Appendix G

MISO Transmission Studies

and Reports

Appendix G
Mankato – Mississippi River Transmission Project
Certificate of Need and Route Permit Application
E002/CN-22-532 and E002/TL-23-157

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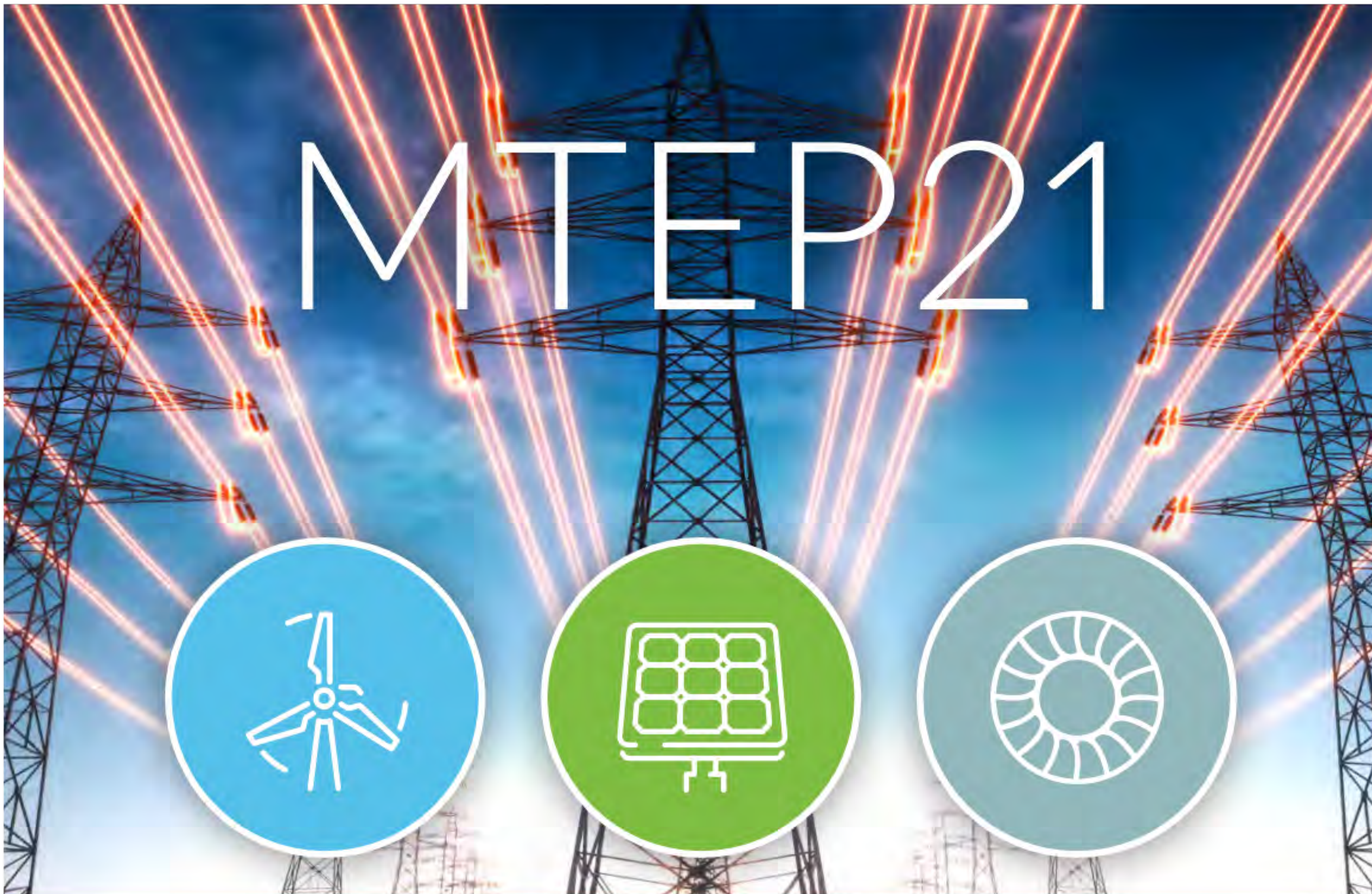
MISO's MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary, Report, and Appendix A



MTEP21 REPORT ADDENDUM: LONG RANGE TRANSMISSION PLANNING TRANCHE 1 EXECUTIVE SUMMARY

Highlights

- This addendum proposes a portfolio of 18 transmission projects located in the MISO Midwest Subregions with a total investment of $10.3 billion, and benefit-to-cost ratios average of 2.6, where benefits well exceed costs

- This Tranche 1 portfolio of least-regrets transmission projects will help to ensure a reliable, resilient and cost-effective transmission system as the resource mix continues to change over the next 20 years

- The Tranche 1 portfolio, with more than 2,000 miles of transmission line, represents the most complex transmission study efforts in MISO's history

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MISO's Long Range Transmission Planning to address the Reliability Imperative: Tranche 1 Portfolio

The *Long Range Transmission Planning (LRTP) Tranche 1 Portfolio* report presents the study findings and benefits analysis associated with the development of regional transmission solutions needed to provide reliable and economic delivery of energy. The report proposes a set of least-regrets transmission projects that will help to ensure a reliable, resilient and cost-effective transmission system as the resource mix continues to change and represents the largest and most complex transmission study effort in MISO's history. Since the last major set of regional overlay projects was approved in 2011, the pace towards more variable renewable generation has increased. Carbon-free and clean energy goals set by MISO member utilities, state and municipal government policies and customer preferences continue to drive growth in wind, solar, battery and hybrid projects. Indeed, the anticipated landscape changes are much more significant and require transformational changes at a faster rate than the previous 2011 portfolio of projects were built to accommodate.

The resulting urgency has required a much more intensive and focused effort. While it took four years to develop the 2011 portfolio of projects, this LRTP Tranche 1 portfolio, which is significantly larger in terms of the cost and line miles, came to fruition in less than half that time, without sacrifice of analytical quality or identification of robust solutions. The resulting portfolio includes 18 transmission projects located in the MISO Midwest subregion, with a total initial investment of $10.3 billion.

The LRTP Tranche 1 portfolio was developed to ensure that the regional transmission system can meet demand in all hours while supporting the resource plans and renewable energy penetration targets reflective of MISO member utilities' goals and state policies. LRTP approached transmission portfolios in tranches in part because the urgent needs identified by the Reliability Imperative are appearing in the near-term for the Midwest subregion, including retirements and resource portfolio changes. This more urgent need put the focus for Tranches 1 and 2 in the Midwest Subregion. Tranche 3 will shift to focus on the South Subregion, with Tranche 4 then looking to strengthen the connection between the Midwest and South subregions.

Further, reflecting the portfolio's urgency, the LRTP Tranche 1 portfolio makes use of existing routes, where possible, to reduce the need to acquire additional greenfield right-of-way, which lowers costs and allows a shorter time to implementation. Construction of new transmission routes across navigable waterways, protected areas and high-value property faces extensive cost and regulatory risks that impede progress in meeting future reliability needs. Co-locating new facilities with existing transmission assets enables more efficient development of transmission projects and minimizes the environmental and societal impacts of infrastructure investment needed to achieve the needs identified in MISO's Future 1.

In addition to the primary benefits of system reliability, the LRTP Tranche 1 portfolio meets the criteria for Multi-Value Projects defined in the Tariff through addressing policy, reliability or economic needs, meeting the minimum cost threshold, and exceeding a benefit-to-cost ratio of 1.0. The types of economic benefits that could be used to meet these criteria represent a broad range of benefits provided by this portfolio of projects.

ID	DESCRIPTION	EXPECTED ISD	EST COST ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689
5	Tremval – Eau Claire – Jump River	6/1/2028	$505
6	Tremval – Rocky Run – Columbia	6/1/2029	$1,050
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755
8	Beverly – Sub 92	12/31/2028	$231
9	Orient – Denny – Fairport	6/1/2030	$390
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769
11	Maywood – Meredosia	6/1/2028	$301
12	Madison – Ottumwa – Skunk River	6/1/2029	$673
13	Skunk River – Ipava	12/31/2029	$594
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572
15	Sidney – Paxton East – Gilman South – Morrison Ditch	6/1/2029	$454
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261
17	Hiple – Duck Lake	6/1/2030	$696
18	Oneida – Nelson Rd.	12/29/2029	$403
	TOTAL PROJECT PORTFOLIO COST		$10,324

Figure 1: LRTP Tranche 1 portfolio includes 18 projects in MISO's Midwest Subregion, with an investment cost of $10.3 billion

QUANTIFIED BENEFITS INCLUDE:

- **Congestion and Fuel Savings** – LRTP projects will allow more low-cost resources to be integrated, replacing higher-cost resources and lowering the overall cost to serve load.

- **Avoided Capital Cost of Local Resources** – LRTP projects will allow renewable resource build-out to be optimized in areas where they can be more productive compared to a wholly local buildout.

- **Avoided Transmission Investment** – LRTP projects will reduce loading and avoid future reliability upgrades, avoiding the cost for replacing facilities due to age and condition.

- **Resource Adequacy Savings** – LRTP projects will increase transfer capability, which will allow access to resources in otherwise constrained areas and defer the need for investment in local resources.

- **Avoided Risk of Load Shedding** – The LRTP portfolio will enhance the resilience of the grid and reduce risk of load loss caused by severe weather events.

- **Decarbonization** – The higher penetration of renewable resources enabled by the LRTP portfolio will result in less carbon dioxide emissions.

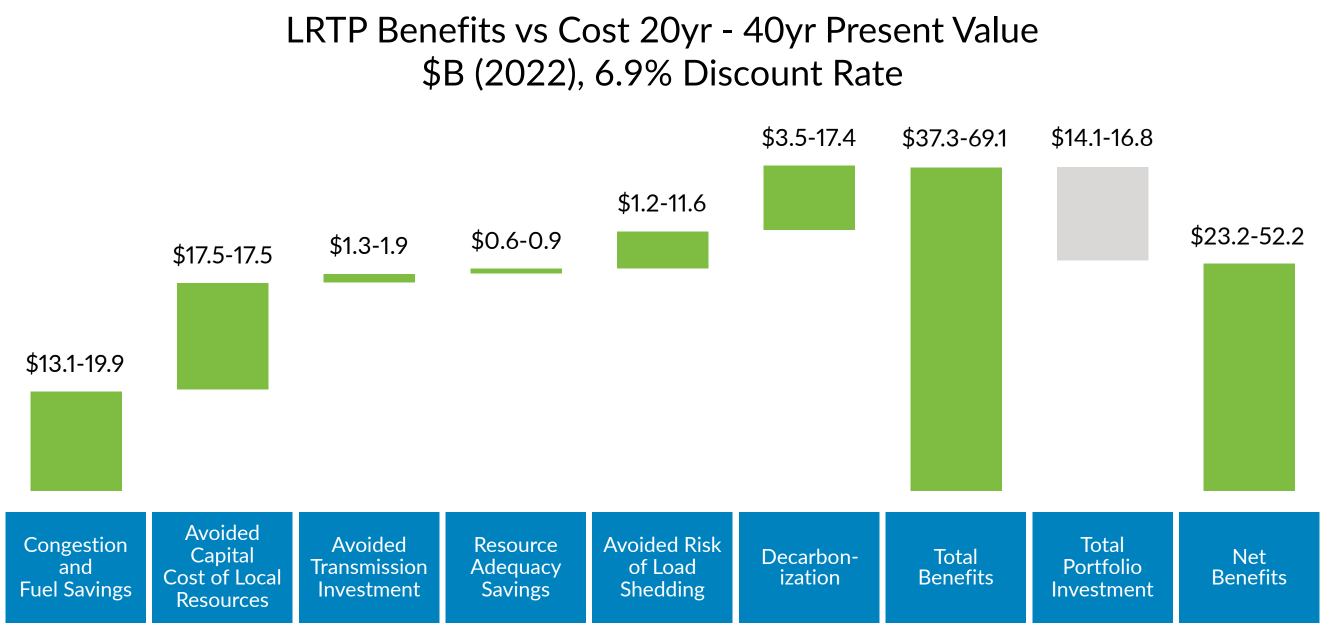

Figure 2: LRTP Tranche 1 Portfolio benefits far outweigh costs (Values as of 6/1/22)*

*Note: This implies benefit-to-cost (B/C) ratio ranges of 20-yr PV B/C = 2.6 and 40-yr PV B/C = 4.0

The Tranche 1 portfolio has a benefit-to-cost ratio of between 2.6 and 3.8, and MISO studies show benefits of this investment at a benefit-to-cost ratio of at least 2.2 for every zone, with benefits well in excess of the LRTP costs. The proposed projects and costs are spread across the entire MISO Midwest subregion, allowing it to benefit multiple states, MISO members and customers. Benefits include more reliable and resilient energy delivery; congestion and fuel savings; avoided resource and transmission investment; improved distribution of renewable energy; and reduced carbon emissions.

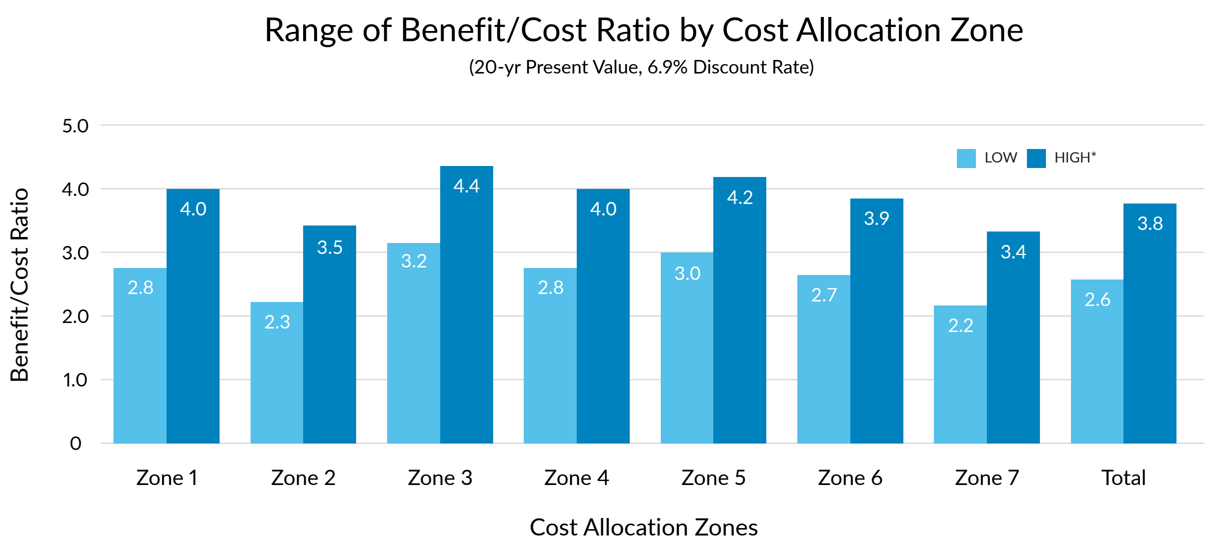

Figure 3: Benefits from the LRTP Tranche 1 portfolio exceed costs in every Midwest Subregion cost allocation zone

* The low and high range of benefit/cost ratios by Cost Allocation Zone are driven by changing two assumptions in the 20-year present value analysis: 1) increasing the Value of Lost Load (VOLL) from $3,500/MWh (low) to $23,000/MWh (high); and 2) increasing the price of carbon from $12.55/ton (low) to $47.80/ton (high).

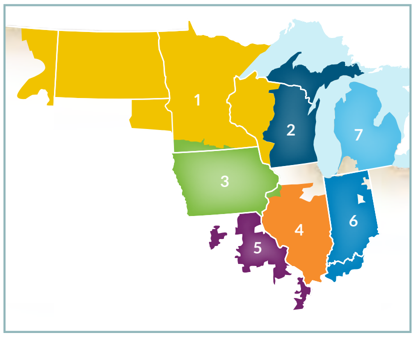

Figure 3a: Map of Midwest Cost Allocation Zone Boundaries (MISO Tariff, Attachment WW)

Transmission for the Future: LRTP Tranche 1 Projects are a “Least Regrets” Imperative

This least-regrets portfolio meets the needs of the first of MISO’s three future planning scenarios, Future 1, which incorporates known and projected generation and load presented by member plans. This portfolio is “least regrets” because MISO is planning for an uncertain future and has chosen to plan towards the needs that represent a current view of member plans. Those portfolio plans continue to accelerate and expand, making Future 1 the conservative, expected case and presenting reliability implications that the Tranche 1 portfolio addresses. That’s why Tranche 1 is a “yes-and” set of transmission that the Tranche 2 study will build off of to continue to meet the increasing renewable penetration levels and electrification growth that the MISO system is expected to see in the future.

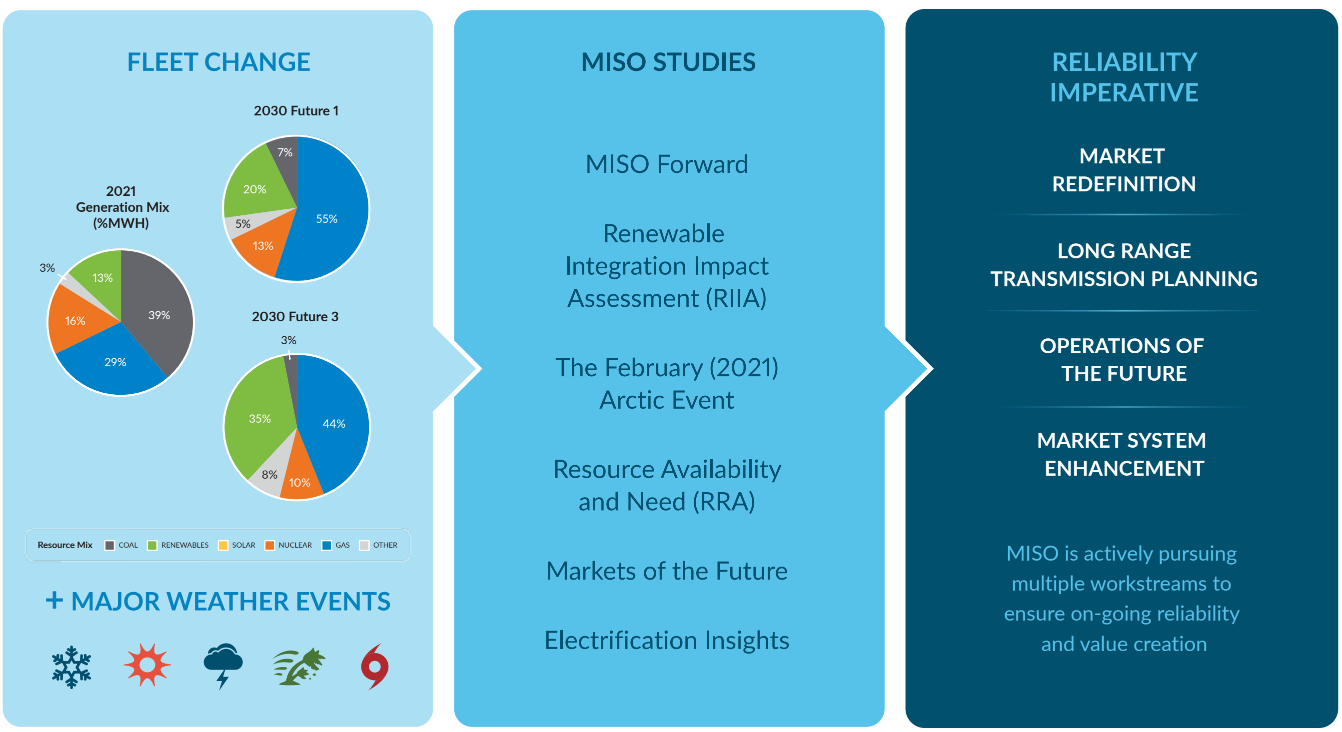

Figure 4: Challenges resulting from the changing resource portfolio and increasing extreme weather risk have created an imperative for broad changes

Subsequent tranches will improve interconnectivity, which helps to move power from where it's generated to where it's needed and, in doing so, not only integrates weather-based resources but improves resiliency during emergency events. Collectively, the multiple tranches of the LRTP comprise one of the four key elements of MISO's Reliability Imperative, which outlines a shared responsibility to evolve MISO's planning, markets, operations, and systems in an orderly fashion that preserves system reliability in the face of rapid changes in the MISO region. Unlike generation resource additions and retirements, which take as little as six months to complete, transmission projects can take up to 10 years from conception to in-service date. Given the long lead time, we must act now to ensure the transmission infrastructure is in place by 2030 to move both renewable and conventional generation across the grid in an efficient and reliable manner.

RELIABLE SYSTEM	Maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply
COST EFFICIENT	Enable access to lower-cost energy production
ACCESSIBLE RESOURCE	Provide cost-effective solutions allowing the future resource fleet to serve load across the footprint
FLEXIBLE RESOURCES	Allow more flexibility in the fuel mix for customer choice

Figure 5: The LRTP Tranche 1 results were identified consistent with the objectives of the LRTP effort

How the Portfolio Evolved: MISO, Stakeholders Execute Accelerated, Robust Study

In response to resource shift trends, MISO began working with its stakeholders through the Planning Advisory Committee (PAC) and LRTP workshops to identify the transmission infrastructure needed to support these changes and ensure reliability. MISO introduced the LRTP conceptual roadmap to stakeholders in March 2021 and began discussions on the study scope and approach. A few months later, MISO began a series of monthly technical workshops to seek input from stakeholders on the study methods and assumptions and to provide regular status updates on the ongoing work and analysis findings. In September 2021, MISO introduced a business case development process to identify the components and define the metrics for quantifying the benefits provided by the initial LRTP Tranche 1 portfolio of LRTP transmission investments.

In parallel, MISO engaged its stakeholders to develop an appropriate cost allocation methodology for such a transmission portfolio through the Regional Expansion Cost and Benefits Working Group (RECBWG).

The conceptual roadmap provided a long-range conceptual regional transmission plan to map out further study and potential solution ideas needed to address future transmission needs. Reliability analysis was then conducted on a series of study models representing various system conditions and dispatch patterns, as reviewed by MISO and stakeholders. Next, MISO evaluated potential alternative solutions developed by stakeholders and MISO to identify the most effective transmission solutions, including both reliability and economic analysis.

Once Tranche 1 projects were identified, MISO calculated the economic benefits of the portfolio. While the primary objective of the LRTP projects was to address reliability issues considering a range of system conditions, their value can extend well beyond reliability. This is especially true for investments like the LRTP projects, whose regional scope and high voltage levels can enable significant broad economic benefits as well.

COSTS COMMENSURATE WITH BENEFITS

The transmission limitations between MISO Midwest and MISO South subregions effectively reduced the flow of benefits between the two subregions. To ensure costs align with beneficiaries, MISO submitted a cost allocation option for new Multi-Value Project portfolios, the cost of which would be regionally allocated on a subregional basis.

In February 2022, after months of work with stakeholders and state regulators, MISO filed with FERC for a cost allocation methodology for Multi-Value Projects to meet the unique needs of the region in developing the LRTP projects. The filing, supported by a majority of MISO transmission owners, was submitted and subsequently approved on May 18, 2022.

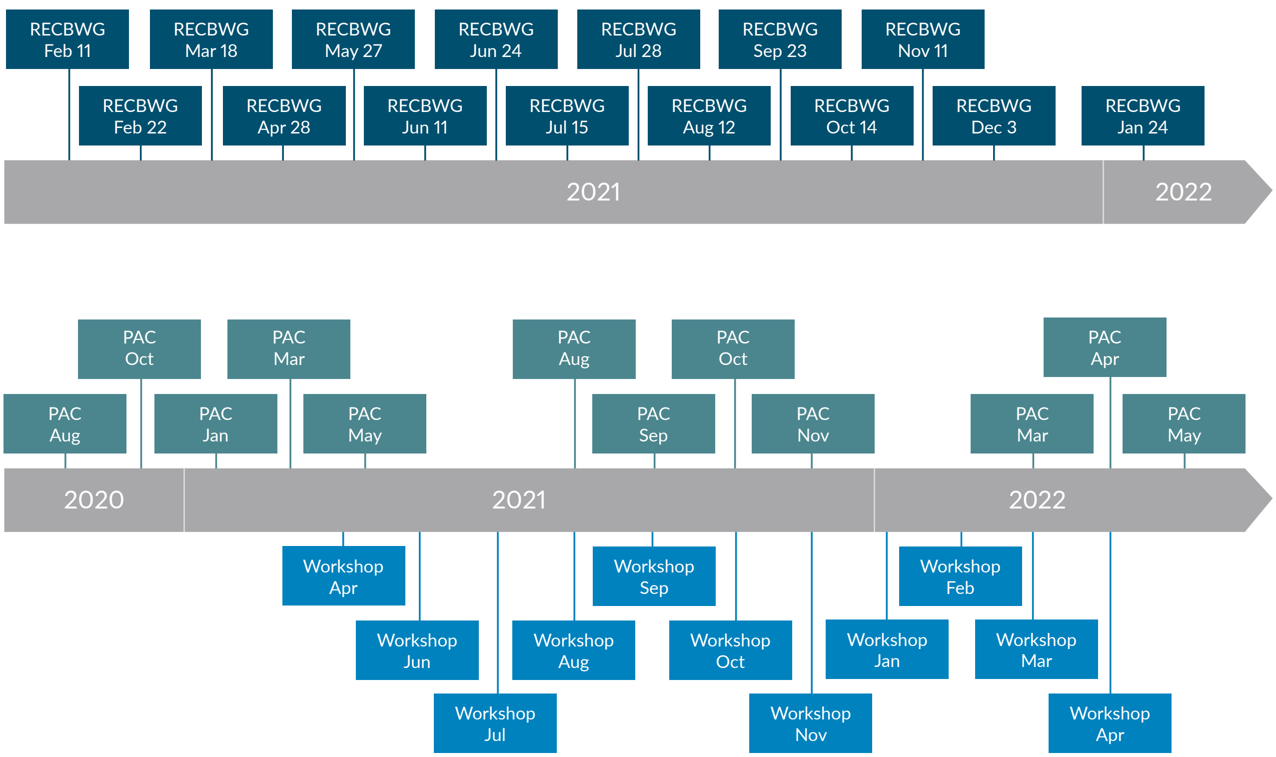

Figure 6: MISO's Long Range Transmission Plan Tranche 1 followed an extensive stakeholder process

Tranche 1 projects solve specific transmission issues across the MISO footprint

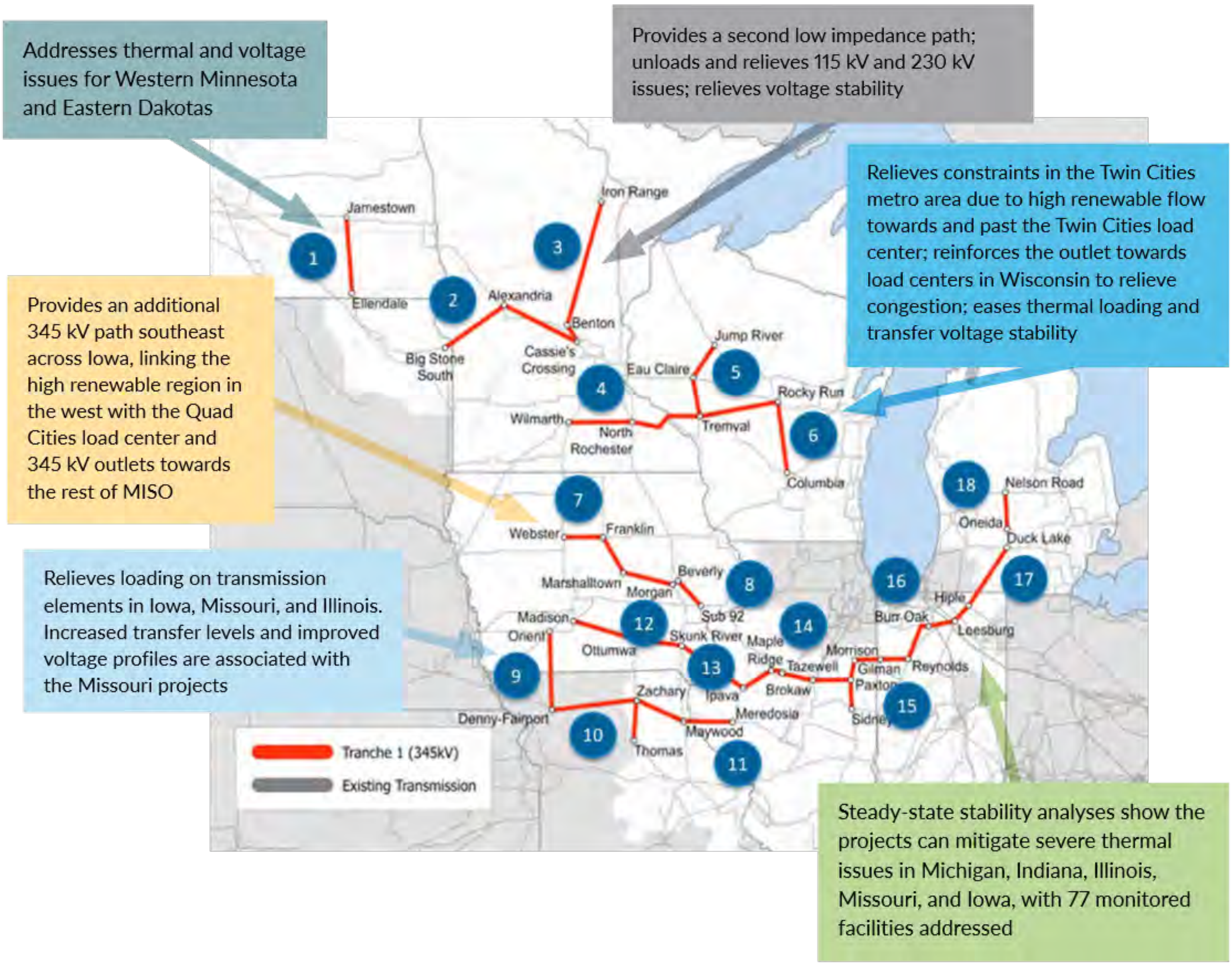

Figure 7: The Tranche 1 portfolio of 18 transmission projects can be divided into six sections with unique regional benefits

ID	DESCRIPTION
1	Jamestown – Ellendale
2	Big Stone South – Alexandria – Cassie's Crossing
3	Iron Range – Benton County – Cassie's Crossing
4	Wilmarth – North Rochester – Tremval
5	Tremval – Eau Claire – Jump River
6	Tremval – Rocky Run – Columbia
7	Webster – Franklin – Marshalltown – Morgan Valley
8	Beverly – Sub 92
9	Orient – Denny – Fairport
10	Denny – Zachary – Thomas Hill – Maywood
11	Maywood – Meredosia
12	Madison – Ottumwa – Skunk River
13	Skunk River – Ipava
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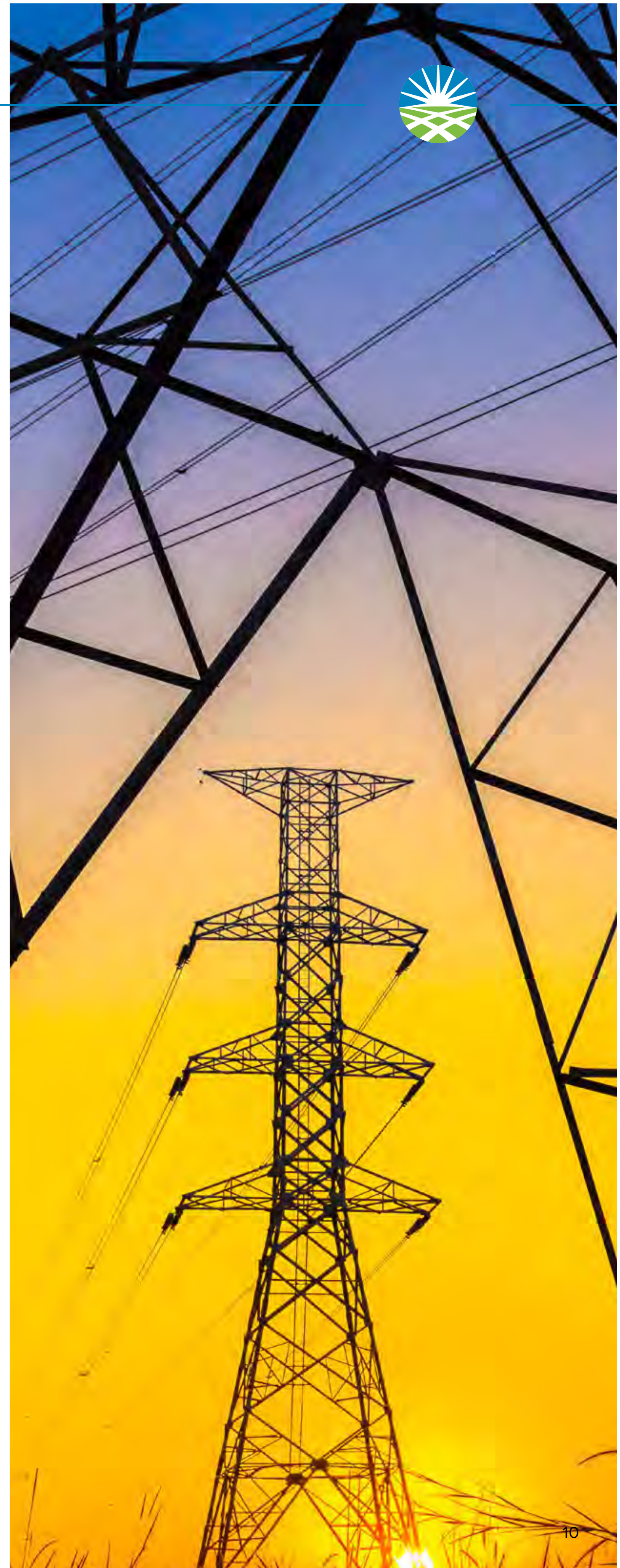
17	Hiple – Duck Lake
18	Oneida – Nelson Rd



Next Steps: A Foundation for Future Needs

A more interconnected system is stronger. Additional study work and stakeholder engagement will help identify the nature and benefits of future LRTP tranches needed to address further deployment of variable, weather-dependent resources, continued volatility created by severe weather events and the benefits of improved interregional connectivity.

While Tranche 1 provides a meaningful start, much work is left to ensure that the shifting resource fleet transition occurs in an orderly, efficient and reliable manner. Though Tranche 1 provides a more robust system in the Midwest, future tranches are needed to address other parts of the MISO footprint and future levels of fleet transition beyond what is captured in Future 1. MISO looks forward to continuing the conversation with stakeholders and regulators to ensure adequate planning to meet future needs.

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MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report

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1 Introduction

MISO's multi-year Long Range Transmission Planning (LRTP) initiative assesses reliability risks looking 10-20 years into the future to identify the transmission investments needed to enable regional delivery of energy. Projections show a drastically different resource fleet, along with other influences such as electrification, that is driving a need for the bulk electric system to be better prepared for these massive shifts. MISO proposes a Tranche 1 Portfolio of 18 transmission projects, equaling approximately $10 billion of investment, to enhance connectivity and maintain adequate reliability for the Midwest Subregion by 2030 and beyond (Figure 1-1, Table 1-1).

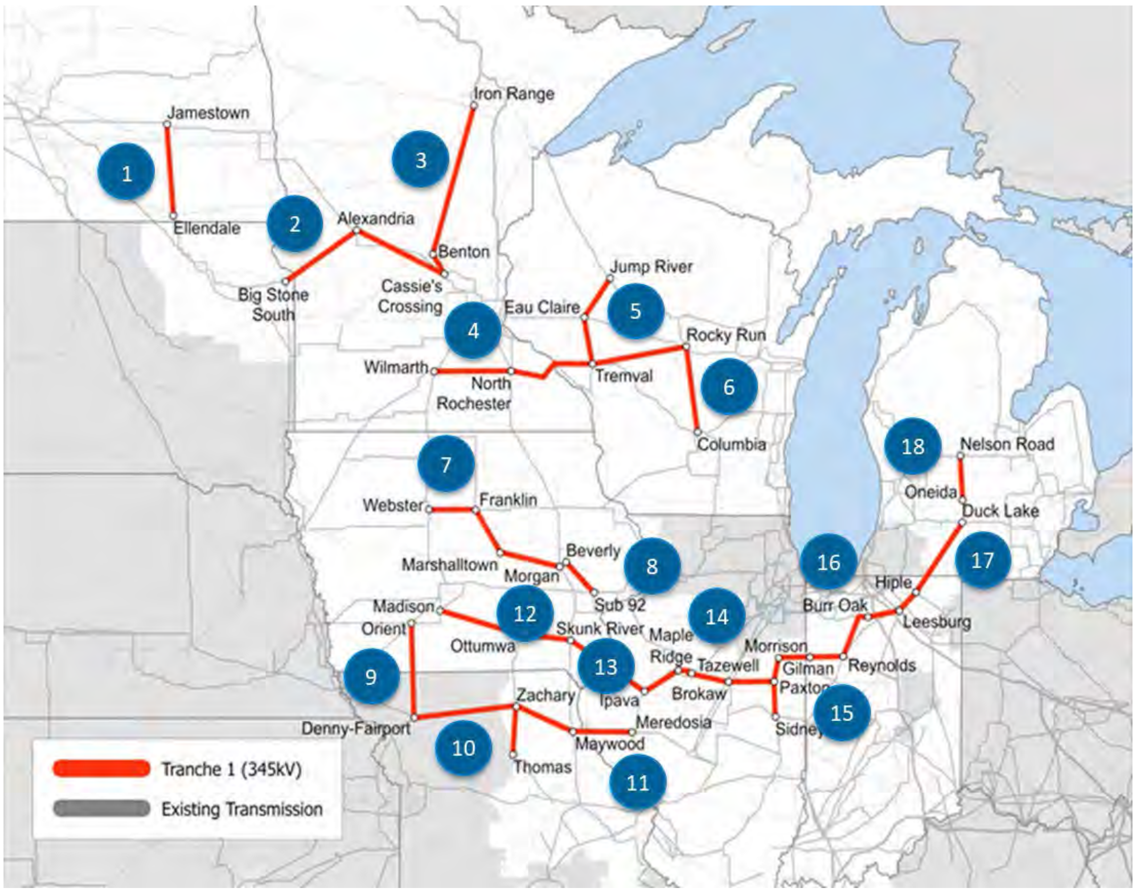

Figure 1-1: LRTP Tranche 1 Transmission Portfolio

LRTP Tranche 1 Portfolio of Projects

ID	Description	Expected ISD	Estimated Cost ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439M
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574M
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970M
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689M
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7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755M
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15	Sidney – Paxson East – Gilman South – Morrison Ditch	6/1/2029	$454M
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261M
17	Hiple – Duck Lake	6/1/2030	$696M
18	Oneida – Nelson Rd.	12/29/2029	$403M
	Total Project Portfolio Cost:		$10,324M

Table 1-1: Proposed Tranche 1 Portfolio of Projects
(Costs as of June 1, 2022 and are subject to change. Costs represent "overnight" costs)

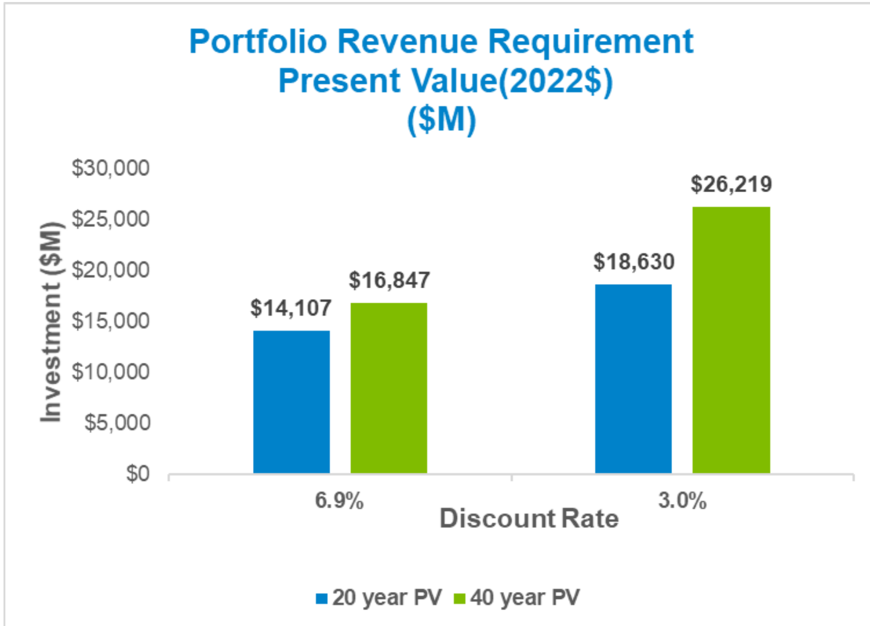


Figure 1-2: Present Value of LRTP Tranche 1 Portfolio (values as of 6/1/2022)

The Tranche 1 Portfolio has a benefit to cost ratio of between 2.6 and 3.8, and MISO studies show benefits of this investment at a benefit to cost ratio of at least 2.2 for every Cost Allocation Zone, well in excess of the LRTP Tranche 1 Portfolio costs (Figure 1-2 and 1-3). The proposed projects and costs are spread across the entire MISO Midwest Subregion, allowing it to benefit multiple states, MISO members and customers. Benefits include more reliable and resilient energy delivery; congestion and fuel savings; avoided resource and transmission investment; improved distribution of renewable energy; and reduced carbon emissions.

