to address the situation. The MPSC Emergency Room may open during this category of event.

Widespread incidents or emergencies affecting a large area of the state, a large number of people, or those with significant media coverage, will also be reported to the Michigan State Police Emergency Manager Coordinator as well as the Emergency Management Coordinator at the Department of Licensing and Regulatory Affairs (Attachment C).

The MPSC Emergency Room is located on the second floor of the MPSC offices, 7109 W. Saginaw Highway, Lansing, MI 48917. EERT members will have entry cards with 24/7 access to the building. In the event of a power outage at this building, certain team members have keys to get into the building.

Depending on the severity of the event overall and impacts to interdependent sectors, the SEOC may be activated. Should the Michigan State Police activate the SEOC, a schedule will be created for EERT members to staff the Energy Desk at the SEOC.

3. Multi-State Emergencies

For energy incidents or emergencies that are multi-state or have the potential to be so, the U.S. Department of Energy (DOE) and surrounding states must be notified via phone or email (by an EEAC). The Energy Emergency Assurance Coordinators system can be used to distribute information to both the DOE and EEAC contacts (*Attachment D*) in Ohio, Indiana, Illinois, Minnesota, and Wisconsin.

4. Severe or Catastrophic Energy Emergencies

For severe or catastrophic state energy emergencies, the executive director of MAE may consult with directors of other state and local agencies to assess the developing emergency, review action plans, and make appropriate recommendations to the Governor. Relevant state agencies include but are not limited to the following: LARA, MDARD, DEGLE, DHHS, MDOT, DTMB, and MSP.

5. Ongoing/Follow-up

Throughout the course of the emergency from initial stages through conclusion, it is important to maintain ongoing and adequate monitoring and communication. Updates should be shared with the MPSC Emergency Distribution group and MSP's MiCIMS computer system, as new information is available.

****Appendices containing call lists and contact information has been redacted.**

Midcontinent Independent System Operator Emergency Procedures[1]

Per Midcontinent Independent System Operator (MISO) Procedures, State Commissions are notified at the following steps:

- Warning – Maximum Generation is projected
- Event step 1a – Emergency-Only generation is being used
- Event step 2a – Load Management procedures in effect
- Event step 5b – Firm load shed in progress
- Termination of Warnings, Alerts or Events

Maximum Generation (Max Gen) Alert

Midcontinent ISO Actions

- Define boundaries of projected Max Gen Alert area based on constraints.
- Define start and end of projected Max Gen Alert.
- Declare Conservative System Operations.
- Suspend transmission maintenance as appropriate.

Member Actions

- Follow MISO Conservative System Operations procedure.
- Update limits, offers, energy interchange tags, deliverability of resources, and accuracy of all information.
- Transmission Operators provide to MISO Reliability Coordinator details on any potential exclusion of constrained pockets within the Alert Area.

Max Gen Warning

Midcontinent ISO Actions

- Define boundaries of projected Max Gen Warning Area based on constraints.
- Define start and end of projected Max Gen Warning.
- Implement Emergency Pricing Tier 1.
- Suspend Coordinated Transaction Scheduling with PJM Interconnection LLC.
- Query Emergency Demand Response (EDR) offers to determine EDR availability and MW amounts for the Warning Period.
- Obtain updated amounts Load Management Measure (LMM) relief available and review Load Modifying Resource (LMR) availability.
- Available external Capacity Resources that would be deliverable to Warning Area, given transmission constraints, to be scheduled into the MISO Balancing Authority Area. Specific instructions on directions external resources are deliverable from will be provided.

1 https://cdn.misoenergy.org/SO-P-EOP-00-002%20Rev%207%20MISO%20Market%20Capacity%20Emergency333797.pdf

- Curtail non-firm Export Schedules, in amounts required to relieve the shortage condition.

Member Actions

a) Market Participants review Offers and ensure accuracy of LMM, EDR and LMR availability.
b) Notify loads of potential interruption.

Max Gen Event Step 1a: Emergency Generation and Emergency Dispatch Ranges

Midcontinent ISO Actions

a) Commit Generation Resources, Demand Response Resources-Type 1, and Demand Response Resources-Type 2.

