Integrating Renewables into Lower Michigan's Electricity Grid

RESOURCE ADEQUACY AND OPERATIONAL ANALYSIS, AND IMPLICATIONS

PREPARED FOR

DTE Energy

PREPARED BY

Judy W. Chang
Kai Van Horn
Akarsh Sheilendranath
Johannes P. Pfeifenberger
Ariel Kaluzhny
Cecile Bourbonnais

March 29, 2019

THE Brattle GROUP

Notice

- This white paper reflects the perspectives and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants. However, we are grateful for the valuable contributions of *many consultants of The Brattle Group*.
- Where permission has been granted to publish excerpts of this white paper for any reason, the publication of the excerpted material must include a citation to the complete white paper, including page references.

Table of Contents

Executive Summary

In recent years, many parts of the U.S. have experienced rapid deployment of renewable resources, driven by supportive public policy and increasingly favorable resource economics. The increase in renewable generation, along with the retirement of aging conventional generating resources has shifted the overall generation resource mix in many regions of the country.

The trajectory in the Midwest has followed this national trend, one that is expected to continue and likely to accelerate. In Michigan, and particularly the Lower Peninsula ("Zone 7" in the Midcontinent Independent System Operator (MISO) system), renewable generation sources[1] are expected to serve approximately 25% of load by 2031 and 30% of load by 2040—a substantial increase relative to today's levels. This growth in intermittent renewable generation and the anticipated retirements of coal generation are expected to shift the system to one that will likely require additional support to maintain system reliability.

- The Lower Peninsula's net peak load (defined as the system peak load after accounting for renewable generation) will shift from late afternoon into the evening hours. This shift will reduce the extent to which additional renewable generation, particularly solar generation, contributes to covering the resource adequacy needs of Zone 7.
- In addition, increasing deployment of intermittent renewable generation will increase the variability and uncertainty of the net load pattern. Such changes could create system reliability and operational challenges in continuous balancing of supply and demand.

To assess the potential impact of the changes to system reliability and operational needs brought about by the shifting resource mix in the Lower Peninsula, we conducted a stochastic analysis to assess the resource adequacy of Zone 7, as well as an operational simulation of the MISO market, with a focus on Zone 7. Both of these analyses were conducted for the years 2031 and 2040, milestone years that represent significant shifts in the generation fleet in Zone 7.

Based on these analyses, we find that the supply mix changes in Zone 7 and in the rest of MISO can pose challenges to Zone 7's future resource adequacy. With the increase in renewable generation, we define resource adequacy in this study to refer to the **ability of generation resources to meet load in every hour**, considering the uncertainties in the availability of resources in each hour, the uncertainty in the energy outputs from intermittent renewable generation resources, and the uncertainties around load forecasting. Accordingly, going forward, the resource adequacy needs for Zone 7 should be assessed and monitored for all hours, not just during system peak.

---

1 Renewable generation sources include solar, wind, and biomass as a share of load not including the assumed 7% T&D losses.

- Resource adequacy is a key indicator of a system's ability to maintain reliability, and is analyzed by evaluating the likelihood of a "loss of load event" experienced by customers due to insufficient resources.
- Currently, Zone 7 has sufficient resources to meet resource adequacy needs. However, maintaining resource adequacy in 2031 will depend on multiple factors, including: (a) the level of capacity import capability from the rest of MISO into Zone 7, and (b) the ability to fully harness the capabilities of the Ludington Pumped Hydro generation facility for the purpose of supporting Resource Adequacy[2] within Zone 7.
- By 2040, maintaining the zone's resource adequacy could be more challenging than in 2031, especially if the decline in the capacity import limit from the rest of MISO into Zone 7—which could potentially decrease from 3,211 MW[3] in 2019/20 to 1,321 MW[4] in the near future due to potential voltage constraints on the interconnected transmission system associated with the proposed generation retirements in Michigan—is not addressed; or if the availability of importable capacity from rest of MISO is at risk due to the neighboring zones' own needs to balance their supply and demand adequately.

Aside from the risk associated with a potential decline in import capabilities and Ludington, our analyses find that Michigan Zone 7 would need to **rely increasingly on demand response** (DR) **resources** to support reliability, especially in 2040. Our simulations show that the performance characteristics of DR will need to evolve to allow for more frequent deployment to support the system's supply and demand balance, particularly during evening hours when the system's reliability risks are expected to increase. This study, however, did not assess the feasibility or the economics of future demand response programs, nor the risks and impacts to program enrollment in the future to achieve the DR levels assumed in our analyses.

Our analyses of 2040 show that Zone 7 could experience reliability challenges due to **a lack of available local ramping capability**. Additional ramping capability will be needed to ensure that the increase in the up and down ramping of net load can be met reliably. Our analyses indicate that:

- The need for ramping capability increases substantially between 2017 and 2040. Over a six-hour period, the average downward and upward ramping need increases respectively from 1,716 MW and 1,755 MW in 2017 to 2,662 MW and 3,269 MW in 2040. Further, the maximum six-hour ramping needs are substantially greater than the averages, increasing

---

2 Our study assumes that Ludington will also be available for sub-hourly operational flexibility needed to respond to the system's operational demands brought about by higher renewable generation levels in the future.

3 MISO LOLEWG Presentation on 2019/20 CIL/CEL Values, October 03, 2018 https://cdn.misoenergy.org/20180911%20LOLEWG%20Item%2003%202019-20%20PY%20CILCEL%20Values273688.pdf

In 2018/19 Zone 7's Import Capability ("Capacity Import Limit") was 3,785 MW.

4 MPSC Case U-20165, direct testimony of Charles Marshall, p, 6 https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000031lpcAAA.

from 6,401 MW (downward) and 6,246 MW (upward) in 2017 to 9,351 MW and 10,609 MW in 2040.

- The system could face challenges in being able to meet ramping needs by 2040—as evidenced both by spikes in ancillary service prices and potential shortfalls in ramping capabilities observed during peak periods in 2040.

Our simulations highlight additional changes to the system's operational performance in the future. Specifically, we observe a **declining ability of the system to integrate additional renewables as the share of renewable generation increases to 30%** by 2040, which results in an increase in curtailed renewable energy. We further document a **growing reliance on imports** from MISO to meet Zone 7 energy needs in the future. More specifically, our analyses indicate that:

- The ability of the system to integrate additional renewable resources is degraded by 2040, which is evidenced both by higher renewable curtailments of about 1% by 2040 and an increased frequency of negative market priced hours of almost 10% by 2040.
- The simulated share of load in Zone 7 served by imports from the rest of MISO increases from 6.7% in 2031 to 13.2% in 2040. The continued reliance on imports to support Zone 7's capacity and energy needs can impose additional risks on customer costs if capacity and/or energy shortages in MISO were to manifest in the future.

Finally, our analyses show that changes to **operations of Ludington, as well as existing and potentially newly installed gas-fired generation, will help to mitigate the identified risks**.

- Ludington is a significant source of flexibility in Zone 7 and its ability to respond to steep ramps in the net load, support peak requirements, and reduce the volume of renewable generation curtailments, will become increasingly valuable as the renewable generation in Michigan's supply mix increases.
- Regarding future gas-fired generation, our analyses indicate that existing and new gas-fired generation could play a growing role in providing energy needs as other conventional generation retires between 2031 and 2040.
- Further, gas-fired combustion turbine (CT) units could provide valuable support during the evening net-load ramping periods. Through our simulation, we observe that the CTs increase their number of start-ups and ramping mileage significantly between 2031 and 2040. These increases demonstrate that Zone 7's CTs will continue to respond to the system's flexibility needs.

Overall, we recommend, as the state continues to examine the future power system needs of the Lower Peninsula, that the identified resource adequacy and operational risks be monitored carefully. We anticipate that some combination of energy storage, demand response, and new gas-fired generation will be needed to continue to support the advancement of renewable generation deployment.

I. Introduction

In recent years, many parts of the U.S. have experienced a rapid buildout of renewable resources, driven by a combination of supportive public policy and improving resource economics. The increase in renewable generation, in combination with the retirement of conventional generating resources, has shifted the overall generation resource mix in many regions of the country.

In the Midwest, the trajectory has followed this national trend, one that is expected to continue and likely to accelerate. In Michigan, and particularly, in Michigan's Lower Peninsula ("Zone 7" in the Midcontinent System Operator (MISO) system), increasing renewable generation deployment and large-scale retirements of coal-fired generation are expected to fundamentally shift the resource mix and therefore the way the system operates in the future.

To assess the potential impact of these future changes to system reliability and operational needs, we conducted a stochastic analysis to assess the resource adequacy of Zone 7 and an operational simulation of the MISO market, with a focus on Zone 7.

As we explain in detail in this whitepaper, capacity and energy imports into Zone 7 from the rest of MISO are and will continue to be an important aspect of resource adequacy and operational flexibility for Zone 7 as it experiences a significant shift in the supply resource mix. This study does not include a transmission analysis, which can substantially affect resource adequacy and operational performance of the system. Specifically, while we understand that future generation retirements are expected to reduce Zone 7's transmission import capability relative to current levels, we have not conducted a transmission study to assess the level of impact that future retirements and addition of renewable generation in Zone 7 would have on its import capability in 2031 and 2040. Instead, we evaluated Zone 7's resource adequacy with a range of assumed import capability levels to reflect those uncertainties. For the operational analysis, we assumed that future import capability will remain at or be restored to the current levels.

We have not conducted a transmission planning analysis to determine the transmission needs within Zone 7. Our operational analysis is a zonal analysis, which does not reflect or evaluate any transmission constraints within Zone 7.

This study does not include an emissions analysis, and has not constrained the operations of certain generating facilities to reflect any emissions limits that may be placed on them due to applicable emission regulations. This study also does not focus on the financial or economic implications of changes in the marketplace on individual generating facilities.

The findings of this study are intended to highlight key considerations for utilities, system operators, and regulators to inform the potential resource adequacy and operational risks associated with the state's resource plan. In the rest of this report, we discuss our assumptions, approach used for the analyses, key findings, and suggestions for future considerations.

A. Michigan Utilities' Planned Resource Mix in 2031 and 2040

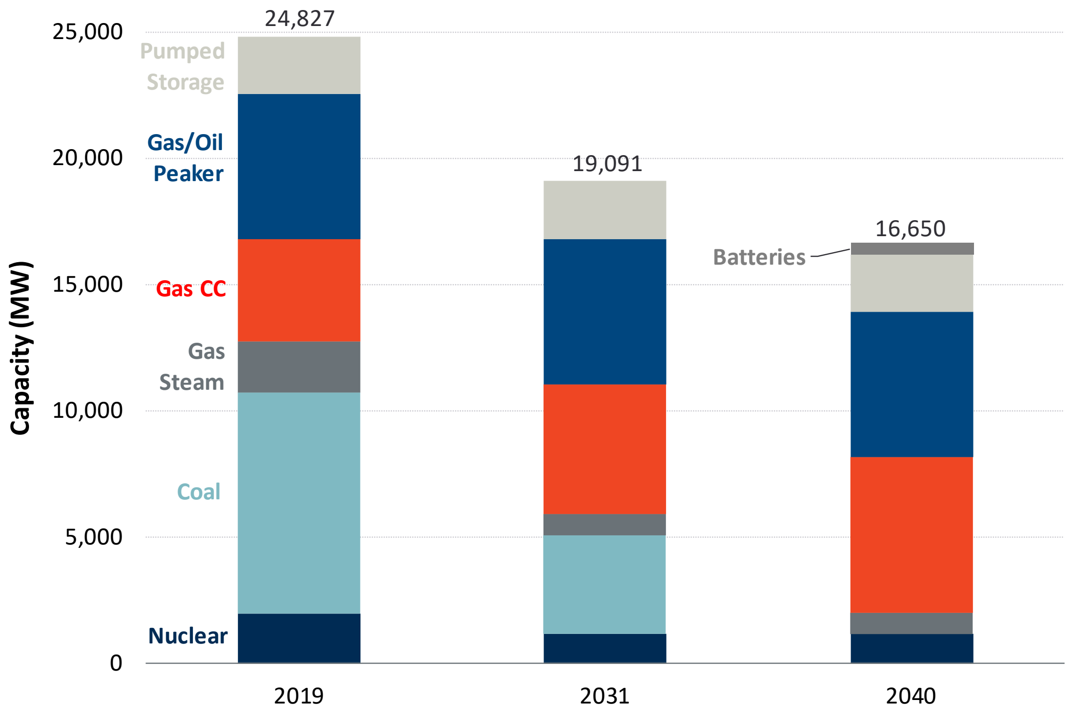
Our resource adequacy and operational analyses are for the years 2031 and 2040—two milestone years that represent shifts in the generation fleet in Zone 7. Between now and 2040, Zone 7 is expected to witness the retirement of a significant portion of the existing generation fleet and the continued addition of utility-scale renewable resources. Measured as the share of load served by renewable generation, for this study, we have assumed that Zone 7 will achieve roughly 25% by 2031 and 30% by 2040.[5]

1. Future Resource Additions and Generation Retirements Assumptions

Over the coming two decades, Zone 7's resource mix is expected to shift towards more renewable generation, with non-renewable generation capacity decreasing from 24,827 MW in 2019, to 19,091 MW in 2031 and 16,650 MW in 2040, per DTE integrated resource plan (IRP) data and the Consumers Energy's Proposed Course of Action (CE PCA). As depicted in Figure 1 below, this decrease will be driven by anticipated retirements in nuclear and coal generation. Coal generation—which has served as dispatchable generation when responding to operational needs—will decline from 8,752 MW in 2019 to 3,922 MW in 2031, and drop to 0 MW by 2040.