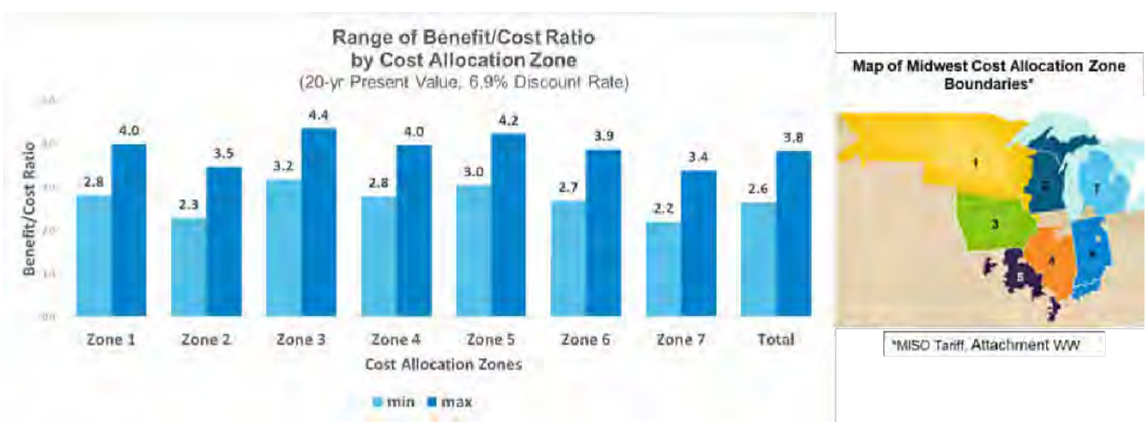


Figure 1-3: Distribution of benefits to Cost Allocation Zones in Midwest (MISO Tariff Attachment WW) (values as of 6/1/22)

The LRTP study was initiated in 2020, and the LRTP Tranche 1 Portfolio Report is the first iteration of MISO's findings and recommendations. This report identifies reliability challenges in the Midwest Subregion associated with MISO's Future 1.

Efforts on Tranche 2 will be underway in the second half of 2022 and will continue to focus on the Midwest Subregion and addressing the needs identified in MISO's Futures. Tranche 3 of the LRTP study will focus on identifying system needs in the MISO South Subregion, and Tranche 4 will look at the part of the system connecting the Midwest and South Subregions.

While the Tranche 1 Portfolio is the result of MISO's long-range planning process being executed for only the second time, the rapid change within the industry will require that it become a more routine aspect of the MISO planning process going forward.

2 History of MISO's Innovative Long Range Transmission Planning Process

The transmission grid, while not top of mind for many people, is a critical component of ensuring the lights come on when a switch is flipped, our favorite devices can be charged, and life-saving machines can operate. But even with that level of importance, transmission investments, especially on a large scale, are very difficult to undertake and are not very common in the United States currently. However, the clear direction of the industry, towards a cleaner energy future, requires investments of this nature. Fortunately, MISO has a proven process, experience, and an engaged stakeholder community to draw upon as we embark on this very difficult journey. This is not the first time we have been here, or successfully facilitated significant grid investment.

As a Regional Transmission Organization/Independent System Operator, MISO coordinates with its members to facilitate transmission system investments needed to ensure continued reliable and efficient delivery of least-cost electricity across the MISO region. This requires a continuous execution of MISO's recurring transmission planning process. The culmination of the extensive work executed during each 18-month planning cycle, including proposed new projects, are codified annually in a MISO Transmission Expansion Plan (MTEP). These plans have put in motion approximately $42 billion in transmission investments going back to 2003.

Section 1.2 of MTEP21 provides an overview of MISO's overall transmission planning process, so only the primary aspects are described here to provide high-level context. The process involves both top-down and bottom-up identification of issues and potential solutions associated with transmission system maintenance and enhancement. There are also several aspects, or objectives of different components of MISO's transmission planning process, including resolving grid reliability issues, transmission expansion needed to connect new generation resources to the grid, and reducing congestion on the system. Assessing these types of needs can occur as often as annually and involves looking out 5-15 years to identify near- and mid-term needs.

The overall process also includes a component that has been exercised less frequently, the long-range transmission planning (LRTP) process, which considers challenges projected in the 20 year and beyond timeframe. Given the extensive lead time associated with large-scale transmission investment, this process is designed to be responsive to situational grid needs and utilized when incremental transmission system fixes, upgrades, and/or additions will not be sufficient to effectively or efficiently address those needs. These situations require that MISO consider the range of potential future states, the implications of those outcomes for the industry, and the transmission system needs this will create. Those potential future scenarios serve to provide bookends for the uncertainty that exists when planning this far out.

The inaugural iteration of MISO's long range planning process culminated in the first-of-its-kind portfolio of projects being approved by the MISO Board of Directors in 2011. Beginning in 2007, in response to an increase of individual Renewable Portfolio Standards within MISO states, MISO began the initial execution of the LRTP process to mitigate the significant impact on the future generation mix and the reliability of the system. During this multi-year effort, a new project type — Multi-Value Project (MVP) — was developed. As codified in the MISO Tariff, a project must meet one or more of the following criteria to be included in an MVP portfolio:

> *Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.*
>
> *Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.*
>
> *Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.*

As the criteria demonstrate, economic benefits are a significant part of the requirements for these types of projects. Given the regional scope of these projects, the level of investment, and the uncertainty associated with the time horizon, a strong business case is paramount. The types of economic benefits that could be used to meet these criteria were defined through collaboration with stakeholders. Those benefits are:

- *Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be* *realized through reductions in both transmission congestion and transmission energy losses. Production cost savings can also be realized through reductions in Operating Reserve requirements.*

- *Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.*
- *Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.*
- *Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.*
- *Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the Transmission System and related to the provisions of Transmission Service.*

The ground-breaking work executed during this process culminated in a nearly $6 billion portfolio, with a projected 1.8-3.1 benefit-to-cost ratio, being approved by the MISO Board of Directors in 2011. MISO was required to periodically reassess the projected benefits to determine if modifications to the MVP criteria were necessary. Each of those analyses found that the projected benefits remained consistent with, and were sometimes greater than, initially estimated, as shown in Figure 2-1. This, along with the fact that all but one of the 17 MVP projects are currently (as of June 2022) in service and fully utilized, demonstrates the effectiveness of MISO's value-based planning process and the use of future scenarios to bookend uncertainty and identify robust solutions, and to project benefits.

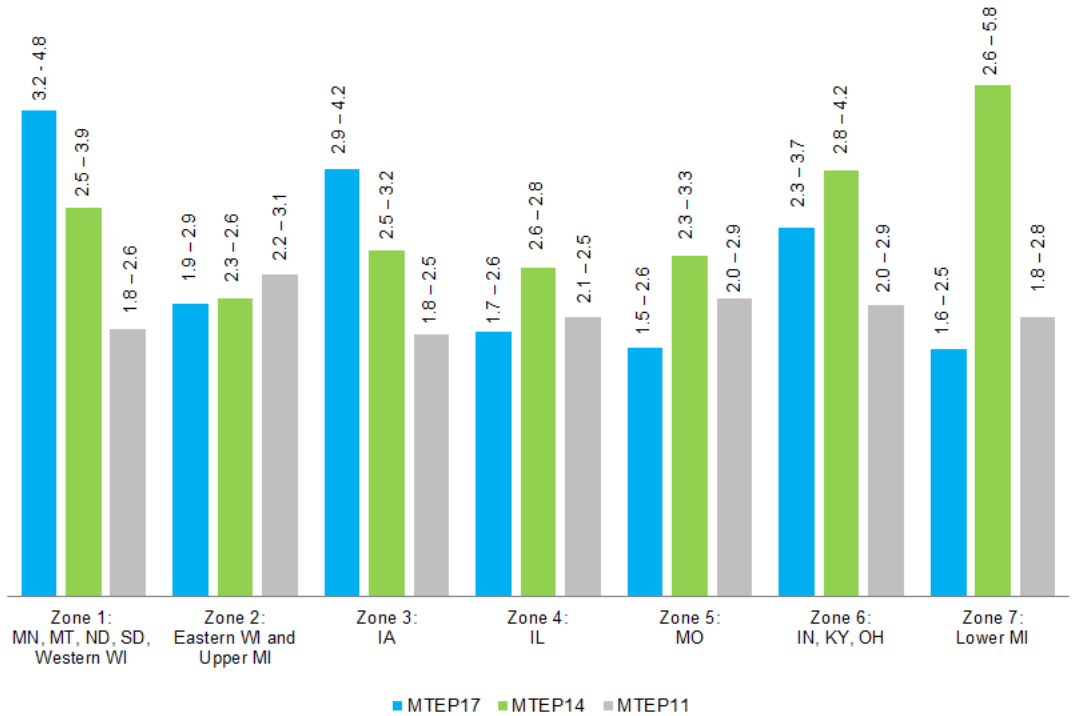


Figure 2-1: Zonal benefit to cost ratios for the original MTEP11 MVP Analysis
and subsequent MTEP14 and MTEP17 Triennial Reviews

In the years immediately following the approval of the MVP portfolio, the level of annual investment put forward in MTEP reports returned to historical levels of approximately $1.5 billion annually. Upgrades or replacements of aging assets, and the added investment associated with the integration of the South Subregion have contributed to the annual average investment rising to $3.4 billion over the last five years, but still well below the level approved in 2011 with the MVPs. While this increased rate of investment is strengthening the grid in the MISO Region, it is not reflective of the magnitude of change that has been occurring across the landscape during this time.

3 The Long Range Transmission Planning Component of MISO's Broad-Based Response to Current Industry Change

The generation mix evolution in the MISO Region that drove the need for the MVP portfolio didn't end with that portfolio's approval. In fact, the pace towards more renewables has increased since that time. Progressively increased carbon-free and clean energy goals set by MISO member utilities, state and municipal government policies and customer preferences continue to drive growth in wind, solar, battery storage and hybrid projects. MISO made a number of incremental changes to its markets, tools, and processes along the way to mitigate the early impacts of this change. However, beginning in 2016, the challenge was becoming obvious and more difficult to mitigate.

Change Drivers and Implications Contributing to Aligning Interests

Over the last several years, MISO began to experience operational situations that required the use of emergency procedures, even outside of the summer period when demand peaks occur, and supply becomes strained. In the real time horizon, when resource margins are projected to be significantly low, MISO will begin to implement the steps in its emergency procedures in an attempt to gain access to additional resources. While not having to make a single emergency declaration in the two years preceding 2016, 41 such emergency declarations have been required since 2016. These events are largely the result of reduced generation capacity due to the retirement of conventional generation as the fleet has transitioned toward more renewable resources and greater reliance on Load Modifying Resources for meeting capacity requirements.

Figure 3-1: Historical MISO MaxGen Alerts, Warnings, and Events

In response to this growing challenge, MISO launched the Resource Availability and Need (RAN) initiative to understand the drivers and identify a variety of changes to markets and resource adequacy process solutions to generation availability issues.

At the same time, and driven by the ongoing fleet shift, MISO executed a multiple-year study called the Renewable Integration Impact Assessment (RIIA) to deepen its understanding of the implications of more renewable generation on the system. This assessment identified inflection points, or renewable energy penetration levels where challenges would get increasingly more complex. It also identified key risks that would result, including insufficient transmission infrastructure.

Figure 3-2: RIIA Study Identified Key Risks with increasing levels of Renewable Energy

The timing of when the region would reach these inflection points was then uncertain. However, an additional driver emerged that accelerated the pace towards more renewables: a growing customer preference for clean energy. MISO began to see a growing number of member utilities and state policies incorporating decarbonization goals into their resource fleet strategies. Around this same time another trend was emerging on the demand side as well. The movement towards electrification will have a significant impact on electricity demand, which has in recent years been relatively stable.

This level of uncertainty makes it very difficult to plan for the future with confidence. However, as demonstrated with the development of the 2011 MVP portfolio, MISO has an existing process to effectively manage these types of risks. MISO, in collaboration with stakeholders, establishes future planning scenarios to understand the economic, policy and technological impacts on future resource needs. Starting in 2019, MISO examined three future scenarios to define and bookend regional resource expectations over the next 20 years (MISO Futures Report[1]). These Futures recognize the widespread clean energy goals of states and utilities within the region, as well as the associated rapid pace of regional resource transformation.

[1] MISO Futures Report

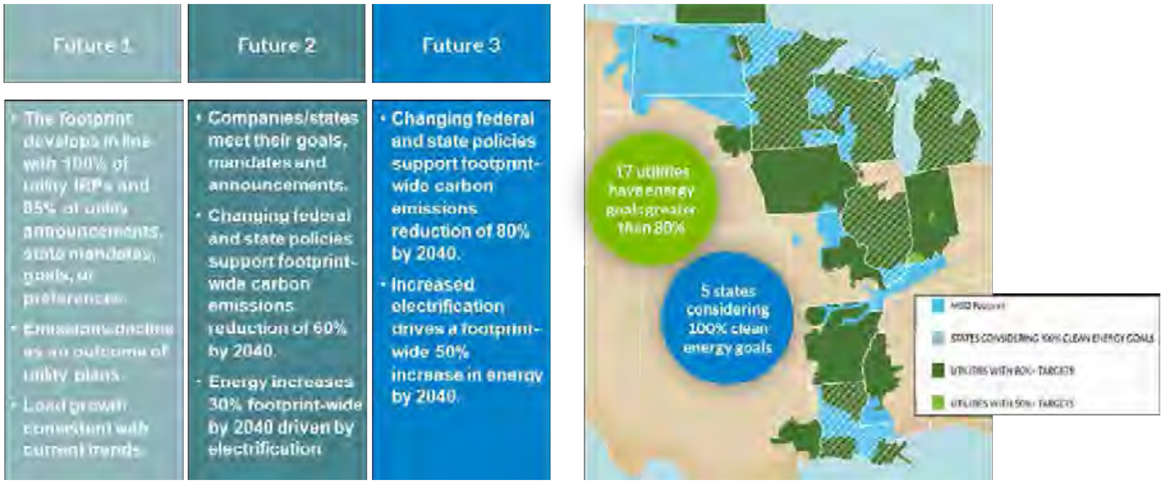


Figure 3-3: MISO Futures Key Drivers

MISO's Reliability Imperative Response: The Long Range Transmission Planning Initiative

These future scenarios reflect the significance of the changes the region must prepare for, and similar to the situation facing the region back in 2007, incremental changes will no longer be adequate. The magnitude of landscape changes has created an imperative for transformational changes across MISO's markets, planning, operations, and technology. The Reliability Imperative Report[2] documents the collection of related initiatives that address the growing risks and that are required to enable member resource plans and strategies. MISO, members, regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges.

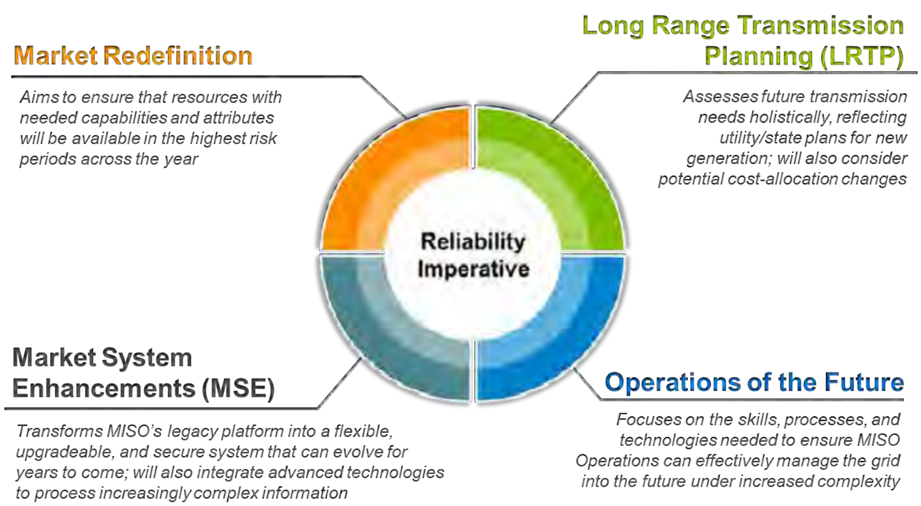


Figure 3-4: MISO's Reliability Imperative Key Initiatives

[2] MISO'S Response to the Reliability Imperative

As work has been underway, an additional risk emerged that has increased the urgency associated with progressing these initiatives. An increase in the frequency of extreme weather events is exacerbating the risks and challenges that originally drove the need for the Reliability Imperative. These types of scenarios can force a large number of generators out of service in a local area, putting reliability at risk. This has contributed to the emergency procedure declarations over the last several years (Figure 3.1).

Robust Business Case for Long-Range Transmission Plan

As the region faces both a changing resource fleet and increased prevalence of extreme weather events, the ability to move electricity from where it is generated to where it is needed most becomes paramount. One needs only to consider the need for increased power flow within and between regions during Winter Storm Uri in February 2021 to understand the importance of transfer capability. MISO can leverage its large geographic footprint and diversity of resources to ease some of these challenges. However, adequate transmission infrastructure is key.

With the landscape once again shifting and expected to do so even more dramatically in the future, the transmission planning aspect of the Reliability Imperative includes the second execution of MISO's long-range transmission planning process. The MISO LRTP initiative, introduced to stakeholders in August 2020 to invite their collaboration, provides a regional approach to transmission planning that addresses future challenges of the resource fleet evolution and electrification. The transformational changes occurring in the industry necessitate the identification of transmission solutions to ensure continued grid reliability and cost-effective transmission investments that will serve future needs.

The objective of LRTP is to provide an orderly and timely transmission expansion plan that supports these primary goals:

- **Reliable System** – maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply
- **Cost Efficient** – enable access to lower-cost energy production
- **Accessible Resources** – provide cost-effective solutions allowing the future resource fleet to serve load across the footprint
- **Flexible Resources** – allow more flexibility in the fuel mix for customer choice

LRTP is designed to assess the region's future transmission needs in concert with utility and state plans for future generation resources.

LRTP is a multi-year effort to address the myriad and complex issues associated with the significant resource transformation underway. Because there is urgency to keep pace with this rapid evolution, MISO is seeking to recommend projects identified in the LRTP effort over several MTEP cycles as work progresses. While it is important to move quickly, MISO must ensure reliable power delivery for customers with investment decisions that appropriately balance generation and transmission solutions on a regional scale to ensure the best cost outcomes for customers.

LRTP continues the MISO Value-Based Planning approach to extend value beyond the traditional planning processes to achieve a more efficient comprehensive long-term system plan.

Tariff Requirements

The needs driving the LRTP portfolio, the scope of the projects and types of benefits they enable aligns relatively well with those of the MVP portfolio and the associated MVP tariff requirements are being applied for the LRTP. The criteria to meet the project definition are listed in their entirety in Section 2, and in summary are: 1) enable the transmission system to reliably and economically deliver energy in support of documented energy policy mandates or laws, 2) provide multiple types of economic value, with a benefit-to-cost of 1.0 or greater, or 3) address at least one reliability issue and provide at least one type of transmission-based economic value.

LRTP Cost Allocation Aligned with Beneficiaries

A condition that must be met prior to any transmission investment being approved is to determine how the costs will be allocated. The original MVP ruleset established a cost allocation methodology of spreading costs footprint-wide on a load-ratio share basis. With the initial Tranche of LRTP projects identified to address reliability issues in MISO's Midwest Subregion only, this approach was not going to meet FERC's requirement of costs spread roughly commensurate with benefits.

To address this risk, MISO proposed a modified MVP methodology where costs could be spread to a subregion only, if the projects within the portfolio primarily provide benefits to a single subregion. This proposal was approved by FERC on May 18, 2022 with a May 19, 2022 effective date. With FERC's approval the costs of the LRTP Tranche 1 Portfolio will be recovered on a pro-rata basis from load in the MISO Midwest Subregion.

4 Rigorous, Collaborative Approach Ensures Robust LRTP Solutions

With this being the second execution of MISO's long-range transmission planning process, it was not groundbreaking, but it is no less significant than the first execution that developed the 2011 MVP portfolio. In fact, the landscape changes being planned for are much more significant now and require prompt action to address the fast pace of transformational changes occurring in the industry. The initial tranche of LRTP projects was developed in a focused effort to deliver a set of least regrets solutions that would be ready to address needs in the next 10 years.

While the process was executed in significantly less time, the quality of the analysis and commitment to identifying robust solutions was not sacrificed. This portfolio of projects represents over 2,000 miles of transmission, a significant level of investment unprecedented in the industry and will have its benefits and costs shared broadly. Given this backdrop, it is incumbent on MISO to perform a rigorous analysis to ensure we identify a robust set of projects that most effectively and efficiently resolve the identified issues and future system needs.

The process MISO follows to identify projects and create a portfolio is designed to result in a business case that justifies the investments. As described in Section 3 of this report, the first step in this process is to create potential future scenarios, or Futures, to essentially establish a target for our planning efforts. In some situations, the Futures could bookend very different directions for the region's generation fleet due to uncertainty around energy policy and other factors. However, given the current clear trends that include Members and States increasingly establishing clean energy goals, the continued retirement of fossil fueled resources from the system, and a growing trend toward electrification, the current set of futures reflect different progressions or the velocity of change in that singular direction.

MISO developed a long range conceptual regional transmission plan to explore and further study possible solutions needed to address future transmission needs. The conceptual plan serves as a set of solution ideas that guide the development of candidate transmission projects that meet the objective of long range planning to achieve reliable and economic delivery of energy in a range of future scenarios. Reliability analysis is conducted on a series of study models that represent various system conditions and dispatch patterns to identify issues. MISO then evaluates the candidate projects and potential alternative solutions developed by MISO and stakeholders to identify the most effective transmission investments to address the issues and performs an economic analysis that factors into selecting the best of the options. Section 5 of this report is a detailed walk-through of the reliability analysis that was undertaken, with the results provided in Section 6.

Once the portfolio of projects is identified, MISO then calculates the economic benefits created by the portfolio. The primary objective of the LRTP projects was to address reliability issues identified in the planning studies that considered a range of system conditions. However, while transmission investments are usually built for a specific purpose, the value that any particular investment brings can extend well beyond addressing the singular issue driving it. That is especially true for investments like the LRTP projects, whose regional scope and high voltage levels can enable significant economic benefits as well.

While the objective of LRTP is primarily focused on the need for reliable energy delivery, the analysis of economic benefits is essential to the demonstration of value of the portfolio as required by the Tariff for eligibility as regionally cost shared projects. The economic benefit types that can be assessed were identified in Section 2 of this report in the discussion on Multi-Value Projects, which the LRTP will be categorized as. The specific metrics that were used to determine the economic benefits of the LRTP portfolio are:

- Congestion and fuel savings – LRTP projects will allow more low-cost renewables to be integrated, which will replace higher-cost resources and lower the overall production cost to serve load.
- Avoided local resource capital costs – LRTP projects will allow renewable resource build-out to be optimized in areas where they can be more productive compared to a wholly local resource build out.
- Avoided future transmission investment – LRTP projects will reduce loading on other transmission lines, in some cases preventing lines from becoming overloaded in the future and thus avoiding the need to upgrade those lines.
- Reduced resource adequacy requirement – LRTP projects will expand transfer capability, which will in certain situations increase the ability for a utility to use a new or existing resource from another part of the MISO region, rather than construct one locally, to meet its resource adequacy obligation.
- Avoided risk of load shed – the LRTP portfolio will increase the resilience of the grid and lower the probability that a major service interruption occurs.
- Decarbonization – the higher penetration of renewable resources that the LRTP portfolio will enable will result in less CO_2 emissions.

The methodology used to calculate each of these economic benefits and the results are the focus of Section 7.

As described in Section 8 of this report, the allocation of LRTP portfolio costs is spread broadly to the entire Midwest Subregion. The Federal Energy Regulatory Commission requires that transmission costs associated with investments of this nature be allocated roughly commensurate with how the benefits are realized. Given the large-scale of the LRTP projects and the fact that they span the Midwest Subregion, benefits flow to the entire subregion. To illustrate this and demonstrate support of FERC's guidance, Section 8 shows the benefits by MISO Cost Allocation Zone.

Given the expected continued key role of natural gas generation, volatility in the price of natural gas can have a significant impact on the cost of producing electricity. The recommended LRTP Tranche 1 Portfolio can partially offset the gas price risk by providing additional access to generation powered by fuels other than natural gas. Chapter 8 includes a sensitivity analysis performed using a range of natural gas prices to demonstrate the robustness of the LRTP Tranche 1 Portfolio across a range of scenarios.

5 LRTP Tranche 1 Portfolio Development and Scope

Most good plans result not from a single work effort, but rather develop from refinements to an effective starting point. The latter characterizes the path to the LRTP Tranche 1 Portfolio. In anticipation of reliability needs in a future with growing renewable penetration and load consumption, MISO developed an indicative transmission roadmap of potential transmission expansions throughout the region for both Future 1 and a combined Future 1, 2, and 3. The roadmap provides an indication of the potential magnitude of transmission expansions that may be needed to maintain reliable and efficient operations under the expected Futures and candidate transmission solutions to be used as a starting point in determining potential projects. This roadmap was developed by MISO planning staff as extensions of the existing grid that would provide for logical connections that could increase connectivity, close gaps between subregions, and support a more robust and resilient grid by enabling the delivery of energy from future resources to future loads and increasing the reliance on geographic diversity to manage the increased dispatch volatility and uncertainty associated with the future resource fleet. The indicative roadmap is not a final plan but instead a starting point for considering solutions to transmission issues expected.

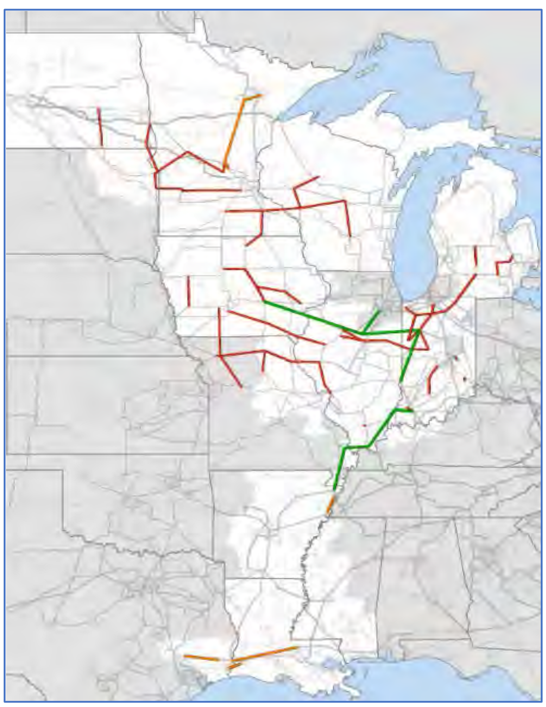


Figure 5-1: Future 1 Indicative Roadmap

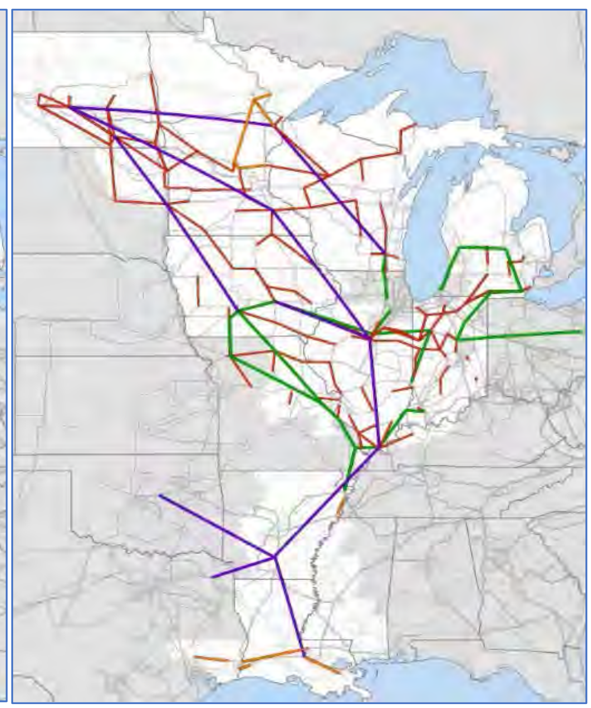


Figure 5-2: Futures 1, 2, & 3 Indicative Roadmap

The initial tranche of the LRTP is focused primarily on enabling the resource expansion and load forecasts associated with the 10- and 20-year timeframe under Future 1 in the Midwest

Subregion. In Future 1, the most significant aspects are resource retirements and increased renewable penetration.

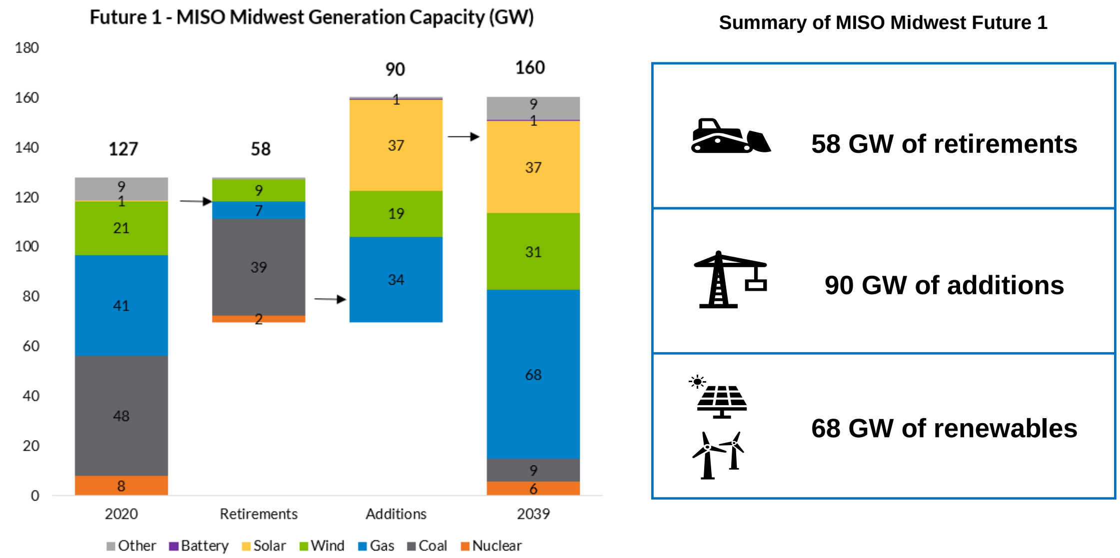


Figure 5-3: Future 1 changes in Generation Capacity for Midwest Subregion

In Futures 2 and 3, higher levels of resource retirements and renewable resource penetration coupled with higher levels of electrification will be significant. Later tranches of LRTP will focus more on Future 2 and Future 3 scenarios.

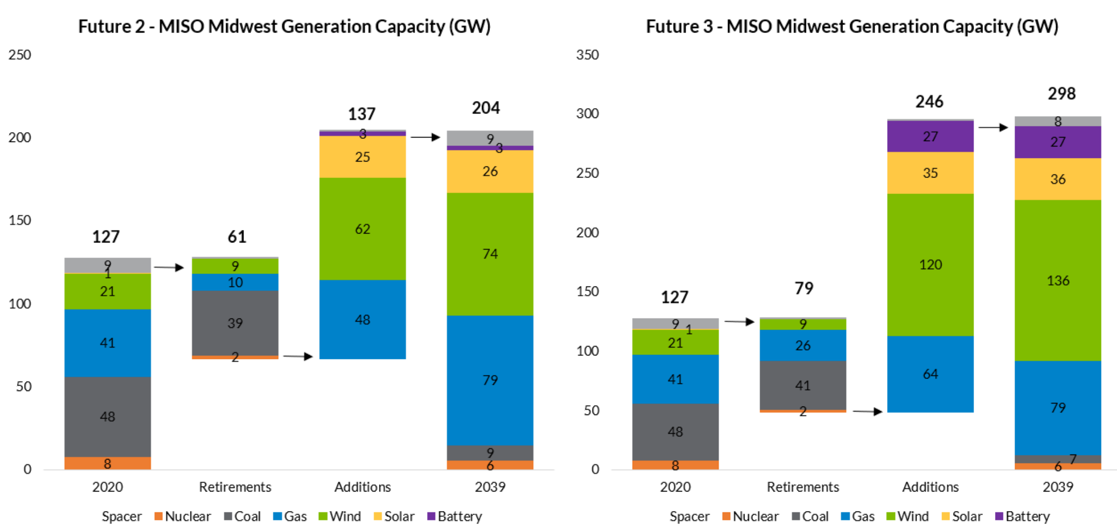


Figure 5-4: Future 2 & 3 changes in Generation Capacity for Midwest Subregion

Reliability Study Scope

MISO developed snapshots of system stress under a Future 1 resource expansion in the 10-year and 20-year timeframe. These scenarios, or base cases, vary based on season of the year, time of the day, load level, and coincident availability of renewable resources. MISO then used the scenarios to test the impact of the LRTP Tranche 1 Portfolio.

Model	Season	Hours	Range of dates and hours used to characterize the model	LRTP modeling definition of load level
1	Summer Peak	Day	Summer :6/21 to 9/20 Hours ending 7:00 to 22:00 EST	The Summer Peak demand expected to be served. (system load >=90 percentile during day)
2	Summer Peak	Night	Summer: 6/21 to 9/20 Hours NOT ending 7:00 to 22:00 EST	The Summer Peak demand expected to be served (system load >=90 percentile during night)
3	Fall/Spring Light load	Day	Fall: 9/21 to 12/20 Spring: 3/21 to 6/20 Hours ending 8:00 to 21:00 EST	Fall / Spring Light load within 50-70% of Summer Peak (Day)
4	Fall/Spring Light load	Night	Fall: 9/21 to 12/20 Spring: 3/21 to 6/20 Hours NOT ending 8:00 to 21:00 EST	Fall / Spring Light load within 50-70% of Summer Peak (Night)
5	Fall/Spring shoulder load	Day	Fall: 9/21 to 12/20 Spring à 3/21 to 6/20	70% to 80% of the Summer Peak Load (Day)
6	Winter Peak	Day	Winter: 12/21 - 3/20 Hours ending 8:00 to 19:00 EST	The Winter Peak demand expected to be served (system load >=90 percentile during day)
7	Winter Peak	Night	Winter: 12/21 - 3/20 Hours NOT ending 8:00 to 19:00 EST	The Winter Peak demand expected to be served (system load >=90 percentile during night)

Table 5-1: Temporal and load parameters for defining base models

The purpose of the reliability study is to ensure the MISO Transmission System can reliably deliver energy from future resources to future loads under a range of projected load and dispatch patterns associated with the Future 1 scenario in the 10-year and 20-year time horizon. The analysis includes ensuring transmission system performance is reliable and adequate with both an intact system and one where contingencies have occurred, and high regional power transfer scenarios that result when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty. Techniques used to analyze projected performance with and without the proposed transmission solutions included steady state contingency analysis to identify thermal loading and voltage issues under normal and contingency conditions, transfer analysis to ensure MISO can rely upon geographic diversity to manage renewable dispatch volatility and uncertainty and voltage stability analysis to ensure voltage stability in the Midwest subregion.

Steady-state contingency analysis is performed to identify any thermal and voltage violations that exist in the seven base reliability cases for each of the 10-year and 20-year models. The analysis requires simulation of the MTEP20 NERC Category P0, P1, P2, P4, P5, and P7 contingency events and selected NERC Category P3, P6 events. Facilities in the Midwest Subregion were monitored for steady state thermal loading in excess of 80% of applicable ratings and for voltage violations per the Transmission Owner voltage criteria.

Transfer analysis is performed to test for robust performance under varying dispatch patterns. The LRTP transfer study includes eight transfer scenarios to assess import requirements in situations where unexpected loss of renewable and thermal resources could occur due to changing weather conditions.

Scenario	Description	Objective	Resource	Sink
1	Central to Iowa	Support resource deficient areas due to unexpected drops in high concentration areas of renewables	All Gen. Local Resource Zones (LRZ) 4-6	Wind in LRZs 1&3
2	MISO to Michigan	Support resource deficient areas due to unexpected drops in high concentration areas of renewables	Renewables in LRZs 1-6	Renewable in LRZ 7
3	Michigan to MISO	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	Renewables in LRZ 7	Renewables in LRZs 1-6
4	Iowa/MN to MH	Support resource deficient areas due to unexpected high magnitude resource outages due to extreme weather events (Uri, polar vortex) – renewable or thermal	Renewables in LRZs 1 and 3	Manitoba Hydro load
5	MISO West to Wisconsin	Support resource deficient areas due to unexpected high magnitude resource outages due to extreme weather events (Uri, polar vortex) – renewable or thermal	Renewables in LRZs 1 and 3	Renewables in LRZ 2
6	Central Renewables to rest of MISO Midwest	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	Renewables in LRZs 4-6	Gen. in LRZs 1,2,3,7
7	MISO Midwest to Central Region	Ensure reciprocal export capability to MISO Subregions in high resource deficiencies	Gen. in LRZs 1,2,3,7	Gen. in LRZs 4-6
8	MISO West to East across the Mississippi	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	MISO West of the Mississippi River Renewables in LRZs 1,2,3,5	MISO East of the Mississippi river Gen. in LRZs 4,6,7

Table 5-2: Transfer Scenarios

Economic analysis supports reliability analysis evaluation of project candidates as needed for selecting the preferred solutions. Production cost simulations analyze the impact of the proposed project on production costs to assess how the economic performance of a project compares to other alternatives that have been proposed. These results are used to supplement the reliability analysis results and provide an additional measure of economic performance to aid in selecting the preferred solution.