Member Actions

a) When notified by MISO, start offline Available Max Emergency Generation Resources.

Max Gen Event Step 1b: Emergency Generation and Emergency Dispatch Ranges

Midcontinent ISO Actions

a) Declare North American Energy Reliability Corporation (NERC) Energy Emergency Alert (EEA) 1 – all available resources are in use.
b) Activate Emergency Maximum Limits utilizing Emergency Pricing.

Member Actions

a) When dispatched, ensure resources move into Emergency range.
b) Ensure co-generation and independent power producers are at maximum output and availability.
c) If capacity is available, coordinate with MISO.

Max Gen Event Step 2a: Implement Load Management Measures

Midcontinent ISO Actions

a) Declare NERC EEA 2 – Load Management procedures in effect.
b) Instruct load to be reduced via Module E LMRs and via LMM-Stage 1 in defined Event Area by Load Balancing Authority (LBA) in MW amounts.

Member Actions

a) When notified by MISO, reduce load via LMM-Stage 1, or dispatch LMRs.

Max Gen Event Step 2b: Implement Load Management Measures

Midcontinent ISO Actions

a) Commit EDR offers as available in the Event Area, in merit order by MW amounts.

Member Actions

a) When notified by MISO, commit EDRs.

Max Gen Event Step 2c: Implement Load Management Measures

Midcontinent ISO Actions

a) Coordinate with neighboring Reliability Coordinators and Balancing Authorities (BA) to determine emergency energy available.
b) Implement emergency energy purchase from neighboring BA's excess energy to conserve Midcontinent ISO BA's operating reserves
c) Instruct LBAs to issue public appeals.

Member Actions

a) When notified by MISO, issue public appeals.
b) Prepare to shed load.

Max Gen Event Step 3a: Utilize Operating Reserves

Midcontinent ISO Actions

a) Notify generator operators who have de-rates from environmental restrictions to request waivers from appropriate government agencies.
b) Implement all spinning and supplemental reserves.
c) Declare NERC EEA3 Firm load interruption imminent or in progress.
    a. If Contingency Reserves fall below minimum required for greater than 30 minutes and no reasonable actions exist to restore within 90 minutes.

Member Actions

a) Generation Operators who have generators in the Event Area with de-rates or other capacity limitations from environmental restrictions are to make this capacity available for dispatch if they are able to do so within government regulations.

Max Gen Event Step 3b: Utilize Operating Reserves

Midcontinent ISO Actions

a) Notify LBAs of required load reduction via LMM Stage 2.
b) If Transmission Load Relief is called and MISO imports are being curtailed, tag for elevation.
c) Declare NERC EEA3 Firm load interruption imminent or in progress.
    a. If Contingency Reserves fall below minimum required for greater than 30 minutes and no reasonable actions exist to restore within 90 minutes.

Member Actions

a) LBAs in defined Event Area reduce load via LMM-Stage 2, including voltage reductions as appropriate, and communicate to Midcontinent ISO when actions have been implemented.

Max Gen Event Step 4a: Implement Operating Reserve Purchases from External BAs

Midcontinent ISO Actions

a) Implement Reserve Call from Contingency Reserve Sharing Group if available.

Member Actions

a) Market Participants review offers and ensure all available emergency ranges and resources are offered.

Max Gen Event Step 4b: Implement Operating Reserve Purchases from External BAs

Midcontinent ISO Actions

a) Implement additional emergency energy purchase (typically from Operating Reserves) from neighboring Bas.

Member Actions

a) Market Participants review offers and ensure all available emergency ranges and resources are offered.