[5] Note that, for the two major utilities—Consumers Energy and DTE—the share of load served from renewables will grow to 25.4% by 2031 and 31.5% by 2040. Shares reflect wind, solar, and biomass generation as a share of load, adjusted for T&D losses.

Figure 1: Assumed Non-Renewable Generation Capacity
Installed Capacity in MISO Zone 7 (MW)[6]



Replacements for retired generation are expected to come from a mix of resources, primarily from solar generation, wind generation, energy efficiency, demand response, market purchases, gas-fired generation, and battery storage.

As shown in Figure 2, it is expected that Zone 7 will experience a significant buildout in renewable generation, consistent with many other regions nationwide. By 2040, the anticipated installed capacity of renewable generation in Zone 7 will reach an aggregate of 13,967 MW, consisting of 4,234 MW in wind and 9,734 MW in solar. We have assumed that new natural gas-fired combined-cycle (CC) generation capacity will amount to 1,116 MW between 2019 and 2031, and an additional 1,287 MW between 2031 and 2040.

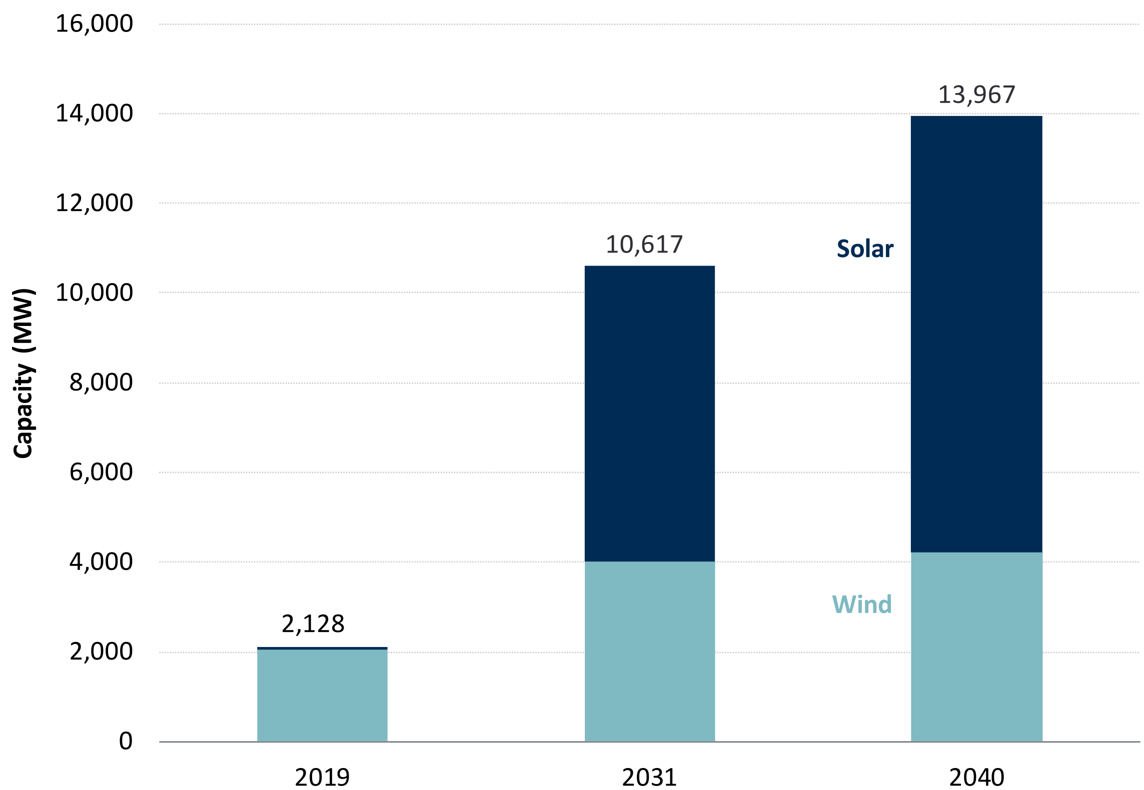
Further, we have assumed that new DR resources would help to meet capacity obligations, with an assumption that DR capacity will increase from the existing 960 MW in 2018, to 1,882 MW in 2031 and 2,387 in 2040. Further, Consumers Energy has reported in its recently filed PCA that it plans to install 450 MW of battery storage by 2040, which we have included in our assumed resource mix.

6 Note that this figure does not include potential capacity from demand response resources that is being added to meet utilities' capacity obligations. We understand from discussions with DTE e that the retirements and additions shown here are consistent with DTE's IRP Pathways A & C

In our analyses for 2031 and 2040, we reflect all these expected resource mix changes in Zone 7. We provide additional details of our modeling input assumptions in the Appendix.

Figure 2: Assumed Renewable Generation Capacity

Installed Capacity in MISO Zone 7 (MW)[7]



2. Net Load Shape

The anticipated changes in Zone 7's resource mix will alter the shape of Zone 7's daily demand or "net load" profile. "Net load" is the amount of load after considering that renewable generation has been used to serve a portion of the load given the expected generation profiles.

Solar production tends to be highest around midday and early afternoon, whereas load is typically highest in the early evening. Wind production varies throughout the day and does not align with load. As a result, adding solar generation resources reduces net load during late morning through the early afternoon and **shifts "net peak load" to the evening hours**, as shown below in Figure 3.

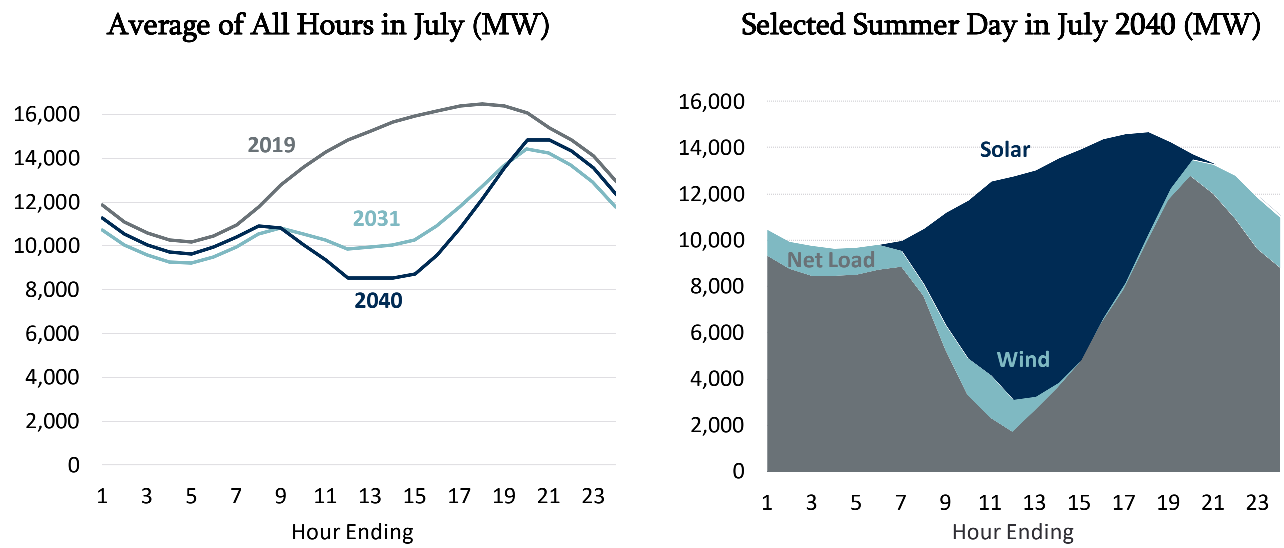
Moreover, the inherent intermittency in solar and wind generation will **increase variability in the daily net load profile**, requiring greater flexibility from dispatchable generation and demand-side resources to maintain system reliability. Our analyses reflect these considerations as we assess the

---

7 We understand from discussions with DTE that the retirements and additions shown here are consistent with DTE's IRP Pathway A

impacts the shifting resource mix will have on Zone 7's future reliability and operational performance. We describe these impacts in greater detail in subsequent sections.

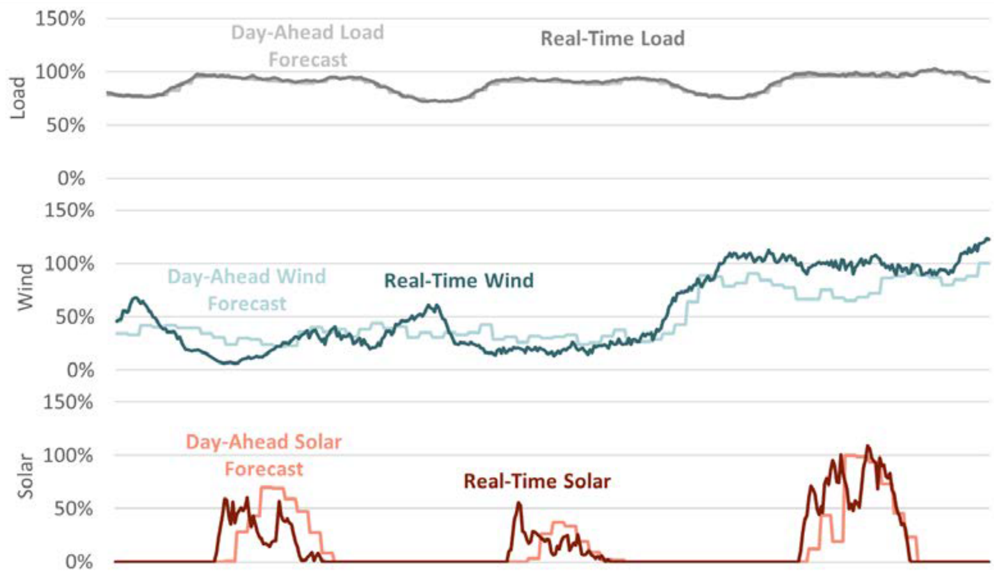
Figure 3: Illustration of Zone 7 Net Load in Summer



3. Renewable Generation Forecast Errors and Net Load Uncertainty / Variability

In addition to the shifts in net peak load, increasing shares of wind and solar generation in Zone 7's fleet will increase net load variability and uncertainty. This is because with increasing renewable energy resources, the forecast errors associated with renewable energy will add to the errors associated with forecasting the net load. To capture the impacts of net load forecast errors, we simulated the uncertainty of wind and solar generation between the day-ahead (DA) and real-time (RT) timeframes. Figure 4 below illustrates the relative magnitudes of the uncertainty levels for load, wind, and solar generation between the day-ahead scheduling, and real-time dispatch timeframes. We discuss the details of our modeling approach and the implications of these changes to Michigan's resource adequacy and system operations in the following sections.

Figure 4: Illustration of Zone 7 Load and Renewables Forecast Error
Percentage of Forecast Quantity



II. Resource Adequacy Implications

Increasing deployment of renewables will increase the variability and uncertainty of the net load pattern. Changes in net load pattern can affect system reliability if continuous balancing of supply and demand cannot be achieved. To assess the potential impact of these changes on system reliability in Michigan's Lower Peninsula, we conducted a **stochastic analysis to assess the resource adequacy of Zone 7**.[8]

Traditionally, resource adequacy has been measured as the supply resources' ability to meet peak load. With the increase in renewable generation, we define resource adequacy in this study to refer to the **ability of generation resources to meet load in every hour**, considering the uncertainties in the availability of resources in each hour, the uncertainty in the energy outputs from intermittent renewable generation resources, and considering the load forecast errors.[9]

Our analysis explores resource adequacy in Zone 7 for two future milestone years, 2031 and 2040. For each of the two years, we conducted our analysis across varying levels of future capacity import limits to Zone 7. These sensitivities were developed to assess the risk of a potential decline in the

---

8 For reference, we also analyzed Zone 7's 2019 resource adequacy.

9 The concept of resource adequacy described in this analysis, as well as the related concept of capacity import limits, refers to the ability of the electric system to deliver electric power when it is needed throughout the day (or over time) and does not refer to the current MISO Resource Adequacy construct, which generally considers only the annual peak load period.

ability to import capacity to serve load in Michigan.[10] We describe the sensitivities analyzed in subsequent sections.