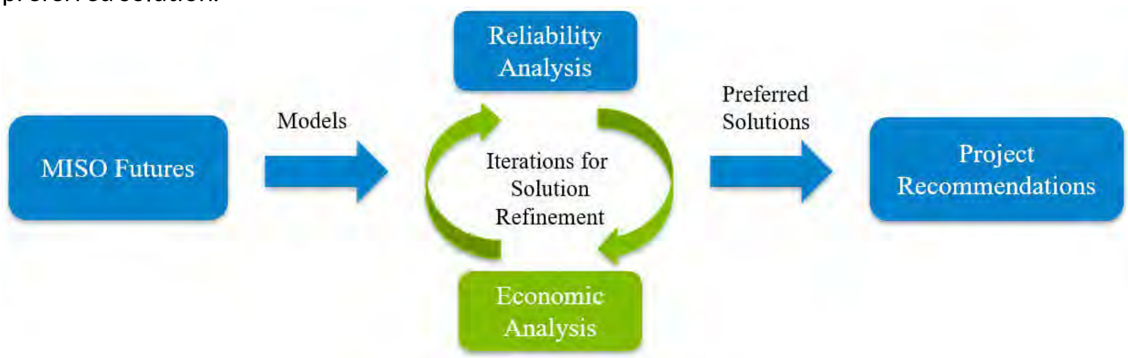


Figure 5-5: Iterative Solution Refinement

The results of the reliability analysis contained in Section 6 of this report discusses the detailed results from this iterative selection process and explains the reasons for selecting the preferred solution, including a summary of any significant economic analysis findings, for projects to be included in the LRTP Tranche 1 Portfolio.

6 LRTP Tranche 1 Projects and Reliability Issues Addressed

The reliability studies were performed on the Future 1 power flow models to assess the system performance and identify any necessary upgrades to ensure reliable energy delivery under different load and dispatch patterns. Analysis of the Future 1 10-year and 20-year base case models without the LRTP Tranche 1 Portfolio indicated numerous thermal and voltage violations throughout the Midwest Subregion. Additionally, transfer analysis was performed to assess transfer capability and identify limiting constraints to be addressed to assess effectiveness of projects under broader future assumptions. Variations of candidate projects identified in the LRTP indicative roadmap were studied to determine areas of focus for project development.

It is important to understand that LRTP is not a NERC compliance study whereby every issue identified must be resolved according to NERC standards and requirements. A NERC compliance study, which is more local in nature in terms of modeling assumptions, is different than the approach taken in a long-range transmission planning study. From that perspective, the LRTP reliability solution testing sought to find solutions that provided a balance between issues resolved and cost to mitigate. This included discounting some issues, for example, as more local in nature or others that will be dealt with in the generator interconnection process. It is also related to the fact that more study work will be done in the next tranches using other Futures and additional needs will be dealt with at that time.

In doing so, MISO used the roadmap as a starting point for testing system solutions but also looked to alternative solutions either from MISO or submitted by stakeholders. Several alternatives have been considered for the Tranche 1 effort. The final portfolio represents those solutions that provided the best fit solution. It is also important to note that the ability to efficiently use existing corridors in developing transmission is a key element. As final solutions were developed, the ability of those solutions to use existing system right of way was a key consideration. Ultimately though final routing will be determined by the applicable state and/or local authorities.

Project selection involved detailed analysis in five geographic focus areas:

- Dakotas and Western Minnesota
- Minnesota – Wisconsin
- Central Iowa
- Northern Missouri Corridor
- Central-East Corridor

Figure 6-1: LRTP Tranche 1 Transmission Portfolio

Dakotas and Western Minnesota

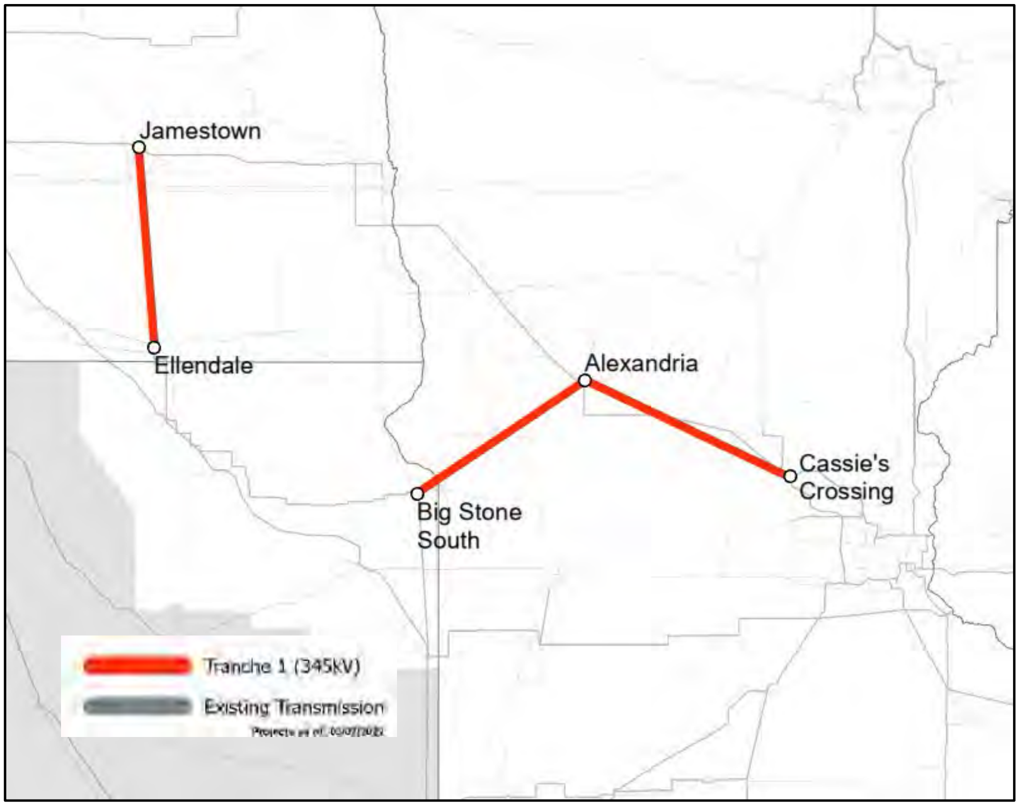


Figure 6-2: Dakotas and Western Minnesota Final Solution

Projects:
Jamestown - Ellendale 345 kV
Bigstone – Alexandria – Cassie's Crossing 345 kV

Rationale:
The Eastern Dakotas and Western/Central Minnesota 230 kV system is heavily constrained for many different seasons through the year. This 230 kV system has been playing a key role in transporting energy across a large geographical area as generation is needing to be transported out of the Dakotas and into Minnesota. Under shoulder load levels and high renewable output, this energy has a bias towards the Southeast into the Twin Cities load center. During peak load, particularly in Winter, this system is a key link for serving load in central and northern Minnesota. The 230 kV system is at capacity and shows many reliability concerns not only for N-1 outages in Future 1, but also for system intact situations. The 345 kV lines in the area provide additional outlets for the Dakotas by tying two existing 345 kV systems together. These lines unload the 230 kV system of concern and improve reliability across the greater Eastern Dakotas and Minnesota.

Issues Addressed:

The Dakotas and Western Minnesota project addresses many thermal and voltage issues for Western Minnesota and Eastern Dakotas. Most notable, the 230 kV system from Ellendale and Big Stone South to Fergus Falls is relieved for all N-1 and N-1-1 outages, as you can see in Figure 6-3 geographically. The solid green lines in Figure 6-3 depict Transmission Lines which no longer have overloads because of the project with circles depicting transformers that are relieved. Voltage depression was seen for a wide geographical area along the South Dakota, North Dakota, and Minnesota border typically described as the Red River Valley Area. Table 6-1 describes overloads seen in Future 1 for the Dakotas and Western Minnesota area which are relieved by the Big Stone South – Alexandria – Cassie's Crossing & Jamestown – Ellendale project. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

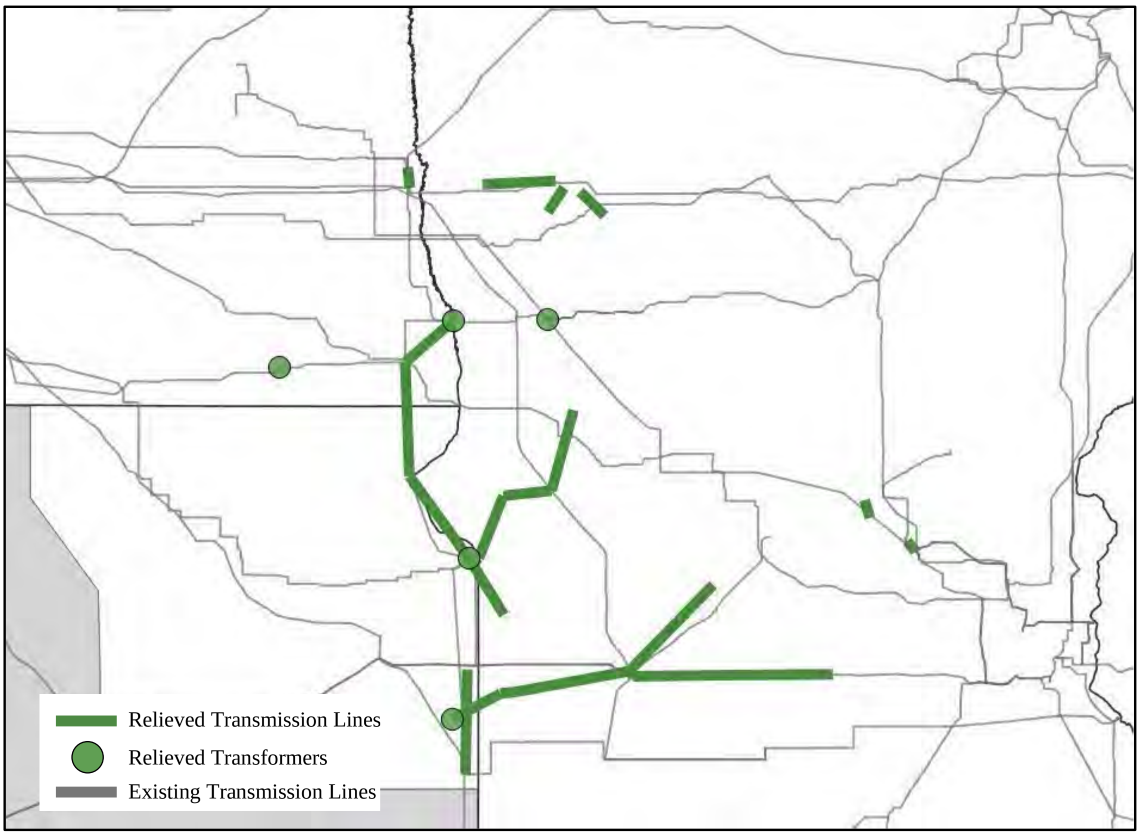


Figure 6-3: Dakotas and Western Minnesota map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	40	214	70	209
230 kV Lines	18	157	25	153

Table 6-1: Elements with thermal issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Minimum p.u. voltage Pre-Project	Count Elements	Minimum p.u. voltage Pre-Project
All	97	0.80	91	0.81
345 & 230 kV Buses	23	0.80	30	0.81

Table 6-2: Elements with voltage issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases for the OTP area (620)

Alternatives Considered:
Big Stone South – Alexandria 345 kV & Jamestown – Ellendale 345 kV
Without double circuit to Cassie's Crossing there are new N-1 issues around Alexandria.

Big Stone South – Hankinson – Fergus Falls 345 kV & Jamestown – Ellendale 345 kV
Solves overloads of concern on 230 kV system around Wahpeton but creates new issues on the 230 kV and 115 kV system around Fergus Falls.

Big Stone South – Hazel Creek – Blue Lake 345 kV & Jamestown – Ellendale 345 kV
Reduces nearly all overloads of concern but not to the extent of the preferred project.

Big South – Alexandria 345 kV & Big Stone South – Hazel Creek – Blue Lake 345 kV & Jamestown – Ellendale 345 kV.
Combination of alternative 1 and 3. This alternative creates new overloads on the 115 kV system around Alexandria but fully relieves reliability issues of concern as the preferred project. However, as this is a combination of alternatives, the southern circuit to Blue Lake (Alternative 3) does not add enough additional value over the preferred project.

Big Stone South – Breckenridge – Barnesville 345 kV & Jamestown – Ellendale 345 kV
Solves many issues in the area of concern without any new issues. However, there are still a few key overloads on the key 230 kV system around Wahpeton which are not solved by this alternative.

Western Minnesota - Dakota

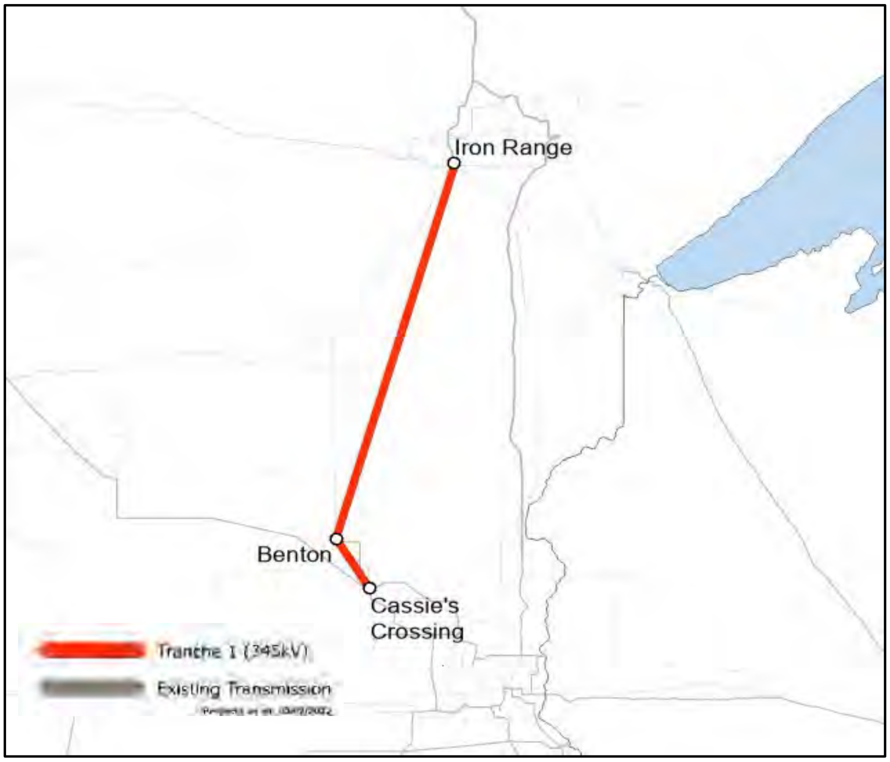


Figure 6-4: Western Minnesota - Dakota Final Solution

Project:
Iron Range – Benton - Cassie's Crossing 345 kV

Rationale:
Minnesota has and is projected to continue to undergo fleet change. This generation shift has resulted in central and northern Minnesota to have a drastic decrease in generation resources creating a large geographical area to be served by only 115 kV and 230 kV transmission. Central to northern Minnesota has moderate load, with heavy load being further north relating to iron mining operations. During the winter, Minnesota load increases significantly. This causes strain on the widespread 115 kV and 230 kV system as power is needing to get from the twin cities to the north to serve load. This large geographical disparity in generation and weak transmission causes voltage stability concerns for a majority of the Minnesota system north of the Twin Cities. The Iron Range – Benton – Cassie's Crossing 345 kV line provides a second low impedance path for power flow from southern Minnesota to the north. This unloads and relieves the 115 kV and 230 kV issues seen and relieves voltage stability concerns.

Issues Addressed:

Iron Range – Benton – Cassie's Crossing 345 kV prevents many thermal and voltage issues on the lower voltage system in central and northern Minnesota, especially for situations where the single 500 kV line heading north from the Twin Cities is lost. Under heavy winter loading situations central and northern Minnesota suffer from voltage collapse issues during transfer scenarios.

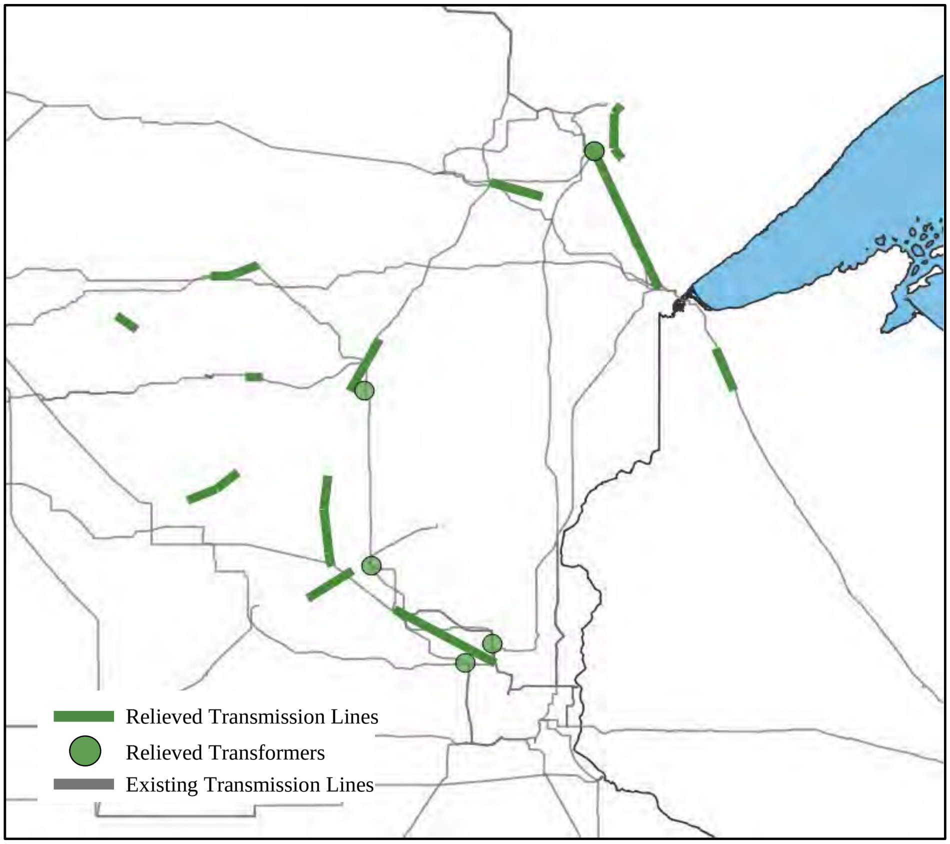


Figure 6-5: Central and Northern Minnesota map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

The chart below is a graph of the Red River Valley area (northwestern Minnesota) voltage after loss of the 500 kV line from Chisago to Forbes for varying levels of transfer to the north through Minnesota. Without Iron Range – Benton – Cassie's Crossing voltage collapses for transfers less than 500 MW. Post project, transfers through Minnesota can be greater than 2000 MW without voltage collapse.

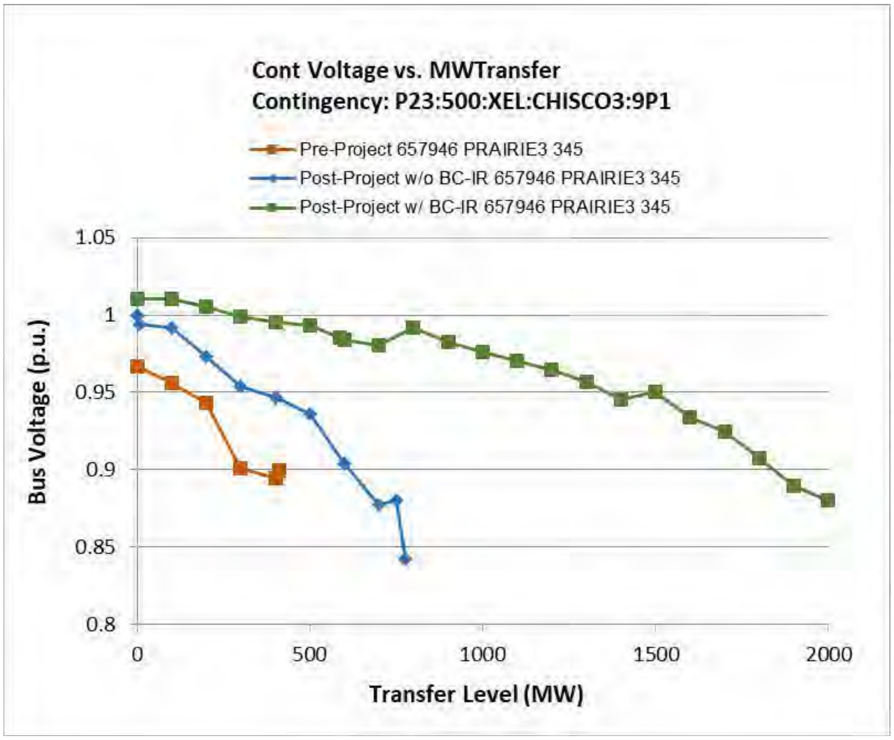


Figure 6-6: Voltage Stability Analysis P-V curve for Minnesota transfers after losing the 500 kV lines from Chisago to Forbes

The tables below describe thermal and voltage issues relieved by the Iron Range to Benton to Cassie's Crossing 345 kV line. Figure 6-5 shows geographically lines and transformers relieved by the project. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	15	110	25	165

Table 6-3: Summary of elements relieved by the Minnesota – Wisconsin projects in Future 1 power flow cases.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Minimum p.u. voltage Pre-Project	Count Elements	Minimum p.u. voltage Pre-Project
All	23	<0.80	105	0.80
230 kV Buses	3	0.93	18	0.85

Table 6-4: Elements with voltage issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases for the MP area (608).

Alternatives Considered:

1. Iron Range – Alexandria 500 kV
2. Iron Range – Arrowhead 500 kV
3. Iron Range – Bison 500 kV
4. Iron Range – Benton 500 kV

A study interface was created to analyze alternatives to the Iron Range – Benton – Cassie's Crossing line. This interface is defined as the northern Minnesota interface (NOMN) which includes the Forbes – Chisago 500 kV line and six underlying 230 kV lines which connect central and northern Minnesota to the Twin cities and North Dakota. This interface was determined to study the system's ability to meet two primary goals.

1. Understand an operating limit for central and northern Minnesota to ensure the ability to serve peak load with a 10% or greater stability margin.
2. Maintain the ability to serve the existing 1400 MW Manitoba Import Limit while also achieving goal 1.

The proposed project, Iron Range – Benton County – Cassie's Crossing double circuit 345 kV meets both goals. Alternatives 1 (Iron Range – Alexandria 500 kV), 2 (Iron Range – Arrowhead 500 kV), and 3 (Iron Range – Bison 500 kV) do not achieve the above goals. Alternative 4 (Iron Range – Benton 500 kV) achieves both goals, however the double circuit 345kV was chosen for many reasons over the 500 kV as described below:

a. Double circuit 345 kV has a higher capacity
    i. 500 kV: 1732 MVA
    ii. 345 kV: 1195 MVA per circuit (2390 MVA Total)
b. Double circuit 345 kV is cheaper per mile compared to 500 kV
    i. 500 kV: $3,036,384 per mile
    ii. 345 kV: $2,829,742 per mile
c. A double circuit creates two lines for N-1 protection
d. Series compensation near Riverton would allow for easier 345/230 kV conversion for future expansion and support for central Minnesota as 345 kV to lower kV is more standard in the Minnesota area than 500 kV to lower kV transformation

Minnesota – Wisconsin

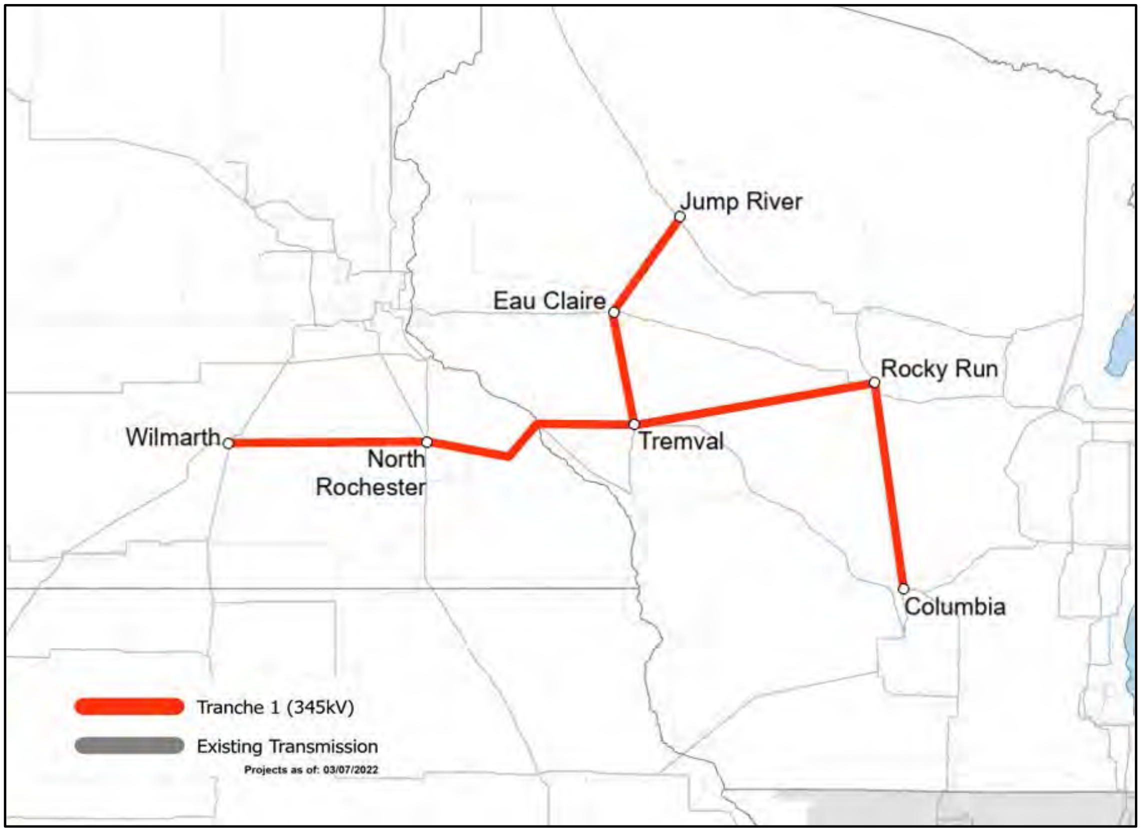


Figure 6-7: Minnesota-Wisconsin Final Solution

Projects:
Wilmarth – North Rochester – Tremval – Eau Claire – Jump River 345 kV
Tremval – Rocky Run – Columbia 345 kV

Rationale:
The transmission system in southern Minnesota is a nexus between significant wind and renewable resources in Minnesota and North and South Dakota, the regional load center of the Twin Cities, and transmission outlets to the East and South. In a future with significant renewable energy growth, MISO sees strong flows West to East across Minnesota to Wisconsin and a need for outlet for those renewables in times of high availability to deliver that energy to load centers in MISO. The Minnesota to Wisconsin projects relieve constraints in the Twin Cities metro area due to high renewable flow towards and past the Twin Cities load center. The projects also reinforce the outlet towards load centers in Wisconsin, providing relief of congestion as well as easing both thermal loading and transfer voltage stability.

Issues Addressed:
The Minnesota – Wisconsin series of projects work together to relieve a number of related issues. Table 6-5 summarizes overloads seen in the Future 1 models which are relieved by the LRTP Tranche 1 Portfolio attributed to the Minnesota – Wisconsin set of projects. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project. Those same elements are shown on a map in Figure 6-8.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	39	95-132%	96	95-151%
345 kV Lines	6	98-119%	9	97-120%
345/xx kV Transformers	9	97-132%	12	95-132%

Table 6-5: Summary of elements relieved by the Minnesota – Wisconsin projects in Future 1 power flow cases

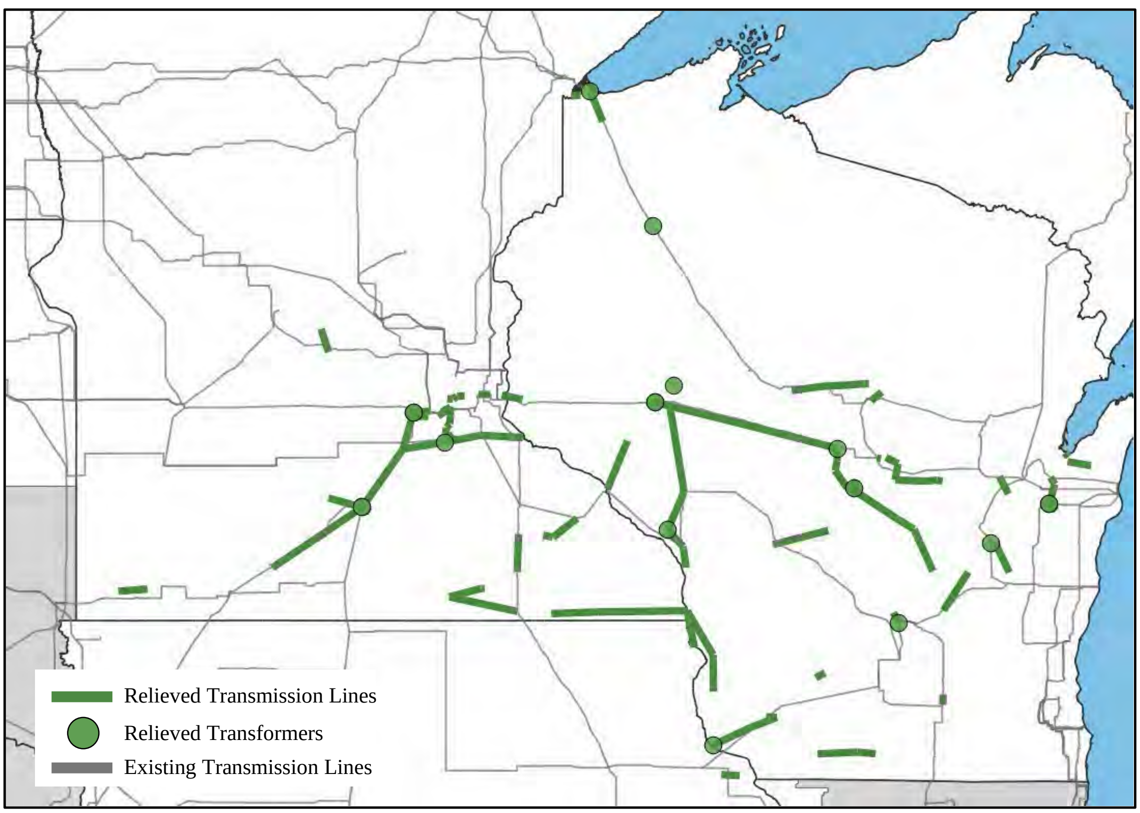


Figure 6-8: Map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Wilmarth to North Rochester parallels a number of 345 kV lines across the Southern Twin Cities that are heavily loaded under high renewable output from southwestern Minnesota and northwestern Iowa. In doing so, it relieves several 345 kV lines and 345/115 kV transformers in the region including Wilmarth – Shea's Lake – Helena – Chub Lake 345 kV and 345/115 kV transformers at Wilmarth and Scott County. These increased flows cause new congestion and overloads on the existing Crandall – Wilmarth 345 kV line. This project includes the rebuild of that line. If uprated, the congestion savings associated with the Wilmarth – North Rochester circuit specifically, and the rest of the Minnesota – Wisconsin project generally, increase significantly.

The connection out of North Rochester towards Tremval and east creates a lower impedance path that pulls power across Wilmarth – North Rochester and diverts power from other heavily loaded Twin Cities facilities, increasing the efficacy of that line. The sections from Tremval to Eau Claire and Jump River relieve loading on a handful of 161 kV and 115 kV facilities in Northwest Wisconsin. Those facilities increase the redundancy of the two Northern 345 kV circuits across Wisconsin and relieve overloads seen on one of the Eau Claire 345/161 kV transformers.

The new path from Tremval to Rocky Run to Columbia completes an outlet for renewable power flow across Wisconsin to the Madison and Milwaukee area load centers. These circuits also bolster voltage stability limited transfer capability across and into Wisconsin. It also relieves overloads on a variety of 345 kV and 138 kV facilities throughout central Wisconsin.

The traditional analysis of voltage stability for the voltage stability interface across Western Wisconsin uses a load to load transfer. MISO performed this analysis for a transfer using Local Resource Zone 2 (LRZ2, roughly comprised of ATC member companies in eastern and central Wisconsin) as the destination subsystem, to capture the impact of directly serving LRZ2 load. MISO measured the impact to voltage stability both with and without Tremval – Rocky Run and Rocky Run – Columbia segments are included in this project. The addition of these facilities adds 250 MW to the transfer capability. Figure 5-9 shows the post-contingent bus voltage for the most limiting bus and outage for either the pre-project or post-project case. Those buses and outages are:

Eau Claire 345 kV for loss of King – Eau Claire 345 kV
Eau Claire 345 kV for loss of Stone Lk. – Gardner Pk 345 kV
Briggs Rd. 345 kV for loss of Stone Lk. – Gardner Pk 345 kV

Both the steady state voltages and the final nose of the stability curve can be seen to improve, with the increase measured from either point being approximately 250 MW. MISO also reviewed this analysis for scenarios using a wide area load subsystem consisting of both Wisconsin load and loads further East in MISO's system. Those cases also showed an approximate increase of 250 MW in the low voltage and voltage stability limits of the system.

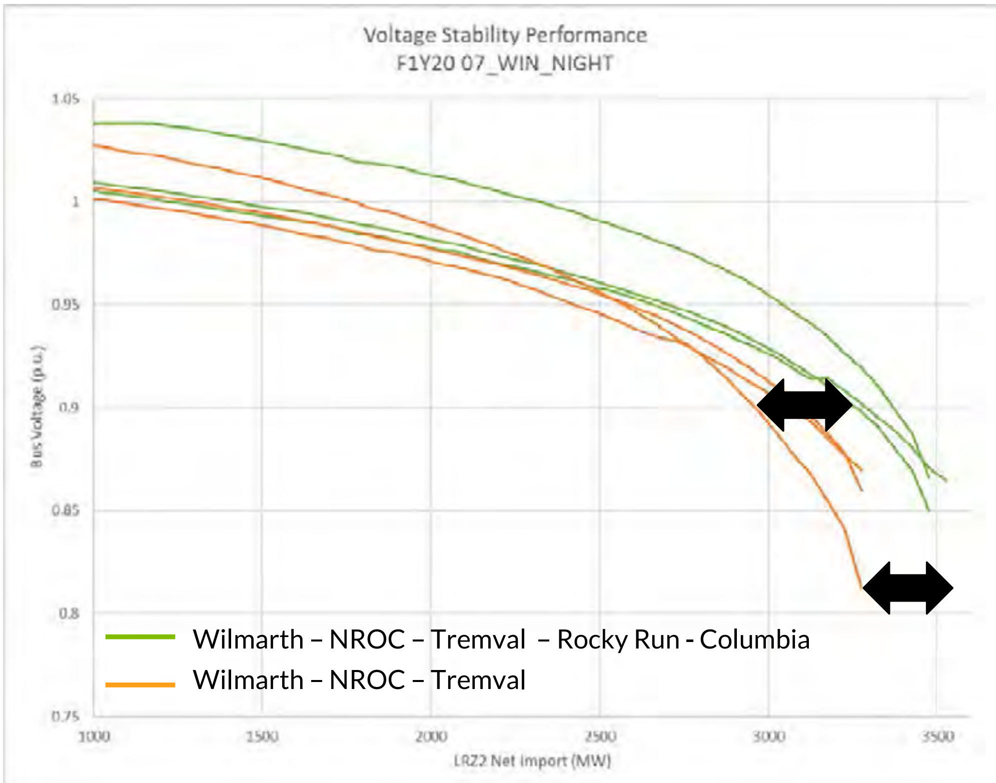


Figure 6-9: Voltage performance for key buses and outages for transfers into LRZ2.
Orange lines indicate buses and outages with just Wilmarth – North Rochester – Tremval 345 kV, while green lines indicate performance with Tremval – Rocky Run – Columbia 345 kV included as well

System Design Benefits of Tremval – Eau Claire – Jump River

To date there are three 345 kV lines that connect Minnesota to Wisconsin. The lines and their lengths are listed below:

Arrowhead – Stone Lake - Gardner Park:	220 Miles
King – Eau Claire – Arpin - Rocky Run:	183 Miles
North Rochester – Briggs Road – North Madison:	250 Miles

Assuming an average Surge Impedance Loading (SIL) value of approximately 400 MW for legacy 345 kV lines such as the ones above, the Safe Loading Limits on these three 345 kV long lines based on the St. Clair curve would be as follows:

Arrowhead – Stone Lake - Gardner Park:	460 MW
King – Eau Claire – Arpin - Rocky Run:	560 MW
North Rochester – Briggs Road – North Madison:	440 MW

Safe Loading Limits[3] were proposed to avoid or mitigate excessive operating risks by limiting the voltage drop along a transmission circuit to 5% or less while maintaining a Steady State Stability Margin of 30% or greater along the transmission circuit. The excessive 345 kV line lengths between Minnesota and Wisconsin result in safe loading limits for these 345 kV lines well below the thermal limits of the lines. Even more alarming is the fact that under an N-1 contingency, the combined Safe Loading Limit on the 345 kV MWEX lines would fall from 1,460 MW to 900 MW, and for an N-2 contingency, the combined Safe Loading Limit on the 345 kV MWEX lines would fall to 440 MW.

The addition of the fourth 345 kV circuit from Minnesota – Wisconsin will significantly improve the situation above by adding additional transmission capacity across MWEX. In the case of a North Rochester – Rocky Run line, the length and Safe Loading Limit of this additional 345 kV line would be as follows:

North Rochester – Rocky Run 345 kV Mileage:	162 – 187 Miles
North Rochester – Rocky Run Safe Loading Limit:	540 MW – 600 MW

While the fourth 345 kV circuit adds considerable benefit, for an N-2 contingency with the fourth 345 kV circuit added, the combined safe loading limit of the 345 kV circuits falls to about 900 MW.

An effective method to strengthen the four parallel 345 kV circuit is to add an intermediate connection between the four 345 kV circuits as close to the midpoint as possible. A major benefit of the Tremval 345 kV Substation and the Tremval – Eau Claire – Jump River 345 kV line is that under contingency conditions, the overall reduction in the combined Safe Loading Limit of the parallel 345 kV circuits is minimized. For example, for a loss of the Eau Claire – Arpin 345 kV circuit, a 345 kV connection remains between the King - Eau Claire 345 kV circuit, and the other three 345 kV lines across the MWEX interface. This not only mitigates loading issues on the transformers at Eau Claire, but also reduces the effective 345 kV impedance across the MWEX interface, which in turn increases the capacity and combined safe loading limit of the MWEX interface. In addition, because the King – Eau Claire 345 kV circuit is still connected at the midpoint of the MWEX interface, the distributed line capacitance associated with the King – Eau Claire 345 kV circuit is available to support voltages in western Wisconsin. Lower overall impedance coupled with higher distributed capacitance means a higher effective SIL for the MWEX interface under contingency conditions.

In summary, there are desirable benefits of tying together long lines at an intermediate point, and there are examples of this technique throughout North America. These types of system design benefits will be crucial to the success of the future transmission system to operate with reliability,

[3] Dunlop, R.D., Gutman, R., Marchenko, P.P., *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-98, No. 2, March/April 1979.

robustness, and resilience under a future with higher renewable generation penetration and electrification.

Alternatives Considered:

MISO reviewed a wide variety of project alternatives in the project focus area between Minnesota and Wisconsin – many of them submitted by stakeholders.

MISO began by reviewing the performance of an LRTP roadmap project against identified needs. This project included Wilmarth – North Rochester – Tremval – Eau Claire – Jump River as well as a double circuit rebuild between Adams and North Rochester, and a new 345 kV line from Colby to Adams. MISO found that the Wilmarth – North Rochester segment was important for resolving Twin Cities area loading, and that the river crossing from North Rochester to Tremval and then Tremval to elsewhere in Northern Wisconsin was effective at both relieving loading across Western Wisconsin and boosting the effectiveness of Wilmarth – North Rochester by providing an outlet and a shorter electrical path towards load centers. The double circuit from North Rochester to Adams directly relieved loading on parallel facilities. Colby – Adams relieved some loading associated with a large amount of future generation sited at Adams, but the effects were very localized.