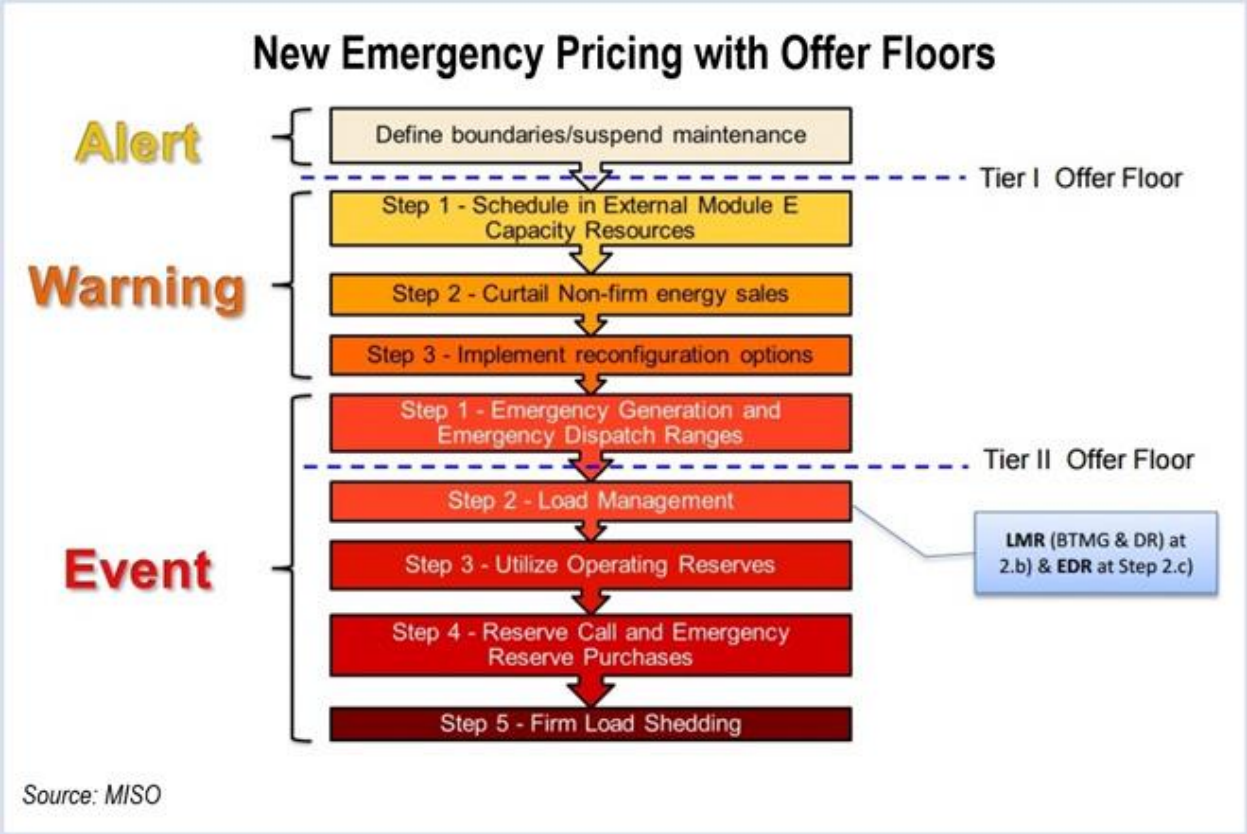
Max Gen Event Step 5: Implement Firm Load Shedding

Midcontinent ISO Actions

a) Determine Load Shedding requirements.
b) Declare NERC EEA 3 – firm load interruption imminent or in progress.
c) Direct firm load shedding in defined Event Area by LBA in MW amounts.
d) Set Locational Marginal Prices and Market Clearing Prices to the Value of Lost Load until Emergency Procedures Step 5 is no longer in effect.
e) If load shed is great than 100MW, coordinate with LBAs to determine reporting requirements.

Member Actions

a) LBAs in defined Event Area reduce firm loads per directives and confirm the actions taken with the MISO Reliability Coordinator.
b) If requested by MISO, complete Department of Energy forms for actions taken to reduce load.


New Emergency Pricing with Offer Floors
Alert
Define boundaries/suspend maintenance
Tier I Offer Floor
Warning
Step 1 - Schedule in External Module E Capacity Resources
Step 2 - Curtail Non-firm energy sales
Step 3 - Implement reconfiguration options
Event
Step 1 - Emergency Generation and Emergency Dispatch Ranges
Tier II Offer Floor
Step 2 - Load Management
Step 3 - Utilize Operating Reserves
Step 4 - Reserve Call and Emergency Reserve Purchases
Step 5 - Firm Load Shedding
LMR (BTMG & DR) at 2.b) & EDR at Step 2.c)
Source: MISO

PJM Interconnection LLC Emergency Procedures[2]

Overview

An emergency in PJM is defined as:

- An abnormal system condition requiring manual or automatic action to maintain system frequency, prevent loss of firm load, equipment damage or tripping of system elements that could adversely affect reliability of an electric system or the safety or persons or property.
- Capacity deficiency or capacity excess conditions.
- A fuel shortage requiring departure from normal operating procedures.
- Abnormal natural events or man-made threats to reliability.
- Abnormal events external to PJM that may require PJM action.
- Many emergencies involve a shortage of reserve generation or inability to deliver generation to load.