A. Drivers of Resource Adequacy in Michigan's Lower Peninsula

The system's ability to maintain resource adequacy depends on a number of factors. For the Lower Peninsula, these factors include the following:

1. Changes to the Resource Mix

Michigan's Lower Peninsula is expected to experience large-scale retirements of coal generation, with replacement capacity coming largely from additions of utility-scale renewable generation between now, 2031, and 2040. From a resource adequacy perspective, intermittent renewable generation generally provides a limited contribution toward resource adequacy. In contrast, dispatchable generation tends to provide a greater contribution toward resource adequacy per MW of installed capability, compared to intermittent renewable generation. Thus, it will be important to consider and ensure that the overall resource mix will be able to sufficiently support the reliability needs of the zone and region and that all sources of capacity, including those from imports, are well analyzed and considered when future resource development decisions are made.

2. Capacity Import Capability

Currently, a portion of Zone 7's resource adequacy needs is met through capacity imports from neighboring zones. The availability of these imports is contingent on the "Capacity Import Limit" (CIL) into Zone 7. A decline in the CIL reduces the ability of a zone to use external resources to meet its resource adequacy needs. MISO defines CIL as the total power transfer capability from the MISO system to its Local Resource Zones (LRZ) under design contingencies, and under certain system conditions.[11] The zone's CIL for each LRZ, including for Zone 7, is evaluated by MISO by performing power transfer analysis studies.

For Planning Year 2019/20, MISO has determined that Zone 7's CIL is 3,211 MW.[12] The planned and expected generation retirements over the coming decades can affect both the voltage and thermal performance of the transmission system, thereby potentially limiting the future CIL levels

---

[10] Resource adequacy captures the sufficiency of supply to meet load in aggregate on an hourly basis. However, it does not capture many resource limitations of operational significance, such as minimum generating limits, or the impacts of intra-hour variability. We assess the implications of such limitations in the operational analysis.

[11] MISO's 2018 Business Practices Manual for Resource Adequacy. Accessed from here: https://www.misoenergy.org/legal/business-practice-manuals/.

[12] MISO's 2019-2020 CIL/CEL Values and Study Timeline, p. 4.

for Zone 7. If such potential limitations in Zone 7's CIL levels are not fully addressed, there will be a need for additional local resources to provide the necessary capacity to meet the resource adequacy needs of Zone 7. A need for additional local resources can also materialize if the rest of MISO were at risk due to the neighboring zones' own needs to balance their supply and demand adequately.

3. Availability of Ludington Pumped Hydroelectric Generation and the Future Evolution of Demand Response Programs

Michigan's large pumped hydroelectric generation resource, Ludington, is an important system resource for maintaining resource adequacy in Zone 7. Ludington pumped hydro is currently undergoing unit uprates on all its six units, which will increase Ludington's maximum generation capacity to 2,292 MW, and its pumping load demand to 2,442 MW by mid-2020.

At nearly 10% of Zone 7's total generation nameplate capacity, and being a responsive hydro storage facility, Ludington has and will continue to provide significant resource adequacy value to Zone 7. However, Ludington's operational pattern will need to change to respond to the changing patterns of Zone 7's net load as renewable generation increases in the future.

- This means that, as more renewable generation in Zone 7 shifts the zone's net load pattern to evening hours, Ludington likely will need to be able to generate during evening hours when the system's reliability risks will be high.
- In addition, Ludington will need to be able to generate and provide ramping needs during the early mornings as the morning load ramps up, but solar generation outputs remain low.
- Consequently, Ludington may not only have to pump to fill its reservoirs during the nights, as is the case today, but will also need to pump during the day to ensure that plant has sufficient stored energy available for responding to the demands of the evenings when the system's reliability risks will be high.

We anticipate that the evolution in Ludington's operational pattern will make Ludington's contribution to the zone's resource adequacy even more valuable in the future.

Demand Response (DR), enabled by various utility programs, will also be valuable in the future. We anticipate that the future DR resources are distinct from the DR resources utilized today, in that it is assumed to respond more frequently and flexibly. For example, in our simulations, we assume that future demand-side resources would respond during evening hours when the system's reliability risks are expected to be relatively high with increasing renewable generation deployment. However, specific DR programs have not yet been identified, and therefore the actual ability for customers to respond during these time periods will have to be analyzed more closely in the future.

Both Ludington pumped hydro and future DR programs will be important system resources for Zone 7's future resource adequacy needs. We assess Zone 7's resource adequacy needs with respect to these key drivers using a probabilistic simulation of the system. We describe our approach in the next section.

B. Analytical Approach for Resource Adequacy

We use a Monte Carlo based stochastic modeling approach to estimate the potential impact of future resource mix changes in Michigan on Zone 7's resource adequacy. We perform the Monte Carlo simulations for 2019, 2031, and 2040. For each of these years, we simulate hourly demand-supply balance across 10,000 replications of the year, considering the uncertainties in resource availability and load. Each replication ("draw") successively model all 8,760 hours in the given year.

1. Sources of Key Assumptions for Resource Adequacy Analysis of Zone 7

a. Load Forecast and Load Uncertainty

Our simulations rely on key inputs provided to us by DTE, based on information consistent with DTE Energy's Integrated Resource Planning.

For the load assumptions, we start with *net* peak load forecasts for Zone 7. This net peak load forecast reflects forecasted peak net of both energy efficiency and assumed DR. To enable modeling of DR separately as a resource for Resource Adequacy modeling purposes, we add the imputed capacities for incremental DR resources to this net peak load forecast, and derive load forecasts that only reflect the load reduction associated with energy efficiency programs. This results in a forecast peak load of 20,214 MW in 2031 and 21,188 MW for 2040. Each simulated Monte Carlo draw then models load forecast error in a plus/minus 2% band around the relevant forecast peak load, based on a normal distribution.

For each of the draws in our Monte Carlo analysis, the stochastic model randomly selects one of eleven (2007–2017) actual, historical load profiles. Load profiles for Zone 7 for 2007–2013 were compiled by ABB Inc. in Velocity Suite. For 2014 to 2017, we developed load profiles using load data reported by MISO on an aggregate level for Zones 2 and 7.

b. Wind and Solar Generation Profiles

In addition to simulating load uncertainties, our Monte Carlo simulations model renewable generation uncertainty. To model renewable generation uncertainty, we deploy the model to select one of sixty-six National Renewable Energy Laboratory (NREL) *wind profiles* and one of six

NREL Typical Meteorological Year (TMY) *solar profiles* applicable to Michigan's Lower Peninsula.[13]

These profiles are then applied to the wind and solar capacities for Zone 7 in the given modeling year.[14]

c. Generation Availability

We model generation for all of Zone 7 based on current generating units and assume additions/retirements reported in DTE's IRP and Consumers Energy's PCA. To reflect the forced outages for each generating unit, the model uses equivalent forced outage rate - demand (EFORd) by technology type.[15] For each modeled generating unit, we calculate the total expected outage length per year, and randomly allocate that outage length per unit in roughly one-week segments. Every random draw then assigns outage periods to randomly selected periods throughout the year so that the forced outage hours are not all concentrated in a single period of time.

We assume that planned outages for generator maintenance will be coordinated with MISO to ensure minimal impact on the zone's resource adequacy. Thus, we do not explicitly account or model generators' planned outages.

d. Loss of Load Expectation Calculations

Our analysis incorporates an hourly resource adequacy estimation. We estimate resource adequacy by calculating the average number of **Loss of Load Events** across a set of 10,000 model runs.

Loss of Load Events capture instances in which the anticipated future resource portfolios **are not sufficient** to meet projected loads, accounting for uncertainty in load, in generation output of renewable resources, and in availability of conventional generation units.[16]

---

13 The wind generation profiles consist of annual NREL profiles for eleven different sites within Zone 7 for each year between 2007 and 2012. For each draw, the model randomly selects a year between 2007 and 2012, and then randomly assigns one of the eleven wind profiles for that year to each of the wind generation resource assumed. The solar profiles similarly represent six different sites in Zone 7, but are constructed from actual, historical irradiance data to represent an NREL TMY.

14 We did not attempt to correlate the wind, solar, and load profiles for each hour of the year. Typically, to capture weather related correlations between load and wind and solar, the Monte Carlo simulation would be set-up to draw the same year shapes for wind, solar, and load. Our modeling did not attempt to do this as NREL wind shapes, historical load profiles, and the NREL solar TMY shapes were not available for a common set of historical years.

15 EFORd data for DTE generating units provided by DTE; for the rest of Zone 7 resources, EFORd data were as reported in the generator database provided by Newton Energy Group as part of the PSO modeling suite.

16 For each hour, our Monte Carlo model aggregates supply across all available generating units and tracks a loss of load hour if the supply resources are insufficient to meet load. In our modeling, a loss of load

Many systems are planned to a loss of load expectation (LOLE) standard of 0.1 days per year (often referred to as the "1-in-10" standard). If the LOLE is found to be greater than 0.1, then additional resources will be needed to ensure the system's resource adequacy performance is in line with requisite standards.

2. Capacity Import Assumption and Sensitivities Analyzed

To assess resource adequacy of Zone 7, we modeled Zone 7's CIL at various levels—from 0 MW to 3,785 MW of CIL, given the uncertainty around the actual transmission import capability in the future. We then evaluate LOLE events for Zone 7 with the various capacity import limits, assuming energy imports are fully available and not subject to any additional outages associated with imported resources.

In the following section, we summarize the scenarios analyzed and the associated findings from the LOLE analysis.

C. Key Findings from Resource Adequacy Analysis

1. Resource Adequacy Scenarios Analyzed

To analyze future resource adequacy of Zone 7, we worked with DTE Energy staff to develop three future Scenarios for Zone 7 for 2031 and 2040. The three scenarios all have the same level of assumed generation retirement capacities, but differ in their assumptions around the availability of DR resources across Zone 7, and the resource deployed by DTE Energy. Specifically, the three scenarios differ in the volume of "voluntary renewables" that can be marketed to customers and the potential addition of a 429 MW gas-fired combined-cycle generation facility in 2031.

Below in Figure 5, we summarize the three Scenarios simulated in the Resource Adequacy analysis, as described below:

- **Case 1** — This case closely aligns with DTE's PCA Pathway A.[17] It reflects a scenario in which DTE can successfully place and deploy 1,390 MW of voluntary renewables and in

event occurs whenever a loss of load hour either follows a non-loss of load hour or is the first hour of the year, such that consecutive loss of load hours constitute a single loss of load event. The reported cumulated results are then calculated as the probability weighted average of LOLEs across these 10,000 simulations of each modeled year of 2019, 2031, and 2040.

17 Case 1 does not include 50 MW of Conservation Voltage Reduction/Volt-Var Optimization (CVR/VVO) included in Pathway A

which the entire amount of DR resources projected for 2031 and 2040 is able to respond flexibly at any time.

- **Case 2** — This case closely aligns with DTE's PCA Pathway C.[18] It stresses one of the key assumptions underlying Case 1, namely customers' willingness to sign up for voluntary renewables. For this purpose, we assume that DTE can place only 500 MW of voluntary renewables (instead of the 1,390 MW in Case 1). This case also reflects a scenario in which we assume that the ability of Zone 7's utilities to employ future DR resources is more constrained than in Case 1. Specifically, DR deployments across the zone are assumed to be a mix of DR resources that can respond flexibly without limitations (for incremental future DR programs) and 960 MW that can be utilized only during the current peak hours (of gross load).[19]
- **Case 3** — This case closely aligns with Pathway D.[20] In general, it reflects assumptions similar to Case 2; however, it further reduces the amount of voluntary renewables by 200 MW of solar and adds a new 429 MW combined-cycle gas generation plant.

Figure 5: Assumptions by Modeled Scenario

		Case 1	*Case 2*	*Case 3*
Assumptions Pertaining to DTE's Generation Fleet and IRP Plans				
EWR Level	[1]	1.75%	1.75%	1.75%
2031 CCGT	[2]	0 MW	0 MW	429 MW
Voluntary Wind	[3]	615 MW	300 MW	300 MW
Voluntary Solar	[4]	775 MW	200 MW	0 MW
Assumptions Pertaining to All of Zone 7				
DR Deployed in Peak Hours	[7]	0 MW	960 MW	960 MW
DR Deployed as Needed	[8]	1,882 MW (2031) 2,387 MW (2040)	922 MW (2031) 1,427 MW (2040)	922 MW (2031) 1,427 MW (2040)
Total Wind	[9]	4,034 MW (2031) 4,234 MW (2040)	3,719 MW (2031) 3,919 MW (2040)	3,719 MW (2031) 3,919 MW (2040)
Total Solar	[10]	6,584 MW (2031) 9,734 MW (2040)	6,009 MW (2031) 9,159 MW (2040)	5,809 MW (2031) 8,959 MW (2040)

Notes: [1] The 1.75% EWR level reflects DTE's proposed 0.25% incremental increase over the forecasts. [5] For Case 2 and Case 3, the 960 MW of existing DR is deployed in all hours where gross load (as opposed to load net of renewables) exceeds 95% of the annual peak load. [6] Incremental DR is deployed in all hours that it is needed, *i.e.*, whenever load exceeds supply (generation plus modeled import capacity).

---

18 Case 2 includes 35 MW more voluntary renewables than Pathway C. Case 2 also does not include 50 MW of CVR/VVO and 100 additional MW of DR included in Pathway C. In addition, Case 2 assumes 1.75% EWR whereas Pathway C assume 2% EWR after 2026.