Several stakeholders submitted alternative projects along the "Southern Corridor". These included a line from Huntley to Pleasant Valley (between Adams and North Rochester), and from Adams to Genoa and Hill Valley. One stakeholder also submitted Colby – Adams as an alternative. MISO reviewed the performance of Huntley – Pleasant Valley and Colby – Adams as alternatives to the Wilmarth – North Rochester line. Colby – Adams by itself is not effective at reducing the West to East loading across Southern Twin Cities 345 kV facilities and shows little reliability value on its own. Huntley – Pleasant Valley, when combined with a double circuit rebuild between Pleasant Valley and North Rochester, resolved many but not all of the same 345 kV and 345 stepdown transformer overloads as Wilmarth – North Rochester. It also showed higher adjusted production cost savings when included in PROMOD simulations. However, the difference in production cost savings was less than the difference in increased cost of Huntley-Pleasant Valley to North Rochester. MISO sees Huntley – Pleasant Valley as a valuable project that may be helpful in reinforcing this region in future cycles of the LRTP study.

Another proposed stakeholder alternative was a line from Adams to Genoa and Hill Valley. MISO initially viewed this project as an alternative to North Rochester – Tremval – Jump River – Eau Claire. However, analysis showed these paths address different sets of reliability concerns, with the Adams – Genoa – Hill Valley project better addressing constraints across northeast Iowa and southern Wisconsin. When tied into Hill Valley, once the Hickory Creek – Hill Valley line is in service, this would effectively form an additional path parallel to Adams – Hazleton 345 kV, and relieve flows being pushed south across eastern Iowa. MISO is prioritizing a northern path (North Rochester – Tremval) in order to address the voltage stability interface and tie into load centers. For that reason, MISO does not propose pursuing Adams – Genoa Hill Valley at this time, but

MISO understands the project's value, especially when paired with Huntley-Pleasant Valley, to potentially reinforcing the region in future cycles of the LRTP study.

MISO initially viewed Tremval – Eau Claire – Jump River and Tremval – Rocky Run – Columbia as alternatives to each other, specifically due to their relationship to the existing voltage stability interface. After some review, though, MISO found them to be addressing separate but complementary sets of issues. Tremval – Eau Claire -Jump River has only a minor impact to the voltage stability performance but relieves a variety of constraints across northern Wisconsin, including several sub-345 kV facilities and some high loading on one of the 345/161 kV transformers at Eau Claire. Tremval – Rocky Run – Columbia has a more significant impact on the voltage stability performance and resolves a number of thermal constraints East of Tremval and Eau Claire. That complimentary performance is what prompted MISO's recommendation of both project segments. MISO also reviewed several variations on the Tremval – Eau Claire – Jump River segment, which proposed different endpoints along either North Rochester – Briggs Rd – North Madison 345 kV or Stone Lake – Gardner Park. MISO found that a line from Alma to Eau Claire would have very similar cost and perform just as well electrically, when compared to Tremval – Eau Claire. MISO sees Tremval as a better tie-in point, due to its more easterly location with better accessibility, which would position it as a better long term hub. A line from Eau Claire to Stone Lake, in comparison to Eau Claire – Jump River, would be significantly more expensive and MISO's screening showed that it was less effective at relieving thermal loading on lines that Eau Claire – Jump River successfully unloaded.

Central Iowa

Figure 6-10: Central Iowa Final Solution

Projects:
Webster – Franklin – Morgan Valley 345 kV
Beverly – Sub 92 345 kV

Rationale:
Within MISO's system, the state of Iowa acts as both a major source of renewable energy and a gateway between MISO's members in the upper Midwest and MISO's Central planning region – Missouri, Illinois, and Indiana. Wind resources sited in Iowa are located primarily in the north and west parts of the state, and a large amount of wind resources are also located in western Minnesota and the Dakotas. During hours with high renewable output levels, power must flow southeast across and out of this region towards MISO load centers. In the LRTP models as well as in previous MISO planning studies, we have seen overloads and congestion across Iowa's central corridor. This project is intended to provide an additional 345 kV path southeast across the state, linking the high renewable region in the west with the Quad Cities load center and 345 kV outlets towards the rest of MISO. In doing so, we form a corridor both west-east and north-south across central Iowa.

Issues Addressed:

The Central Iowa projects between Webster and Sub 92 relieve a number of related issues. Table 6-6 summarizes overloads seen in the Future 1 models which are relieved by the LRTP Tranche 1 projects and attributed to the Central Iowa set of projects. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project. Those same elements are shown on a map in Figure 6-11.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	21	95-128%	34	96-132%
345 kV Lines	6	96-128%	7	97-128%
345/xx kV Transformers			4	96-127%

Table 6-6: Elements relieved by the Central Iowa projects in Future 1 power flow cases

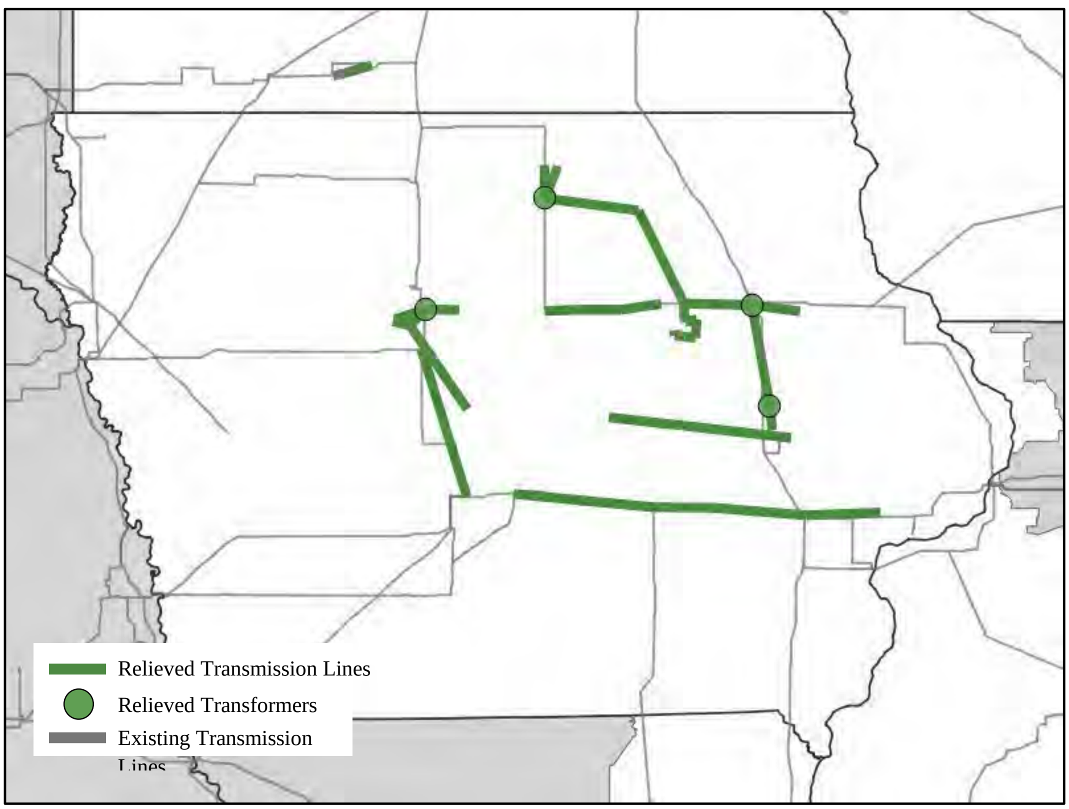


Figure 6-11: Map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Webster – Franklin – Marshalltown – Morgan Valley 345 kV forms a new connection from the 345 kV network in northwest Iowa (roughly west and north of Lehigh) to the north-south corridor across eastern Iowa (Adams – Hazleton – Hills – Maywood 345 kV). A previously approved line from Morgan Valley to Beverly stretches a few miles to the east, from which a new line can connect south from Beverly to Sub 92 345 kV. With that added segment, the overall path also completes a link from the northern 345 kV across central Iowa (Ledyard – Colby – Killdeer – Blackhawk – Hazleton 345 kV) down to a southern corridor (Bondurant – Montezuma – Hills – Sub 92 345 kV). By reinforcing the system in both directions, the project relieves loading on both west-east and north-south transmission facilities paralleling it. This loading is primarily seen in high renewable output cases, when renewable resources across western Iowa and southern Minnesota are producing high output. Lines seeing the greatest relief include Hazleton – Arnold 345 kV, Lehigh – Beaver Creek – Grimes 345 kV, and Montezuma – Diamond Trail – Hills 345 kV.

Alternatives Considered:

MISO reviewed several project alternatives and variations of the proposed central Iowa project set.

MISO began by reviewing the performance of an LRTP roadmap project against identified needs. This project included the proposed version of this project (Webster – Franklin – Marshalltown – Morgan Valley 345 kV and Beverly – Sub 92 345 kV), as well as some additional facilities. These included a new line between Marshalltown and Montezuma, with both the Franklin – Marshalltown and Marshalltown – Montezuma lines built as double circuit 345 kV. Two transformers were also sited at Franklin and Marshalltown. MISO found that the double circuit line sections did not relieve an appreciable number of additional facility overloads. MISO saw that the inclusion of a line from Marshalltown to Montezuma contributed minimal reliability benefit. Of the proposed transformers, MISO found no clear benefit to including 345/161 kV transformers at Franklin. At Marshalltown, a single 345/161 kV transformer can relieve some local loading on the lower kV system, but a second 345/161 kV transformer did not appear necessary.

MISO also reviewed a roadmap project in western Iowa that was submitted as a stakeholder alternative as well. Ida County – Avoca 345 kV would create a new line between Ida County in NW IA and a new 345 kV substation in SW Iowa adjacent to the existing Avoca 161 kV station. In comparison to the proposed project, this project was similarly successful at relieving loading on Lehigh – Beaver Creek – Grimes 345 kV and parallel facilities, but ineffective at relieving constraints east of that corridor, or generally east of the Des Moines metro area.

MISO reviewed portions of the Iowa – Michigan corridor project and the Iowa – Missouri project, in comparison to the proposed project. These facilities were not effective at relieving most of the facilities north and east of Des Moines that are relieved by the proposed project. They did relieve overloads in the Des Moines metro area and in southeastern Iowa and reduced some of the loading that the proposed project moved into southeastern Iowa. Within Iowa, MISO sees the reliability benefit of these two additional project groups as additive, in addition to the benefits of the central Iowa project.

East-Central Corridor

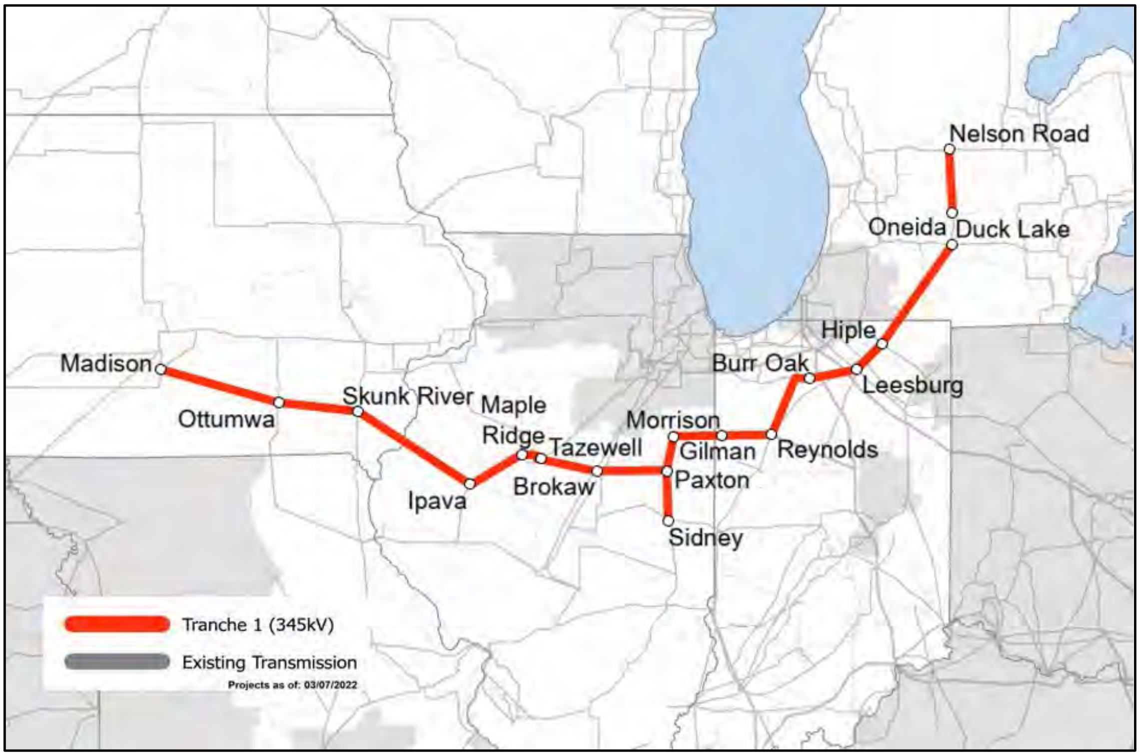


Figure 6-12: East-Central Corridor (Iowa to Michigan) Final Solution

Projects:
Madison – Ottumwa – Skunk River – Ipava – Maple Ridge 345 kV
Tazewell – Brokaw - Paxton – Gilman – Morrison – Reynolds – Hiple – Duck Lake 345 kV
Paxton – Sidney 345 kV
Oneida – Nelson Road 345 kV

Rationale:
MISO performed steady-state and voltage stability analyses on the proposed Iowa to Michigan LRTP projects. The steady-state results show the projects can mitigate severe thermal issues in Michigan, Indiana, Illinois, Missouri, and Iowa, with 77 monitored facilities addressed. The top 20 monitored facilities with worst-case contingencies are shown in Table 6-7.

The voltage stability results further demonstrate the effectiveness of the projects in improving voltage profiles and increasing transfer levels from West-East/East-West (Figures 6-14, 6-15, 6-16).

Issues Addressed:
The Iowa to Michigan projects addresses 600 thermal violations associated with 77 unique monitored facilities (Figure 6-13). For this metric, a constraint was considered relieved if its worst

pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the projects.

- 28 issues resolved in Michigan
- 16 issues resolved in Indiana
- 19 issues resolved in Missouri and Illinois
- 14 issues resolved in Iowa

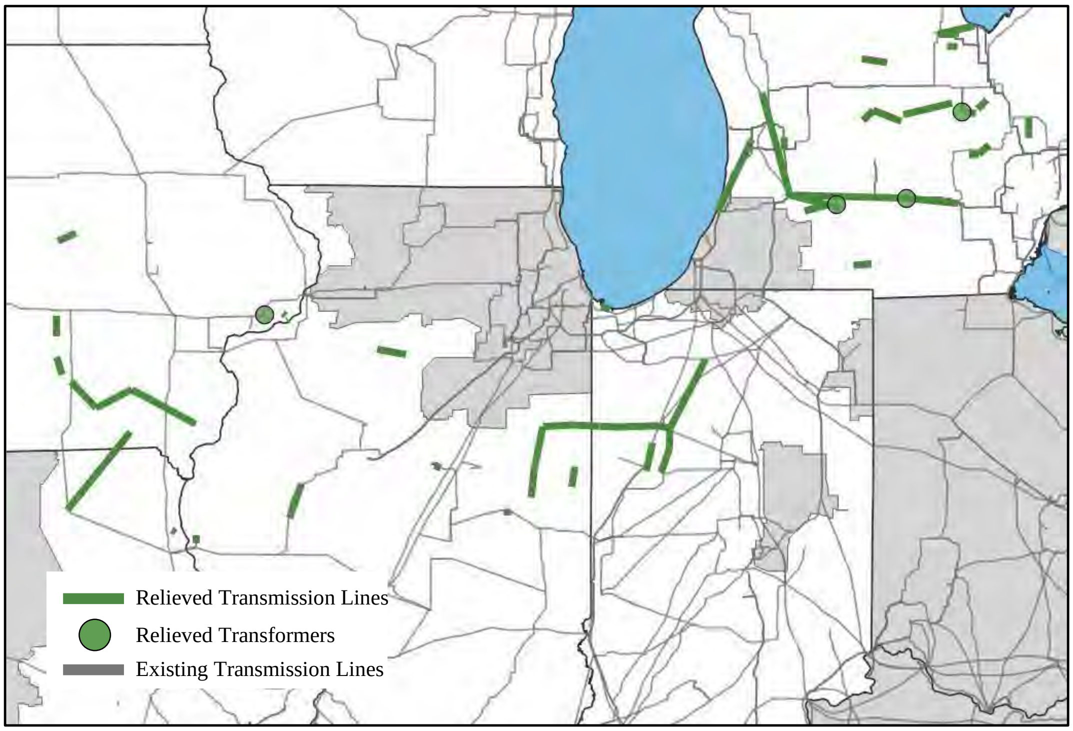


Figure 6-13: East-Central Corridor (Iowa to Michigan Line) map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

		% Loading	
Monitored Facility	**Area**	**Base + West LRTP***	**+ IA to MI Projects**
Goodland – Reynolds 138 kV Ckt. 1	NIPS	383	< 65
Reynolds 345/138 kV Transformer	NIPS	278	86
Reynolds – Magnetation 138 kV Ckt. 1	NIPS	264	67
Monticello – Magnetation 138 kV Ckt. 1	NIPS	263	67
Springboro – Monticello 138 kV Ckt. 1	DEI/NIPS	230	72
Lafayette 2 – Springboro 138 kV Ckt. 1	DEI	186	< 65
Morrison Ditch – Sheldon South 138 kV Ckt. 1	NIPS/AMIL	181	< 65
Gilman – Paxton East 138 kV Ckt. 1	AMIL	171	< 65
East Winamac – Headlee 138 kV Ckt. 1	NIPS	163	79

Westwood – South Prairie 138 kV Ckt. 1	DEI/NIPS	163	<65
Sheldon South – Watseka 138 kV Ckt. 1	AMIL	157	< 65
Burr Oak – East Winamac 138 kV Ckt. 1	NIPS	155	72
Island Rd 138 kV Bus	METC	155	67
Ottumwa 345/161 kV Transformer	ALTW	150	96
Poweshiek – Irvine 161 kV Ckt. 1	ALTW	144	98
Monticello – Headlee 138 kV Ckt. 1	NIPS	144	< 65
Gilman – Watseka 138 kV Ckt. 1	AMIL	136	< 65
Goodland – Morrison Ditch 138 kV Ckt. 1	NIPS	135	< 65
Tompkin – Majestic 345 kV Ckt. 1	METC/ITCT	133	82
Mahomet 138 kV Bus	AMIL	127	93

*Base + West LRTP projects = Ell-Jam, BSS-Alex-Cass, MN-WI

Table 6-7: Top 20 thermal issues addressed by East-Central Corridor

Transfer levels increase and voltage profiles improve in Indiana, Missouri, and Michigan with the IA – MI projects (Figures 6-14, 6-15, and 6-16).

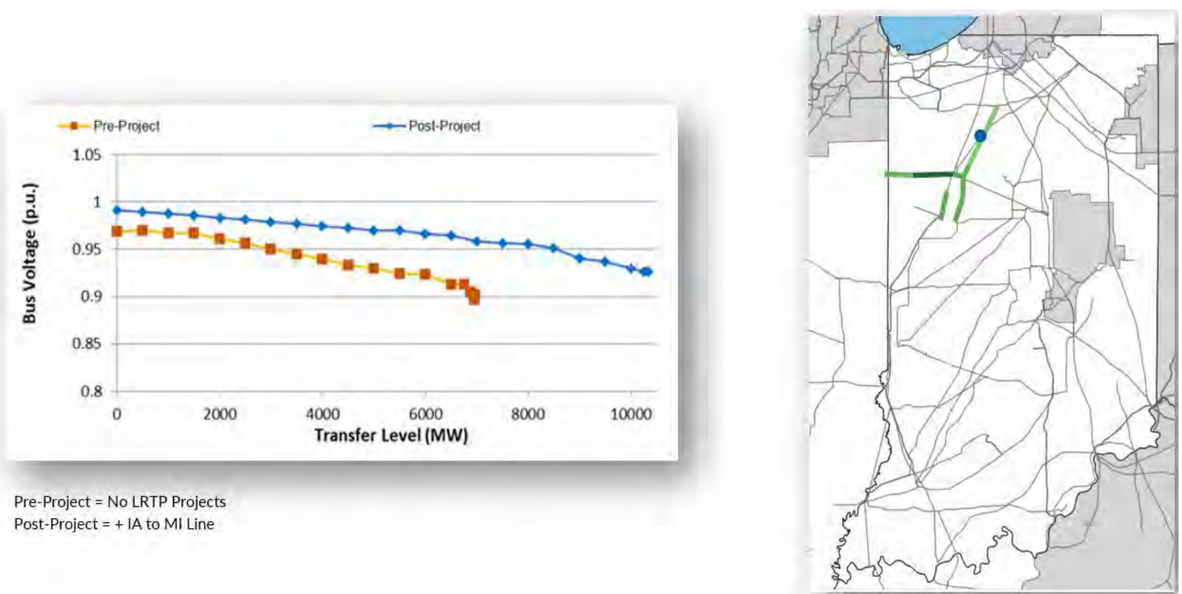


Figure 6-14: Improved voltage profiles in Indiana and Increased transfer levels with the Iowa to Michigan Projects

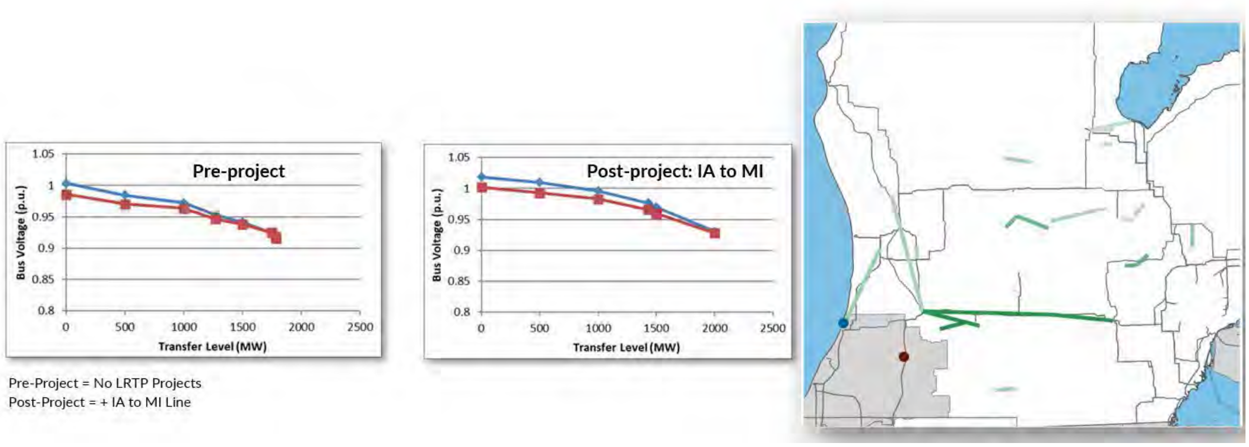


Figure 6-15: Improved voltage profiles in Michigan and Increased transfer levels with the Iowa to Michigan Projects

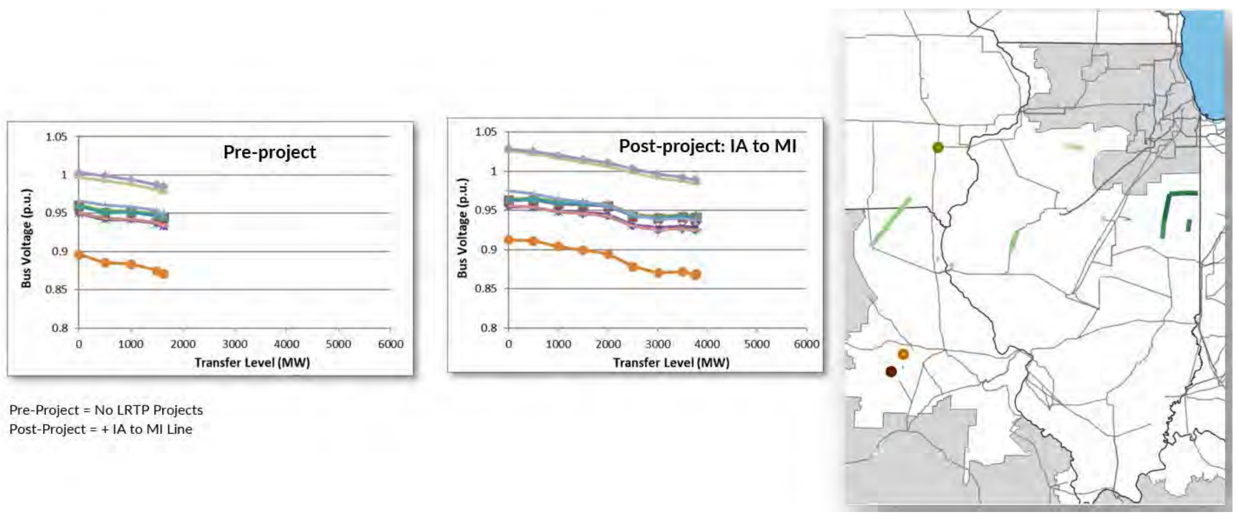


Figure 6-16: Improved voltage profiles in Missouri and Increased transfer levels with the Iowa to Michigan Projects

Alternatives Considered:
Two alternative solutions were received during the alternative submittal period, Duck Lake to Weeds Lake and Hiple to Duck Lake (MISO Main Proposal). Four additional alternatives were also evaluated. The alternative solutions resolve issues in Michigan, but fewer unsolved contingencies are associated with the road map project or MISO Main Proposal.

- Duck Lake to Weeds Lake, resolves 28 thermal issues:
- Hiple to Duck Lake (MISO main proposal), resolves 28 thermal issues
- Tie One Circuit in Argenta (resolves 28 thermal issues)
  - Argenta – Hiple
  - Argenta – Duck-Lake
- Oneida to Madrid (double-circuit), resolves 36 thermal issues
- Iowa to Indiana with Duck Lake Configuration, resolves 15 thermal issues

Northern Missouri Corridor

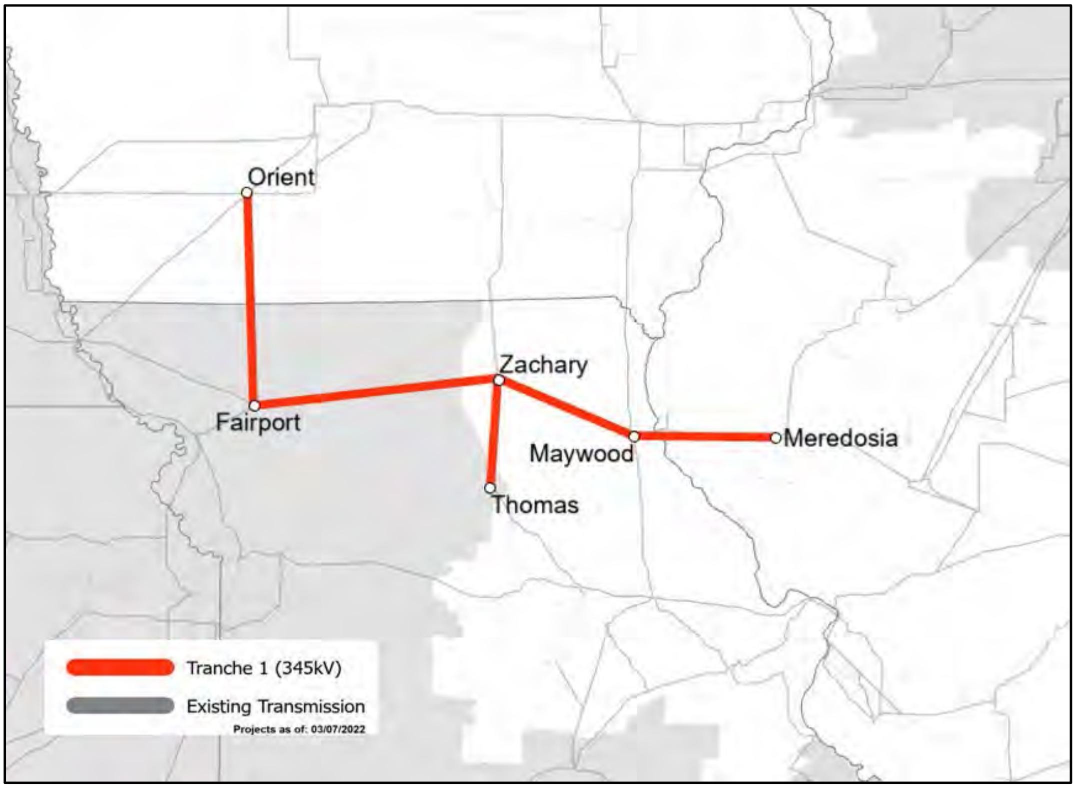


Figure 6-17: Northern Missouri Corridor Final Solution

Projects:
Orient – Fairport – Zachary – Maywood – Meredosia 345 kV
Zachary – Thomas 345 kV

Rationale:
The northern Missouri Corridor relieves loading on transmission elements in Iowa, Missouri, and Illinois. Increased transfer levels and improved voltage profiles are associated with the Missouri projects (Figure 6-17).

Issues Addressed:
The Missouri Corridor addressed thermal issues (Figure 6-18). Facilities mitigated by the Missouri Corridor are listed in Table 6-8. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

- 14 issues resolved in Missouri and Illinois
- 5 issues resolved in Iowa

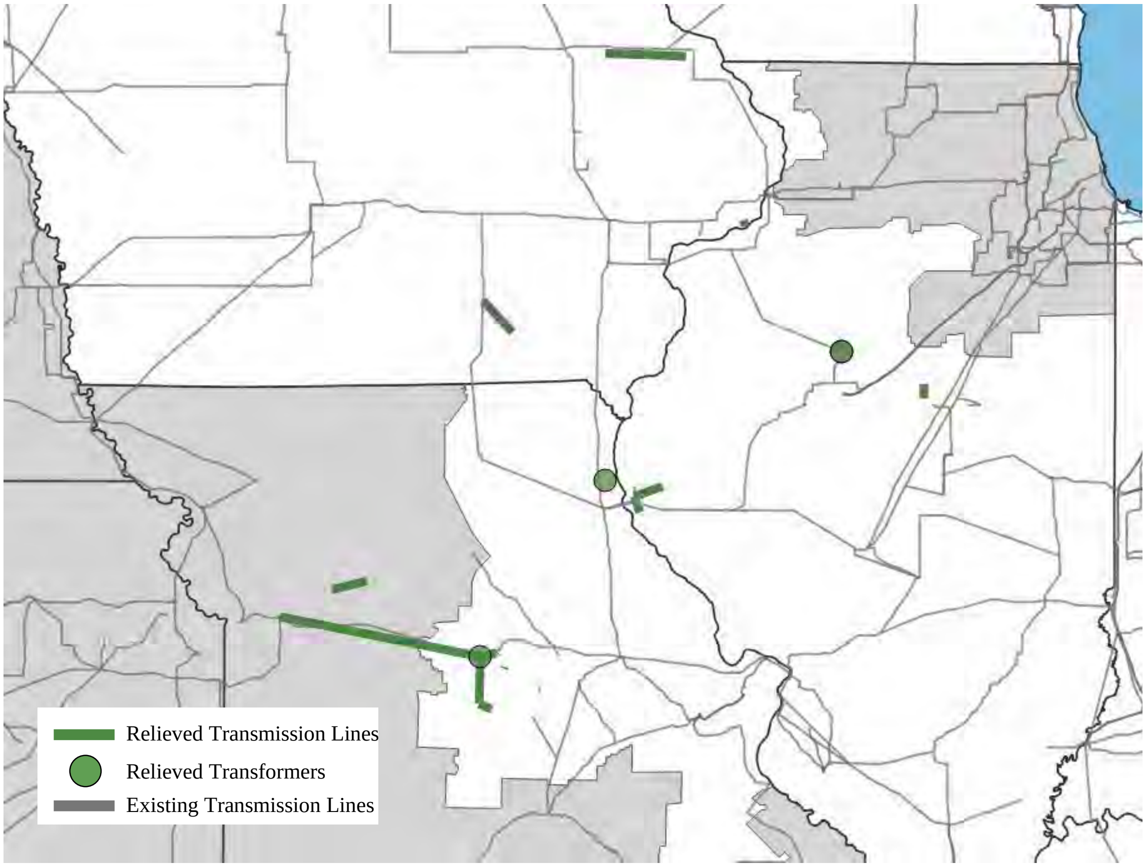


Figure 6-18: Northern Missouri Corridor map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

		% Loading	
Monitored Facility	**Area**	**Base + West LRTP***	**+ IA to MI Project + MO Projects**
Marblehead 161/138 kV Transformer	AMIL	137	85
Fargo 345/138 kV Transformer 1	AMIL	122	98
Fargo 345/138 kV Transformer 2	AMIL	122	98
Herleman 3 – Quincy S. 138 kV Ckt. 73	AMIL	120	79
Herleman 1 – Quincy N. 138 kV Ckt. 50	AMIL	120	79
Diamond Start Tap – White Oak Wind Bus 138kV Ckt. 1	AMIL	114	100
Overton 345/161 kV Transformer	AMMO	109	97
Overton – Sibley 345 kV Ckt. 1	AMMO	102	88
Huntsdale – Overton 1 161 kV Ckt. 1	AMMO	101	91
California 161 kV Bus 1 – Overton 2 161 kV Ckt. 1	AMMO	98	88
Huntsdale – Perche Creek 161 kV Ckt. 1	CWLD	97	87
McBaine Bus #2 – McBaine Tap 161 kV Ckt. 1	AMMO	97	85

Maurer Lake 161 kV Bus 1 – Carrollton 161 kV Ckt. 1	AMMO	96	70
California 161 kV Bus	AMMO	95	85
Sub 71 – Sub 88 161 kV Ckt. 1	MEC	109	98
Heights – Ottumwa 161 kV Ckt. 1	ALTW	103	95
Heights – Woody 161 kV Ckt. 1	ALTW	101	93
Liberty – Hickory Creek 161 kV Ckt. 1	ALTW	98	91
Liberty – Dundee 161 kV Ckt. 1	ALTW	98	91

*Base + West LRTP projects = Ell-Jam, BSS-Alex-Cass, MN-WI

Table 6-8: Facilities mitigated by the Missouri Corridor

The Missouri projects can help power delivery, in addition to increasing transfer levels from East-West/West-East. Moreover, the projects address voltage instability in Missouri (Figure 6-19).

- In the Pre-project case (without LRTP projects), with the transfer level reaching 1640 MW, one 345 kV bus in Missouri shows voltage dropping to 0.87 p.u. following loss of a large generating plant, which demonstrates voltage instability in this source area
- With the proposed IA – MI 345 kV line, the transfer level is increased to 3773 MW
- With the addition of the MO Project, the transfer level is further increased to 6000 MW

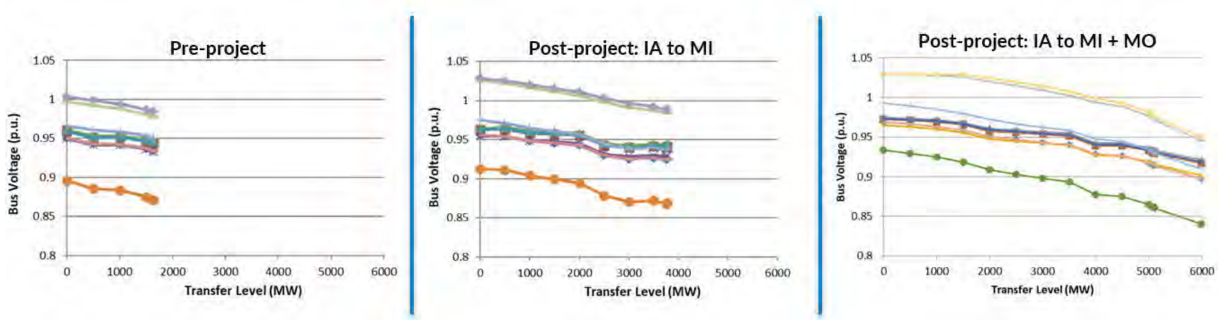


Figure 6-19: Bus Voltage Profiles

Alternatives Considered:

Segments of the Missouri corridor were considered separately, the full Missouri path (Orient – Fairport – Zachary – Maywood – Meredosia 345 kV / Zachary – Thomas 345 kV) is a better solution, with 19 issues addressed by the full path compared to:

- Zachary – Thomas – Maywood – Meredosia, resolves 11 issues
- Thomas – Zachary, resolves 4 issues
- Zachary – Maywood, resolves 6 issues
- Zachary – Maywood – Meredosia, resolves 9 issues
- Zachary – Maywood – Thomas, resolves 5 issues

7 LRTP Tranche 1 Portfolio Benefits

In accordance with the guiding principles of the MISO planning process, the allocation of costs for the transmission investment must be roughly commensurate with the expected benefits. As Multi-Value Projects, the eligibility of LRTP projects is established by Tariff requirements that define the need to demonstrate financially quantifiable benefits in excess of costs.

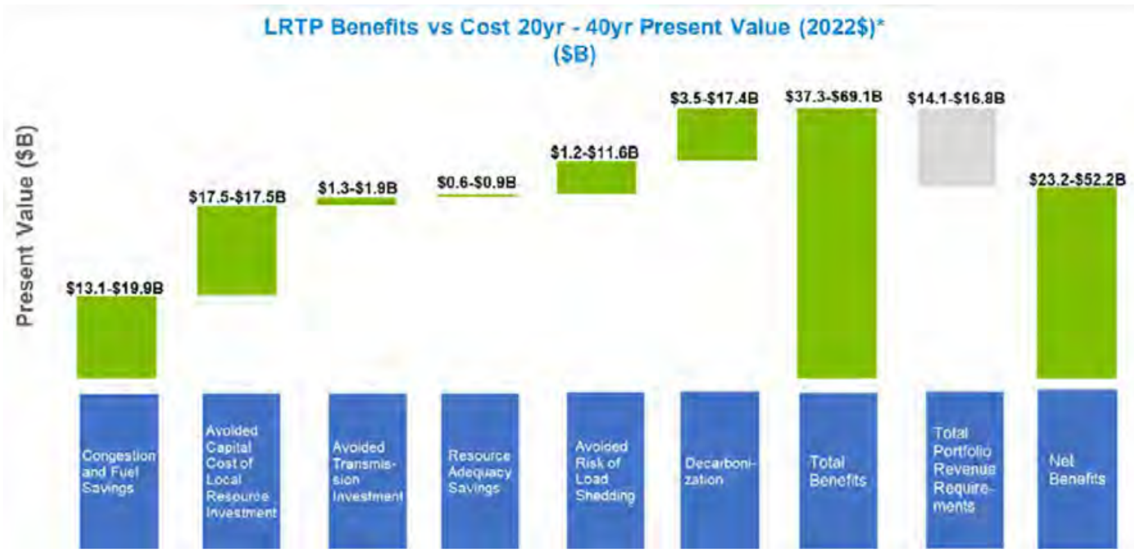


Figure 7-1: Financially Quantifiable Benefits of LRTP Tranche 1 Portfolio (values as of 6/1/22)

Guided by the allowable economic benefits defined in the tariff for MVP projects, the following benefit components were evaluated to determine the amount of value delivered by the LRTP Tranche 1 Portfolio:

- Congestion and fuel cost savings
- Avoided capital costs of local resource investment
- Avoided future transmission investment
- Reduced resource adequacy requirements
- Avoided risk of load shedding
- Decarbonization

Each benefit metric represents a distinct piece of the overall value resulting from either the transmission investments or the generation changes enabled by the transmission projects. Each benefit component is discussed in more detail, explaining what is captured in the metric, how LRTP projects impact the value being measured, and the methodology used to calculate the benefit. Starting from their assumed in-service year of 2030, benefits were calculated over a twenty-year horizon to evaluate eligibility as a multi-value project, and over a forty-year period to demonstrate the additional value provided over the expected useful life of the assets.