Emergency Procedures – PJM Control Area

- Carried out together across PJM regional transmission operators up to load dump assuming no transmission or other operating limitations.
    - Procedures may be issued by control zone if transmission limitations exist.
- When procedures get to load dump, the control zone(s) that is capacity deficient will shed load.
- Determination of who is capacity deficient will be each control zone comparison of their generation with load.
    - Adjusted based on zone's net capacity position.
    - Adjusted based on any external purchase allocated to control area.

Reserve Generation

- Reserve requirements are values of reserve which enable the system to operate reliably and economically while providing protection against load variations, forecast error and equipment failure.
- This also enables the control area to restore tie lines to pre-contingency state within 10 minutes of contingency that causes an imbalance between load and generation.

Synchronous Reserve (aka Spinning Reserve)

- Increase (or decrease in a Load Response Resource) in output energy level of a synchronized generator which can be attained in 10 minutes.
- Maximum energy output achieved in 10 minutes by a unit operating as a synchronous condenser.

Quick Start Reserve

- Not synchronized to system
- Includes maximum energy output level of a unit that can be attained in 10 minutes from the PJM request.
- Generally, run of river hydro, pumped hydro, combustion turbines and diesel type units.

2 http://www.pjm.com/~/media/documents/manuals/m13.ashx

Contingency Reserve (aka Primary Reserve)

- Synchronous Reserve
    - Spinning (generation)
    - Customer Demand Response
    - Quick Start Response
- All MW available within 10 minutes.

Supplemental Reserve (aka Secondary Reserve)

- The reserve capability that can be fully converted into energy in 10-30 minute interval following a request by PJM.
- Equipment does not need to synchronized to the system.
- Secondary reserve is tracked and reported in real-time for the entire PJM footprint via Instantaneous Reserve Checks.

Operating Reserve

- Generation available from either offline or online units within 30 minutes.
- Scheduled to meet Operating Reserve requirements in Day-Ahead Market.
- Contingency Reserve + Supplemental Reserve = Operating Reserve
- Calculated on an annual basis involving variables that adversely impact system reliability:
    - Load Forecast Error
    - Generator Forced Outage Rates

Day Ahead Scheduling Reserves = Load Forecast Error + Generator Forced Outage Rates

Energy Emergency Alerts (EEA)

- Issued by Reliability Coordinator for capacity and energy shortages.
- Three levels:
    - Provides common terminology for reliability coordinators to use when explaining energy emergencies to each other.
    - Levels may be declared in whatever order necessary, sequentially not required.

Alert Level 1

- Issued when a Control Area "foresees or is experiencing conditions where all available resources are committed".

Alert Level 2

- Issued when a Control Area "foresees or has implemented procedures up to but excluding interruption of firm load commitments".
    - Public appeals, voltage reduction, load management.

Alert Level 3

- Issued when a Control Area "foresees or has implemented firm load obligation interruption".
- Prior to declaring
    - All generation online, regardless of cost.

    - All purchases made, regardless of cost.
    - All non-firm sales recalled.
    - All contractually interruptible load curtailed.
- PJM issues prior to a Manual Dump Action

Capacity Shortages

- Capacity Alerts are issued in advance (day-ahead) of the period to allow Load Control Centers (LCC) and Market Operation Centers time to prepare.
    - Maximum Emergency Generation Alert
    - Primary Reserve Alert
    - Voltage Reduction Alert

Maximum Emergency Generation Alert

Purpose: To provide an early alert that PJM Emergency Procedures may be required.