19 960 MW of existing DR of the total 2,387 MW of DR is modeled to be able to respond only in hours in which load exceeds 95% of annual peak load. Annual peak load represents the modeled gross peak load forecast.

20 Note that Case 3 does not include another 165 MW of voluntary renewables included in Pathway D.

2. Key Results and Findings

We summarize the LOLE results of our Monte Carlo simulations for each of the three scenarios analyzed in Figure 6 below. We evaluate the resource adequacy performance of Zone 7 using sensitivity analyses across multiple future CIL levels for Zone 7. Results in Figure 6 show the estimated LOLE at various CIL levels for Zone 7 for 2031 and 2040. The resource adequacy level that is acceptable for MISO (both footprint-wide and on the Local Resource Zone level) is 0.1 or fewer days per year of experiencing loss of load.[21]

Results of our analyses summarized in Figure 6 show LOLE values that violate MISO's acceptable resource adequacy standards in a pink shade. Acceptable LOLE values, *i.e.*, those that are below 0.05 are illustrated in green shade. We illustrate potentially borderline LOLE values, *i.e.*, those that fall at or within 0.05 and 0.10, with yellow shading in Figure 6.

Figure 6: Loss of Load Events (LOLE) by Year and Modeled Scenario

Available Imports (MW)	*Case 1*			*Case 2*			*Case 3*		
	2019	2031	2040	2019	2031	2040	2019	2031	2040
0	0.87	0.81	6.95	0.87	2.85	16.12	0.87	1.81	11.76
650	0.32	0.31	3.71	0.32	1.21	9.44	0.32	0.72	6.64
1,321	0.10	0.10	1.68	0.10	0.43	5.07	0.10	0.25	3.35
1,950	0.03	0.03	0.69	0.03	0.15	2.53	0.03	0.08	1.50
2,600	0.01	0.01	0.22	0.01	0.04	1.04	0.01	0.02	0.55
3,211	0.00	0.00	0.07	0.00	0.01	0.39	0.00	0.01	0.20
3,785	0.00	0.00	0.02	0.00	0.00	0.14	0.00	0.00	0.07

a. Case 1

Our simulation results for Case 1 show that having additional renewable generation and flexible DR result in improved reliability performance over the other two scenarios. For 2031, if the risks of significant reduction in Zone 7's current level of CIL of 3,211 MW can be mitigated, and if no new risks relating to the availability of importable capacity from rest of MISO manifest themselves, Zone 7's resource adequacy performance would adequately meet MISO's LOLE requirements.

However, as noted previously, proposed generation retirements could impact Zone 7's current CIL of 3,211 MW, potentially reducing it in the future. If such an outcome were to manifest by 2031,

[21] The North American Electric Reliability Corporation (NERC) guidelines set a planning target for the expected number of annual loss of load expectation (LOLE) of 0.1 days per year. MISO similarly defines its LOLE requirement as "such that the loss of Load is no greater than 0.1 days in one (1) year" in its Open Access Transmission Tariff, Definitions – L, available at https://cdn.misoenergy.org/Tariff%20-%20As%20Filed%20Version72596.pdf. Depending on scenario and modeling methodology, this target may be equivalent to 0.1 events per year, which may be a more relevant metric for a system with high renewables penetration. In our analysis, we report LOLE in terms of number of events per year.

our simulations show that despite Case 1's higher levels of renewable generation and assumed deployment of nearly 2,000 MW of flexible DR, Zone 7's resource adequacy performance will decrease. As shown in the left-most panel of Figure 6, if the CIL decreases below 1,321 MW, the LOLE would increase to a level that is not acceptable.

For 2040, our simulations indicate that Zone 7's resource adequacy will likely be at risk, especially if the anticipated decline in CIL due to generation retirements is not addressed or improved. By 2040, even at the current CIL level of 3,211 MW, Zone 7's LOLE will reach 0.07, which may be only borderline acceptable. At a CIL level of 1,321 MW, Zone 7's LOLE will reach 1.68, which represents a 17-fold increase in Zone 7's simulated 2019 LOLE level of 0.10, indicating a significant worsening of Zone 7's resource adequacy performance and violating MISO standards for Local Clearing Zones.

b. Cases 2 & 3

Results of our simulations for Cases 2 & 3 indicate that the assumed future supply shifts under these scenarios will have a more significant and more adverse impact on Zone 7's resource adequacy. This is due primarily to the assumption that there will be less flexible DR in these scenarios.

For Case 2, our simulations indicate that Zone 7's resource adequacy will be at risk by 2031 if the anticipated Zone 7 CIL level declines to 1,321 MW. Our simulations indicate that even at an assumed 1,950 MW of CIL, Zone 7's resource adequacy performance would be at risk as the resulting LOLE increases to 0.15, thereby violating the 0.1 or lower LOLE threshold requirement.

For 2040, Zone 7's LOLEs across the assumed CIL levels would violate the 0.1 or lower LOLE threshold requirements. Under the range of CIL levels analyzed (between zero to 3,211 MW), Zone 7's LOLEs range from 16.12 to 0.39, each of which is significantly higher than the 0.1 threshold requirement for maintaining requisite resource adequacy. At the 3,785 MW CIL assumption, which reflects an increase of approximately 575 MW to current Zone 7 CIL, the estimated LOLE is 0.14, indicating a resource adequacy need would still persist in Zone 7.

Results for Case 3 are similar in trend as those observed for the Case 2 scenario in that they generally do not reach LOLE levels below the 0.1 threshold requirement. However, they do show a marked improvement in resource adequacy performance relative to Case 2, which is attributable to the assumed additional gas-fired generation in the Case 3 scenario. For example, at the CIL level of 1,950 MW, LOLE levels decrease from 0.15 in 2031 and 2.53 in 2040 to 0.08 in 2031 and 1.50 in 2040.

Without the additional gas generation, the risks could increase, especially if other risks described below manifest themselves and/or if some of the renewable capacity additions tied to voluntary demand contemplated in DTE's PCA are not realized.

3. Risks and Other Considerations

All the simulated outcomes for the scenarios analyzed depend greatly on assumed ability for Zone 7 to leverage Ludington and flexible DR. Thus, these two types of resources, while very valuable, will present risks for how well Zone 7 can meet its reliability standards for LOLE. We describe some of these key risk factors below.

a. *Risk Factor 1: Demand on Ludington for Increased Resource Adequacy Contribution*

In our simulations, we model the Ludington pumped hydro facility by applying generating and pumping profiles that have been optimized to align generation with shifted net load.[22] This means we have assumed full availability of Ludington's capabilities during morning and evening ramps to support resource adequacy needs in the future. Because Zone 7 relies on Ludington for these needs, **if Ludington faces operational or economic constraints that do not allow it to operate as flexibly as we have assumed, other resources will be needed to support the system**.

Any significant inability to evolve Ludington's operational patterns to be dispatched fully and flexibly in the future, including having generation and pumping schedules to ensure the facility is available to meet Zone 7's resource adequacy needs of early morning and evening net load ramps, can put upward pressure on resource adequacy risk, resulting in worsening resource adequacy performance than those observed in our simulations.

b. *Risk Factor 2: Evolution of Demand Response to Respond Flexibly and Often*

The results of our resource adequacy simulations highlight the potentially growing role of DR. Much like Ludington, we have assumed that DR resources would contribute significantly to meeting resource adequacy needs in the future.[23] However, we recognize that to deliver the needed flexibility, DR program design will need to evolve significantly.

- In our simulations, especially for 2040, we find that DR resources are **called upon much more frequently** to support resource adequacy than they are today.[24]

---

22 The modeling further reflects Ludington's resource flexibility by restricting pumping as needed to avoid a loss of load hour.

23 We assume 1,882 MW of DR resources are available in Zone 7 by 2031, rising to 2,387 MW by 2040. Such programs were developed for current market conditions, and—while available as capacity resources to reduce load—do not necessarily maintain the flexible attributes required to meet the marginal system needs identified through this analysis.

24 Assuming the capacity import limit of 1,321 MW, available demand response would be called an average of 4 hours in 2031 and 53 hours in 2040. Assuming the current capacity import limit of 3,211 MW, available demand response would not be needed in 2031 but would be called an average of 8 hours in

- Furthermore, DR resources will be **called upon during different times** than today (primarily the late evening hours) to support shifting resource adequacy needs.

While we anticipate that future technologies will help enable DR resources to provide responses with more ease, the risks associated with the type of programs, the associated technologies needed, and their costs will need to be evaluated carefully to ensure that DR is capable of supporting resource adequacy in the expected manner.[25]

c. Risk Factor 3: Availability of Capacity Imports

Further, as described previously, the anticipated generation retirements in Michigan through 2032 **could potentially decrease the CIL** from the current 3,211 MW[26] level to 1,321 MW in the future, according to recent METC testimony.[27] Similarly, additional coal retirements anticipated for the early 2030s and 2040 could further decrease Michigan's import capabilities. While we understand that the import limit into Zone 7 could be restored or increased (although we have not conducted such analysis), any future decline of import capabilities into Zone 7 from the rest of MISO has the potential to significantly increase the risk of resource adequacy concerns in the zone.

Our simulations also assume that resources in neighboring zones are available to be imported into Zone 7 whenever they are needed for resource adequacy purposes (*i.e.*, that the capacity import limit can be fully utilized). However, there is a risk that those resources would be needed for responding to their own local resource adequacy needs whenever Zone 7 is in a similar situation. Overall, if the availability of importable capacity from the rest of MISO is at risk during key periods of reliability needs—due to the neighboring zones' own needs to balance their supply and demand adequately—Zone 7's resource adequacy performance would be affected adversely.

Further, there is some capacity contribution from voluntary renewables assumed in the cases analyzed, and those capacity contributions will not be realized if the voluntary demand contemplated in DTE's PCA are not realized.

2040. For context, prior to the recent Polar Vortex-driven event, demand response had not been utilized in Zone 7 since the introduction of the MISO Resource Adequacy construct (2013).

25 We have not assessed the ability or the economics of future demand response programs, nor the risks and impacts to program enrollment in the future to achieve the DR levels assumed in our analyses. Our 2031 and 2040 analyses however reflect that total DR, as a percent of the future peak load, will constitute approximately 10% and 13% respectively, compared to approximately 5% for 2019. This represents a significant increase from current levels in Zone 7.

26 Zone 7's 2018/19 Import Capability ("Capacity Import Limit") was 3,785 MW.

27 METC proposed to install static VAR compensators to address reliability needs created by retirements and restore the CIL. DTE is investigating non-transmission alternative solutions to the underlying transmission system issue.

d. Other Considerations

Our study did not simulate or analyze the potential risks associated with extreme weather conditions. Extreme weather conditions could have significantly dramatic effect on renewable energy resources. For example, during the January 2019 Polar Vortex period, a significant amount of wind generation in MISO could not operate due to the adverse effects of the freezing conditions on wind generation equipment.[28] Similarly, events during which weather limits renewable generation output for an extended period of time—for e.g., due to extended solar cloud cover conditions or lower than normal wind conditions—could also create adverse resource adequacy outcomes. While these are likely infrequent, they do need to be considered, particularly as the supply mix shifts towards greater renewable generation composition. Thus, continued monitoring and learning from experiences will be very valuable for future resource planning.

III. Operational Analysis

In addition to assessing the potential system reliability impacts arising from changes in the Lower Peninsula's future resource mix, we analyzed how these changes would affect the operational needs of the system. We simulated the entire MISO market, with specific focus on Zone 7. Similar to the resource adequacy analysis, our operational analysis was performed for 2031 and 2040.

From a bulk power system's operational perspective, maintaining reliability requires supply and demand to be balanced ***around-the-clock***, taking into account the operational limits of resources. Generally, maintaining reliable service hour-to-hour and minute-to-minute means that resources that are generating—and those that can be started quickly—have the capability to respond to fluctuations in the net load, while the system simultaneously maintains a sufficient amount of reserves to meet unforeseen outages and larger-than-expected net load changes.

From an operational performance perspective, large-scale deployment of intermittent renewable generation can present certain integration challenges. For example, if the system lacks sufficient operational support to manage the variability of renewable generation outputs, and thus that of the net load, integration challenges would manifest. These challenges could include increasing intervals of negative pricing for energy, curtailment of renewable generation, more frequent ramping of conventional generation—which can increase wear and tear on facilities and the risk of forced outages—and increasing reliance on external support via imports to provide energy and/or ramping capability.

Thus, in addition to resource adequacy challenges, the changing supply resource mix in Zone 7 could further impose operational challenges. To assess the operational performance of Zone 7

---

28 MISO, "MISO January 30-31 Maximum Generation Event Overview," February 27, 2019, p. 4-5, 15, accessed at:
https://cdn.misoenergy.org/20190227%20RSC%20Item%2004%20Jan%2030%2031%20Max%20Gen%20Event322139.pdf

resources in the future—*i.e.*, in 2031 and 2040 when Zone 7 is expected to have significant renewable generation—we performed detailed simulations of the day-ahead and real-time operations in MISO. For this analysis, we used the Power Systems Optimizer (PSO)—a Security Constrained Unit Commitment and Economic Dispatch model. We describe our analysis approach in the following section.