For consistency and comparability, a general set of assumptions and variables was applied in the analysis of benefits. All benefit values are expressed in 2022 dollars. An inflation rate of 2.5% is assumed when adjusting for the benefit period. A rate of 3 percent is used to represent the value a ratepayer would typically receive on a risk-adjusted investment. A discount rate of 6.9 percent is used to calculate the minimum value used to assess the benefit to cost ratio and based on the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments. The benefits analysis also includes evaluation of a natural gas price sensitivity to determine how benefits change with respect to swings in natural gas prices. While the benefits of the LRTP Tranche 1 Portfolio business case are analyzed for a Future 1 resource expansion scenario based on a specific gas price assumption, the sensitivity analysis offers additional insights into the value of LRTP under a broader set of assumptions.

Congestion and Fuel Cost Savings

In the MISO Futures[4], transmission limitations require robust solutions that not only reduce system congestion but also facilitate access to the diverse, ever-changing resource mix. The LRTP Tranche 1 Portfolio helps deliver economic benefits by providing more transmission infrastructure to distribute loading on other facilities and by enabling the connection of more low-cost resources.

Congestion and Fuel Savings benefit analysis is determined by calculating Adjusted Production Cost (APC[5]) savings between a reference case and a change case production cost model. The makeup of the reference case includes sufficient resources to meet Future 1 energy requirements, without applying the limitations of the transmission system, as well as Future 1 Regional Resource Forecast (RRF) resources that do not require the LRTP Tranche 1 Portfolio to connect to the system. The change case includes the LRTP Tranche 1 Portfolio and Future 1 RRF resources enabled by regional transmission to connect to the system. To determine which RRF resources are included in the reference and change case models, MISO performed a distribution factor (DFAX[6]) analysis on reliability constraints addressed by the LRTP Tranche 1 Portfolio. Only renewable RRF resources with $\geq$ 5% DFAX are included in the change case and renewable RRF resources with < 5% DFAX will be included in both the reference and change cases (Figure 7-2).

[4] MISO Futures Report
[5] MISO APC White Paper
[6] The DFAX analysis utilized LRTP Powerflow models and identified LRTP reliability issues addressed by the LRTP Tranche 1 Portfolio and involves the computation of change in flow on a network branch in the transmission model to the injection of power at a bus where generation is located which determines the amount of generator impact on facility loading.

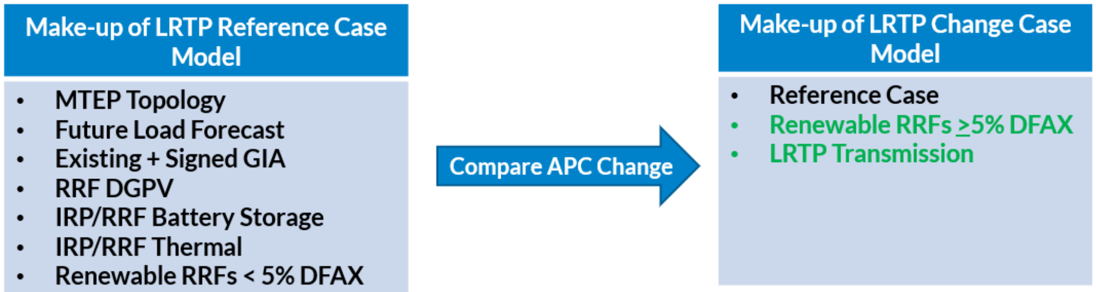


Figure 7-2: LRTP Reference and Change Case Criteria

As seen in Figure 7-3, application of this criteria resulted in 136.6 GW of resources being added to the LRTP Reference Case to meet Future 1 energy requirements and left 20.4 GW of renewable RRF resources available for DFAX analysis. This assessment resulted in the enablement of 20.1 GW of renewable RRF resources being added to the change case. Reference Figure 7-4 for geographical representation of the enabled renewable RRF resources in relation to the LRTP Tranche 1 portfolio.

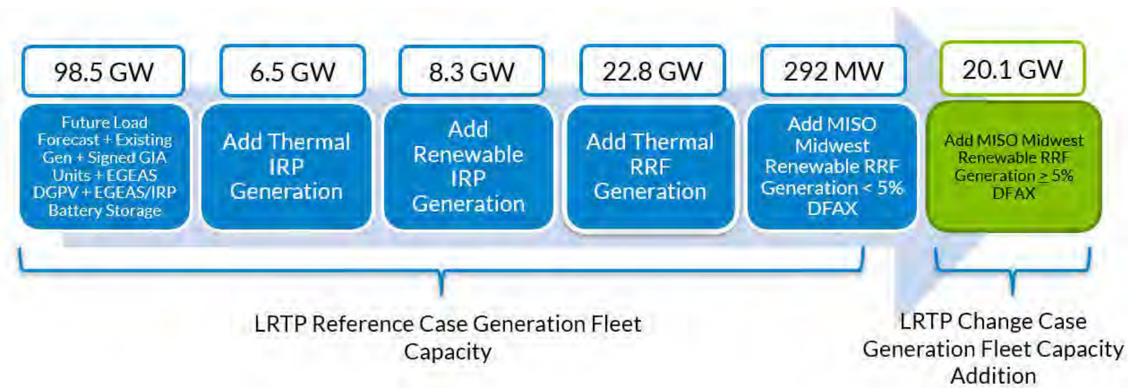


Figure 7-3: LRTP Reference and Change Case Criteria Capacity Result

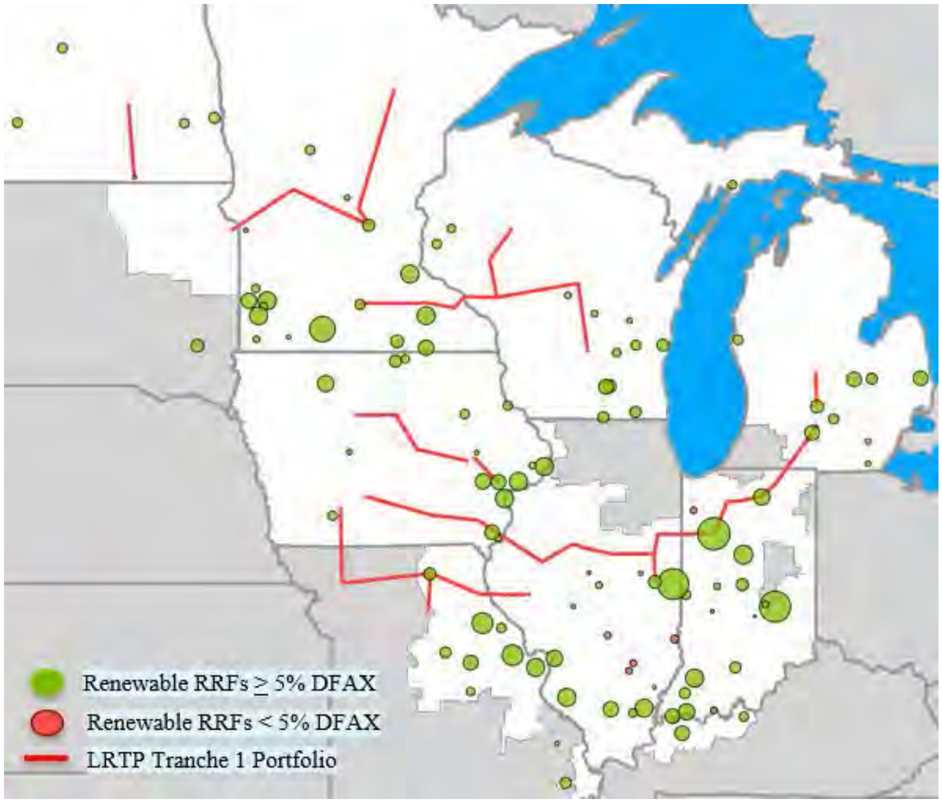


Figure 7-4: Geographic Map of RRF Resources Enabled by LRTP Tranche 1 Portfolio

The APC savings created by the LRTP Tranche 1 Portfolio generated $13.1 billion in congestion and fuel savings benefits over a 20-year period at a 6.9% discount rate. See Table 7-1 for additional benefit details on a Cost Allocation Zone (CAZ) granularity.

Present Value		**20-year PV (Millions-2022$)**		**40-year PV (Millions-2022$)**	
Discount Rate		**6.9%**	**3.0%**	**6.9%**	**3.0%**
CAZ	**1**	$3,169	$4,455	$4,668	$8,797
	2	$1,049	$1,511	$1,667	$3,313
	3	$2,195	$3,060	$3,151	$5,823
	4	$1,352	$1,934	$2,107	$4,133
	5	$1,471	$2,078	$2,205	$4,210
	6	$2,884	$4,133	$4,517	$8,890
	7	$1,006	$1,432	$1,543	$2,993
		$13,125	**$18,603**	**$19,858**	**$38,160**

Table 7-1: LRTP Tranche 1 Portfolio Congestion and Fuel Savings Benefits

Avoided Capital Costs of Local Resource Investments

The Avoided Capital Costs of Local Resource Investments metric captures the cost savings realized from a more cost-effective regional resource buildout that is enabled by regional transmission investment instead of depending on a more costly local resource buildout that is required due to local transmission limitations. In this specific case, the cost savings created by the LRTP Tranche 1 Portfolio will be determined by calculating an increase in costs for the resources enabled by the LRTP Tranche 1 Portfolio using a local versus regional capacity ratio.

To determine what the local resource investments would be, MISO had to first build local resource expansion models in EGEAS utilizing the same Future 1 assumptions[7] used in the regional expansion plan.

The local expansion plan EGEAS model assumptions are as follows:

- Local representation would be represented by Local Balancing Authority (LBA) granularity.
- Each LBA is treated as its own pool, self-constructing resources necessary to meet simulation constraints such as Planning Reserve Margin (PRM) and emissions.
- MISO PRM value of 18% was scaled for each LBA based upon its alignment to the MISO coincident peak.
- Utilizes the same assumptions as the regional Future 1 analysis and resources are attributed to LBAs based on resource ownership.
- Capacity purchases are enabled for the first year to meet each LBA's PRM due to limitations driven by the construction lead time for new resource alternatives.
- LBA-specific wind and solar profiles are used instead of the regional profiles which averaged multiple profiles from different locations across MISO.

[7] MISO Futures Report

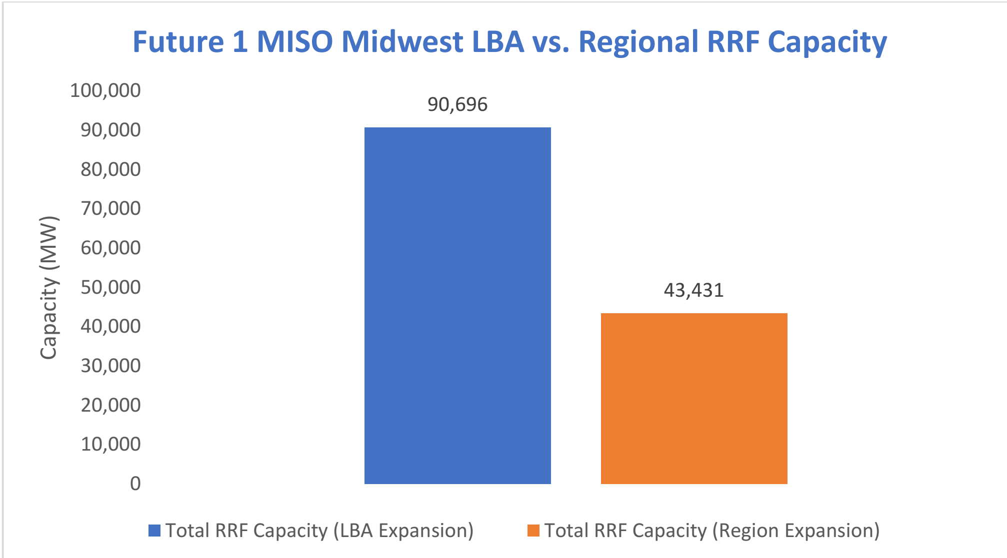


Figure 7-5: Future 1 LBA vs. Regional RRF Expansion Plan

As indicated in Figure 7-5, the LBA-specific scenario requires a much greater amount of localized resource expansion due to limited transmission capability, which is represented by isolating each LBA into its own EGEAS (transmission-less) model, compared to the equivalent regional expansion.

While Future 1 assumptions[8] were modeled consistently between the regional and LBA EGEAS models, the avoided capital cost benefit cannot be calculated by directly subtracting the regional expansion capital costs from local LBA expansion capital costs, as this would over-state the benefit created directly by regional transmission. To avoid this situation MISO had to consider what cost savings the Tranche 1 Portfolio would create. After evaluating several different options[9] with stakeholders to link the LRTP Tranche 1 Portfolio to the regional and local expansion, MISO proposed revised calculations and reviewed the details of the changes with stakeholders in the LRTP workshop discussions.[10] The ultimately decided on calculations are shown in equations (1) and (2) below:

$$Adjusted\ Capital\ Cost_{LBA\ Expansion} = \sum_{Year\ 2020}^{Year\ 2040} Enabled\ RRF\ Capital\ Cost_{Region\ Expansion} \times \frac{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{LBA\ Expansion})}{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{Regional\ Expansion})} \quad (1)$$

[8] MISO Futures Report
[9] January 21, 2022, LRTP Workshop
[10] February 25, 2022 LRTP Workshop

$$\mathit{Avoided\ Capital\ Cost\ of\ Local\ Resource\ Investments} = \mathit{Adjusted\ Capital\ Cost}_{LBA\ Expansion} - \mathit{Enabled\ RRF\ Capital\ Cost}_{Region\ Expansion} \quad (2)$$

Equation (1) is used to determine what the assumed local resource expansion cost would be by increasing the cost of the enabled resources by a ratio set by the LBA and regional EGEAS expansion results.

- $\mathit{Adjusted\ Capital\ Cost}_{LBA\ Expansion}$ represents the assumed capital cost of a local (LBA) resource expansion for MISO Midwest
- $\mathit{Enabled\ RRF\ Capital\ Cost}_{Regional\ Expansion}$ is the capital cost associated with the enabled[11] Regional Resource Forecasting (RRF) units determined by EGEAS using Future 1 assumptions[12], reduced to MISO Midwest
- $\mathit{Total\ RRF\ Capacity}_{LBA\ Expansion}$ is a summation of MISO Midwest's LBA RRF capacity determined through EGEAS by applying Future 1 assumptions on a LBA level
- $\mathit{Total\ RRF\ Capacity}_{Regional\ Expansion}$ is a summation of MISO Midwest's regional RRF capacity determined through EGEAS by applying Future 1 assumptions on a regional level

Equation (2) is used to determine what the Avoided Capital Costs of Local Resource Investments would be by subtracting the $\mathit{Enabled\ RRF\ Capital\ Cost}_{Regional\ Expansion}$, that is already accounted for, from the assumed LBA expansion capital cost calculated in equation (1).

As a result of being able to utilize the regional transmission buildout of the LRTP Tranche 1 Portfolio, approximately $17.5 billion of savings can be realized through the avoidance of local resource investment (Figure 7-6).

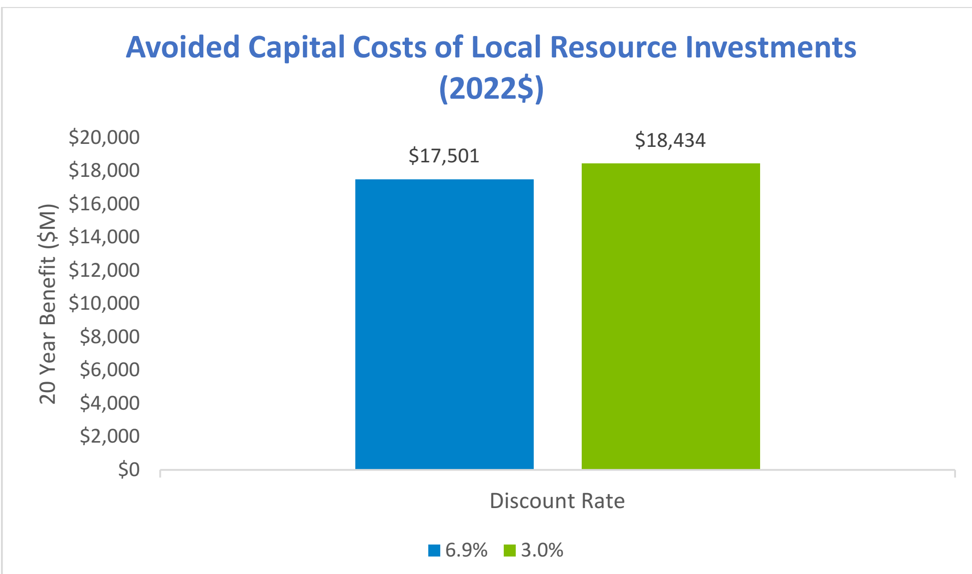


Figure 7-6: Avoided Capital Cost of Local Resource Investments Created by LRTP Tranche 1 Portfolio

[11] Renewable RRFs located in MISO Midwest Subregion which have ≥5% DFAX on reliability constraints addressed by LRTP Projects
[12] MISO Futures Report

Avoided Transmission Investment

The development of the LRTP Tranche 1 Portfolio provides a regional solution to addressing the future energy needs rather than an incremental approach to reliability planning. Avoided Transmission Investment captures the benefit provided by LRTP regional projects that address both avoided reliability projects and avoided age and condition replacement projects on right-of-way shared by LRTP projects.

LRTP projects deliver benefits by addressing future reliability issues and avoiding the costs of future upgrades that would have been required absent the LRTP Tranche 1 Portfolio. Benefits of avoided future reliability upgrades are based on potential overloads in the future rather than issues observed within the LRTP study period, in order to avoid double counting of benefits.

Identification of future upgrades considers facilities with high thermal loading but not overloaded in the 20-year reference case without LRTP reinforcements, and uses the thermal loading observed in the 10-year reference case to calculate the projected overload (equation below).

$$Flow_{proj} = Flow_{20} + (Flow_{20} - Flow_{10})$$

These projected overloads are analyzed in the LRTP case to determine if the LRTP Tranche 1 Portfolio mitigates the overload condition and are included as candidates for avoided future upgrades.

For future avoided transmission facilities >=345 kV a cost adjustment is applied to reduce the value by 50% to offset future production cost benefits that may be realized. These upgraded extra high voltage (EHV) facilities will reduce future congestion and offset production cost savings in the long term and discounting reduces potential for double counting of benefits. EHV facilities support regional energy delivery and generally have greater influence on production cost than lower voltage facilities that provide local reliability.

LRTP solutions in some cases make use of existing transmission corridors to reduce the need for new right-of-way and often the existing facilities have long been in service and in need of replacement. The avoided transmission investment benefit component also includes the avoided cost of upgrades where LRTP Tranche 1 projects are constructed on existing right-of-way with facilities that would have required upgrades as a result of facility age and condition. Where LRTP Tranche1 projects require rebuilding the structures and facilities of the aging circuits to accommodate the new transmission line, the future cost of the replacement is eliminated.

Facilities included in the Avoided Transmission Investment metric were verified with Transmission Owners to determine if facility upgrades are already planned or existing circuits on shared right-of-way are not candidates for age and condition replacement and were excluded from further consideration. Costs for avoided transmission investment use exploratory cost estimates that are based on the type of upgrade or replacement required. MISO estimated costs are derived from the MISO *Transmission Cost Estimation Guide for MTEP21* and are show in Table 7-2 below.

Upgrades are assumed to be needed prior to the end of the LRTP 20-year study period, and capital investment is assumed to be spread equally over the 5-year period prior to the in-service date of 2040.

Facility Improvement Type	Unit Cost($M)	Quantity/Miles	Cost ($M)
Bus-tie Replacement	$1.50	2	$3
Transformer Replacement =345	$5.00	4	$20
Transformer Replacement <345	$3.00	5	$15
Transmission line Replacement =345kV (per mile)	$2.65	21	$56
Transmission line Replacement <345kV (per mile)	$1.60	1012	$1,617
Transmission line upgrade=345kV (per mile)	$0.56	230	$64
Transmission line upgrade <345kV (per mile)	$0.34	124	$43
		Total	**$1,819**

Table 7-2: Estimated Costs of Avoided Transmission Investment (values as of 6/1/22)

Analysis Results
Cost savings associated with avoided future upgrades and future facility replacement for age and condition yields 20-40 year present value benefits from $1.3B to $1.9B (2022$).

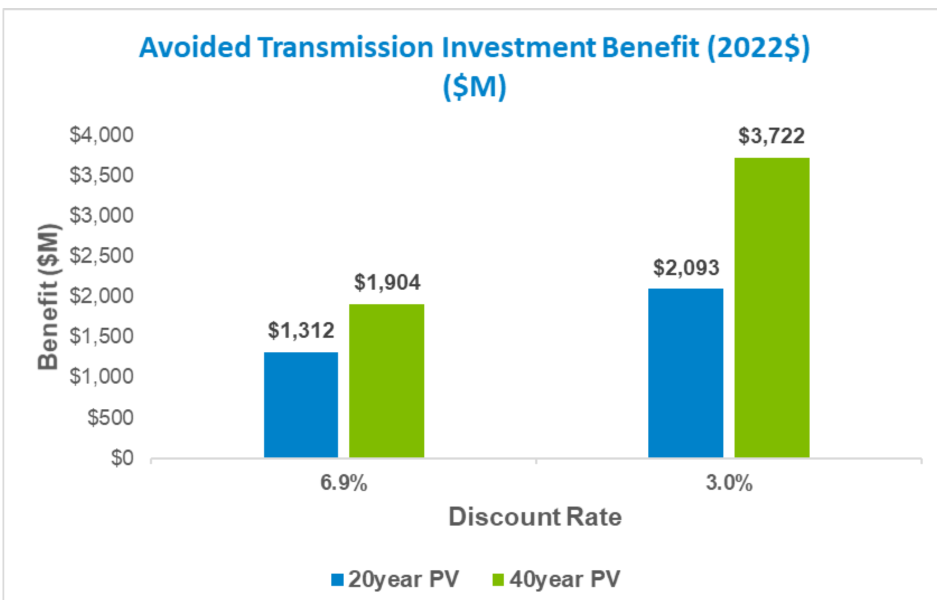


Figure 7-7: Avoided Transmission Investment Benefit (values as of 6/1/22)

Reduced Resource Adequacy Needs

The Reduced Resource Adequacy benefit metric represents a deferral of capacity that would be needed to address resource adequacy requirements due to increased zonal import limits. The transmission enhancements provided by the LRTP Tranche 1 Portfolio increases import capability and enables access to resources across the subregion. This decreases the need to procure capacity locally to meet resource adequacy needs.

The load serving entities (LSEs) that are located within the Local Resource Zones (LRZ) in MISO are required to meet two planning reserve margins in the Planning Resource Auction (PRA): the zonal planning reserve margin requirement (PRMR), which is based on the MISO-wide coincident peak load and MISO-wide PRM, and the local clearing requirement (LCR), which is based on each zone's non-coincident peak load and the local reliability requirement (LRR). The resource adequacy benefits presented in this section are related to the LCR.

Modeling and Assumptions

The modeling includes two parts; the first one involves a transfer analysis and the second one includes the monetization of the benefit.

1. Transfer Study: The CIL analysis generally aligns with the study methodology used in the Planning Resource Auction (PRA). The transfer analysis starts with the Future 1-2040 "peak load day" power flow model and associated input files (monitored elements and contingencies and sub-systems). These are then used in the TARA simulation tool to determine the incremental amount of power that can be transferred from source to sink. The First Contingency Incremental Transfer Capability (FCITC) is determined and the CIL is calculated for a base case (without LRTP Tranche 1 Portfolio) and change case (including LRTP Tranche 1 Portfolio). The definition of each case, in terms of the resource dispatch and demand levels, is consistent with the LRTP Future 1 reliability models.

2. Economic value of LCR reductions: The economic value of the LCR reduction is estimated as a function of the total unforced capacity (UCAP), CIL, and the LRR. The 2040 unforced capacity for each LRZ is determined using forced outage rates for thermal resources and the effective load carrying capability for non-thermal resources.

   The excess capacity within each LRZ is calculated as follows:

   Excess Capacity (LRZ_i) = 2040 UCAP (LRZ_i) – 2040 LCR (LRZ_i; without LRTP),
   where "i" represents the LRZ number (from 1-7).

   The RA benefits are estimated as follows:

   If Excess Capacity < 0 → Benefit = (Cost of new entry) x (-Excess Capacity)
   If Excess Capacity > 0 → Benefit = $0/year

   The LRR-UCAP percentages from the PY22-23 LOLE Study and the 2040 non-coincident peak load forecasts are used to set the LRR for each LRZ. The cost of new entry (CONE) assumptions is also consistent with the PY22-23 MISO LOLE study.

Analysis Results

The resulting CIL, with and without the LRTP Tranche 1 Portfolio, are shown in Table 7-3. The CIL values include the net-area interchange (e.g., the base transfer) gathered from the power flow model. Although their impact on the LCR benefit is negligible, the other components used in the CIL equation, e.g., border external resources (BER), coordinated owner (CO), and exports are kept unchanged in the base and reference cases.

Local Resource Zone	CIL (Base)	CIL (Change-With LRTP)	Delta CIL(MW)
1	5412	6070	658
2	4188	5223	1035
3	5062	6453	1391
4	7117	7609	492
5	6131	6183	52
6	6005	6171	166
7	3367	4659	1292

Table 7-3: Change in Capacity Import Limits (CIL)

A summary of the UCAP, LCR, LRR, and the Excess Capacity calculated for each LRZ is included in Table 7-4. The excess capacity shown in row 7 reflects the pre-LRTP scenario and a negative value represents a potential shortfall situation. The excess capacity shown in row 8 reflects the case with LRTP and confirms the ability of Tranche 1 projects to hedge against potential shortfall situations. The total 20-year and 40-year net present values are shown in Figure 7-8.

Row Number	Summary of resource adequacy benefits								
	LRZ	1	2	3	4	5	6	7	Formula Key
1	2040 Unforced Capacity (MW)	22,981	15,458	12,079	11,111	8,274	20,659	23,982	A
2	2040 Local Reliability Requirement Unforced Capacity (MW)	23,672	16,431	12,405	14,230	12,391	24,196	27,814	B
3	Without LRTP CIL (MW)	5,412	4,188	5,062	7,117	6,131	6,005	3,368	C
4	With LRTP CIL (MW)	6,070	5,223	6,453	7,609	6,183	6,171	4,659	D
5	Without LRTP LCR (MW)	18,260	12,243	7,343	7,113	6,260	18,191	24,446	E=B-C
6	With LRTP LCR (MW)	17,602	11,208	5,952	6,621	6,208	18,025	23,155	F=B-D
7	Excess capacity after LCR	4,721	3,216	4,737	3,998	2,014	2,468	-465	G=A-E

	without LRTP (MW)								
8	Excess capacity after LCR with LRTP (MW)	5,379	4,251	6,128	4,490	2,066	2,634	827	H=A-F
9	Deferred capacity value (M$)	0	0	0	0	0	0	-44	I=G*CONE

Table 7-4: Summary of resource adequacy benefits

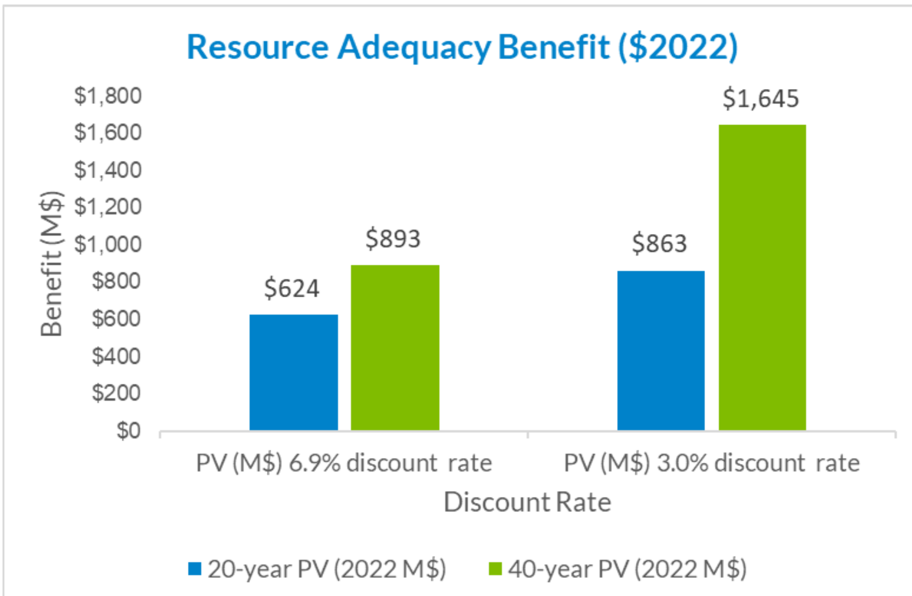


Figure 7-8: Resource Adequacy Benefit Total 20-year and 40-year Present Value

Avoided Risk of Load Shedding

Avoided Risk of Load Shedding is one of several metrics that is used to quantify the benefits provided by the LRTP Tranche 1 Portfolio. The method for determining this resiliency value considers high impact events with an expectation of a significant amount of controlled load shedding to ensure reliable system performance and/or prevent system collapse. While smaller, more common contingencies can result in the need for load shedding actions to maintain reliability, these events are often local in nature and beyond the scope of this analysis, which examines the impact of large-scale generation loss events caused by changing weather conditions or under extreme weather events. In a future with extensive penetration of renewable resources, the variability in weather introduces the potential for loss of renewable production. Additionally, extreme winter weather patterns can cause fuel supply disruptions that may result in extensive thermal generation outages. LRTP projects help to enable regional transfers mitigating the risk associated with these high impact generation outage events.

Analysis of load shedding risk was performed using 2040 winter peak reliability powerflow models, which represent system conditions under which the severe winter weather generation loss event is expected to occur. Weather events may be limited in scale to smaller areas that can affect a single resource zone or may be extreme in nature and have widespread impacts across the footprint. Study scenarios are defined for zonal and system-wide events that specify the generation outages resulting from severe winter weather impacts. Analysis of severe winter weather impacts on generation performance is generally straightforward but captures only one area of the risk associated with loss of load. This narrow focus results in a conservative estimate of the value of avoided risk of load shedding.

Historical weather event data is used to understand and develop assumptions about the frequency of significant winter weather events that could lead to large scale generation loss. MISO analyzed information on significant freeze and storm events over the past 40 years that have resulted in significant economic impact in order to establish the frequency of occurrence for evaluating risk (Figure 7-9).

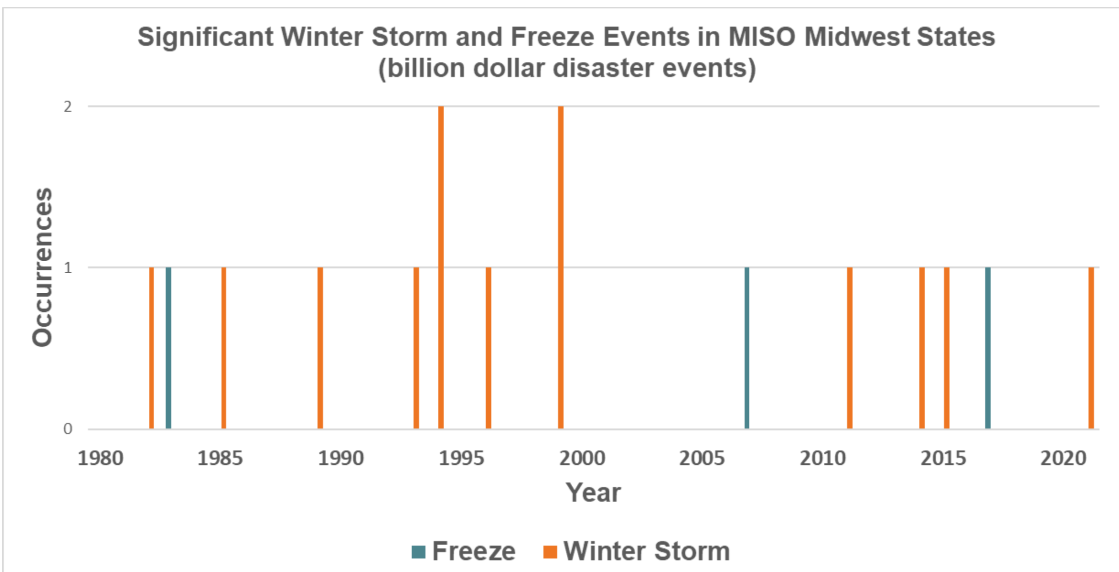
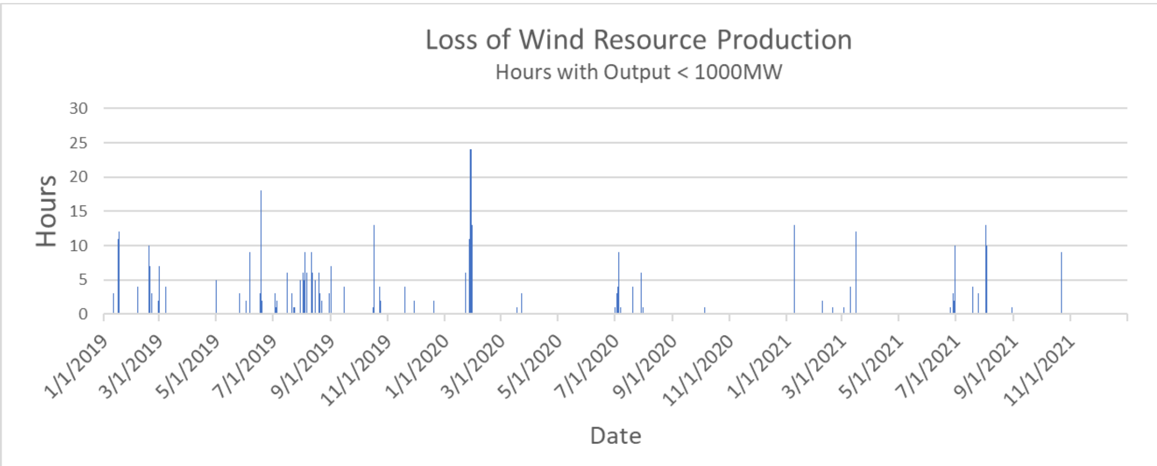


Figure 7-9: Winter storm and freeze events have been occurring every three years on average

Data Source: NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2022). https://www.ncei.noaa.gov/billions/, DOI: 10.25921/stkw-7w73

Additionally, operational event data was analyzed to examine trends in resource availability events over time when severe winter weather conditions occur, which provides insights into how fleet composition affects the risk of generation deficiency. While many of these weather events have not caused major disruption of generation supply in the past, recently there have been a growing number of instances where weather conditions caused the need to implement emergency measures to maintain adequate supply. In the last five years, tight generation supply during winter conditions presented operational challenges that will continue with growing dependency on renewable resources and gas-fired generation. The MISO response to the Reliability Imperative report[13] notes a key indicator of the change in risk profile for the region is seen in the 41 MaxGen emergencies that have been declared since 2016.

Historical generation output data highlights recurring risks associated with periods of low renewable production which can occur during any season and any time of the day (Figure 7-10). Such events can leave a significant amount of generation capacity unavailable to meet load requirements and where the duration of generation shortfall can last several hours.



Data Source: MISO Historical Hourly Wind, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc

Figure 7-10: Periods of low wind production may last several hours

The interruption of load may have far reaching impacts that include risk to public health and safety, financial loss, and regulatory/legal burdens, which are difficult to accurately quantify. The monetization of value of lost load is often considered in the context of customer willingness to pay to avoid interruption. While the application of the MISO Tariff defined Value of Lost Load (VOLL) in the LRTP business case does not suggest that VOLL represents the full value of risk, it does provide a reasonable measure that is indicative of the LRTP benefits and closely aligns with other business processes. The value of avoided risk of load loss of the LRTP Tranche 1 Portfolio considers a range of VOLL from $3,500/MWh to $23,000/MWh. The $3,500/MWh is currently defined by the MISO Tariff for use in market pricing while $23,000/MWh is a value recommended by the MISO Independent Market Monitor to be more representative of the value. This value of VOLL is applied to the calculated MW value of load loss determined by the zonal and system-wide studies in order to capture the benefits associated with the LRTP Tranche 1 Portfolio.

[13] MISO's Response to the Reliability Imperative

Method for Calculating Value of Avoided Risk of Load Shedding

Scenario Development

Analysis of historical winter storm and freeze event data from the past 20 years and recent extreme winter weather events indicates that significant winter storms are recurring every three years on average with extreme winter storms and temperature conditions observed periodically (polar vortex, Uri). The increased influence of weather due to the variability of renewable resources and impact of cold temperatures on fuel supply and availability of gas-fired generation will result in more periods of risk for load loss. Thus, each occurrence of a severe winter event every one out of three years represents a risk of load shedding due to the widespread generation outages. This risk persists beyond a single day since winter storms often occur over multiple days.

Duration of the load loss was derived using hourly wind production data to examine periods of low wind output since variability in wind output will have a large influence on the risk of an event. While the duration of low wind output events can range from 1 hour to 24 hours for a given day (Figure 7-10), approximately half of the events occurring in winter season are greater than 10 hours and period of risk for load loss is assumed to be eight hours per day over a two-day period for the purpose of assessing the risk of load shedding caused by a severe winter weather event.

A series of event scenarios were developed to represent significant generation loss due to weather related conditions. Events were created to reasonably reflect the loss of future renewable and thermal resources within defined zones or groups of zones. Loss of wind resources was modeled to represent a 90% drop in output from the maximum capacity and loss of solar output was modeled as a 50% reduction from maximum capacity. For regional and zonal event analysis, loss of thermal generation was derived by using outage information from the recent extreme winter storm event to establish a 50% outage rate in regional scenarios and 40% outage rate in zonal scenarios to capture the higher impact from future growth in gas-fired resources. Where modeled wind output is less than 10% of maximum capacity or solar output less than 50% in either zonal or regional scenarios, no adjustment is applied to the wind or solar output.

Load Loss Analysis

In zonal load loss analysis, the 2040 winter peak powerflow models were used to evaluate available generation, load requirements, and import capability for a given local resource zone. Load is escalated by 5% to assess the risk of load higher than normally forecast in planning analysis. Reliability analysis models normally apply a 50/50 load forecast, which reflects the normal peak load expected in the planning horizon. However, during extreme weather conditions, the peak load is expected to reach a 90/10 peak load forecast level, which is typically 5% higher. Resources were grouped within a single zone and event generation outage scenario applied to determine the amount of generation remaining. The amount of shortfall or surplus, in MW, is then calculated by subtracting the total zone load and losses and adding any net imports into the zone. The future CIL calculated in the resource adequacy analysis is used to determine if sufficient import capability exists to support any shortfall and any change in CIL due to the addition of the

LRTP projects is used to determine the amount of benefit, in MW, provided by the LRTP Tranche 1 Portfolio.