Trigger:

- When Maximum Emergency Generation is called into the operating capacity.
- Operating reserve requirement is greater than scheduled operating reserve.

PJM Actions:

- Notifications
    - Internal – PJM Management
    - External – Members: Issue NERC EEA1
- Set up Supplementary Status Report
    - May not request until operating day for which alert is in effect.

Member Actions

- Notifications: Management, generating stations, key personnel.
- Defer any maintenance or testing of generating or transmission equipment.
- Report any fuel limited facilities to PJM.

Primary Reserve Alert

Purpose: To alert members of an anticipated shortage of operating reserve capacity in a future critical period.

Trigger: When the estimated operating reserve is less than the forecasted primary reserve requirement.

PJM Actions:

- Notifications.
- Report significant changes in estimated operating reserve capacity.

Member Actions

- Notifications: Management, generating stations, key personnel.

- Defer any maintenance or testing of generating or transmission equipment.

Voltage Reduction Alert

Purpose: To alert members that a voltage reduction may be required in a future critical period.

Trigger: When the estimated operating reserve is less than the forecasted spinning reserve requirement.

PJM Actions

- Notifications.
    - Internal – PJM Management.
    - External – Members.
    - Give LCCs estimated hour of implementation.

Member Actions

- Notifications: Management, generating stations, key personnel.
- Take any necessary steps to expedite implementation of voltage reduction, should one become necessary.
- System Operations Subcommittee (SOS) members consider issuance of public appeals.
- Marketers proceed on heightened awareness regarding potential need for emergency energy purchases.

Public Appeals

- Issued via media outlets (radio, TV) to inform and request customer conservation
- SOS – Transmission determines when to release and scope.
- PJM and member Communications departments can tailor messages for specific situations.
- Messages give instructions for conservation to public.
    - Lower thermostats, close blinds.
    - Reduce appliance usage during peak hours.
- Draft messages are in Manual 13, Attachment A.
    - Level 1: Cold/Hot Weather Advisory
    - Level 2: Statement/News Release for Cold/Hot Weather Emergency (released following load management programs)
    - Level 3: Statement/News Release for Cold/Hot Weather Emergency (released following voltage reductions)
    - Level 4: Statement/News Release for Cold/Hot Weather Emergency (released following Manual Load Dump)
    - Also contains messages for exiting emergencies.
- Manual M-13 combines Warnings and Actions in their most probable sequence based on notification requirements during extreme peak conditions.
- Depending on the severity of the emergency, it is unlikely that some steps would be implemented.
- PJM Operators have flexibility to implement Warnings and Actions in any order they feel necessary.

- Warnings are typically issued prior to an associated Action.

Capacity Shortage Warnings

- Warnings are issued during present operations.
    - To inform members of actual capacity shortages and contingencies that may affect the reliability of the PJM Control Area.

Three Warnings:

1. Primary Reserve Warning
2. Voltage Reduction Warning and Reduction of Non-Critical Plant Load
3. Manual Load Dump Warning

Five Actions

1. Maximum Emergency Generation
2. Emergency Mandatory Load Management Reductions
3. Emergency Voluntary Energy Only Demand Response Reductions
4. Voltage Reduction/Curtailment of Non-Essential Load
5. Manual Load Dump

Pre-Emergency Load Management Reductions

- PJM registered DR with a 30, 60, or 120-minute lead time are dispatched.
- PJM notifies members to consider the use of public appeals to conserve usage.

Emergency Mandatory Load Management Reductions

- Customers receiving capacity credits and/or reduced retail rates in exchange for reducing load during emergencies.
- PJM and/or LCC controlled and directed.
- Have various names including, but not limited to:
    i. Active Load Management (ALM)
    ii. Qualified Interruptible Loads (QIL)
    iii. Interruptible, Curtailable, or Load Management
- Can be issued system wide or by one, depending on current or projected system conditions.

Full Emergency Load Response Restrictions

- Interruptible by PJM for 10 times during planning period (June-May).
- Interruptible for up to 6 hours, from 12:00 to 20:00 on non-holiday weekdays.
- Able to be implemented within 2 hours.
- Not used to assist adjacent Control areas.