A. Analysis Approach and Key Assumptions

We simulate hourly day-ahead scheduling and 10-minute real-time operations of the system, capturing the uncertainty in load, wind, and solar generation that materializes between the day-ahead and real-time decision making timeframes. As illustrated in Figure 4 above, our simulations incorporate wind and solar output's variability that can manifest within short periods of time, and between day-ahead and real-time, even as their annual generation profiles may generally remain consistent.

1. Analysis Approach

a. Simulating MISO's Energy and Ancillary Services Markets

We simulate the MISO system by co-optimizing the energy market and six types of ancillary services products (regulation up/down,[29] spinning reserve, supplemental reserve, and ramping capability up/down). This is generally consistent with the way MISO operates its system.

b. Simulating Generation Characteristics

Like standard production cost simulations, we include the operating constraints and characteristics of generation resources when simulating efficient unit commitment, dispatch, and ancillary service reservations of the MISO system in 2031 and 2040.

The generation resource constraints and characteristics we model in our operational simulations include minimum generation, minimum up and down times, heat rates, ramp rates, start-up costs, planned outages, and variable operating and maintenance costs. Our modeling further includes representation of additional constraints between day-ahead and real-time cycles,[30] such as dispatch commitments, forced outages, failed starts[31], pumped storage, and battery operations. The detailed

---

29 MISO has a single regulation ancillary service product and does not distinguish between regulation up and regulation down.

30 The day-ahead cycle is modeled as hourly, and the real-time cycle is modeled at 10-minute intervals. MISO operates an hourly day-ahead and a 5-minute real-time market.

31 In our modeling, failed starts and forced outages are differentiated based on the length of time that the plant must remain out of service. Forced outages means a generator cannot be committed again until

and specific nature of modeling inputs—along with our day-ahead and real-time market uncertainty modeling—allow for realistic operational results and provide for a more detailed assessment of potential operational challenges in Zone 7.

c. Simplifying Representation of MISO

For this study, we model inter-zonal transfer limitations between MISO zones, between MISO North and South, and flows between MISO and its neighboring markets using fixed schedules. We do not simulate intra-zonal transmission system constraints within Zone 7 or other MISO zones. We have not placed certain operational constraints onto the generators, such as unit-specific environmental and emissions limits. Thus, overall, we have not focused on any location-based operational constraints that could arise from transmission and emissions limitations within each of the MISO zones.

2. Summary of Key Assumptions

For the operational analysis, we analyzed the Case 1 only. The key modeling assumptions of Case 1 are previously described in Figure 5. These unit characteristics for MISO and Zone 7 units modeled for 2031 and 2040 are summarized in the Appendix.

We assess the operational performance of MISO and Zone 7's resources by analyzing key operational and economic metrics based on the market simulations for 2031 and 2040. These key metrics include:

- Market prices for energy and ancillary services;
- Imports into and exports out of Zone 7;
- Renewable generation curtailments; and
- Cumulative "mileage"[32] and number of generation start-ups for dispatchable generation units.

Changes in these metrics are instructive as to how system operations in Zone 7 may be affected under the simulated future conditions. We discuss the results in the key findings section below.

B. Key Findings from the Operational Analysis

Results from our detailed market simulations show that operational challenges in Zone 7 begin to emerge by 2031, and increase significantly by 2040 with additional retirements of dispatchable generation and higher renewable deployment. Overall, the key issues are:

---

after its minimum outage time. In contrast, after a failed start, the generator can attempt to start in the next DA cycle, which for the purposes of this simulation is one hour.

32 Cumulative mileage is measured as the total absolute change in unit output from hour to hour.

1. Lack of ability to harness all of the available renewable generation (the need to curtail renewable generation at certain times);
2. Scarcity in Ramping capability during certain periods of time;
3. Increase in frequency of ramping conventional generation up and down ;
4. Increase in the value of flexible generation, exemplified by the changes in Ludington's operations and its capacity constraints; and
5. Risks associated with the continued reliance on imports from neighboring zones to respond to Zone 7's needs.

We provide detailed discussions on each of these key issues below.

1. Harnessing Available Renewables

From our operational simulations of the MISO market for 2031 and 2040, we find that MISO Zone 7 would be able to integrate and harness available renewable resources in 2031. However, **by 2040, the system's ability to integrate available renewable resources and harness their full benefits could be degraded significantly**.

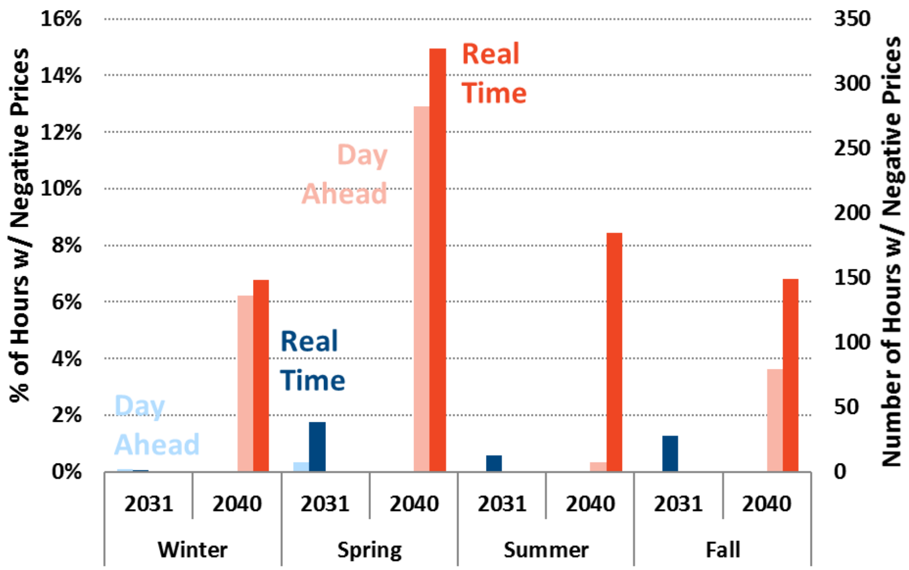
This is evidenced by **increases in negatively priced hours**—reaching almost 10% for the year in real-time by 2040, and by **increasing renewable generation curtailments**, which rise to approximately 1% of total renewable generation output capability for 2040.

- Renewable generation profiles do not necessarily line up with energy demand. Therefore, when significant renewable generation is added, the marginal market price for energy could be increasingly set by renewables. We observe that the 2040 marginal prices are negative for a significant portion of the year (almost 10% of real-time intervals).
- As prices become significantly more negative, it becomes more economic to curtail renewable generation output than to turn down other generation resources. At this point, the system has **excess generation and cannot harness its full benefits**. While we do not observe significant levels of curtailment in our simulation, we do see them starting to materialize in 2040.

Figure 7 below shows the percent of negatively priced hours, categorized by season, for 2031 and 2040. This chart shows several additional patterns:

- Negatively priced hours (and curtailments) **are more frequent during the spring**: Load is usually higher in the winter and summer. Therefore, fewer negatively priced hours are observed in those seasons. In the spring, however, when wind generation tends to be high and solar output high, the load profile and the renewable generation output profiles are less aligned. This leads to an increase in negatively priced hours compared to summer.

Figure 7: Michigan Zone 7 Frequency of Negatively Priced Hours[33]
Day-ahead and Real-time (% of Seasonal Hours)



- Furthermore, negative pricing is significantly **more frequent in real-time than day ahead-markets**. This implies that as renewable generation levels increase, the system is unable to turn down dispatchable resources to manage all the variability and uncertainty of renewable generation between the day-ahead forecast and real-time output.
- Lastly, as discussed above, negatively priced hours **start occurring by 2031 and increase significantly by 2040**: As shown in Figure 7 , Zone 7 is generally able to integrate and harness the available renewable generation for 2031 even though spring and fall months begin to show small percentages of negatively priced time intervals. In 2040, however, these seasonal differences are exacerbated—with day-ahead negatively price intervals rising to 12.9%, and real time intervals reaching 14.9% of spring-time hours. More importantly, the annual negatively price intervals in 2040 increase to almost 10% of all real time intervals, from just 1.0% for 2031. This result is indicative of a 2040 system constrained in its ability to harness the full benefits of available renewable generation.

As discussed above, further increases in renewable generation in the system could increase both the frequency and volume of renewable generation curtailment—which decreases the value of those renewable resources.

Our simulations also show that the Rest of MISO would likely experience greater generation curtailment—of about 4.5%—compared to Zone 7. We illustrate this outcome in Figure 8 below. The key reason why Zone 7 appears to experience lower curtailment levels with high renewables is that it **benefits greatly from Ludington's ability to manage day-ahead to real-time market**

33 Shown as a percentage over each season's total hours.

variabilities in renewable outputs in Zone 7. Figure 9 below illustrates that Ludington provides Zone 7 with significantly more storage capabilities relative to peak load than the Rest of MISO.

Figure 8: 2040 Annual Day-Ahead (Scheduled) vs Real-Time (Actual) Renewable Curtailments

Percentage of Potential Renewable Generation

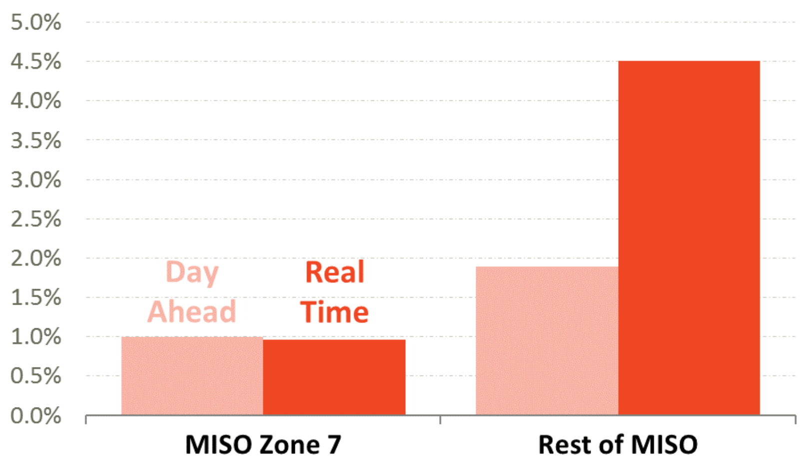


Figure 9 illustrates the significant difference in storage capacity compared to peak load in Zone 7 versus the rest of MISO.

Figure 9: Zone 7 and Rest of MISO Storage Capacity in 2040

	Storage Capacity (% of Peak Load)
Michigan Zone 7	15%
Rest of MISO	2%

In summary, increasing percentage of negatively priced hours in Zone 7 will become a concern by 2040, even as the zone's ability to maintain a high share of storage relative to renewables allows it to better manage both curtailments and negatively priced hours compared to rest of MISO.

a. *Impact of Forecast Errors and Intra-zonal Transmission on Curtailment and Negative Prices*

As discussed before, intra-zonal transmission impacts curtailment and negative pricing. Our simulations do not reflect impacts from intra-zonal transmission constraints—since those were not analyzed in the study. Consequently, it is possible that the intervals with negative pricing and curtailments would be higher than indicated by our analyses.

Similarly, increases in forecast error between the day-ahead time frame and real-time operations above and beyond those captured in our simulation would put upward pressure on generation curtailment levels.

2. Availability of Ramping Capability

As discussed previously, as renewable penetration increases, so does the resulting variability in net load. Therefore, the proportion of flexible generation—*i.e.*, dispatchable resources that can provide ramping capability to cover the net load variability—will be important for reliable system operations.

In our analysis, we assess ramping needs within Zone 7 and the ability of its resources to cover them for both hour-to-hour needs, and—in the longer time-frame—6-hour needs, which will be required to cover ramps from the mid-afternoon to evening net load peaks.

a. Hourly Ramping Needs

Hourly ramping capability is needed to ensure that the increase in the hourly shifts (both up and down) in net load can be met by the system reliably. Our operational simulations indicate that a growing need for ramping capabilities will manifest in 2031, and will increase further by 2040.

Figure 10 below illustrates the growing volumes of the average hourly ramping need and the maximum hourly ramping need for 2031 and 2040.[34]

- As shown in Figure 10 below, the average hourly ramping needs increase significantly—by nearly 70% between 2017 and 2031. By 2040, the increase in average hourly ramping needs is expected to exceed two-fold current levels.
- Further, our 2040 operational simulations show that system will experience more frequent large ramps, and consequently, demand greater utilization of the Zone 7's resources providing ramping services.
- Our simulations indicate that the maximum hourly ramping requirements in Zone 7 are expected to increase substantially, increasing approximately three-fold and two-fold from the current level to the expected 2040 need for upward and downward ramping capability, respectively.

34 Hourly ramping needs are calculated for every hour as the net load in the subsequent hour less net load in that given hour. Average/maximum upward ramping need represents the average/maximum upward ramping MW across all hours in which the ramping need is positive, and average/maximum downward ramping need represents the average/maximum downward ramping MW across all hours in which the ramping need is negative.