Area/Zonal Event Scenario

Generation Loss:
Thermal: 40% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Capacity Import Limit (CIL)

For all LRZ 1-7

$$\textbf{LoadLossMW} = GenMW_{net} - 1.05 * LoadMW - TxLossMW + \text{Capacity Import Limit (MW)}$$
$$\text{where } GenMW_{net} = GenMW_{cap} - GenMW_{loss}$$

In regional load loss analysis, the 2040 winter peak powerflow models were used to evaluate available generation, load requirements, and import capability for a given group of local resource zones. Similar to zonal analysis, the load is escalated by 5% to assess the risk of load higher than normally forecast in planning analysis due to the extreme weather. Resources were grouped within a set of zones and event generation outage scenario applied to determine the amount of generation remaining. In the regional analysis scenarios, the amount of thermal generation loss is escalated to 50% of capacity to represent a more extreme condition with regional scale impacts. The amount of shortfall or surplus, in MW, is then calculated by subtracting the total load and losses and adding any net imports into the study group. The incremental transfer capability is calculated using the power flow model and added to the existing group net imports to determine the total transfer capability to support any shortfall and the change in total transfer capability due to the LRTP projects is calculated to determine the amount of benefit, in MW, provided by the LRTP Tranche 1 Portfolio.

Two scenarios are included for evaluating risk of load loss for regional scale events:

> Scenario 1 assesses the impact of an extreme winter storm primarily on the western part of the MISO footprint causing large scale loss of generation in MISO upper Midwest areas and Southwest Power Pool (SPP) with SPP imports assumed to be 7,500 MW.
>
> Scenario 2 assesses the impact of extreme winter storm activity in the MISO central areas and Ohio Valley with PJM exports curtailed to 0 MW.

Regional Event Scenario

Generation Loss:
Thermal: 50% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Total Transfer Capability

Scenario 1: Source: MISO Zones 4-7 + PJM
Sink: MISO Zones 1-3 + SPP

Scenario 2: Source: MISO Zones 1-3 + SPP
Sink: MISO Zones 4-7

$$\textbf{LoadLossMW} = \text{GenMW}_{net} - 1.05 * \text{LoadMW} - \text{TxLossMW} + \text{Total Transfer Capability (MW)}$$
$$\text{where } \text{GenMW}_{net} = \text{GenMW}_{cap} - \text{GenMW}_{loss}$$

The value of avoided risk of load shedding is monetized by the use of the Value of Lost Load (VOLL) to represent a portion of the outage costs associated with load curtailment during generation deficiency events. While VOLL is based on outage costs, it is a market pricing mechanism that considers a customer's willingness to pay for energy to avoid load curtailment under emergency conditions and does not fully consider the related impacts or the effects of extended outages in more extreme scenarios. Furthermore, there is a wide range of opinion concerning the appropriate value that should be used with $3,500/MWh currently being used in the MISO market pricing structure while MISO's Independent Market Monitor has recommended a value of $23,000/MWh to be used in the MISO market. Thus the $3,500/MWh figure is a conservative estimate for capturing the benefit of avoided risk of load loss with the $23,000/MWh value used to establish the upper bound of the value.

The load loss hours are summed for all scenarios to obtain the load risk of load loss in MWhr and the range of values for VOLL is applied to obtain the monetary value.

Avoided Load Loss Value ($) = VOLL * LoadLossMW * duration(hrs.)
where VOLL – Value of Lost Load: $3,500- $23,000[14]

[14] IMM Quarterly Report: Summer 2020,

Analysis Results

The additional transfer capability provided by the LRTP Tranche 1 Portfolio enables power transfers to address supply deficiency caused by weather related generation outages and delivers 20- to 40-year present value benefits of $1.2 billion to $11.6 billion (2022$).

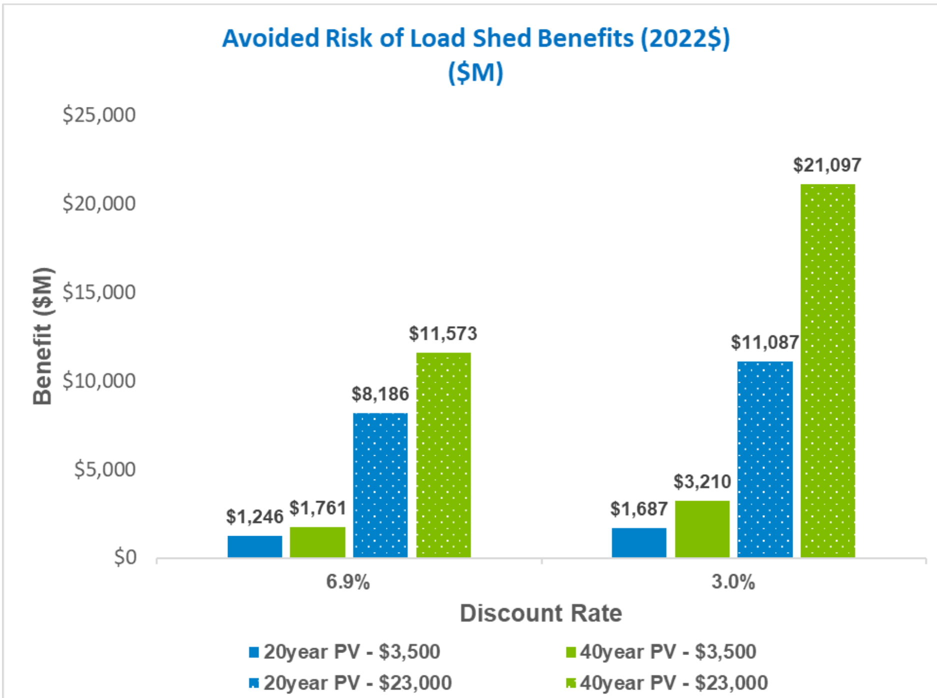


Figure 7-11: Benefits of Avoided Risk of Load Shedding (values as of 6/1/2022)

Decarbonization

MISO continues to explore how the rapid growth of members' decarbonization goals creates additional needs and opportunities to provide value. The robust transmission planning embodied by the LRTP initiative can signal better locations that deliver decarbonization, among other benefits. This item captures a range of potential cost savings from LTRP-enabled Decarbonization.

MISO acknowledges there is no cost of carbon applicable to the entire footprint currently. However, with the energy transition and changing landscape, it is possible that additional emissions standards may be placed on the electric industry. Since the 1990s, sulfur dioxide has decreased by 94%, nitrogen oxides by 88% and mercury emissions by 95% across the U.S. electric power sector.[15] Many of the benefits associated with these emission reductions have already been captured throughout the footprint.

[15] Edison Electric Institute: Climate and Clean Air

Over the past several years, MISO members have announced large carbon emission reduction goals that will rely on intermittent low-cost energy. The LRTP initiative aims to help ensure an efficient dispatch of energy across MISO during this fleet transition. With the rationale above, MISO conducted research to develop a price range to express Decarbonization's value. MISO chose sources within the U.S., at state and federal levels, within and outside of the MISO footprint. The range in prices draws from regulatory and market-based approaches, both of which are influenced by policy. From MISO's PROMOD analysis, carbon emissions are reduced by 399 million metric tons over 20 years and 677 million metric tons over 40 years of LRTP Tranche 1 project life (Figure 7-11).[16]

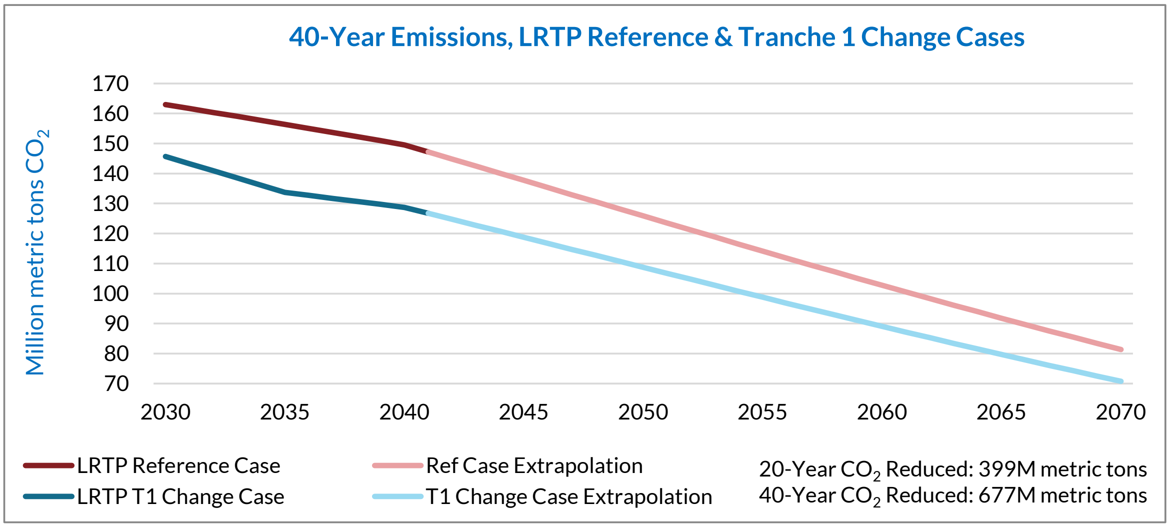


Figure 7-12: 40-Year CO_2 Emissions of LRTP Reference and Tranche 1 Change Cases

MISO took two steps to standardize price terms. First, as applicable, MISO converted source price data to dollars per metric ton, using a conversion factor of one U.S. (short) ton = 0.9071847 metric tons.[17] Second, MISO converted prices from nominal dollar-years of origin into 2022 dollars using the Consumer Price Index Inflation Calculator.[18] For consistency, the month of January was used for dollar-year conversions except in cases related to market prices, which used the month of auction settlement as the origin date. A range of CO_2 emission prices were identified to estimate a benefit value, and are summarized below:

- The Minnesota Public Utility Commission (MN PUC) price began with the 2022 Low[19] price of $9.46 per short ton in 2015 dollars and yielded $10.43 per metric ton; $12.55 per metric ton in 2022 dollars.

[16] MISO interpolated emissions data among PROMOD model years 2030, 2035, and 2040 and used linear extrapolation for post-2040 emissions reductions. 20-year and 40-year benefits refer to projects' in-service value to 2050 and 2070, respectively.
[17] U.S. Energy Information Administration
[18] U.S. Bureau of Labor Statistics Consumer Price Index Inflation Calculator
[19] Minnesota Public Utility Commission

- The Regional Greenhouse Gas Initiative (RGGI) Q4 2021 Auction average (mean)[20] price of $12.47/short ton yielded $13.75/metric ton; $13.87 in 2022 dollars.

- The California and Quebec (CA-QC) Cap-and-Trade Program Q4 2021 Auction settlement[21] price of $28.26/metric ton is $28.59 in 2022 dollars.

- The Federal price is the average of two price data inputs: the 45Q Tax Credit and the Social Cost of Carbon.[22] The 45Q Tax Credit follows a prescribed price schedule; starting with $31.77/metric ton in 2020, increasing to $50 by 2026, and inflation-adjusted afterwards by 2.5% annually. This interpolation yields a 2022 value of $37.85. The Social Cost of Carbon (SCC) follows a similar schedule, but in 2020 dollars. Converting the SCC schedule in 2020 dollars from $51/metric ton (2020) yields $55.58 and $85 (2050) yields $92.64 for those price-years, in 2022 dollars. The SCC's 2022 value in 2022 dollars is $57.76. Beyond 2050, annual inflation of 2.5% is applied. To produce the Federal price, the annual values of 45Q and SCC through 2069 are averaged, beginning in 2022 at $47.80/metric ton in 2022 dollars.

The Decarbonization assessment employs the following overall methodology:

- From the Congestion and Fuel Cost Savings analysis, calculate the difference in CO_2 emissions between the LRTP Reference case and LRTP Change case

- Convert the reduced emissions to metric tons

- Use range of carbon prices to produce yearly values at 2.5% inflation as applicable

- Multiply yearly values by annual reduced emissions and discount rates to produce discounted annual benefits

- Sum discounted annual benefits to yield net present values for 20- and 40-year emission reduction benefits along the price range (Figure 7-12, Table 7-4, Table 7-5)

Detailed assumptions, calculations and formulas are found in the supplementary LRTP Business Case Analysis workbook.

	MN PUC	RGGI Q4 2021	CA-QC Q4 2021	Federal
2022$/metric ton	$12.55	$13.87	$28.59	$47.80
20-Year Benefit (2022$, M):	$3,473	$3,839	$7,913	$13,438
40-Year Benefit (2022$, M):	$4,548	$5,026	$10,361	$17,364

Table 7-4: Full Range of Carbon Prices and Tranche 1 Decarbonization Benefits at 6.9% Discount Rate

[20] Regional Greenhouse Gas Initiative (Q4 2021 average [mean] price)
[21] California-Quebec Carbon Allowance Price (November 2021)
[22] Federal: 45Q Tax Credit, Social Cost of Carbon

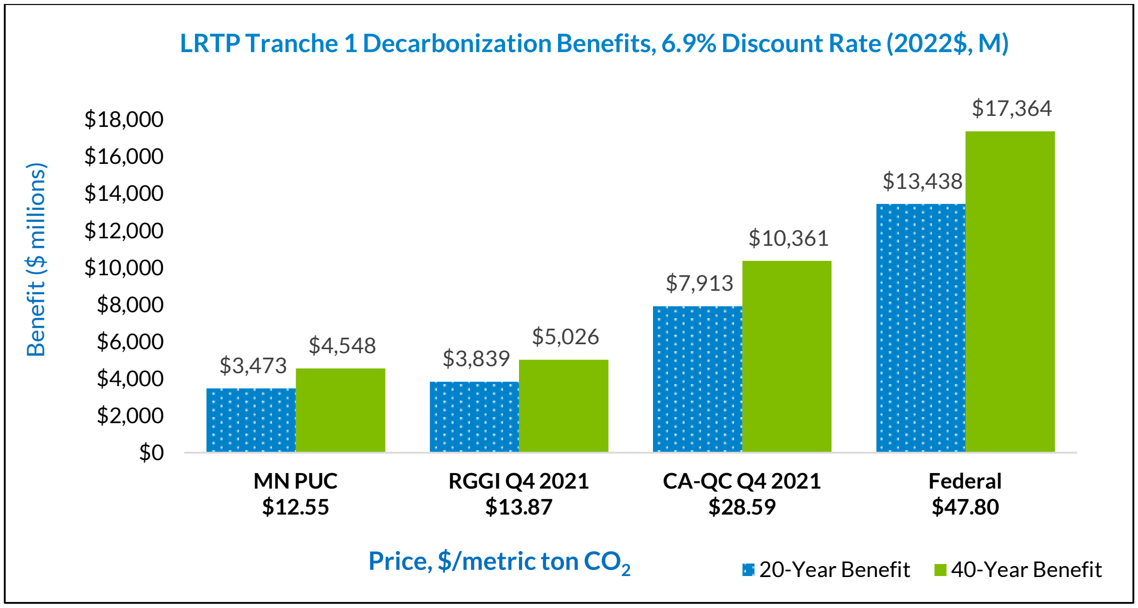


Figure 7-13: LRTP Tranche 1 Decarbonization 20- and 40-Year Benefits Using Full Carbon Price Range, Applying 6.9% Discount Rate (2022$, M)

	6.9% Discount Rate		3% Discount Rate	
	MN PUC (Min)	Federal (Max)	MN PUC (Min)	Federal (Max)
2022$/metric ton	$12.55	$47.80	$12.55	$47.80
20-Year Benefit (2022$, M):	$3,473	$13,438	$4,781	$18,404
40-Year Benefit (2022$, M):	$4,548	$17,364	$7,818	$29,498

Table 7-5: Min/Max Carbon Prices and Tranche 1 Decarbonization Benefits at Two Discount Rates

8 Benefits Are Spread Across the Midwest Subregion

The LRTP Tranche 1 Portfolio of projects was developed to address regional energy delivery needs for the MISO Midwest subregion. As Multi-Value-Projects, the costs of the LRTP Tranche 1 Portfolio will be recovered on a pro-rata basis from load in the MISO Midwest Subregion. Analysis of benefits examined how much each benefit accrued to the Midwest Subregion Cost Allocation Zones in order to compare the relative impacts between zones and the relationship with cost allocation. The distribution of benefits of the LRTP Tranche 1 Portfolio is shown to yield significant benefits for all Cost Allocation Zones (CAZs) well in excess of the share of portfolio costs.

Distribution of Benefits

Congestion and fuel savings are distributed to CAZs based on the production cost simulations used to calculate the savings and aggregated to the CAZs.

Avoided capital cost of local resource investment benefits are assigned based on load ratio share of each CAZ and aligns with the goal of the resource expansion to meet the future energy needs of the Midwest Subregion.

Avoided transmission investment benefits are allocated to the CAZ in which the baseline transmission upgrades, and age and condition replacement facilities are located. Costs for these avoided projects would otherwise be borne by the local pricing zone which yields a benefit to those specific CAZs.

Reduced Resource Adequacy savings are assigned directly to the CAZs in which the cost savings are realized since each CAZ has a responsibility for their own resource adequacy needs, and the CAZs in the Midwest Subregion align with the Local Resource Zones used for resource adequacy.

Avoided Risk of Load Shedding benefits are distributed to CAZs based on load ratio share to reflect the widespread protection against load loss in the interconnected electric system.

Decarbonization captures the benefits of reduced carbon emissions in energy production that is used to serve load across the Midwest subregion and is allocated by load ratio share to CAZs.

Distribution of LRTP Tranche 1 Portfolio Costs

The cost for Multi-Value Projects are allocated to load in the Midwest Subregion according to load ratio share of energy withdrawals. To determine the benefit/cost ratios by Cost Allocation Zone the energy withdrawals by the applicable LBAs included in each zone have been aggregated for Figure 8-1. Additionally, indicative annual MVP usage rates for the LRTP Tranche 1 Portfolio were calculated over a 40-year period using the current project cost estimates and estimated in-service dates. This information on the estimated MVP usage rates is provided in Appendix A-3.

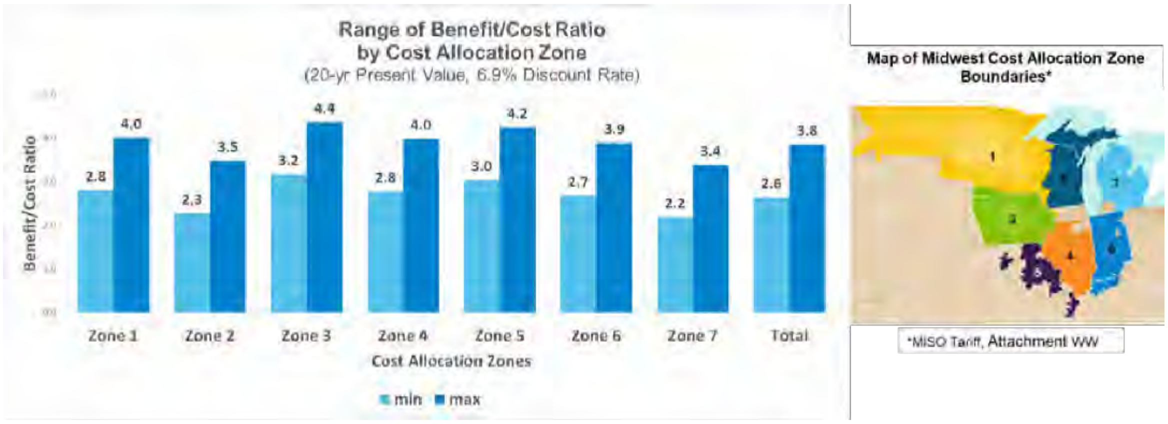


Figure 8-1: Distribution of benefits to Cost Allocation Zones in Midwest Subregion (MISO Tariff Attachment WW) (values as of 6/1/22)

The LRTP Tranche 1 Portfolio provides broad distribution of benefits across the Midwest subregion zones and delivers a benefit to cost ratio of at least 2.2 for every CAZ. Analysis of the zonal benefit distribution indicates that the spread of benefits is roughly commensurate with the allocation of portfolio costs.

9 Natural Gas Price Sensitivity

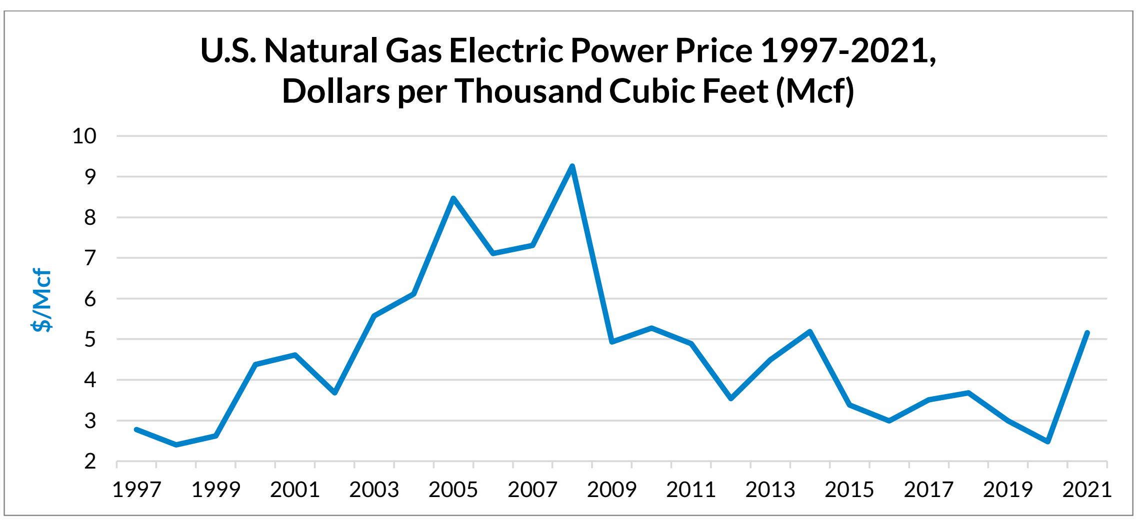


Figure 9-1: Historic U.S. Natural Gas Electric Power Prices

Beginning in 2021, natural gas prices increased sharply, reversing the general price decline seen over the last decade as production grew dramatically from the shale revolution (Figure 9-1).

U.S. export capacity of liquefied natural gas (LNG) has grown rapidly since beginning in 2016, from 0.55 billion cubic feet per day (Bcf/d) to an estimated peak of 11.6 Bcf/d as of November 2021. The U.S. Energy Information Administration estimates U.S. LNG peak export capacity will reach 16.3 Bcf/d by the end of 2024.[23]

Considering the expansion of LNG exports along with the growing prevalence of extreme weather events and current geopolitical developments, U.S. gas price exposure to the global market has increased as well. The recommended LRTP Tranche 1 Portfolio can partially offset the gas price risk by providing additional access to generation powered by fuels other than gas.

Two sensitivity analyses were performed on the LRTP Tranche 1 Congestion and Fuel Savings Reference and Change Case PROMOD models to quantify the impact of changes in gas prices. The sensitivity cases maintained the same production cost modeling assumptions from the business case analysis, except for the gas prices. The sensitivity assumed gas price increases of 20 and 60 percent, respectively. For both analyses, the prices increased starting in the year 2030 and escalated by inflation thereafter.

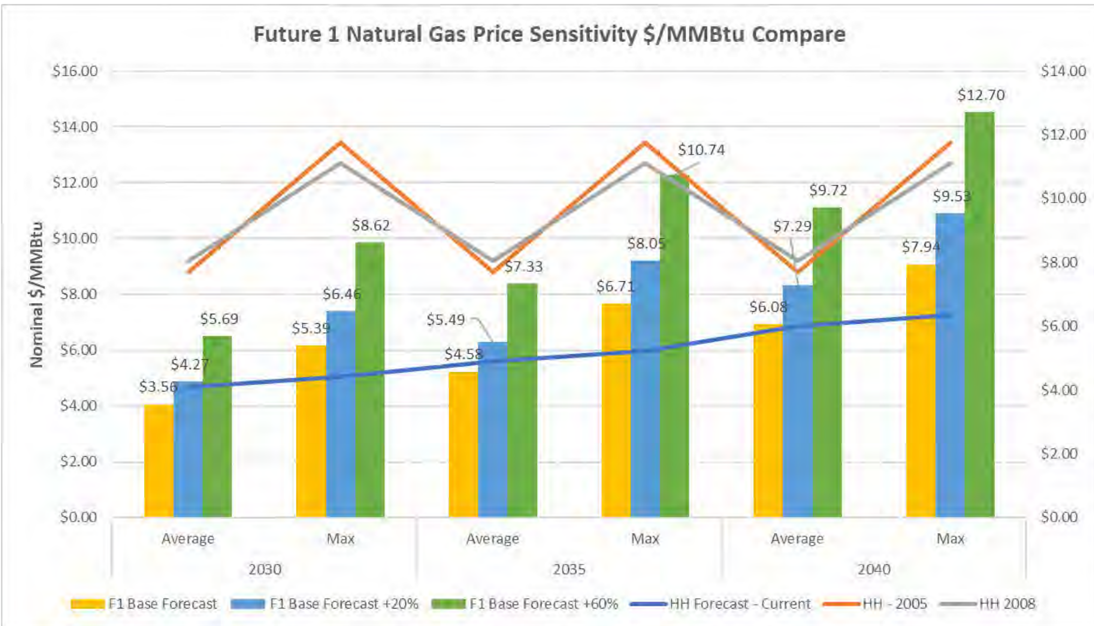


Figure 9-2: Future 1 Natural Gas Price Sensitivity $/MMBtu per LRTP PROMD Study Year

The resulting natural gas price increases achieved (Figure 9-2) created a gas price increase that ensures each study year's average fuel cost is greater than current Henry Hub (HH) projections as

[23] https://www.eia.gov/todayinenergy/detail.php?id=50598

well as representing HH highest historical sale prices from 2005 and 2008. This sensitivity concluded that the LRTP Tranche 1 Portfolio offsets gas price volatility by providing additional Congestion and Fuel Savings benefits by enabling access to renewable energy, as shown in Figure 9-3.

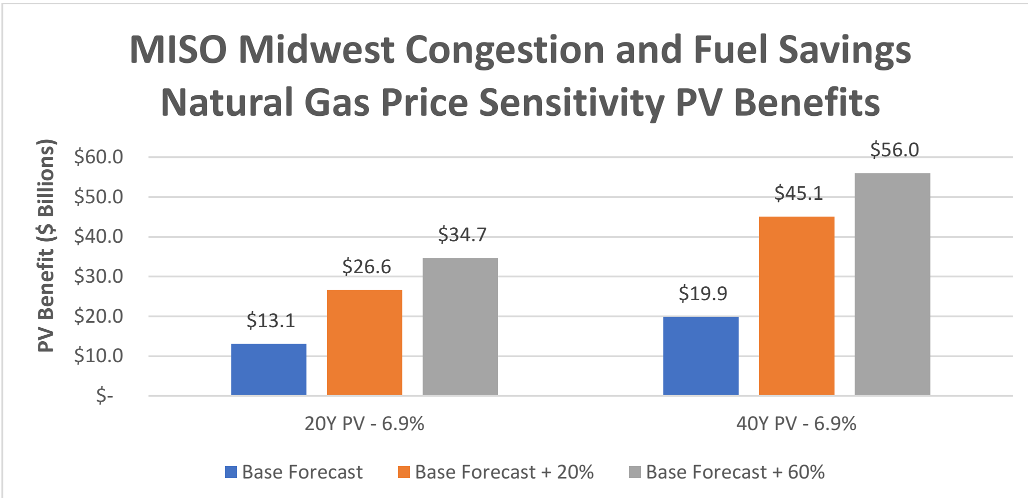


Figure 9-3: Natural Gas Price Sensitivity Results

10 Other Qualitative and Indirect Benefits

In addition to the quantifiable economic and reliability benefits, the LRTP Tranche 1 Portfolio enables other value streams that are reflected qualitatively.

Transmission reinforcements strengthen the grid to support the stability of the larger interconnection and provide greater resilience to recover from unexpected system events without adverse impacts. The interconnected nature of the power system provides support between neighboring systems during severe system disturbances. Regional transmission projects bolster the network, enabling greater bulk power transfers to address the developing conditions and avoid further degradation of the system performance.

Investment in regional transmission projects expand access to a greater diversity of lower-cost resources across the footprint, allowing more options for customer choice of fuel mix. Transmission allows for leveraging of the wide geographic and fuel diversity offered by the MISO region. The stronger regional ties offer more flexibility to handle the variability of renewable output caused by differences in weather patterns across different areas of the MISO footprint. This capability offers greater protection against both market price risk and possible load curtailment measures.

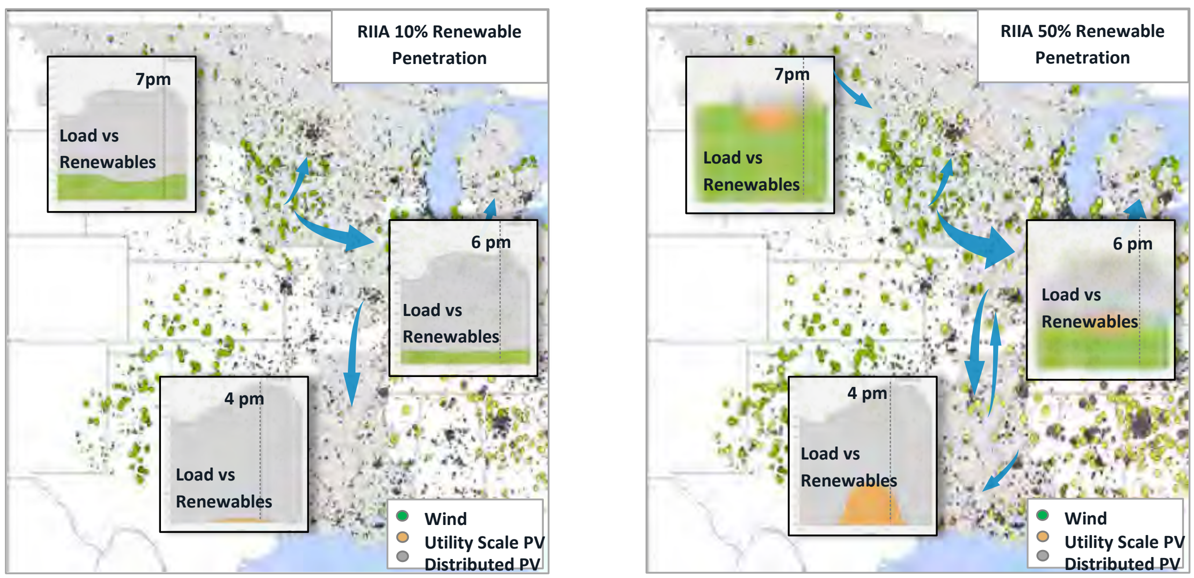


Figure 10-1: Illustration of flow changes with increasing renewable penetration spread throughout the MISO footprint (MISO Renewable Integration Impact Assessment (RIIA) Summary Report, February 2021 https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf)

The addition of transmission facilities allows greater operational flexibility related to unplanned and planned transmission facility outages. While the Congestion and Fuel Savings metric described earlier captures economic value related to reduced congestion, it represents value under normal system intact conditions. In practice, numerous outages occur throughout the year which introduce additional congestion which is not reflected in the calculation of the economic benefits. Furthermore, as the grid moves to a higher penetration of renewables and seasonal load curve flattens, outage scheduling becomes more challenging. Additional transmission improves system utilization and allows more opportunity for scheduling transmission outages with less risk of causing operational issues or rescheduling of outages.

The LRTP Tranche 1 Portfolio makes use of existing routes, where possible, to reduce the need to acquire additional greenfield right-of-way which lowers costs and allows a shorter time to implementation. Construction of new transmission routes across navigable waterways, protected areas and high value property faces extensive cost and regulatory risks that impede progress in meeting future reliability needs. Co-locating new facilities with existing transmission assets enables more efficient development of transmission projects and minimizes the environment and societal impacts of infrastructure investment needed to achieve the needs identified in MISO's Future 1.

The LRTP Tranche 1 Portfolio gives more flexibility to better support diverse policy needs. The proactive long-range approach to planning of regional transmission provides regulators greater confidence in achieving their policy goals by reducing uncertainty around the future resource expansion plans. Elimination of much of the high transmission cost barriers allows resource planners to assume less risk in making resource investment decisions.

Project Table Field Legend

Appendix A contains projects which are being or have been approved by MISO Board of Directors.
Transmission Owners are obligated to make a good faith effort to construct projects in Appendix A.

Project table has blue highlighted header. A project may have multiple facilities.
Facility table has beige highlighted header. A project's facilities may have different in service dates.

*In some cases, it is not possible to identify the entity with responsibility to own and construct facilities identified in Appendix A of MTEP at the time of Board approval, such as where the facilities are Competitive Transmission Facilities or subject to a State Right of First Refusal law ("ROFR") that requires the applicable Transmissible Owner confirm its intent to construct the facilities within a specified period. MISO has indicated where this has occurred by listing "Local TO(s)" or "To Be Determined" in Column D of Appendix A. MISO staff shall update such entries to list the name of the applicable entity: (1) within 90 days after Board of Director Approval of Appendix A for all facilities subject to state ROFR law; and (2) at the conclusion of the Competitive Developer Selection Process for all Competitive Transmission Facilities.

Project Table Field Legend

Field	Description
Target Appendix	Target appendix for the MTEPyy planning cycle. Example: "A in MTEP15" projects were reviewed in MTEP15. .
Region	MISO Planning Region: Central, East, West or South
Geographic Location by TO Member System	Project geographic location by Transmission Owner member systems*
PrjID	Project ID: MISO project identifier
Project Name	Project name (short name)
Project Description	A description of the project's components
State 1	State project is located or first state if in multiple states
State 2	If applicable, the second state the project is located
Allocation Type per FF	Project Type per Attachment FF of Tariff. BaseRel is Baseline Reliability, GIP is Generator Interconnection Project, TDSP is Transmission Delivery Service Project, MEP is Market Efficiency Project, MVP is Multi Value Project, Other is none of the above. Preliminary project allocation types may be designated for projects in Appendix B
Share Status	Cost allocation status for projects in Appendix A or moving to Appendix A in current planning cycle. Projects are Shared, Not Shared or Excluded. Preliminary sharing designations may be input for Appendix B projects
Other Type	Indicates the project driver behind Other type projects.
Estimated Cost	Total estimated project cost from Facility table
Expected ISD (Min/Max)	Dates when project is expected to be in service. Min and Max dates. Expected ISD are in Facility table.
Max kV	Maximum facility voltage in project. Summary information from Facility table
Min kV	Minimum facility voltage in project. Summary information form Facility table

MTEP21 LRTP Addendum Appendix A (data as of 06/17/2022)

Target Appendix	Planning Region	Geographic Location by TO Member System	Preliminary PrjId	Project Name	Project Description	State1	State2	System Need	Submitting Comp.	Allocation Type per FF	Share Status	Expected ISD	Max kV	Min kV	Min of Plan Status	Estimated Cost
A in MTEP21	North	MDU, OTP, Local TO(s)	LRTP-1	Jamestown – Ellendale	Install single circuit 345kV transmission line (constructed with double circuit capable 345kV structures) from the existing Jamestown Substation, to the existing Ellendale Substation.	ND	ND	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	12/31/2028	345	230	Proposed	$438.7M
A in MTEP21	North	Local TO(s)	LRTP-2	Big Stone South – Alexandria – Cassie's Crossing	Install single circuit 345kV transmission line from existing Big Stone South Substation, to the existing Alexandria Substation (constructed with double circuit capable 345kV structures), to the new Cassie's Crossing Substation.	SD	MN	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2030	345		Proposed	$573.5M
A in MTEP21	North	Local TO(s)	LRTP-3	Iron Range – Benton County – Cassie's Crossing	Install double circuit 345kV transmission line from the existing Iron Range Substation, to the existing Benton Country Substation, to the new Cassie's Crossing Substation.	MN	MN	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2030	500	345	Proposed	$969.9M
A in MTEP21	North	ATC, DPC, SMMPA, WPPI, XEL, Local TO(s)	LRTP-4	Wilmarth – North Rochester – Tremval	Install single circuit 345kV transmission line from the existing Wilmarth Substation, to the existing North Rochester Substation, to the existing Tremval Substation.	MN	WI	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2028	345	69	Proposed	$689.1M
A in MTEP21	North	ATC, XEL, Local TO(s)	LRTP-5	Tremval – Eau Claire – Jump River	Install single circuit 345kV transmission line from the existing Tremval Substation, to the existing Eau Claire Substation, to the new Jump River Substation.	WI	WI	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2028	345	115	Proposed	$504.5M
A in MTEP21	North	ATC, XEL, Local TO(s)	LRTP-6	Tremval – Rocky Run – Columbia	Install single circuit 345kV transmission line from the existing Tremval Substation, to the existing Rocky Run Substation, to the existing Columbia Substation.	WI	WI	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2029	345	69	Proposed	$1,049.5M
A in MTEP21	North	Local TO(s)	LRTP-7	Webster – Franklin – Marshalltown – Morgan Valley	Install single circuit 345kV transmission line from the existing Webster Substation, to the existing Franklin Substation, to the existing Marshalltown Substation (constructed with double circuit capable 345kV structures), to the existing Morgan Valley Substation.	IA	IA	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	12/31/2028	345	115	Proposed	$755.0M
A in MTEP21	North	Local TO(s)	LRTP-8	Beverly – Sub 92	Install single circuit 345kV transmission line from the existing Beverly Substation to the existing Sub 92 Substation.	IA	IA	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	12/31/2028	345		Proposed	$231.0M
A in MTEP21	North	Local TO(s), To Be Determined	LRTP-9	Orient – Denny - Fairport	Install single circuit 345kV transmission line from the existing Orient Substation to a new Denny Substation, to the existing Fairport Substation.	IA	MO	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2030	345		Proposed	$389.9M
A in MTEP21	Central	AmerenMO, To Be Determined	LRTP-10	Denny – Zachary – Thomas Hill – Maywood	Install single circuit 345kV transmission line from the new Denny Substation to the existing Zachary Substation, to the existing Thomas Hill Substation, to the existing Maywood Substation.	MO	MO	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2030	345	161	Proposed	$768.7M
A in MTEP21	Central	AmerenIL, AmerenMO	LRTP-11	Maywood – Meredosia	Install single circuit 345kV transmission line from the existing Maywood Substation to the existing Meredosia Substation.	MO	IL	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2028	345	161	Proposed	$300.8M
A in MTEP21	Central	Local TO(s)	LRTP-12	Madison – Ottumwa – Skunk River	Install single circuit 345kV transmission line from the existing Madison Substation, to the existing Ottumwa Substation, to the existing Skunk River Substation.	IA	IA	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2029	345	161	Proposed	$673.0M
A in MTEP21	Central	AmerenIL, Local TO(s)	LRTP-13	Skunk River – Ipava	Install single circuit 345kV transmission line from the existing Skunk River Substation to the existing Ipava Substation.	IA	IL	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	12/31/2029	345	161	Proposed	$594.4M
A in MTEP21	Central	AmerenIL	LRTP-14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	Install single circuit 345kV transmission line from the existing Ipava Substation, to the existing Maple Ridge Substation, to the existing Tazewell Substation, to the existing Brokaw Substation, to the existing Paxton East Substation.	IL	IL	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2028	345	138	Proposed	$571.7M
A in MTEP21	Central	AmerenIL, NIPSCO	LRTP-15	Sidney – Paxson East – Gilman South – Morrison Ditch	Install single circuit 345kV transmission line from the existing Sidney Substation, to the existing Paxton East Substation, to the existing Gilman South Substation, to the existing Morrison Ditch Substation.	IL	IN	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2029	345	138	Proposed	$454.1M
A in MTEP21	East	NIPSCO	LRTP-16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	Install single circuit 345kV transmission line from the existing Morrison Ditch Substation, to the existing Reynolds Substation, to the existing Burr Oak Substation, to the existing Leesburg Substation, to the existing Hiple Substation.	IN	IN	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2029	345	138	Proposed	$260.9M
A in MTEP21	East	Local TO(s), To Be Determined	LRTP-17	Hiple – Duck Lake	Install double circuit 345kV transmission line from the existing Hiple to the new Duck Lake Substation.	IN	MI	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2030	345		Proposed	$696.2M
A in MTEP21	East	Local TO(s)	LRTP-18	Oneida – Nelson Rd.	Install double circuit 345kV transmission line from the existing Oneida Substation, to the existing Nelson Road Substation.	MI	MI	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	12/29/2029	345		Proposed	$403.4M

Facility Table Field Legend

Project table has blue highlighted header. A project may have multiple facilities.
Facility table has beige highlighted header. A project's facilities may have different in service dates.