PJM Actions

- Notifications
    - Internal – Management, Communications
    - External – Members, Reliability Coordinators, Curtailment Service Providers
    - Issue EEA2
- Provide LCCs an estimate of the magnitude and approximate duration of curtailment.

    - Request implementation of Full Emergency Load Response Long Lead/Short Lead time.
- Suggest LCCs consider use of public appeals.

Member Actions

- Notifications: Internal/External, government agencies.
- Consider use of public appeals.
- Implement load management programs.

Primary Reserve Warning

Purpose: To warn the LCCs that the primary reserve is less than required and operations are getting critical.

Trigger:

- Issued when the primary reserve is less than the Primary Reserve Requirement, but greater than the Spinning Reserve Requirement.
- All secondary reserve (except MW's in Max Emergency) is first moved to primary reserve status.

PJM Actions

- Notifications: Internal/External.
- Verify Secondary Reserve moved to Primary Status and all available generation is scheduled.
- Verify all deferrable maintenance or testing halted.

Member Actions

- Notifications: External/Internal, key station personnel.
- Prepare to load primary reserve.
- Halt any deferrable maintenance or testing.
- Marketers proceed on heightened awareness regarding potential need for Emergency Energy purchases.

Maximum Emergency Generation Action - Step 4A

Purpose: To increase generation above the maximum economic level.

Trigger: Real-time Generation is needed to meet the load demand that is greater than the highest incremental cost level.

PJM Actions

- Notifications: Internal/External.
- Request Emergency Energy (via Open Access Same-Time Information System & Security Coordinator Information System).
- Suspend regulation.

- Recall off system sales backed by PJM capacity unit(s).
- Implement Scarcity Pricing
- Load Max Emergency Generation and start purchases of emergency bids received.
    - Typically, Max Emergency combustion turbines are loaded prior to Max Emergency steam to preserve spinning reserve and unit reliability.

Member Actions

- Notifications: Internal/External.
- Recall off system sales that are recallable.
- Suspend regulation when requested.
- Load units to Max Emergency levels as requested.
- Market Participants submit bids to supply Emergency Energy from sources outside PJM.

Emergency Bid Process

- Member is responsible for delivery and transmission service.
- PJM attempts to provide 60 minutes notice before energy is required.
- Fax bid form and call to verify receipt.
- Manual 13, Attachment D.
- PJM accepts offers and schedules energy based on the following:
    - Least cost offers accepted first based on energy price and minimum hours.
    - Similarly priced offers are selected based on timestamps (first in, first selected).
    - Emergency Purchases do NOT set locational marginal pricing.
    - Emergency Purchases are NOT capped at $1000/MW.
    - Energy accounted for according to the emergency energy accounting procedures (see M-28 Operating Agreement Accounting).
    - PJM implements and curtails Emergency Purchases with as much notice as possible to allow for reliable transition.
    - PJM request emergency energy from neighboring control areas after all energy offers by PJM Members is accepted.
        - Exception: Unless there is an immediate need for energy.

Emergency Voluntary Energy Only Demand Response Reduction Action - Step 4B

- Any customer capable of reducing at least 100kW of load or generating at least 100kW.
- Be available between 09:00 and 22:00 any or all days of the week.
- Achieve reduction within one hour of request.
- Minimum duration of reduction is 2 hours.
- PJM offers an Emergency and Economic Load Response Programs.
    - Economic program reduces based on a strike locational marginal pricing.

Purpose: To request end-use customers who participate in the PJM Emergency Voluntary Energy Only Demand Response Program to reduce demand.

Trigger: Additional load relief is needed.

PJM Actions

- Notifications: Internal/External.
- Issue Load Reduction Action.
    - Entire regional transmission operator or selected control zones.

Member Actions

- Notifications: Internal/External.
- Emergency Load Response Curtailment Service Providers notify PJM of anticipated reductions.
    - Via Load Response Application.
    - Perform load reduction.

Voltage Reduction Warning & Reduction of Non-Critical Plant Load - Step 5

Purpose: To inform the LCC that spinning reserve is less than required and present operation has deteriorated such that voltage reduction may be required.

Trigger:

- When Spinning Reserve is less than the requirement.
- All secondary and primary reserve (except MWs in Max Emergency) are first moved to spinning reserve status.