Figure 10: Average and Maximum Expected Hourly Ramping Needs (MW)

	2017	2031	2040
Average Ramping Needs			
Upward Ramp	380	641	827
Downward Ramp	332	574	716
Maximum Ramping Needs			
Upward Ramp	1,330	3,326	4,330
Downward Ramp	2,062	3,774	3,992

Notes: For 2017, ramping needs are computed using the 2017 MISO load profile reported on an aggregate level for Zones 2 and 7. We assume a two-thirds factor for Zone 7. For 2031 and 2040, ramping needs are based on results of the 2031 and 2040 operational simulations.

b. Six-Hour Ramping Needs

As we detailed in the resource adequacy discussion above, the system needs are assessed by analyzing the hourly availability of capacity, considering the uncertainty in resource availability, load, and renewable generation. In addition, the system requires access to resources that are available for dispatch, and can ramp up or down their outputs to meet resource adequacy needs in the *subsequent hours* as the net load experiences significant ramp up and down.

To investigate this second-degree resource adequacy need, we perform a high level assessment by analyzing the likely ramping capability needs over a 6-hour ramping horizon in Zone 7 for 2031 and 2040.[35]

- Results of our simulations show that the ramping needs over a six-hour period significantly increase in 2031 and especially 2040 compared to current levels. As shown in Figure 11, average upward and downward ramping needs are expected to increase by approximately 38% and 25% respectively between 2017 and 2031, and by another 35% and 24% between 2031 and 2040. Maximum upward and downward ramping needs are expected to increase by around 32% and 28% respectively between 2017 and 2031, and by another 28% and 14% between 2031 and 2040.

[35] We analyze ramping needs over a period of 6 hours because 6-hours is the time difference between the net load mid-day valley and the evening net peak. A 6-hour ramping need analysis assesses whether the system has sufficient ramp capability to respond to the evening net load ramp as the load picks up and as solar generation output falls.

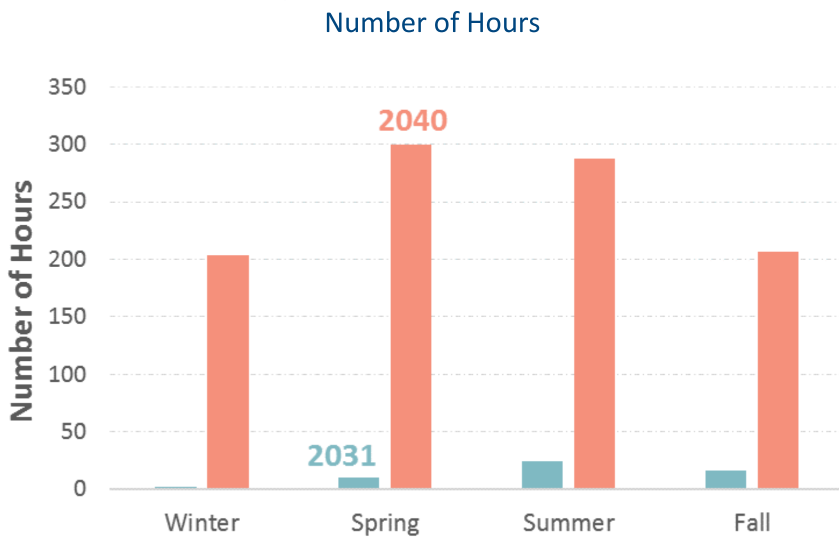
Figure 11: Average and Maximum Expected 6-Hour Ramping Needs (MW)

	2017	2031	2040
Average Ramping Needs			
Upward Ramp	1,755	2,415	3,269
Downward Ramp	1,716	2,149	2,662
Maximum Ramping Needs			
Upward Ramp	6,246	8,274	10,609
Downward Ramp	6,401	8,173	9,351

Notes: For 2017, ramping needs are computed using the 2017 MISO load profile reported on an aggregate level for Zones 2 and 7. We assume a two-thirds factor for Zone 7. For 2031 and 2040, ramping needs are based on results of the 2031 and 2040 operational simulations.

- The significant increase in 6-hour ramping needs could lead to situations in which Zone 7 does not have sufficient dispatchable resources to cover the necessary ramping needs. As shown in Figure 12 below, this is starting to occur in 2031 and our simulations show that, by 2040, almost 1,000 hours (11.3% of all hours in 2040) will experience insufficient ramping capability from local Zone 7 resources to cover net load ramping needs. This exposes Zone 7 to reliance on imports to cover ramps in net load.

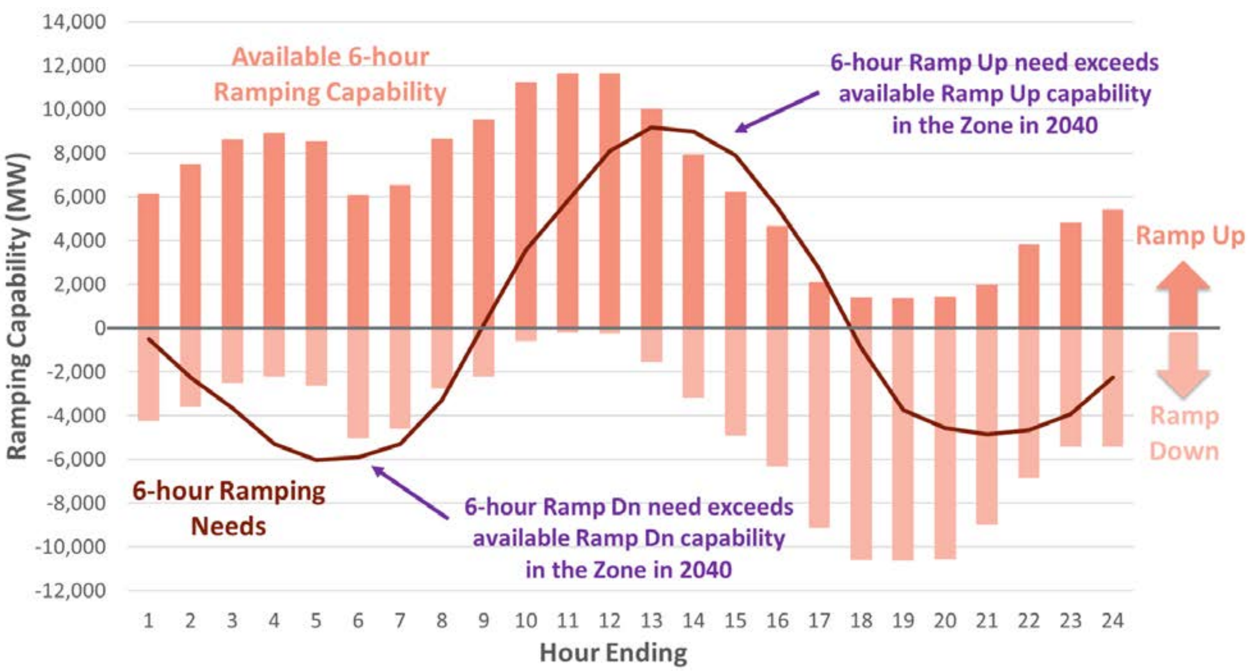
Figure 12: Number of Hours Needing Imported Resources for Ramping, by Season in 2031 vs. 2040



Our simulations of 2040 reveal that Zone 7's declining ramping capability could lead to shortages on very "tight" days. To further examine this, we analyze the ramping needs and ramping capability in Zone 7 for a selected day. September 20, 2040 represents a tight system day, and is illustrative of how the declining ramping capability in 2040 could lead to shortage conditions, if only relying on Zone 7 resources.

Below in Figure 13, we show the available 6-hour ramping capability within Zone 7 for said day. This example illustrates a situation where Zone 7 resources' ability to meet the 6-hour ramp down needs for hours 3 to 8, as well as the ramp up needs to cover the evening peak (*i.e.* 6-hour ramp up need shown for hour 14 onwards) becomes challenging, and the zone must rely on imports to meet these operational needs.

Figure 13: September 20, 2040 Hourly 6-hour Ramping Needs and Available 6-hour Ramping Capability
MW



Note: Ramping capability and needs represent the availability and requirement of online capacity 6-hours from that time. For example, the 6-hour ramping needs from hours-ending 14 to 16 represent the evening peak net load in hours ending 20 to 22.

c. Ancillary Service Prices

Resource flexibility and ramping capability become more valuable as renewable deployment increases.[36] Hence, another way to gauge the sufficiency of ramping capabilities is to evaluate the

[36] There is a multiplicative (adverse) effect of increasing renewable penetration on ramping capability. First, increased renewable generation increases the ramping needs to cover the variability of renewable generation and also the renewable forecast error effects on net load variability. Second, increasing renewable generation typically reduces the amount of dispatchable resources both available and on-line at times when the renewable generation is expected to generate but may not show up in real-time. The minimum generation requirements associated with gas-fired generation means that some generators are not scheduled to be on-line until it is too late for them to ramp up to provide the flexibility that the

prices of the corresponding ancillary services—specifically regulation services that are called upon for minute-to-minute fluctuations in demand.

- In our operational simulations, we observe a significant increase in the market prices for regulation service between 2031 and 2040.
- When there are high demands on regulation services, it signifies that the system is using higher costs resources to ramp up and down at the last minute.
- The high prices observed for regulation services shown in our simulations, therefore, further corroborates the observations made in the prior section, and highlight the fact that the system is beginning to deplete the resources that have the ability to ramp up when needed.

Figure 14: MISO Zone 7 Average Daily Real-time Regulation Price Patterns by Season[37]
$/MWh

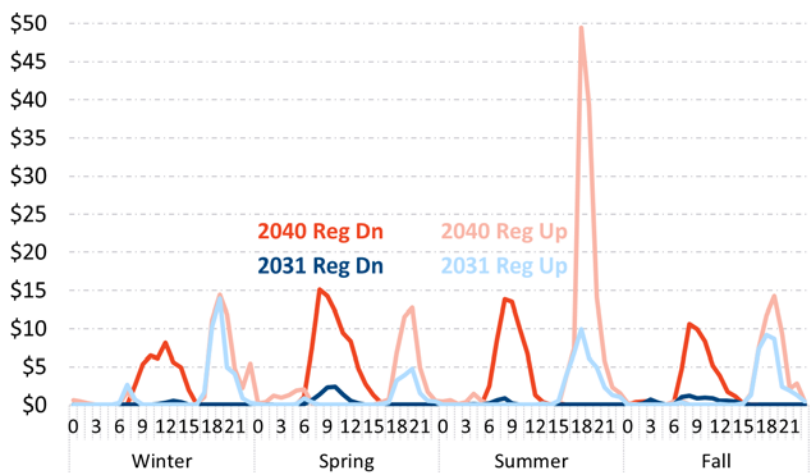


Figure 14 above shows the regulation prices between 2031 and 2040 based on our simulations of the MISO regulation ancillary services product. As shown, regulation up prices (light blue/red series) increase in all seasons, but spike considerably in summer, during the evening peaks. These increases are indicative of a scarcity of online ramping capability and occasional shortages.

The spike in regulation up price shown for the summer of 2040 is a reflection of scarcity, primarily driven by uncertainty in renewables and load, as well as generator forced outages in summer months. This indicates that the system is at a higher risk of experiencing a reliability event during these periods.

system might need when the anticipated renewable generation cannot generate. Additionally, generator forced outages compound the adverse reliability impact on the rest of the system, resulting in conditions of scarce on-line ramping capability.

37 MISO does not differentiate between RegUp and RegDn.

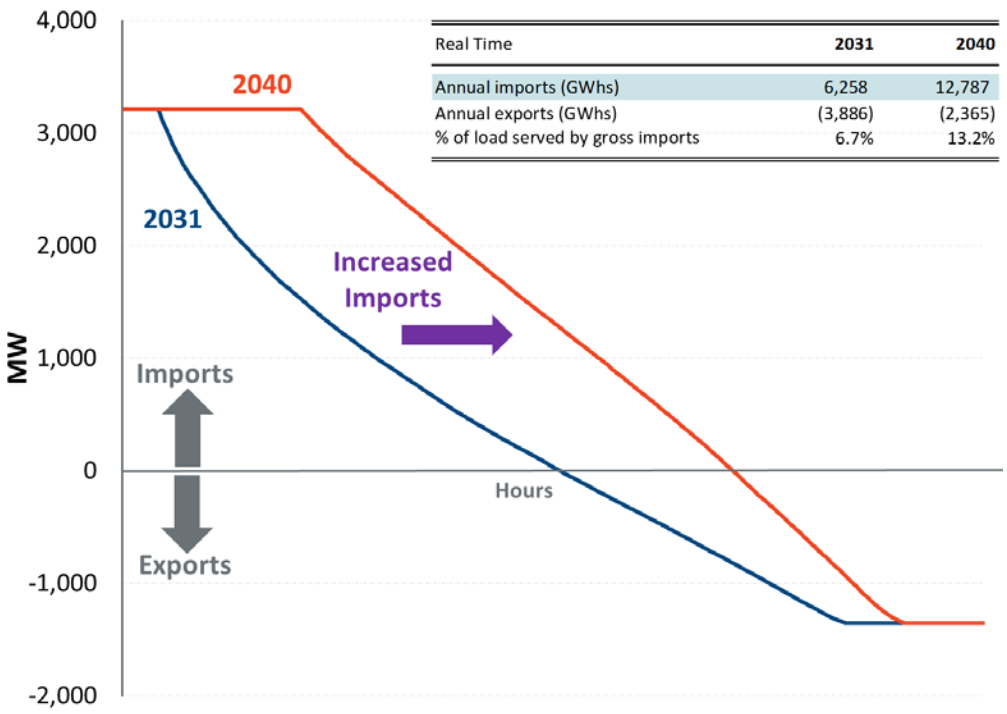
3. Reliance on Neighboring Zones

Our analysis assesses the changes in the amount of imports and exports into Zone 7 from the rest of MISO. This assessment includes an evaluation of the MW power flows between Zone 7 and the rest of MISO for the 2031 and 2040 simulated years.