*In some cases, it is not possible to identify the entity with responsibility to own and construct facilities identified in Appendix A of MTEP at the time of Board approval, such as where the facilities are Competitive Transmission Facilities or subject to a State Right of First Refusal law (“ROFR”) that requires the applicable Transmissible Owner confirm its intent to construct the facilities within a specified period. MISO has indicated where this has occurred by listing “Local TO(s)” or “To Be Determined” in Column D of Appendix A. MISO staff shall update such entries to list the name of the applicable entity: (1) within 90 days after Board of Director Approval of Appendix A for all facilities subject to state ROFR law; and (2) at the conclusion of the Competitive Developer Selection Process for all Competitive Transmission Facilities.

Facilty Table Field Legend

Field	Description
Target Appendix	Target appendix for the MTEPyy planning cycle. Example: "A in MTEP15" projects were reviewed in MTEP15.
Region	MISO Planning Region: Central, East, West or South
Geographic Location by TO Member System	Project geographic location by Transmission Owner member systems*
PrjID	Indicates the Facility's Project. Projects may have multiple facilities.
Facility ID	Facility ID: MISO facility identifier
Expected ISD	Expected In Service Date for this facility
From Sub	From substation for transmission line or location of transformer or other equipment
To Sub	To substation for transmission line or transformer designation
Ckt	Circuit identifier
Max kV	Maximum voltage of this facility
Min kV	Minimum voltage of this facility (transformer low-side voltage)
Facility Rating	Rating of the facility in applicable units. Typically Summer rate
Facility Description	Brief description of transmission facility
State	State the facility is located in
Miles Upg.	Transmission line miles on existing rights of way (ROW)
Miles New	Transmission line miles on new rights of way (ROW)
Plan Status	Indicates status of project in planning or implementation. Conceptual, Proposed, Planned, Last Milestone Achieved, Under Construction and In Service
Estimated Cost	Total estimated facility cost
Cost Shared	Y if facility is cost shared per Attachment FF
Postage Stamp	Y if facility has postage stamp cost allocation per Attachment FF
MISO Facility	Y for facilities under MISO functional control. NT for non-transferred facilities under Agency Agreements

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	North	OTP	1		SUB	12/31/2028	Jamestown 345 kV			345		3000	1793	Add 1-345kV line position (replace existing 345kV ring bus with breaker-and-a-half bus) Add 1-345kV 50MVAr line reactor (for outgoing transmission line to Ellendale)	ND				$15.6M
A in MTEP21	A	North	MDU, OTP	1		LN	12/31/2028	Jamestown 345 kV	Ellendale 345		345		3000	1793	Construct new 345kV single circuit transmission line (constructed with double circuit capable 345kV structures)	ND		95		$379.6M
A in MTEP21	A	North	MDU	1		SUB	12/31/2028	Ellendale 345			345		3000	1793	Add 1-345kV line position (replace existing 345kV ring bus with breaker-and-a-half bus) Add 1-345kV 50MVAr line reactor (for outgoing transmission line to Jamestown)	ND				$9.5M
A in MTEP21	A	North	OTP	1		SUB	12/31/2028	Maple River 345 kV			345	230		2 transformer each 500MVA	Replace two existing 230/345kV, 336MVA transformers with two new 230/345kV 500MVA transformers	ND				$22.0M
A in MTEP21	A	North	Local TO(s)	1		SUB	12/31/2028	Twin Brooks 345 kV			345		N/A	N/A	Add 2-345kV 25MVAr shunt connected reactors in substation	SD				$12.0M
A in MTEP21	A	North	Local TO(s)	2		SUB	6/1/2030	Big Stone South 345 kV			345		3000	1793	Add 1-345kV line position (replace existing ring bus with breaker-and-a-half bus) Add 1-345kV 50MVAr line reactor (for outgoing transmission line to Alexandria 345kV)	SD				$12.0M
A in MTEP21	A	North	Local TO(s)	2		LN	6/1/2030	Big Stone South 345 kV	Alexandria 345kV		345		3000	1793	Construct new 345kV single circuit transmission line (constructed with double circuit capable 345kV structures)	SD/MN		128		$441.2M
A in MTEP21	A	North	Local TO(s)	2		SUB	6/1/2030	Alexandria 345kV			345		3000	1793	Add 2-345kV breaker-and-a-half positions (replace existing 345kV ring bus with breaker-and-a-half bus) Add 2 345kV 50MVAr line reactors (for outgoing transmission line to Big Stone South and outgoing transmission line to Cassie's Crossing)	MN				$16.7M
A in MTEP21	A	North	Local TO(s)	2		LN	6/1/2030	Alexandria 345kV	Outside Monticello Substation		345		3000	1793	Install second 345kV circuit on open spare position on existing structures on Alexandria - Monticello 345kV line.	MN	106			$36.0M
A in MTEP21	A	North	Local TO(s)	2		LN	6/1/2030	Outside Monticello Substation	Cassie's Crossing		345		3000	1793	Replace existing GRE single circuit 230kV transmission line with double circuit capable 345kV transmission line, one circuit initially strung, Mississippi river crossing will include second circuit. Strung circuit will carry Alexandria-Cassie Crossing circuit.	MN	1.5	1.5		$15.0M
A in MTEP21	A	North	Local TO(s)	2		LN	6/1/2030	Cassie's Crossing			345		3000	1793	Modify existing 345kV transmission lines to connect into Cassie's Crossing Substation.	MN	2			$10.3M
A in MTEP21	A	North	Local TO(s)	2		SUB	6/1/2030	Cassie's Crossing			345		3000	1793	Construct new 11-position, 345kV breaker-and-a-half bus substation	MN				$42.3M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2030	Cassie's Crossing	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W		345		3000	1793	Replace existing GRE single circuit 230kV transmission line with double circuit 345kV transmission line. Both lines will tie to Benton County.	MN	12.5			$48.8M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2028	Sherco	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W		345		3000	1793	Replace the existing Benton County-Sherco line to accommodate a rating greater than 3000 Amps. Including south deadend structure for new conductor. This line will tie to Benton County.	MN	7.3			$25.0M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2030	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	Benton County		345		3000	1793	Replace existing GRE single circuit 230kV transmission line with double circuit 345kV transmission line. One line will tie to Sherco and other to Cassie Crossing.	MN	12.5			$48.8M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2028	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	Benton County		345		3000	1793	Replace the existing Benton County-Sherco line to accommodate a rating greater than 3000 Amps. Including north deadend structure for new conductor. This line will tie to Cassie Crossing.	MN	14.1			$47.4M

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	North	Local TO(s)	3		SUB	6/1/2030	Benton County			345		3000	1793	Add 345kV 7-position breaker-and-a-half bus with 2 transformer positions and 5 line positions (one an existing modification), with two line connected 70MVAr shunt reactors on Iron Range lines, and modify 230kV position for one 230/345kV transformer	MN				$25.5M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2030	Benton County	Riverton 230/115kV		345		3000	1793	Construct new 345kV double circuit transmission line	MN		78		$312.0M
A in MTEP21	A	North	Local TO(s)	3		SUB	6/1/2030	Riverton 230/115kV			345		3000		Add 4-345kV series capacitor bank groups (2 in series for each circuit) with protective bypass equipment. Impedance of series capacitor bank will be approximately 60% compensation of line	MN				$80.0M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2030	Riverton 230/115kV	Iron Range 500/230kV		345		3000	1793	Construct new 345kV double circuit transmission line	MN		78		$312.0M
A in MTEP21	A	North	Local TO(s)	3		SUB	6/1/2030	Iron Range 500/230kV			345		3000	1793	Add 4-position 345kV ring bus (expandable to breaker-and-a-half bus) for 2-345/500kV transformer positions and 2 line positions (includes 2-345 kV shunt reactors on lines to Benton, est. 50 MVAR each)	MN				$20.0M
A in MTEP21	A	North	Local TO(s)	3		SUB	6/1/2030	Iron Range 500/230kV			500	345		1200	Add 2-345/500kV 1200MVA transformers (with 1 single phase spare on-site)	MN				$36.4M
A in MTEP21	A	North	Local TO(s)	3		SUB	6/1/2030	Iron Range 500/230kV			500		3000	2598	Add 5-position 500 kV ring bus (line to Dorsey, 500-230 TX, 500-345 TX, Cap Bank, 500-345 TX)	MN				$14.0M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	Crandall	Last double circuit structure from Wilmarth (44.032, -94.293)		345		3000	1793	Increase load capability of existing transmission line	MN	30			$69.2M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2026	Chub Lake			345		3000	1793	Add 1-345kV transformer position (replace existing ring bus with breaker-and-a-half bus)	MN				$3.3M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2026	Chub Lake			345	115		448	Add 1-115/345kV 448MVA transformer	MN				$6.8M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2026	Chub Lake			115		3000	598	Add 1-115kV transformer position (replace existing ring bus with breaker-and-a-half bus)	MN				$2.6M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	Wilmarth			345		3000	1793	Add 1-345kV line position (breaker-and-a-half bus)	MN				$4.6M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	Wilmarth	North Rochester		345	115	345kV: 3000 115kV: 1834	345kV: 1793 115kV: 365.3	Replace existing XEL Wilmarth - Faribault Energy Park single circuit 115kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 115kV. Construct new 345kV single circuit transmission line from Faribault Energy Park - North Rochester	MN	44	42		$327.9M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	North Rochester			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	MN				$6.5M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	North Rochester	161kV structure along line to Chester (44.173, -92.390)		161		1746	487	Construct new 161kV single circuit transmission line	MN		17		$28.7M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	North Rochester	161kV structure along line to Chester (44.173, -92.390)		345		3000	1793	Re-energize existing (currently operated at 161kV) conductors to 345kV	MN				$.0M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	161kV structure along line to Chester (44.173, -92.390)	161kV structure along line Wabaco (44.1937, -92.0859)		345		3000	1793	Install second 345kV circuit on existing spare position	MN	17			$7.7M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	161kV structure along line Wabaco (44.1937, -92.0859)	Kellogg		161		2000	558	Construct new 161kV single circuit transmission line	MN		11		$18.8M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	Kellogg			161		2000		Construct transmission structures to cut-in existing Wabaco - Alma 161kV transmission line into Kellogg Substation	MN	1			$1.5M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	Kellogg			161		2000		Construct new 3-position 161kV ring bus in the Kellogg Substation 1. Cut-in to existing Wabaco - Alma 161kV transmission line 2. Cut-in to existing Wabaco - Alma 161kV transmission line 3. 69/161kV, 112MVA transformer	MN				$6.7M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	Kellogg			161	69		112	Add 1-69/161kV, 112MVA transformer	MN				$.7M

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	Kellogg			69		2000		Construct new 2-position 69kV straight bus in the Kellogg Substation and cut-in existing Alma-Utica 69 kV transmission line.	MN				$1.9M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	Kellogg			69		2000		Construct transmission structures to cut-in existing Alma-Utica 69kV transmission line into Kellogg Substation	MN	1			$1.3M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	Kellogg	Alma						Install OPGW across Mississippi River to provide communications protection of new Alma-Kellogg 161 kV line	MN				$.2M
A in MTEP21	A	North	DPC	4		SUB	6/1/2028	Alma			161				Protection Upgrade at Alma to accommodate new Alma-Kellogg 161 kV line protection Requirements	WI				$.3M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	161kV structure along line Wabaco (44.1937, -92.0859)	345kV deadend structure (44.297, -91.905)		345		3000	1793	Re-energize existing (currently operated at 161kV) conductors to 345kV	MN				$.0M
A in MTEP21	A	North	DPC	4		LN	6/1/2028	345kV deadend structure (44.297, -91.905)	161kV structure outside Alma Substation		345	69	345kV: 3000 69kV: 552	345kV: 1793 69kV: 66	Replace existing DPC single circuit 69kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 69kV.	WI	1			$4.3M
A in MTEP21	A	North	DPC	4		LN	6/1/2028	161kV structure outside Alma Substation	Tremval		345	161	345kV: 3000 161kV: 1237	345kV: 1793 161kV: 345	Replace existing DPC single circuit 161kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 161kV.	WI	34			$167.8M
A in MTEP21	A	North	ATC, DPC, SMMPA, WPPI, XEL	4		LN	6/1/2028	Tremval			345		3000	1793	Modify existing Briggs Road - North Madison single circuit 345 kV transmission line to construct transmission structures to cut-in existing Briggs Road - North Madison 345kV transmission line into Tremval Substation	WI	1			$4.6M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	Tremval			345		3000	1793	Add 6-345kV line positions (breaker-and-a-half bus). 1. New transmission line from near Alma 2. New transmission line to Eau Claire 3. Cut-in to existing Briggs Road-North Madison 345kV line 4. Cut-in to existing Briggs Road-North Madison 345kV line 5. New transmission line to Rocky Run Substation 6. Bus connected 345kV, 80MVAr reactor	WI				$23.7M
A in MTEP21	A	North	Local TO(s)	5		LN	6/1/2028	Tremval	Eau Claire		345	161	345kV: 3000 161kV: 601	345kV: 1793 161kV: 167.6	Replace existing Xcel single circuit 161kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 161kV.	WI	46			$226.7M
A in MTEP21	A	North	XEL	5		SUB	6/1/2028	Eau Claire			345		3000	1793	Add 2-345kV line positions (ring bus). 1. New transmission line to Tremval 2. New transmission line to Jump River	WI				$5.4M
A in MTEP21	A	North	ATC, XEL	5		LN	6/1/2028	Eau Claire	Jump River		345	115	345kV: 3000 161kV: 1266 115kV: 1200	345kV: 1793 161kV: 353 115kV: 239	Replace existing Xcel single circuit 161kV and 115kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 161kV or 115kV.	WI	51			$250.9M
A in MTEP21	A	North	ATC	5		LN	6/1/2028	Jump River (45.3, -90.95)			345		3000	1793	Modify existing Stone Lake -- Gardner Park 345 kV single-circuit transmission line to construct transmission structures to cut-in existing Stone Lake - Gardner Park 345kV transmission line into Jump River Substation. Remote station upgrades.	WI	1			$4.6M
A in MTEP21	A	North	ATC	5		SUB	6/1/2028	Jump River (45.3, -90.95)			345		3000	1793	Construct new 4-position, 345kV ring bus substation. 1). New transmission line from Eau Claire 2). Cut-in to existing Stone Lake to Gardner Park 3). Cut-in to existing Stone Lake to Gardner Park 4). Bus-connected 345kV, 80MVAr reactor	WI				$16.9M
A in MTEP21	A	North	~~ATC, XEL~~ Local TO(s)	6		LN	6/1/2029	Tremval	Rocky Run		345		345kV: 3000 138kV: 895 69kV: 142	345kV: 1793 138kV 214 69kV: 17	Replace existing Xcel single circuit 69 kV structures with double circuit structures, with 1 circuit operated at 345kV and 1 circuit operated at 69kV for approximately 21 miles. Construct new 345kV single circuit transmission line for approximately 47 miles. Replace existing ATC single and double circuit 69kV, 138kV and 345kV structures with double circuit structures, with 1 circuit operated at 345kV and 1 circuit operated at 69kV, 138kV or 345kV for approximately 31 miles	WI	52	47		$398.4M
A in MTEP21	A	North	ATC	6		SUB	6/1/2029	Rocky Run			345		3000	1793	Modify existing transmission lines to connect to Rocky Run substation	WI	3			$9.5M

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	North	ATC	6		SUB	6/1/2029	Rocky Run			345		3000	1793	Replace existing 6-position 345kV ring bus, with 9-position 345kV breaker-and-a-half bus. Replaced bus will terminate all existing 6-positions, and 3 new bus positions - 1). New transmission line from Tremval 2). New transmission line to Columbia 3). Bus-connected 345kV, 80MVAr reactor	WI				$38.3M
A in MTEP21	A	North	ATC	6		LN	6/1/2029	Rocky Run	Columbia		345	69	345kV: 3000 138kV: 766 115kV: 1682 69kV: 669	345kV: 1793 138kV: 183 115kV: 335 69kV: 80	Replace existing single circuit 69kV, 115kV, 138kV, and 345kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 69kV, 115kV, 138kV or 345kV.	WI	114			$558.2M
A in MTEP21	A	North	ATC	6		LN	6/1/2029	345 kV Structure (43.477439, -89.284950)	Columbia		345		345kV: 3000	345kV: 1793	Replace existing double circuit 345 kV structures with new double circuit 345 kV structures, both 345 kV circuits rated for 3000Amps	WI	9			$35.2M
A in MTEP21	A	North	ATC	6		SUB	6/1/2029	Columbia			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus). 1). New transmission line to Rocky Run 2). Bus-connected 345kV, 80MVAr reactor	WI				$9.9M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2026	Webster			345		3000	1793	Add 1-345kV line position (ring bus)	IA				$3.8M
A in MTEP21	A	North	Local TO(s)	7		LN	12/31/2026	Webster	North Franklin		345	161	345kV: 2912 161kV: 1008	345kV: 1740 161kV: 281	Replace existing MEC single circuit 161kV structures with double circuit structures capable of supporting 1 circuit operated at 345kV and 1 circuit operated at 161kV.	IA	42	1		$135.0M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2026	North Franklin			345		3000	1793	Construct new 4-345kV line position (breaker-and-a-half bus) substation. 1. New transmission line from Webster 2. New transmission line to Marshalltown 3. Cut-in to existing Quinn-Black Hawk 345kV line 4. Cut-in to existing Quinn-Black Hawk 345kV line Add 2-345kV 50MVAr line reactors for outgoing transmission lines to Webster and to Marshalltown	IA				$44.3M
A in MTEP21	A	North	Local TO(s)	7		LN	12/31/2028	North Franklin	Marshalltown		345		2912	1740	Construct new 345kV single circuit transmission line (constructed with double circuit capable 345kV structures)	IA		69		$310.5M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Marshalltown			345		3000	1793	Add 3-345kV positions (ring bus, expandable to breaker-and-a-half bus). 1. New transmission line to North Franklin 2. New transmission line to Morgan Valley 3. 1-161/345kV 560MVA transformer Add 1-345kV 55MVAr line reactor for outgoing transmission line to Morgan Valley	IA				$21.0M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Marshalltown			345	161		560	Add 1-161/345kV 560MVA transformer	IA				$7.5M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Marshalltown			161	115		250	Add 1-115/161kV 250MVA transformer	IA				$3.0M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Marshalltown			161		3000	837	Add 1-161kV transformer position (breaker-and-a-half bus) for the 161/345kV transformer Utilize existing spare 161 kV position for 115/161kV transformer	IA				$2.3M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Marshalltown			115		2000	398	Add 1-115kV transformer position	IA				$1.5M
A in MTEP21	A	North	Local TO(s)	7		LN	12/31/2027	Marshalltown	Morgan Valley		345		3000	1793	Replace existing 115kV transmission line with new 345kV single circuit transmission line	IA	65			$221.0M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Morgan Valley			345		3000	1793	Add 1-345kV line position (breaker-and-a-half bus)	IA				$5.1M
A in MTEP21	A	North	Local TO(s)	8		SUB	12/31/2028	Beverly			345		3000	1793	Add 1-345kV line position (replace existing bus with ring bus) Add 1-345kV 55MVAr line reactor for outgoing transmission line to Sub 92	IA				$9.0M
A in MTEP21	A	North	Local TO(s)	8		LN	12/31/2028	Beverly	Sub 92		345		2912	1740	Construct new 345kV single circuit transmission line and replace existing 115kV transmission line with new 345kV single circuit transmission line for a portion of the route	IA	28	30		$203.0M
A in MTEP21	A	North	Local TO(s)	8		SUB	12/31/2028	Sub 92			345		3000	1793	Add 1-345kV line position (replace existing bus with ring bus)	IA				$19.0M
A in MTEP21	A	North	Local TO(s)	9		SUB	6/1/2030	Orient			345		3000	1793	Add 1-345kV line position (breaker-and-a-half bus) Add 1-345kV 50 MVAr line reactor (for outgoing line to Denny)	IA				$10.0M
A in MTEP21	A	North	Local TO(s)	9		LN	6/1/2030	Orient	IA/MO State Border		345		2912	1740	Construct new 345kV single circuit transmission line.	IA	8	44		$208.0M

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	North	To Be Determined	9		LN	6/1/2030	IA/MO State Border	Denny		345		3000	1793	Construct new 345kV single circuit transmission line.	MO		50		$139.3M
A in MTEP21	A	North	To Be Determined	9		SUB	6/1/2030	Denny			345		3000	1793	Construct new 4-position 345kV ring bus substation. 1. New transmission line to Orient. 2. New transmission line to Fairport. 3. New transmission line to Zachary. 4. Add 1-345kV bus 50 MVAr reactor	MO				$15.3M
A in MTEP21	A	North	To Be Determined	9		LN	6/1/2030	Denny	Fairport		345		3000	1793	Construct new 345kV single circuit transmission line	MO		2		$6.0M
A in MTEP21	A	North	To Be Determined	9		SUB	6/1/2030	Fairport			345		3000	1793	Add 1-345kV line position (replace existing bus with ring bus)	MO				$11.3M
A in MTEP21	A	Central	To Be Determined	10		LN	6/1/2030	Denny	Zachary		345		3000	1793	Construct new 345kV single circuit transmission line.	MO		135		$375.0M
A in MTEP21	A	Central	AmerenMO	10		SUB	6/1/2030	Zachary			345		3000	1793	Add 3-345kV positions (replace existing ring bus with breaker-and-a-half bus). 1. New transmission line to Denny 2. New transmission line to Thomas Hill 3. New transmission line to Maywood	MO				$12.6M
A in MTEP21	A	Central	To Be Determined	10		LN	6/1/2030	Zachary	Maywood		345		3000	1793	Construct new 345kV single circuit transmission line.	MO		60		$166.5M
A in MTEP21	A	Central	AmerenMO	10		LN	6/1/2030	Zachary	Thomas Hill		345	161	161kV: 1198	161kV: 334	Replace existing Ameren single circuit 161kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 161kV. Replace existing 161kV conductor, insulators, and hardware.	MO	44			$189.5M
A in MTEP21	A	Central	To Be Determined	10		LN	6/1/2030	Zachary	Thomas Hill		345	161	345kV: 3000	345kV: 1793	Install new 345kV conductor, insulators, and hardware on replaced transmission line structures.	MO	44			$14.4M
A in MTEP21	A	Central	To Be Determined	10		SUB	6/1/2030	Thomas Hill			345		3000	1793	Add 1-345kV line position	MO				$4.2M
A in MTEP21	A	Central	AmerenMO	10		SUB	6/1/2030	Maywood			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	MO				$6.5M
A in MTEP21	A	Central	AmerenIL, AmerenMO	11		LN	6/1/2028	Maywood	Meredosia		345	161	345kV: 3000 161kV: 1162 138kV: 1360	345kV: 1793 161kV: 324 138kV: 325	Replace existing Ameren 161kV single circuit transmission line with double circuit structures capable of support 1 circuit at 345kV and 1 circuit at 161kV for approximately 6 miles. Replace existing Ameren 138kV single circuit transmission line with double circuit structures capable of support 1 circuit at 345kV and 1 circuit at 138kV for approximately 56 miles. Construct new 345kV single circuit transmission line for approximately 2.5 miles	MO/IL	62	2.5		$296.6M
A in MTEP21	A	Central	AmerenIL	11		SUB	6/1/2028	Meredosia			345		3000	1793	Add 1-345kV line position (breaker-and-a-half bus)	IL				$4.2M
A in MTEP21	A	Central	Local TO(s)	12		SUB	12/31/2028	Madison County			345		3000	1793	Add 1-345kV line position (ring bus) Add 1-345kV, 50MVAr line reactor (for outgoing line to Ottumwa)	IA				$10.3M
A in MTEP21	A	Central	Local TO(s)	12		LN	12/31/2028	Madison County	Ottumwa Generation		345	161	345kV: 3000 161kV: 599	345kV: 1793 161kV: 167	Construct new 345kV single circuit transmission line (a portion of the route assumed to be double circuit with existing ITCM single circuit 161kV structures between Lucas County - Ottumwa). The portion that uses the existing 161kV line route will utilize double circuit structures 1 circuit operated at 345kV and 1 circuit operated at 161kV.	IA	42	53		$378.5M
A in MTEP21	A	Central	Local TO(s)	12		SUB	12/31/2026	Ottumwa Generation			345		3000	1793	Add 3-345kV line positions (replace existing bus with breaker-and-a-half bus). 1. New transmission line to Madison County 2. New transmission line to Skunk River 3. Bus-connected 345kV, 55MVAr reactor	IA				$11.9M
A in MTEP21	A	Central	Local TO(s)	12		LN	12/31/2026	Ottumwa Generation	Skunk River		345	161	345kV: 3000 161kV: 599	345kV: 1793 161kV: 167	Construct new 345kV single circuit transmission line (a portion of the route assumed to be double circuit with existing ITCM single circuit 161kV structures between Ottumwa - Woody - Jefferson County - Henry County). The portion that uses the existing 161kV line route will utilize double circuit structures 1 circuit operated at 345kV and 1 circuit operated at 161kV.	IA	60	2		$248.0M
A in MTEP21	A	Central	Local TO(s)	12		SUB	6/1/2029	Skunk River (40.973, -91.634)			345		3000	1793	Modify existing Sub T - Maywood 345 kV single-circuit transmission line to construct transmission structures to cut-in existing Sub T - Maywood 345kV transmission line into Skunk River Substation	IA	1			$2.6M

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	Central	Local TO(s)	12		SUB	6/1/2029	Skunk River (40.973, -91.634)			345		3000	1793	Construct new 5-position 345kV breaker-and-a-half bus substation 1. New transmission line to Ottumwa 2. New transmission line to Denmark 3. Cut-in to existing Sub T - Maywood transmission line 4. Cut-in to existing Sub T - Maywood 5. Bus-connected 345kV, 50MVAr reactor	IA				$21.7M
A in MTEP21	A	Central	Local TO(s)	13		LN	12/31/2029	Skunk River	Denmark		345	161	345kV: 3000 161kV: 800	345kV: 1793 161kV: 223	Construct new 345kV single circuit transmission line (a portion of the route assumed to be double circuit with existing ITCM single circuit 161kV structures between Jefferson County - Henry County - Denmark). The portion that uses the existing 161 kV line route will utilize double circuit structures 1 circuit operated at 345kV and 1 circuit operated at 161kV.	IA		25		$102.5M
A in MTEP21	A	Central	Local TO(s)	13		SUB	12/31/2029	Denmark			161		3000	837	Add 1-161kV transformer position (replace existing bus to breaker-and-a-half bus)	IA				$18.5M
A in MTEP21	A	Central	Local TO(s)	13		SUB	12/31/2029	Denmark			345	161		560	Add 161/345kV 560 MVA transformer	IA				$7.5M
A in MTEP21	A	Central	Local TO(s)	13		SUB	12/31/2029	Denmark			345		3000	1793	Add 3-345kV positions (ring bus) 1. New Transmission line to Skunk River 2. New transmission line to Ipava 3. New 161/345kV 560MVA transformer Add 1-345kV, 55MVAr line reactor (for outgoing transmission line to Ipava)	IA				$15.6M
A in MTEP21	A	Central	Local TO(s)	13		LN	12/31/2029	Denmark	IA/IL State Border - Mississippi River		345		3000	1793	Construct new 345kV single circuit transmission line (a portion of the route assumed to be double circuit with existing ITCM single circuit 161kV structures between Denmark - Burlington). The portion that uses the existing 161 kV line route will utilize double circuit structures 1 circuit operated at 345kV and 1 circuit operated at 161kV.	IA		30		$123.0M
A in MTEP21	A	Central	AmerenIL	13		LN	6/1/2028	IA/IL State Border - Mississippi River	Ipava		345		3000	1793	Replace existing Ameren-IL 138kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 138 kV.	IL	69			$320.8M
A in MTEP21	A	Central	AmerenIL	13		SUB	6/1/2028	Ipava			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	IL				$6.5M
A in MTEP21	A	Central	AmerenIL	14		LN	6/1/2028	Ipava	Maple Ridge		345		Replaced segment: 3000 Spare position segment: 2000	Replaced segment: 1793 Spare position segment: 1195	Replace existing transmission line, and install second 345kV on spare position. Replaced transmission line structures will be capable of supporting 2-345kV circuits. Replaced segment: 21 miles of Ameren-IL single circuit 345kV structures from Ipava, to a structure outside Duck Creek (40.4598, -89.9851). Replace existing 345kV conductor with new conductor. Second circuit on spare position: 21 miles from a structure outside Duck Creek (40.4598, -89.9851) to Maple Ridge	IL	42			$90.5M
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Maple Ridge			345		3000	1793	Add 2-345kV line positions (replace existing bus with breaker-and-a-half bus)	IL				$7.3M
A in MTEP21	A	Central	AmerenIL	14		LN	6/1/2028	Maple Ridge	Tazewell		345		345kV: 2000 138kV: 2000 69kV: 1200	345kV: 1195 138kV: 478 69kV: 143	Construct new and re-energize existing conductors to a higher voltage (currently operated at 69kV from Maple Ridge to Edwards & at 138kV from Edwards to Tazewell) to 345kV. Construct new 69kV single circuit transmission line for approximately 5.5 miles from a structure outside Maple Ridge (40.595, -89.759) to Edwards Construct new 138kV single circuit transmission line from Edwards to Tazewell for approximately 9 miles.	IL		14.5		$22.3M
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Tazewell			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	IL				$6.5M
A in MTEP21	A	Central	AmerenIL	14		LN	6/1/2028	Tazewell	Brokaw		345		345kV: 3000 138kV: 2000	345kV: 1793 138kV: 478	Replace existing Ameren single circuit 138kV structures (Havanna - Old Danvers) with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 138kV for approximately 25 miles. Construct new 345kV single circuit transmission line for approximately 20 miles.	IL	25	20		$173.0M

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Brokaw			345		3000	1793	Add 6-position 345kV breaker-and-a-half bus 1. Re-terminate Brokaw-South Bloomington into added bus 2. Re-terminate Brokaw-Clinton into added bus 3. New transmission line to Tazewell 4. New transmission line to Paxton East 5. Tie to existing Brokaw ring bus 6. Tie to existing Brokaw ring bus	IL				$21.7M
A in MTEP21	A	Central	AmerenIL	14		LN	6/1/2028	Brokaw	Paxton East		345	138	345kV: 3000 138kV: 2000	345kV: 1793 138kV: 478	Replace existing Ameren single circuit 138kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 138kV.	IL	45			$209.1M
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Paxton East			345		3000	1793	Add 5-position 345kV breaker-and-a-half bus 1. New transmission line to Brokaw 2. New transmission line to Gilman South 3. New transmission line Sidney 4. 1-138/345kV 700MVA transformer 5. Bus-connected, 345kV, 50MVAr reactor	IL				$23.1M
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Paxton East			345	138		700	Add 1-138/345kV 700MVA transformer	IL				$5.9M
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Paxton East			138		3000	717	Replace 6-position 138kV breaker-and-a-half bus 1. Re-terminate Paxton-Paxton East into replaced bus 2. Re-terminate Paxton East-Gilman South into replaced bus 3. Re-terminate Paxton East-Sidney into replaced bus 4. Re-terminate Paxton East-Hoopeston into replaced bus 5. Re-terminate Paxton East-Pioneer Wind into replaced bus 6. New 138/345kV 700MVA transformer	IL				$12.3M
A in MTEP21	A	Central	AmerenIL	15		SUB	6/1/2029	Sidney			345		3000	1793	Add 1-345kV line position (breaker-and-a-half bus)	IL				$3.8M
A in MTEP21	A	Central	AmerenIL	15		LN	6/1/2029	Sidney	Paxton East		345	138	345kV: 3000 138kV: 2000	345kV: 1793 138kV: 478	Replace existing Ameren single circuit 138kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 138kV.	IL	31			$144.7M
A in MTEP21	A	Central	AmerenIL	15		LN	6/1/2029	Paxton East	Gilman South		345	138	345kV: 3000 138kV: 2000	345kV: 1793 138kV: 478	Replace existing Ameren single circuit 138kV structures with double circuit structures, with 1 circuit operated at 345kV and 1 circuit operated at 138kV for approximately 21 miles. Construct new 345kV single circuit transmission line for approximately 2.5 miles	IL	21	2.5		$104.8M
A in MTEP21	A	Central	AmerenIL	15		SUB	6/1/2029	Gilman South			345		3000	1793	Add 3-position 345kV ring bus (expandable to breaker-and-a-half bus) 1. New transmission line to Paxton East 2. New transmission line to Morrison Ditch 3. 1-138/345kV 700MVA transformer	IL				$12.0M
A in MTEP21	A	Central	AmerenIL	15		SUB	6/1/2029	Gilman South			345	138		700	Add 1-138/345kV 700MVA transformer	IL				$5.9M
A in MTEP21	A	Central	AmerenIL	15		SUB	6/1/2029	Gilman South			138		3000	717	Add 1-138kV line position (replace existing bus with ring bus)	IL				$6.7M
A in MTEP21	A	Central	AmerenIL, NIPSCO	15		LN	6/1/2029	Gilman South	Morrison Ditch		345	138	345kV: 3000 138kV: 2000	345kV: 1793 138kV: 478	Replace existing Ameren & NIPSCO single circuit 138kV structures with double circuit structures capable of supporting 1 circuit operated at 345kV and 1 circuit operated at 138kV for approximately 30 miles. Construct new 345kV single circuit transmission line for approximately 2 miles.	IL	30	2		$147.5M
A in MTEP21	A	Central	NIPSCO	15		SUB	6/1/2029	Morrison Ditch			345		3000	1793	Add 3-345kV positions ring bus (expandable to breaker-and-a-half bus) 1. New Transmission line from Gilman South 2. New Transmission line to Reynolds 3. New 138/345kV 560MVA transformer	IN				$11.8M
A in MTEP21	A	Central	NIPSCO	15		SUB	6/1/2029	Morrison Ditch			345	138		560	Add 1-138/345kV 560MVA transformer	IN				$4.8M
A in MTEP21	A	Central	NIPSCO	15		SUB	6/1/2029	Morrison Ditch			138		3000	717	Add 1-138kV transformer position (ring bus) Replace substation bus for 3000A	IN				$2.3M
A in MTEP21	A	Central	AmerenIL	15		LN	6/1/2029	Hoopeston West	Rossville		138		2000	478	Replace 138kV conductor to achieve 2000A	IL	5.5			$8.8M
A in MTEP21	A	Central	AmerenIL	15		SUB	6/1/2029	Hoopeston West			138		2000	478	Replace substation bus to achieve 2000A	IL				$1.0M
A in MTEP21	A	East	NIPSCO	16		LN	6/1/2029	Morrison Ditch	Reynolds		345	138	345kV: 3000 138kV: 3000	345kV: 1793 138kV: 717	Replace existing NIPSCO single circuit 138kV structures with double circuit structures capable of supporting 1 circuit operated at 345kV and 1 circuit operated at 138kV for approximately 30 miles. Construct new 345kV single circuit transmission line for approximately 7 miles.	IN	30	7		$157.7M
A in MTEP21	A	East	NIPSCO	16		SUB	6/1/2029	Goodland				138	3000	717	Replace terminal equipment to achieve 3000A	IN				$1.0M

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	East	NIPSCO	16		SUB	6/1/2029	Reynolds			345		3000	1793	Add 3-345kV line positions (breaker-and-a-half bus) 1. New transmission line to Morrison Ditch 2. New transmission line to Burr Oak 3. New 138/345kV 560MVA transformer	IN				$14.9M
A in MTEP21	A	East	NIPSCO	16		SUB	6/1/2029	Reynolds			345	138		2 transformers of 560MVA each	Add 1-138/345kV 560 MVA transformer Replace 1-138/345kV 350 MVA transformer with a 138/345kV 560MVA transformer	IN				$9.5M
A in MTEP21	A	East	NIPSCO	16		SUB	6/1/2029	Reynolds			138		3000	717	Add 1-138kV transformer position Replace existing straight bus with a ring (expandable to breaker-and-a-half) bus	IN				$7.7M
A in MTEP21	A	East	NIPSCO	16		LN	6/1/2029	Reynolds	Monticello		138		2368	566	Replace 138kV conductor from ACSR conductor to ACSS conductor of same size and replace fiber optic cable	IN	7			$11.1M
A in MTEP21	A	East	NIPSCO	16		SUB	6/1/2029	Monticello			138		3000	717	Replace terminal equipment to achieve 3000A	IN				$1.0M
A in MTEP21	A	East	NIPSCO	16		LN	6/1/2029	Reynolds	Burr Oak		345		3000	1793	Install second 345kV circuit on open spare position on existing structures on existing Reynolds - Burr Oak 345kV transmission line	IN	48			$15.8M
A in MTEP21	A	East	NIPSCO	16		Sub	6/1/2029	Burr Oak			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	IN				$6.5M
A in MTEP21	A	East	NIPSCO	16		LN	6/1/2029	Burr Oak	Leesburg		345		3000	1793	Install second 345kV circuit on open spare position on existing structures on existing Burr Oak - Leesburg 345kV line	IN	29			$9.5M
A in MTEP21	A	East	NIPSCO	16		Sub	6/1/2029	Leesburg			345		3000	1793	Add 2-345kV line positions (replace existing bus with breaker-and-a-half bus)	IN				$7.3M
A in MTEP21	A	East	NIPSCO	16		LN	6/1/2029	Leesburg	Hiple, F G		345		3000	1793	Add 345kV circuit to spare position on existing transmission line structure	IN	23			$7.6M
A in MTEP21	A	East	NIPSCO	16		Sub	6/1/2029	Hiple, F G			345		3000	1793	Add 3-345kV line positions (breaker-and-a-half bus) 1. New transmission line to Leesburg 2. New transmission line to Duck Lake 3. New transmission line to Duck Lake	IN				$11.3M
A in MTEP21	A	East	To Be Determined	17		LN	6/1/2030	Hiple, F G	IN/MI State Border		345		3000	1793	Construct new 345kV double circuit transmission line	IN		55		$253.7M
A in MTEP21	A	East	Local TO(s)	17		LN	6/1/2030	IN/MI State Border	Duck Lake		345		3000	1793	Construct new 345kV double circuit transmission line	MI		72		$406.7M
A in MTEP21	A	East	Local TO(s)	17		SUB	12/29/2026	Duck Lake (42.41, -84.792)			345		3000	1793	Construct new 8-position 345kV breaker-and-a-half bus substation. Loop in Argenta-Tompkins, Battle Creek-Oneida, and Oneida-Majestic 345 kV lines into Duck Lake.	MI				$35.8M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2029	Oneida			345		3000	1793	Add 2-345kV line positions (replace existing bus with breaker-and-a-half bus)	MI				$8.9M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2029	Oneida	Nelson Road		345		3000	1793	Construct new 345kV double circuit transmission line	MI		38.5		$181.9M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2029	Nelson Road			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	MI				$5.5M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2026	Duck Lake (42.41, -84.792)	Tompkins		345		3000	1793	Replace double circuit 345kV transmission line (one circuit)	MI	16			$20.6M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2027	Tompkins	Majestic		345		3000	1793	Replace double circuit 345kV transmission line (one circuit)	MI	28			$36.0M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2028	Tompkins			345		3000	1793	Replace terminal equipment to achieve 3000A	MI				$2.2M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2028	Majestic			345		3000	1793	Replace terminal equipment to achieve 3000A	MI				$1.5M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2028	Majestic	Wayne		345		3000	1793	Replace conductor to achieve 3000A	MI	31			$55.9M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2028	Wayne			345		3000	1793	Replace terminal equipment to achieve 3000A	MI				$5.5M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2028	Majestic	Coventry		345		3000	1793	Replace conductor to achieve 3000A	MI	20			$26.5M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2028	Coventry			345		3000	1793	Replace terminal equipment to achieve 3000A	MI				$1.1M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2027	Duck Lake (42.41, -84.792)	Majestic		345		3000	1793	Replace double circuit 345kV transmission line (one circuit)	MI	43.5			$57.8M