Member Actions

- Notifications: Internal/External, key station personnel, and government agencies.
- Appropriate personnel of potential need for load management programs.
- Order all Generating Stations to curtail non-essential station light and power.
- Prepare for implementation of voltage reduction.

Manual Load Dump Warning

Purpose: To warn LCCs of increasingly critical system conditions that may require manually dumping load.

Trigger:

- When the primary reserve is less than the largest generating unit or the loss of a transmission facility jeopardizes reliability.
- All possible measures are first taken to increase reserves.

PJM Actions

- Notifications
    - Internal – Management, Communications.
    - External – FERC Division of Reliability electronic pager system.
- Establish mutual awareness with LCCs of need for action with minimum delay (post contingency).
- Examine bulk voltages.

Member Actions

- Internal/External, key station personnel, and government agencies.
- Reinforce internal communications so load dumping can occur with minimum delay.
- Review procedures and prepare to dump load.
- "Finger on the Button" (be ready to shed load when ordered).

Voltage Reduction Action

Purpose: To reduce load to provide a sufficient amount of reserve to maintain tie flow schedules and preserve limited energy resources or to increase transmission system voltages.

Triggers:

- Load relief still needed to maintain ties.
- Curtailment of non-essential building load may be implemented prior to, but no later than the voltage reduction.

Voltage Reduction Actions

- Voltage is reduced at distribution levels by 5% of nominal values.
    - Increases transmission voltages.
- Produces a 2-3% decrease in system load.
- Generally not noticed by customers.
    - Lights dimmer, slower heating.
    - City of Chicago limited to 2.5% voltage reduction.
- Curtailment of non-essential building load (Step 7B) may be implemented prior to, but no later than the same time as a voltage reduction.

PJM Actions

- Notifications
    - Internal – Management, Communications.
    - External – Outside Systems (Reliability Coordinator Information System).
        - NERC EEA2
        - US Department of Energy
- Suggest LCCs consider use of public appeals.
- Order 5% Voltage Reduction.

Member Actions

- Notifications: Internal/External, government agencies.
- Consider use of public appeals.
    - With SOS authorization, issue applicable C3 or H3 Public/Media Notification Messages (Attachment A).
- Implement Voltage Reduction.

Curtailment of Non-Essential Building Load - Step 6

PJM Actions

- Notifications: Internal – Management, Communications.
- External – Outside Systems (Reliability Coordinator Information System).
    - US Department of Energy.
- Suggest LCCs consider use of public appeals.
- Request curtailment of non-essential building load.

NOTE: Curtailment of non-essential building load may be implemented prior to, but no later than the same time as a voltage reduction

Member Actions

- Notifications: Internal/External, government agencies.
- Consider use of public appeals.
- Implement curtailment of all non-essential light and power in company owned commercial, operations and administrative offices.

Deploy All Resources Action - Step 7

PJM Actions

- Suspend all reserve and regulation assignments.
- Recall any external capacity.
- Dispatch Load Management.
- Issue NERC EEA Level 2.

Member Actions

- Raise all available online generating units to emergency max.
- Start offline generation and ramp to emergency max.
- Curtailment service providers reduce load immediately.

Manual Load Dump Action - Step 10

- Process described here pertains only to capacity deficient situations.
    - For transmission constraints or voltage problems, load dump will be ordered in areas where it is most effective.
- If Mid-Atlantic region is deemed deficient, total load shed must be further broken down by Manual Load Dump Allocation Tables.
    - Manual M-13, Attachment E
- Manual Load Dump last utilized by PJM on January 19, 1994.

Purpose: To provide load relief when all other possible means have been exhausted to prevent a catastrophe within PJM.

- Implemented only in control zone that is capacity deficient.

Trigger: Implemented when PJM cannot provide adequate capacity to meet load, or critically overloaded transmission lines or equipment cannot be relieved in any other way.