In our simulations, we find that Zone 7 would rely on neighboring zones significantly (particularly for imports) to balance Zone 7's supply and demand on an hourly basis. Recall that for the operational analysis, we assumed that the import capabilities remain similar to the 2019/20 capabilities (3,211 MW). As explained previously, there is considerable risk surrounding this assumption as planned and expected future generation retirements are expected to adversely impact the current import capability.

Our simulations of 2031 and 2040 indicate that the increased variability in the net load and decrease in dispatchable generation between 2031 and 2040 in Zone 7 would be partially met by importing more frequently from the rest of MISO. As shown in Figure 15 below, Zone 7's reliance on imports from the rest of MISO would nearly double between 2031 and 2040, increasing from an estimated 6.7% to 13.2% of its annual load consumption in 2031 and 2040, respectively.

Figure 15: Michigan Zone 7 Import Duration Curves (MW)



Real Time	2031	2040
Annual imports (GWhs)	6,258	12,787
Annual exports (GWhs)	(3,886)	(2,365)
% of load served by gross imports	6.7%	13.2%

The ability for Zone 7 to rely on imports to meet its energy and ramping needs will depend greatly on the availability of import capability. As discussed previously, the risks associated with import capability include both the electric system's ability to physically deliver the power from neighboring zones into Zone 7 and the ability for resources outside of Zone 7 to be operationally available when needed. Import capability and needs, however, require further study as the resource mix and transmission system evolve to ensure Zone 7 maintains the capability to harness support from neighboring zones.[38]

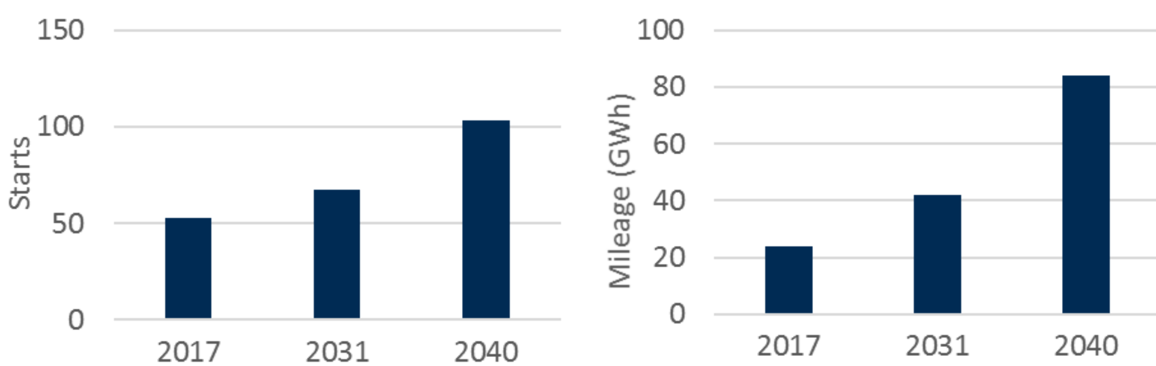
In contrast, if export capability becomes constrained due to transmission limitations, Zone 7 will likely witness greater renewable energy curtailment as a result of bottled up excess generation. This could occur if the export capability is degraded, or as renewable levels in Zone 7 push beyond those contemplated for 2040.

4. Changes in Unit Operations

To assess the potential impact of adding renewable generation in Zone 7 on the gas-fired generation fleet, we analyze the gas-fired resources' generation "mileage," and the frequency of startups as measures of changes in unit operations. It is important to analyze the changing operations of conventional generation to assess how the operations of the generation fleet are impacted by increasing renewable deployment in the zone.

Based on our simulations for 2031 and 2040, we observe increased mileage and a greater number of startups for gas-fired CTs, which indicate that dispatchable gas-fired CTs in Zone 7 would **increasingly be used to provide ramping services** to compensate for more variable net load. Specifically, the gas-fired CTs in Zone 7 start more often and operating with higher mileage (*i.e.*, cycling more frequently) in 2031 and 2040 than today, as shown in Figure 16 below. More frequent starts can increase wear-and-tear on the units and thereby can increase maintenance costs or decrease unit lives.

Figure 16: DTE Combustion Turbine Operational Metrics
Capacity-Weighted Average



The increased mileage of the CTs is an indication that they are providing some of Zone 7's needed flexibility by responding to fluctuations in net load and forecast errors.

38 MISO's Capacity Import Limit assessment is typically performed for peak load conditions. Increasing renewable generation penetration region-wide could aggravate transmission constraints in off-peak conditions, thereby imposing greater limitations to Zone 7's import capability levels reported under peak load conditions.

We also analyzed the performance of—and the implications on—Zone 7's gas-fired CCs in 2031 and 2040.

- The retirement of all coal generation in Zone 7 by 2040 results in significant energy replacement needs in the zone. Consumers Energy projected almost no dispatchable generation buildout to replace its coal generation retirements, but DTE's gas CC additions modeled in this scenario contribute significantly to meeting the zone's energy needs of 2040.

Lastly, our simulations show that Ludington's operation follows net load quite closely, reflecting its ability to provide even greater support for the system, thereby buffering significant flexibility concerns that would otherwise manifest in the zone with the analyzed levels of renewable generation deployment. Ludington's role will be discussed in more detail in the next section of this report.

5. Ludington as a Bellwether of Zone 7 Operational Needs

Ludington pumped storage hydro plant's operations in our 2031 and 2040 simulations directly reflect the changes in system needs for ramping and flexibility with increasing renewable generation deployment in Zone 7. Our simulations highlight that Ludington's generation and pumping schedules in 2031 and 2040 would align with the net load, with the plant's generation increasingly concentrated during the evening peak, while its pumping schedule moves from the nights (today) into mid-day by 2040, as shown in Figure 17 below.

As explained previously, Zone 7 experiences significantly lower levels of negative pricing and curtailments than the rest of MISO. The lower curtailment levels in Zone 7 compared to MISO are attributed to Ludington facility's ability to ramp down its production in response to increasing renewable generation, and also to manage day-ahead to real-time market variabilities in renewable outputs in Zone 7. But for this significant support, Zone 7 too **would experience more significant curtailments** as the ramp down capabilities of its resources get stretched by 2040 (see Figure 8 above).

Our simulations highlight that Ludington is able to **provide upward ramping capability** when needed.

Figure 17: Ludington Average Daily Dispatch by Season[39]
MW, Generating (above) and Pumping (below)

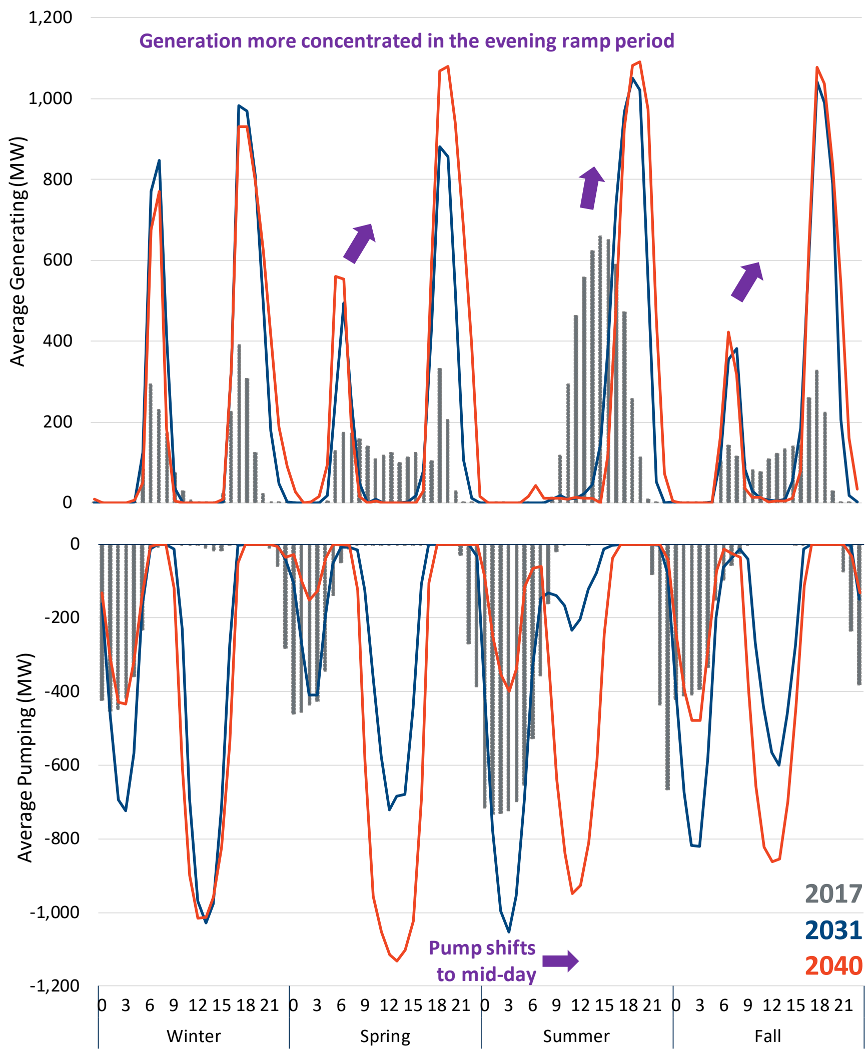
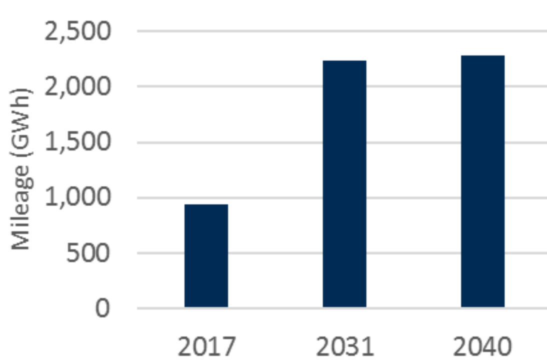


Figure 18: Ludington Mileage (GWh)



39 Chart shows DTE's share of the 2017 historical plant output and the simulated total plant output multiplied by DTE's ownership share. DTE is a 49% owner of the plant.

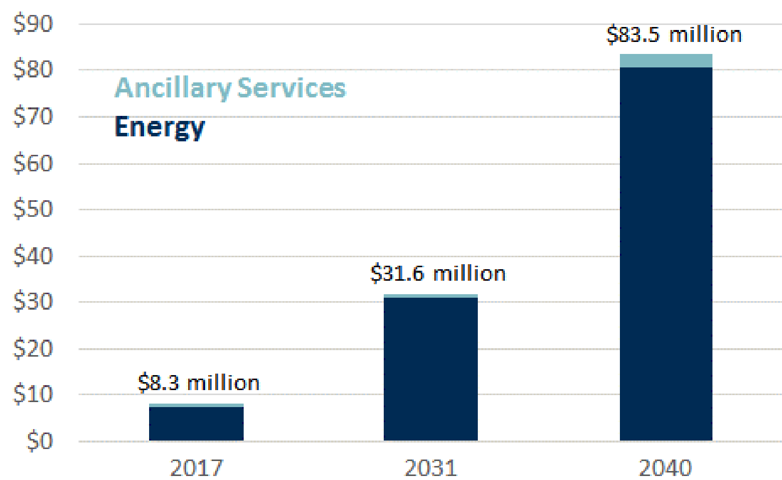
Ludington's contribution to supporting the ramping requirements of Zone 7 are highlighted by changes to its operating metrics and its energy and ancillary services revenues.

- Ludington's mileage metric is illustrated in Figure 18 above. As shown, our analyses finds that Ludington's mileage characteristics would increase significantly from its 2017 level of approximately 1,000 GWh to over 2,000 GWh in both 2031 and 2040.
- During the same period, its annual revenues from the energy and ancillary services markets increase about 10-fold to nearly $84 million from current levels (see Figure 19 below).

Both these outcomes strongly highlight Ludington's significance in providing the flexibility needs of Zone 7 as large amounts of renewable generation is deployed in the Zone in the near future.

Figure 19: Historical and Simulated Annual Ludington Energy and Ancillary Services Revenues

$million[40]

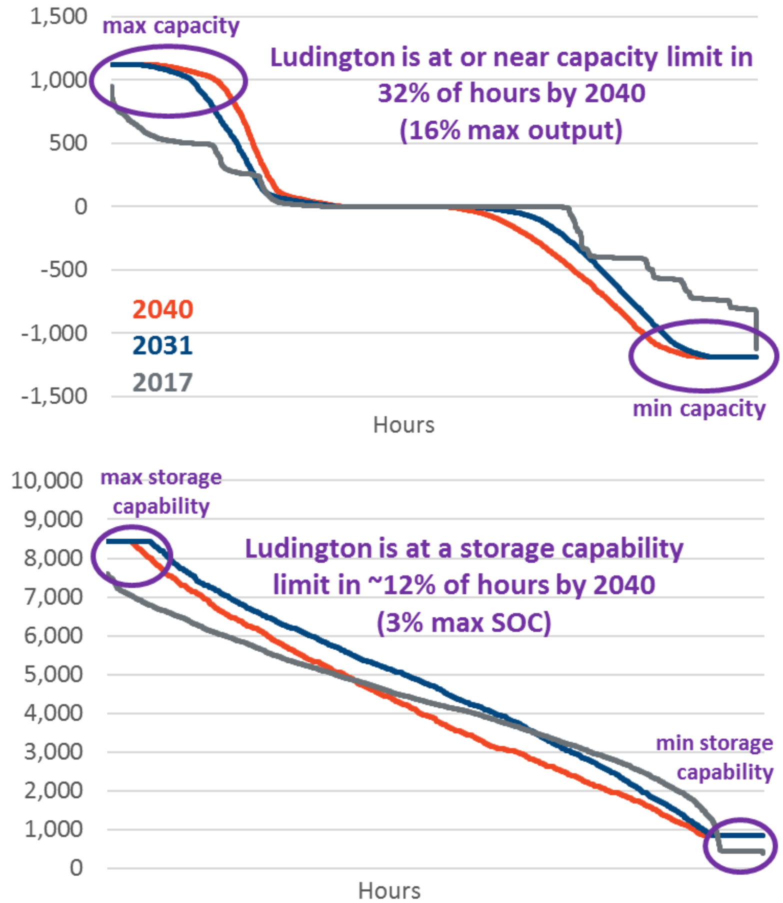


Even as Ludington would provide a significant portion of the flexibility needs of the system by 2040, our analysis shows that Ludington will start to become capacity constrained by 2031, and even more so by 2040.

- As show in Figure 20 below, our analysis indicates that Ludington would operate at or near its maximum *capacity* (generating or pumping) in nearly 32% of all hours by 2040. By contrast, it would be only at its maximum or minimum *energy capability* (*i.e.*, fully charged/discharged) in only 12% of hours.
- If and when renewable generation deployment in the zone increases to levels beyond those considered in our analyses, we anticipate that Ludington could become energy constrained more significantly.

40 Chart shows DTE's 2017 historical Ludington revenues and the simulated total Ludington revenues multiplied by DTE's ownership share. DTE is a 49% owner of the plant.

Figure 20: Ludington Output and State of Charge (SOC) Duration Curves[41]
MW Output (above) and MWh SOC (below)



---

41 Chart shows DTE's share of the plant 2017 historical output and the simulated total plant output multiplied by DTE's ownership share. DTE is a 49% owner of the plant. Reported SOC reflects the total plant SOC multiplied by DTE's ownership share (2017 historical and simulated).

IV. Overall Observations and Recommendation for Continued Monitoring and Analyses

In this study, we conduct detailed resource adequacy and operational simulations to assess the evolving renewable energy needs of Michigan's Lower Peninsula (Zone 7 of the MISO interconnected System) as renewable generation is added to the zone. This assessment analyzes the extent to which planned and expected future supply mix shifts in Zone 7 over the next two decades would impact system reliability, particularly as renewable generation sources are expected to serve approximately 25% of the zonal load by 2031, and 30% by 2040—both of which reflect a substantial increase relative to current levels.

Below we summarize the key observations from this Study:

1. Resource adequacy is a key indicator of a system's ability to maintain reliability, and is analyzed by evaluating the likelihood of a "loss of load event" experienced by customers due to insufficient generation resources. Based on these analyses, we find that the expected supply mix changes in Zone 7 and in the rest of MISO can **pose challenges to Zone 7's future resource adequacy.** Maintaining resource adequacy in 2031 will depend on multiple factors, including: (a) the level of capacity import capability from the rest of MISO into Zone 7, and (b) the ability to harness greater performance and more flexible operation of the Ludington Pumped Hydro generation facility within Zone 7. By 2040, the zone's resource adequacy could be more challenged if the decline in capacity import limits from the rest of MISO into Zone 7 is not addressed; or if the availability of importable capacity from rest of MISO is at risk due to the neighboring zones' own needs to balance their supply and demand adequately.

   Additional risks could manifest, as we find that that Zone 7 would need to **rely increasingly on demand response** to support reliability both in 2031 and 2040. We find that the performance characteristics of DR programs will need to evolve to allow for more frequent deployment to support the system's supply and demand balance, particularly during evening hours when the system's reliability risks are expected to increase.

2. Our operational analyses show that Zone 7 could experience reliability challenges due to **a lack of available ramping capability by 2040**. We assess that additional ramping capability will be needed to ensure that the increase in the up and down ramping of net load can be met reliably. Our analyses indicate that the need for ramping capability would increase substantially between 2017 and 2040 to cover a six-hour period of up and down ramp necessary to maintain reliability while harnessing the benefits of increased deployment of renewable generation in the zone. We find that during key periods of tight system conditions such as on summer peak days, the increase in ramping need will be more substantial, which could result in shortfalls in ramping capabilities by 2040.

3. Our simulations highlight additional changes to the system's operational performance in the future. Specifically, we observe a **declining ability of the system to integrate additional renewables as the share of renewable generation increases to 30%** by 2040, which results in an increase in negatively priced hours for energy, and an increase in curtailed renewable energy. Our analysis points to a **growing reliance on imports** from MISO to meet Zone 7 energy requirements in the future, which can impose additional risks on customer costs if capacity and/or energy shortages in MISO were to manifest in the future.
4. Our analyses show that changes to operations of Ludington and existing and potentially newly installed gas-fired generation will help to mitigate the identified risks. Ludington is a significant source of flexibility in Zone 7 and its ability to respond to steep ramps in the net load, support peak requirements, and reduce the volume of renewable generation curtailments, will become increasingly valuable as the renewable generation in Michigan's supply mix increases. Regarding future gas-fired generation, our analyses indicate that existing and new gas-fired generation could play a growing role in providing energy needs as other conventional generation retire between 2031 and 2040 and as energy needs increase beyond those served by renewable generation.

Overall, we recommend, as the state continues to examine the future power system needs of the Lower Peninsula, that the identified resource adequacy and operational risks be monitored carefully. We recommend that the detailed study of future system needs should continue as the resource mix begins to shift toward increasing amount of renewable generation in the state.

List of Acronyms

CC	Combined-Cycle
CCGT	Combined Cycle Gas Turbines
CE	Consumers Energy
CEL	Capacity Export Limit
CIL	Capacity Import Limit
CT	Combustion Turbine
DA	Day Ahead
DG	Distributed Generation
DR	Demand Response
DTE	DTE Energy
EFORd	Equivalent Forced Outage Rate Demand
EIA	Energy Information Administration
EWR	Energy Waste Reduction
GWh	Gigawatt Hour
ISO	Independent System Operator
IRP	Integrated Resource Plan
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRZ	Local Resource Zone
METC	ITC Michigan
MISO	Midcontinent Independent System Operator
MPSC	Michigan Public Service Commission
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
PCA	Proposed Course of Action
PSO	Power Systems Optimizer
RegDn	Regulation Down
RegUp	Regulation Up

RT	Real Time
SOC	State of Charge
T&D	Transmission and Distribution
TMY	Typical Meteorological Year

V. Appendix A: Additional Details on Key Modeling Assumptions

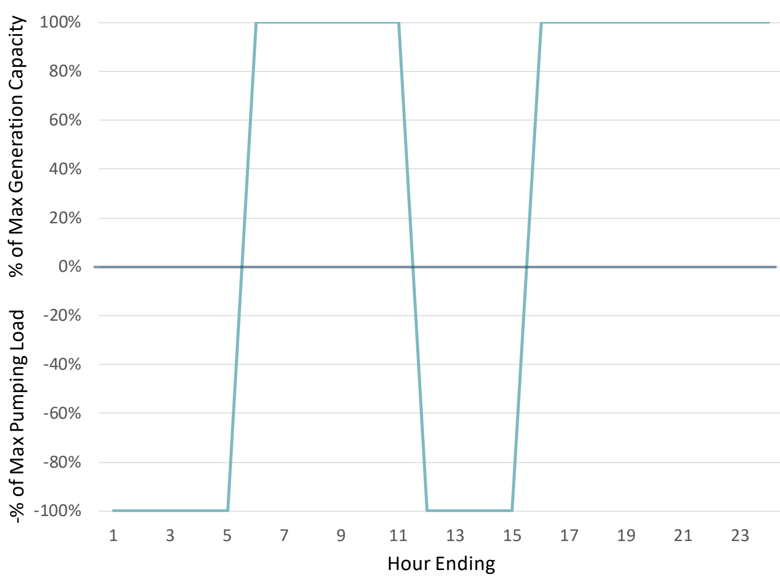
A. Resource Adequacy

1. Ludington Pumped Hydro Modeling Assumptions

In our simulations for 2031 and 2040, we model full utilization of Ludington's capabilities during morning and evening ramps to align generation with the shifted net load. The profile is illustrated below in Figure 21. Note that for resource adequacy analysis, (1) this modeling does not factor in the efficiency losses associated with the charging/discharging cycle of the generating units and (2) does not assess whether Ludington has sufficient time to recharge during periods of extended, low generation from renewable sources.

Additionally, to capture Ludington's resource flexibility, our resource adequacy modeling restricts pumping in any hour where load exceeds generation in order to avoid an LOLE event.

Figure 21: Modeled Ludington Hourly Dispatch Profile for 2031 and 2040
(as a % of Nameplate Capacity)



B. Operational Analysis

1. Summary of Key Input Assumptions

For the operational analysis, we analyzed Case 1 only. The key modeling assumptions employed in our operational simulations of this case are summarized below in Figure 22.

Figure 22: Operations Analysis Modeling Assumptions[42]

		2031		2040	
	Unit	Zone 7	Rest of MISO	Zone 7	Rest of MISO
Gas Prices	2017$/MMBtu	$4.54		$4.80	
Carbon Price	2017$/tonne	$7.00		$10.00	
Peak Load	GW	18.3	105.7	18.8	111.0
Annual Load	TWh	99.4	595.2	102.6	645.3
Installed Capacity	MW	29,708	175,789	30,618	214,595
DA Cycle		1 hour			
RT Cycle		10 minutes			

Notes: Peak Load values are net of energy efficiency and DR.

Our operational analysis includes robust modeling of the specific unit characteristics of generating resources, and their operational limitations. These unit characteristics for MISO and Zone 7 units modeled for 2031 and 2040 are summarized in Figure 23 below. Additional operation simulation input assumptions are provided in Workpapers.

Figure 23: Summary of MISO Thermal Generating Unit Characteristics

	2031 Summer Capacity	2040 Summer Capacity	Min Load	Min Up Time	Min Down Time	Fully Loaded Heat Rate	Forced Outage Rate	Ramp Rate	Startup Cost	Variable O&M Cost
	MW	*MW*	*% of capacity*	*hours*	*hours*	*BTU/kWh*	*%*	*MW/min*	*$/MW*	*$/MWh*
Biomass/Biogas	1,722	1,722	2%	1.0	1.0	23,110	10.6%	0.7	$85	$0.3
Coal	36,060	27,965	50%	23.1	11.8	10,405	7.1%	3.4	$133	$2.5
Gas CC	36,576	38,424	48%	6.0	8.0	8,090	4.3%	10.0	$196	$2.5
Gas Peaker	27,111	29,324	18%	1.0	1.0	13,126	10.6%	14.7	$12	$9.2
Gas Steam	12,481	12,481	24%	9.7	8.6	11,816	9.9%	5.9	$224	$4.2
Nuclear	10,966	8,727	100%	146.2	146.2	10,447	3.8%	N/A*	$117	$0.0
Oil Peaker	3,253	3,253	19%	1.1	1.1	13,642	16.4%	14.3	$25	$9.2

Notes: Startup costs reflect both fuel, and non-fuel start costs. Summary statistics are derived as the capacity weighted average of units in the type category. *Nuclear units do not show a ramp rate because they are assumed to be block loaded. Planned outages are modeled on a unit-specific basis using prior analysis of outage scheduling capturing seasonal needs/availability.

42 Day-ahead and real-time peak and annual load differ due to uncertainty in load forecast error.

BOSTON
NEW YORK
SAN FRANCISCO
WASHINGTON
TORONTO
LONDON
MADRID
ROME
SYDNEY

THE Brattle GROUP