PJM Actions

- Notifications
    - Internal – Management, Communications.
    - External – Control Areas (Reliability Coordinator Information System).
        - NERC EEA Level 3.
        - US Department of Energy.
        - Federal Emergency Management Agency.
        - FERC Division of Reliability via electronic paging system.
- Suggest LCCs consider use of public appeals.
- Suspend all remaining regulation.
- Verify load dumping will help and not aggravate the condition.
- Determine block of load required for relief.
    - Only under-producing zones will be asked to shed load.
- Order appropriate LCCs to dump required amount of load.

Member Actions

- Notifications: Internal/External, government agencies.
- Consider use of public appeals.
    - Note: With SOS approval, applicable C4 or H4 Public/Media Notification Message should be issued before load dump action.
- Suspend remaining regulation.
- Promptly dump an amount of load equal to or in excess of LCC's allotment of load dump order.

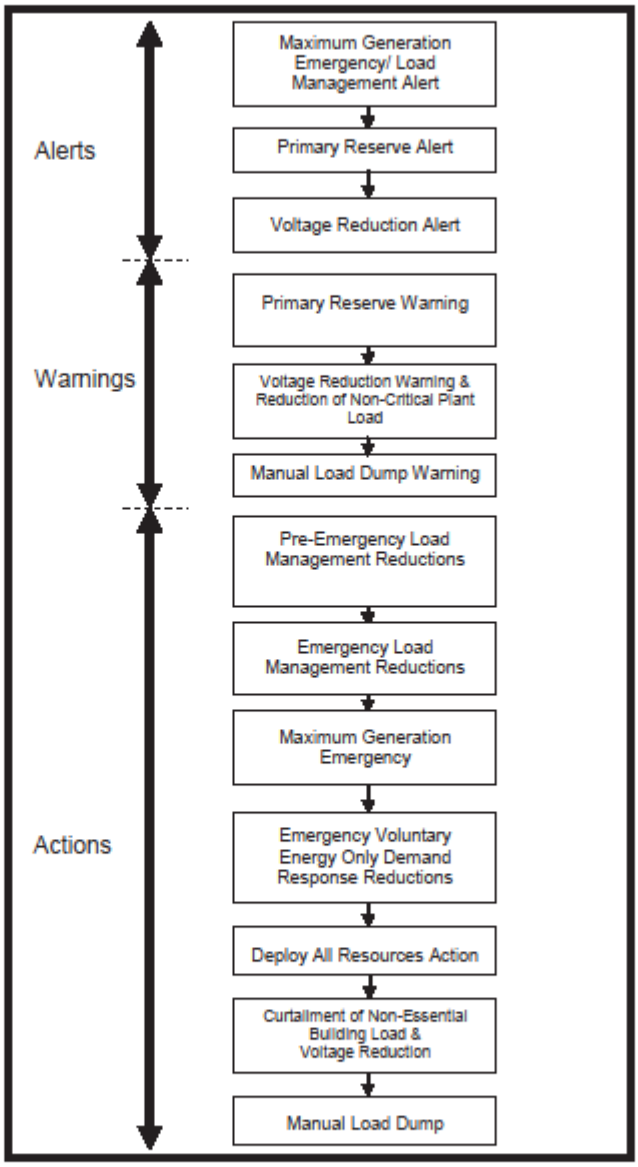


Exhibit 1: Emergency Levels

Links to MPSC-Approved Rate Books for Michigan Natural Gas Utilities

1. Consumers Energy Company:
   https://www.michigan.gov/mpsc/0,4639,7-159-16385-423810--,00.html

2. DTE Gas Company:
   https://www.michigan.gov/mpsc/0,4639,7-159-16385-422797--,00.html

3. Michigan Gas Utilities Corporation:
   https://www.michigan.gov/mpsc/0,4639,7-159-16385-422861--,00.html

4. Northern States Power Company – Wisconsin (Xcel):
   http://www.michigan.gov/mpsc/0,4639,7-159-16385-417490--,00.html

5. Presque Isle Gas Cooperative:
   https://www.michigan.gov/mpsc/0,4639,7-159-16385-419987--,00.html

6. SEMCO Energy Gas Company:
   http://www.michigan.gov/mpsc/0,4639,7-159-16385-419459--,00.html

7. Upper Michigan Energy Resources Corporation (UMERC)
   http://www.michigan.gov/mpsc/0,4639,7-159-16385-418157--,00.html