Appendix G-2

MISO's LRTP Tranche 1 Portfolio Detailed Business Case

LRTP Tranche 1 Portfolio Detailed Business Case

- Long Range Transmission Planning (LRTP) addresses the future challenges of the resource fleet evolution
- The LRTP Detailed Business Case summarizes the analysis of the reliability and economic benefits used to demonstrate that the value exceeds the total cost of the projects and supports recommendation of the portfolio
- The LRTP Tranche 1 portfolio provides a total 20-year present value benefit to cost ratio of 2.6

MISO Transmission Planning Objectives

- The goal of MISO Planning is to identify and support development of transmission infrastructure that is sufficiently robust to meet reliability needs and support a competitive energy market, policy goals and competitive transmission development
- MISO Board of Directors Guiding Principles
  - Ensure a reliable and resilient transmission system to meet operational needs
  - Make benefits of an economically efficient electricity market available to customers by identifying transmission solutions that enable access to the electricity at the lowest total electric system cost
  - Support federal, state and local energy policy and member goals by planning for access to a changing resource mix
  - Provide an appropriate cost allocation mechanism that ensures that costs are allocated in a manner roughly commensurate with the projected benefits
  - Analyze system scenarios and make results available to energy policy makers and stakeholders to provide context and inform their choices
  - Coordinate planning process with neighbors and work to eliminate barriers to reliable and efficient operations

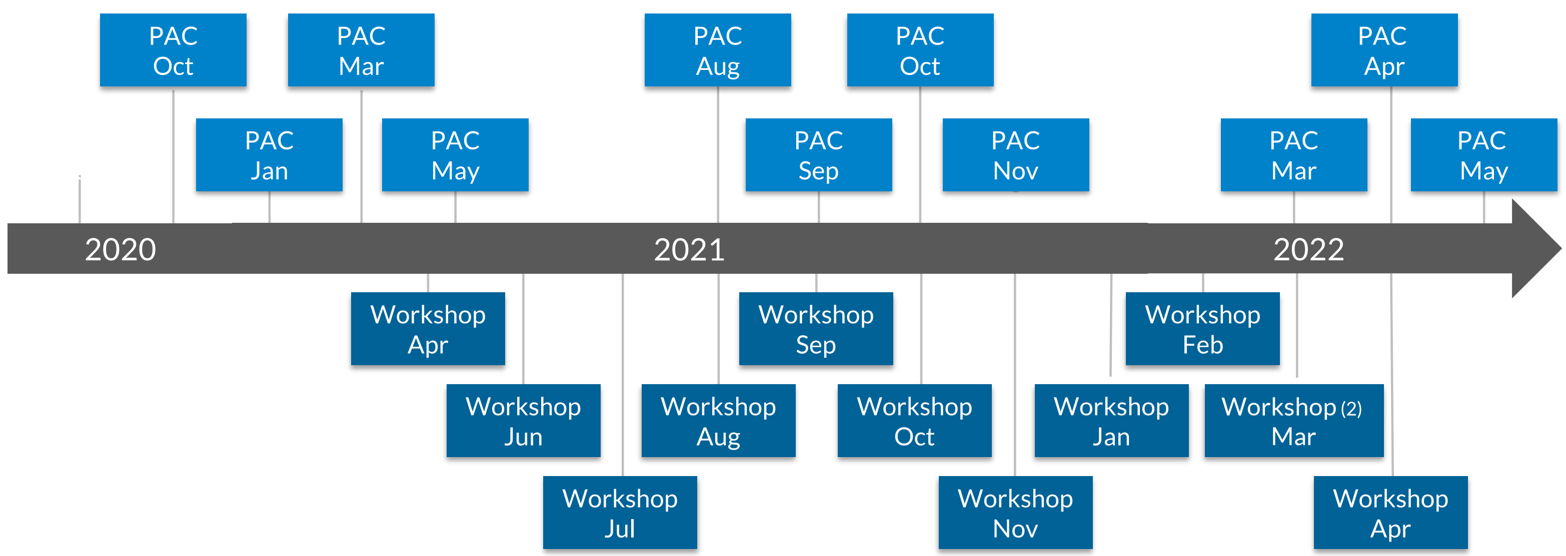
Long range focus on system planning needed in response to unprecedented industry changes

- The initial 2019 MISO Forward report began to examine industry trends around resource and technology developments that highlighted growing challenges around resource availability, flexibility and visibility of the resource fleet in meeting future energy needs
- The Renewable Integration Impact Assessment explored challenges of increased renewable penetration and identified significant reliability issues that would need to be addressed through possible reinforcements to maintain robust performance
- In recognition of the need for more long-term proactive planning to meet the pace of change, Long Range Transmission Planning began with a conceptual roadmap of ideas to help guide development of planning analysis that would be needed to identify possible transmission solutions

Timeline of LRTP development

- MISO introduced the LRTP conceptual roadmap to stakeholders in June 2020 to begin discussions on the study scope and approach
- MISO began a series of technical discussions in Aug 2020 to seek input from stakeholders on the study methods and assumptions and to provide regular status updates on the ongoing work and analysis findings
- MISO initiated discussions on cost allocation mechanisms with the Regional Expansion Criteria and Benefits Working Group in Feb 2021 to investigate possible Tariff changes that would be needed before recommendation of projects
- MISO introduced Business Case development in the Sept 2021 LRTP workshop to begin identifying the benefit components and defining the metrics for quantifying the benefits provided by the initial portfolio of LRTP transmission investments

Workshops and Stakeholder feedback are critical to the LRTP process and success



LRTP Projects must meet one of three MVP criteria defined in the MISO Tariff

MISO Tariff - Attachment FF, II.C.2...

a. *Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade*

b. *Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.*

c. ***Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.***

The MISO MVP Tariff further defines the ‘specific types of economic value’ which may be included

MISO Tariff - Attachment FF, II.C.5...

a. *Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Productions cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.*

b. *Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.*

c. *Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.*

d. *Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.*

e. *Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the transmission system and related to the provisions of Transmission Service.*

The objective of LRTP is to enable reliable and economic delivery of energy in the future with lower-carbon resources

- Enable access to lower-cost energy production
- Provide more flexibility in fuel mix for customer choice
- Maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply

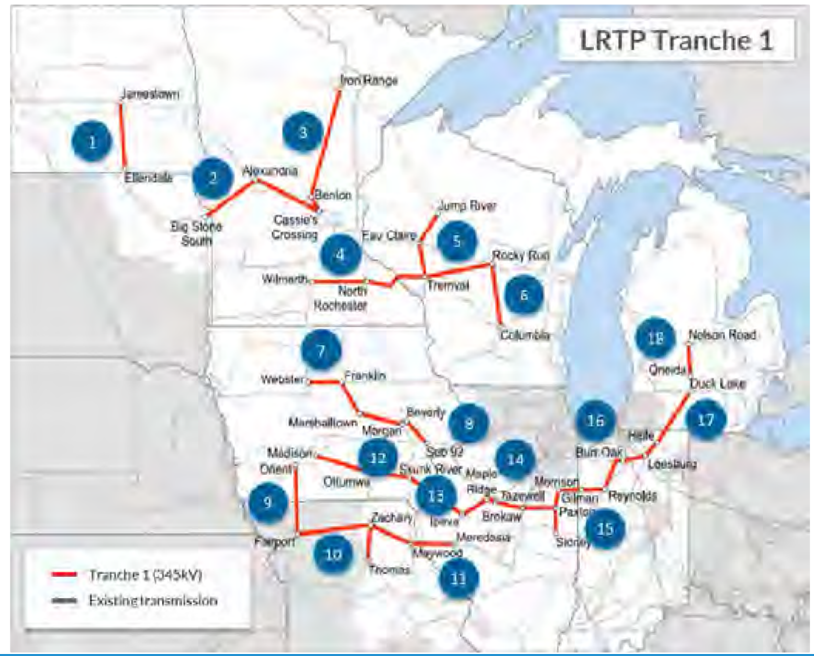
The scope of LRTP business case analysis includes quantifying the reliability and economic benefits

A. Congestion and fuel savings
B. Avoided capital costs of local resource investments
C. Avoided transmission investment
D. Reduced resource adequacy requirements
E. Avoided risk of load shedding
F. Decarbonization
G. Reliability issues addressed by LRTP
H. Other qualitative and indirect benefits

LRTP business case analysis uses a range of variables

- LRTP benefits examine value over the 20- to 40-year period from the in-service date (All projects assumed in service by 2030)
  - Benefit/cost calculations are evaluated on a 20-year time horizon
  - Additional benefits are shown for the 40-year horizon to align with assumed life of the assets
- LRTP benefits are evaluated for a range of discount rates from 3.0 – 6.9%
  - The social discount rate of 3.0% represents the value a ratepayer would typically receive on their risk-adjusted investment
  - The Weighted Average Cost of Capital (WACC) of 6.9% is the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments

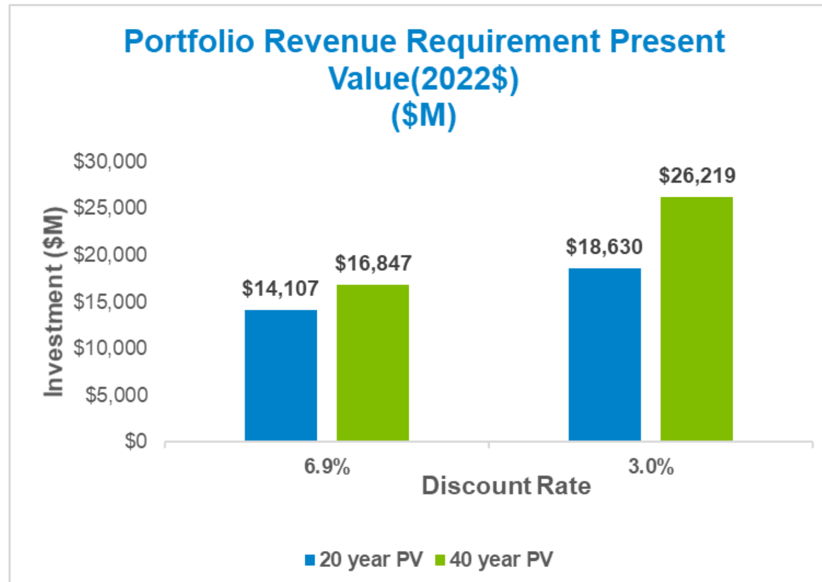
- Portfolio embodies needed transmission for the ever-changing fleet
- Addresses needs across the MISO Midwest subregion
- Analysis of reliability needs and benefits associated with Future 1 resource expansion



Total portfolio cost estimate for LRTP Tranche 1 is $10.3 B for projects located across the MISO Midwest subregion

ID	Project Description	Est. Cost ($M, 2022)
1	Jamestown – Ellendale	$439
2	Big Stone South – Alexandria – Cassie's Crossing	$574
3	Iron Range – Benton County – Cassie's Crossing	$970
4	Wilmarth – North Rochester – Tremval	$689
5	Tremval – Eau Clair – Jump River	$505
6	Tremval – Rocky Run – Columbia	$1,050
7	Webster – Franklin – Marshalltown – Morgan Valley	$755
8	Beverly – Sub 92	$231
9	Orient – Denny - Fairport	$390
10	Denny – Zachary – Thomas Hill – Maywood	$769
11	Maywood – Meredosia	$301
12	Madison – Ottumwa – Skunk River	$673
13	Skunk River – Ipava	$594
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	$572
15	Sidney – Paxson East – Gilman South – Morrison Ditch	$454
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	$261
17	Hiple – Duck Lake	$696
18	Oneida – Nelson Rd.	$403
	Total Project Portfolio Cost	**$10,324**

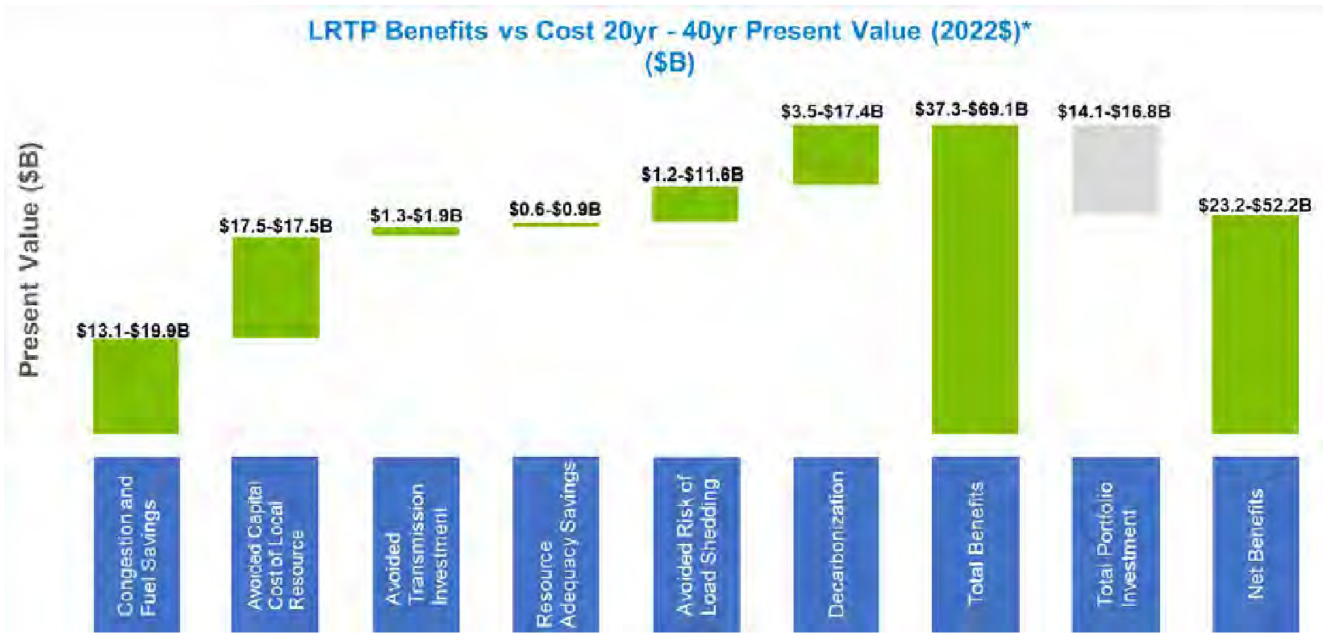
The LRTP Tranche 1 portfolio cost (20-year and 40-year present value at 6.9% and 3.0% discount rate)



*6.9% Discount Rate

Benefit Metrics

The business case analysis indicates total economic benefits significantly exceed cost of the Tranche 1 LRTP portfolio



APC Benefits will be determined by comparing MISO Midwest APC in the LRTP Reference Case with the MISO Midwest APC in the LRTP Change Case

Make-up of LRTP Reference Case Model

- MTEP Topology
- Future Load Forecast
- Existing + Signed GIA
- RRF DGPV
- IRP/RRF Battery Storage
- IRP/RRF Thermal
- Renewable RRFs < 5% DFAX

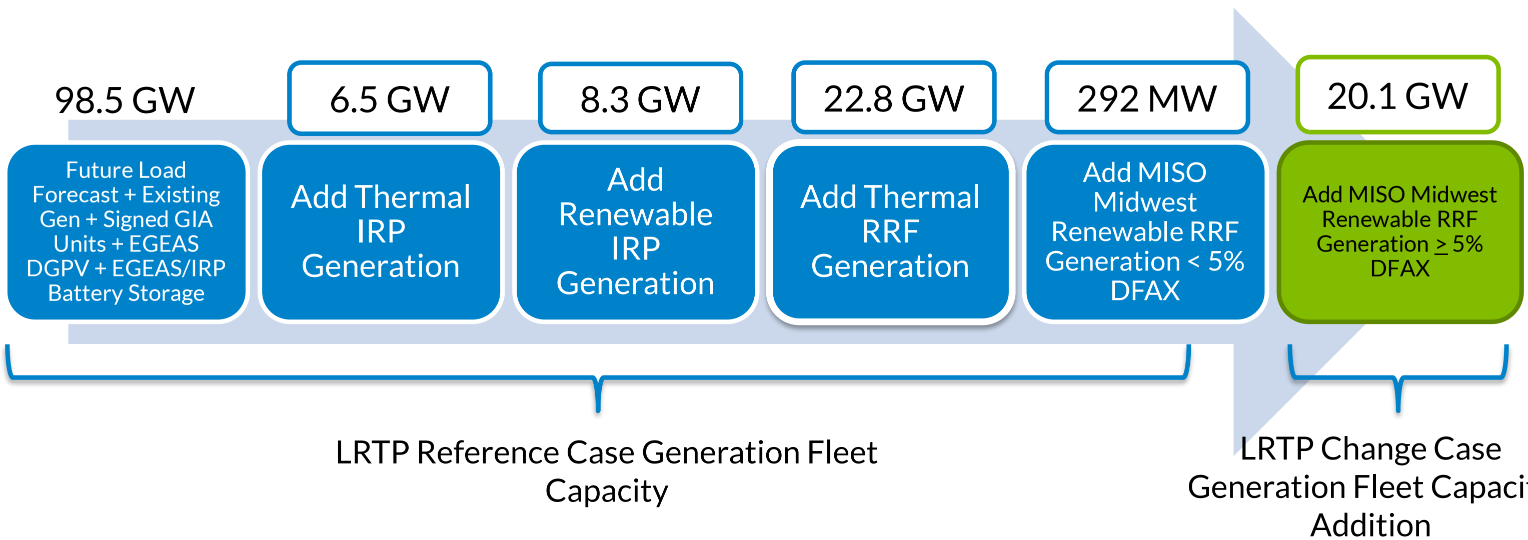
Compare APC Change →

Make-up of LRTP Change Case Model

- Reference Case
- Renewable RRFs ≥5% DFAX
- LRTP Transmission

- The LRTP Reference Case represents necessary generation to serve Futures Load Forecast (on copper sheet)
- The LRTP Change Case includes Renewable RRFs located in MISO Midwest which have ≥ 5% DFAX on reliability constraints addressed by LRTP projects

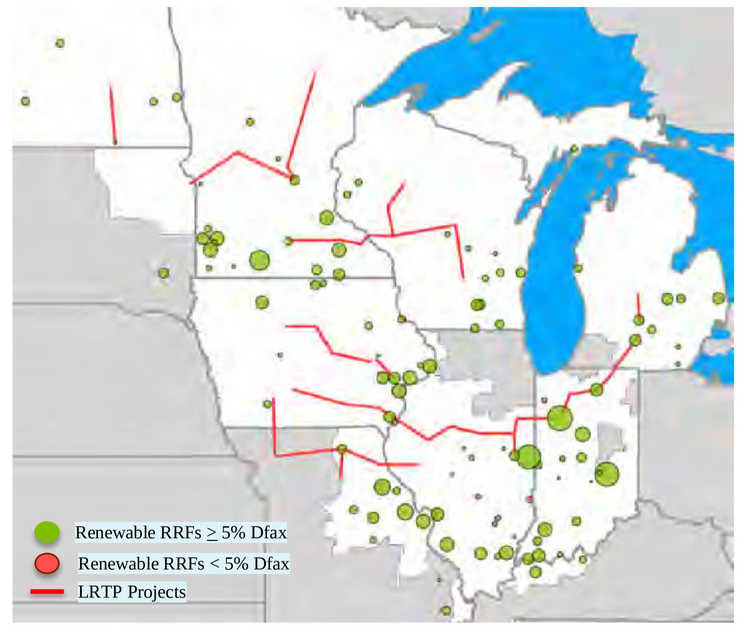
MISO Midwest-focused Reference Case generation determination process and results to meet copper sheet energy requirements in Future 1



A. Congestion and Fuel Savings

LRTP Tranche 1 projects congestion and fuel savings results

Present Value	20 year PV (Millions-2022$)		40 year PV (Millions-2022$)	
Discount Rate	6.9%	3.0%	6.9%	3.0%
CAZ				
1	$3,169	$4,455	$4,668	$8,797
2	$1,049	$1,511	$1,667	$3,313
3	$2,195	$3,060	$3,151	$5,823
4	$1,352	$1,934	$2,107	$4,133
5	$1,471	$2,078	$2,205	$4,210
6	$2,884	$4,133	$4,517	$8,890
7	$1,006	$1,432	$1,543	$2,993
	$13,125	**$18,603**	**$19,858**	**$38,160**



Appendix G-2
Mankato – Mississippi River Transmission Project
Certificate of Need and Route Permit Application
E002/CN-22-532 and E002/TL-23-157

B. Avoided Capital Costs of Local Resource Investments

Resource capital investments can be avoided by taking advantage of broader regional renewables instead of purely local resources

- Magnitude, cost, & locations of resources differ based upon approach used
- Regional transmission is the bridge between these scenarios

- EGEAS LBA (local) granularity expansion models utilizing Future 1 assumptions
- Calculation to relate the LBA and Regional expansion to LRTP transmission and determine what the avoided capital costs of local resource investments would be

Overview of EGEAS LBA expansion models used to determine what a local build out would be

- The runs treat each LBA as its own pool.
- Each LBA then self-constructs resources necessary to meet the simulation constraints such as PRM and emissions.
- Utilizes the same assumptions as the regional Future 1 analysis and resources are ascribed to LBAs based on resource ownership.
- Capacity purchases are enabled for the first year to meet each LBA's PRM and is driven by the construction lead time for new resource alternatives.
- LBA-specific wind and solar profiles are used instead of the regional profiles which averaged multiple profiles from different locations across MISO.

B. Avoided Capital Costs of Local Resource Investments

Calculation to relate the LBA and Regional expansion to LRTP transmission to determine cost savings

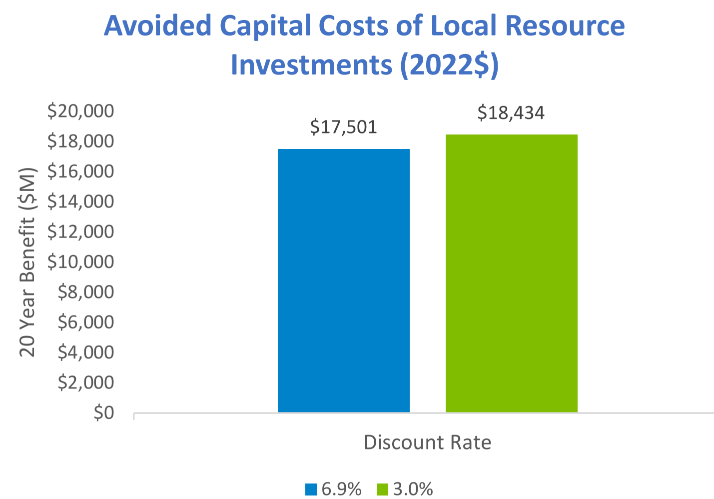
- Due to Regional and LBA modeling assumptions, the avoided capital costs of local resources investments can not be determined by subtracting Regional expansion costs from the total LBA expansion costs (doing so would over-state realized benefit)
- Regional and LBA Regional Resource Forecasting (RRF) expansion reflects Local Resource Zones (LRZ) that make up MISO Midwest (LRZ 1 – LRZ 7)
- Enabled RRF capacity reflects RRF resources enabled by LRTP transmission, meaning those resources have $\geq$ 5% Dfax for LRTP transmission resolved reliability issues
- Utilizes costs of LRTP transmission enabled capacity to infer avoided capital cost of local resources savings

$$\frac{\sum_{LRZ\ 1}^{LRZ\ 7}\left(Total\ RRF\ Capacity_{LBA\ Expansion}\right)}{\sum_{LRZ\ 1}^{LRZ\ 7}\left(Total\ RRF\ Capacity_{Regional\ Expansion}\right)}$$

Avoided capital costs of local resource investments benefit

$$\frac{90{,}969\ MW}{43{,}431\ MW} = \$33.58B$$

- LRTP enables regional resource sharing and reduces local overbuild yielding a 20-year present value benefit of $17.5B*



* using the 6.9% Discount Rate

Transmission investment is avoided by developing regional solutions vs incremental fixes

- Captures the avoided cost of reliability upgrades and replacements that will not be required in the future as a result of the addition of LRTP projects
- Includes facilities where thermal loading is approaching the rating but not overloaded
  - Avoided reliability upgrades are determined by using the 10-year and 20-year analysis results to project future loading on facilities loaded near the rating with and without LRTP projects

$$Flow_{proj} = Flow_{20} + (Flow_{20} - Flow_{10})$$

Example: Facility is included in avoided costs of future transmission investment							
Line name	kv	RatingMVA	case	Flow10	Flow20	Flowproj	
Forest - Valley 161kV	161kV	335	w/o LRTP	324	331	338	without LRTP, future upgrade is needed
			w/ LRTP	315	322	329	with LRTP the overload is resolved

- Includes replacement of existing facilities due to age and condition that would not be required because the LRTP projects use existing ROW of aging facilities

C. Avoided Transmission Investment

Re-use of existing ROW for LRTP projects offsets the costs of age and condition replacement of aging facilities

- The LRTP Tranche 1 portfolio of projects potentially use 836 miles of existing facilities where age and condition of the facilities is expected to require replacement of assets
- Construction of LRTP on the existing right-of-way would include replacement of existing structures and equipment that would avoid the future cost of replacing the existing facilities

Transmission investment is avoided by developing regional solutions vs incremental fixes

- Avoided transmission investment uses exploratory cost estimates based on type of facility improvement required
- Like in the 2011 MVP business case, an adjustment is applied to avoided reliability upgrades >=345kV to reduce value by 50% to account for potential production cost benefits provided by the upgrades
- Capital investment for future transmission is assumed to be spread equally over the 5-year period prior to the in-service date (2040) of the avoided reliability upgrades
- The Annual Transmission Revenue Requirement was calculated to obtain the 20-year net present value discounted to 2022$ values

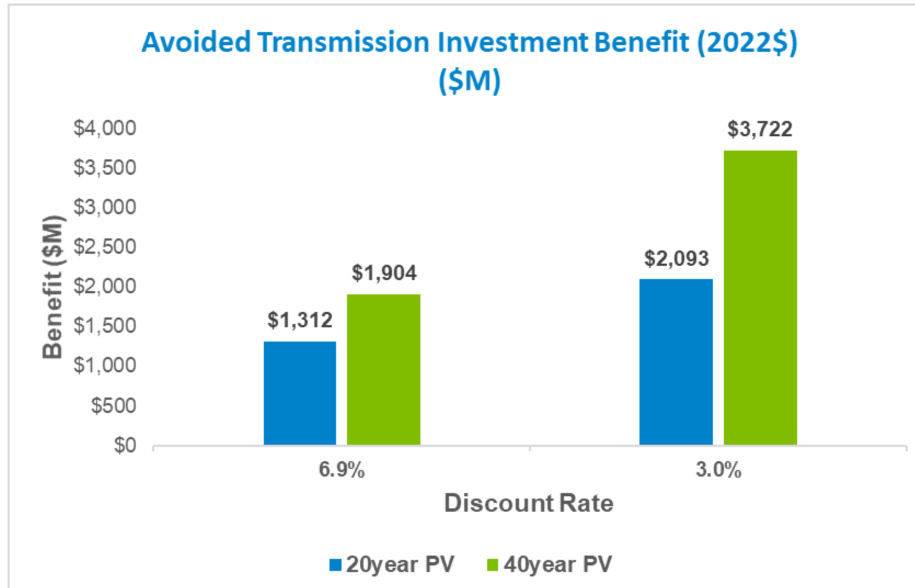
Facility Improvement Type	Unit Cost ($M)	Quantity/Miles	Cost ($M)*
Bustie Replacement	$1.50	2	$3
Transformer Replacement =345	$5.00	4	$20
Transformer Replacement <345	$3.00	5	$15
Transmission line Replacement =345kV (per mile)	$2.65	21	$56
Transmission line Replacement <345kV (per mile)	$1.60	1012	$1,617
Transmission line upgrade=345kV (per mile)	$0.56	230	$64
Transmission line upgrade <345kV (per mile)	$0.34	124	$43
		Total	**$1,819**

*MISO Estimates

C. Avoided Transmission Investment

LRTP provides benefits by eliminating the need for other transmission projects

- LRTP avoids the need for transmission investment that yields 20- to 40-year present value benefits from $1.3B to $1.9B*



* using the 6.9% Discount Rate

The resource adequacy benefits are related to an increase in transfer capability and a reduction in the total LCR*

- As LRTP increases the transfer capability within the footprint, the increase in transfer limit is quantified
- The potential economic value unlocked by the availability of least-cost resources across the footprint due to increase in transfer capability is estimated
- A two-step process was developed to quantify the LCR reduction benefits and approximate the monetary value

*Local Clearing Requirement

Step 1: Perform a transfer analysis to determine the LCR for each local resource zone (LRZ)

1. Calculate the capacity import limit (CIL) for each LRZ and case*
   - Determine the import limit (e.g., TrLim) for each LRZ and study case
   - Determine the area interchange for each LRZ and study case
2. Determine the LCR for each LRZ and case*
   - The LRR UCAP** percentages from the PY22-23 LOLE Study and the 2040 non-coincident peak load forecasts are used to set the LRR for each LRZ

Local Resource Zone	CIL (Base)	CIL (With LRTP)	Delta CIL (MW)
LRZ1	5412	6070	658
LRZ2	4188	5223	1035
LRZ3	5062	6453	1391
LRZ4	7117	7609	492
LRZ5	6131	6183	52
LRZ6	6005	6171	166
LRZ7	3367	4659	1292

*With and without LRTP projects (14 total cases) | **Unforced capacity

Step 2: Monetize the benefits identified in Step 1

1. The 2040 unforced capacity for each LRZ is determined using forced outage rates (thermal) and ELCC* (non-thermal)
2. The excess capacity within each LRZ is calculated as follows:
   - Excess Capacity = 2040 Unforced Capacity – LCR (without LRTP)
3. The RA benefit is estimated as follows:
   - If Excess Capacity < 0 → Benefit = (CONE**) x (-Excess Capacity)
   - If Excess Capacity > 0 → Benefit = $0/year

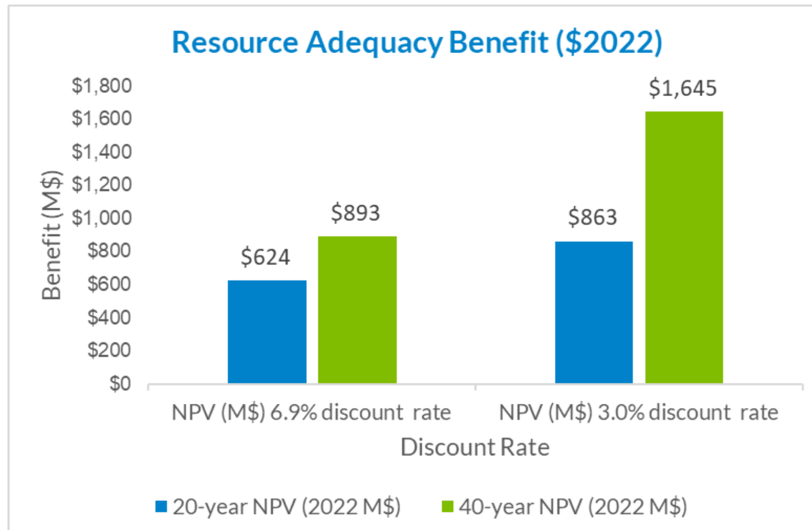
LRZ	1	2	3	4	5	6	7
PY22-23 CONE ($/MW-yr)	$91,270	$89,490	$86,380	$90,300	$97,190	$89,040	93,770

* Effective Load Carrying Capability | ** Cost of new entry

D. Reduced Resource Adequacy Requirements

The annual economic benefits related to resource adequacy are estimated to be $44M per year

- LRTP reduces the total LCR and yields 20- to 40-year present value benefits from $624-$893M*



* using a 6.9% Discount Rate

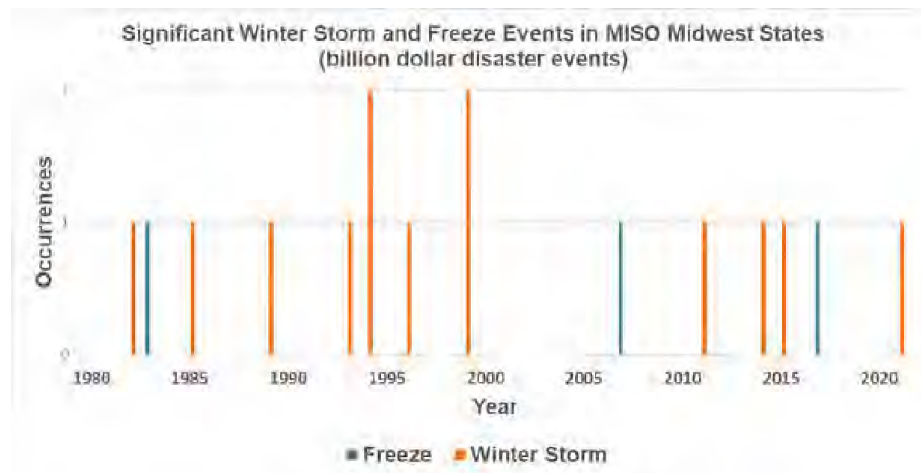
E. Avoided Risk of Load Shedding

LRTP transmission can reduce risk of load shedding due to unplanned generation events

- Large scale unexpected loss of generation in an area presents a risk of significant load shedding
- Transmission reinforcements provided by LRTP increase transfer capability to allow load to be served from resources located in other areas
- Benefits are associated with avoided risk of load shedding focus on risks of large-scale generation loss caused by severe weather
    - Renewable production is dependent on weather conditions
    - Thermal resources have operational limitations under extreme temperature conditions
- Weather-related events occur in various scales
    - Event scenarios examine generation and load balance after loss of significant resources to determine if import capability is sufficient to cover generation deficiency
    - Risk of load shedding exists where generation deficiency cannot be covered by existing import capability
- Benefits are calculated using Value of Lost Load (VOLL) ranging from $3500-$23,000* /MWh

*IMM Quarterly Report: Summer 2020, https://cdn.misoenergy.org/IMM%20Quarterly%20Report_Summer%202020478028.pdf

Analysis of risk focus on recurring severe winter weather events and variability of renewable resources



Data Source: NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2022). https://www.ncei.noaa.gov/billions/, DOI: 10.25921/stkw-7w73

E. Avoided Risk of Load Shedding

Weather conditions affect the availability of resources

- Renewable resources regularly experience periods of low output lasting several hours

Source: *MISO's Response to the Reliability Imperative*,
https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf

Data Source: MISO Historical Hourly Wind, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc

LRTP transmission can reduce risk of load shedding due to unplanned loss of generation due to severe winter weather events

Area/Zonal Event Scenario

LoadLossMW =
$GenMW_{net}$ – 1.05 * LoadMW – TxLossMW + Capacity Import Limit(MW)
where $GenMW_{net} = GenMW_{cap} - GenMW_{loss}$

+

Regional Event Scenario

Generation Loss:
Thermal: 50% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Total Transfer Capability

Scenario 1: Source: MISO Zones 4-7 + PJM
Sink: MISO Zones 1-3 + SPP

Scenario 2: Source: MISO Zones 1-3 + SPP
Sink: MISO Zones 4-7

LoadLossMW =
$GenMW_{net}$ - 1.05 * LoadMW – TxLossMW + Total Transfer Capability(MW)
where $GenMW_{net} = GenMW_{cap} - GenMW_{loss}$

E. Avoided Risk of Load Shedding

Total avoided risk of load shedding includes all winter event scenarios

Zonal

zone	GenLoss(therm)	GenLoss(wind)	GenLoss(solar)	Gen Remaining		Gen Surplus	CIL (no LRTP)	shortfall	newCIL (LRTP)	CIL diff	benefit
1	6607	6693	4612	12178		-5083	5412	-329	6070	658	
2	5369	1082	1049	8246		-3527	4188	-661	5223	1035	
3	3762	8001	3306	9529		-195	5062	-4867	6453	1391	
4	3358	2442	2065	6645		-2532	7117	-4585	7609	492	
5	2414	691	1185	5499		-2092	6131	-4039	6183	52	
6	7362	1461	2858	11873		-6680	6005	675	6171	166	166
7	6164	1714	3445	13387		-3574	3368	206	4659	1291	206
							Total Avoided Load shed				372
							Assumed duration				16
							Total Avoided Load shed hours				5954

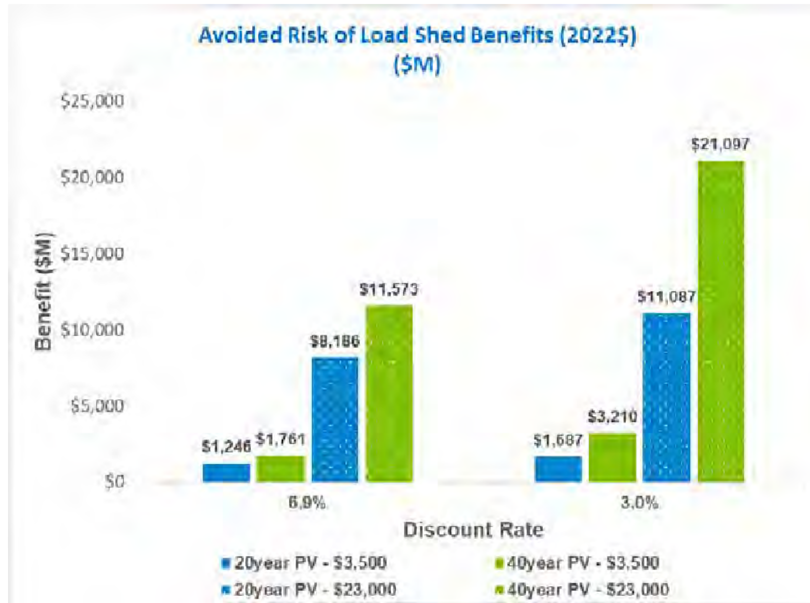
Regional

zone	GenLoss(th)	GenLoss(w)	GenLoss(s)	Gen Remaining	Extimp	Gen Surplus	TTC (no LRTP)	shortfall	newTTC (LRTP)	TTC diff	benefit
Lrz1-3	19672.34	15776.433	8967.45	26018.897	7500	-20239.783	7260.8	12978.983	9391	2130.2	2130.2
Lrz4-7	24123.405	6307.11	9553.2	32579.295	0	-19702.2	6192.5	13509.695	8185	1992.5	1992.5
							Total Avoided Load shed				4122.7
							Assumed duration				16
							Total Avoided Load shed hours				65963.2
							Total for all Events				71917.1

Risk of load shedding is assumed to occur every three years based on the frequency of severe winter weather events

E. Avoided Risk of Load Shedding

Value of avoided risk of load shedding is determined by applying the Value of Lost Load (VOLL)



*IMM Quarterly Report: Summer 2020, https://cdn.misoenergy.org/IMM%20Quarterly%20Report_Summer%202020478028.pdf

 ** using a 6.9% Discount Rate

F. Decarbonization

MISO has developed a carbon price range to capture LRTP's long-term benefits of reducing CO_2 emissions by enabling reliable delivery of low-cost, clean energy

- Calculate emissions reduced between LRTP Reference Case and LRTP Change Case used for the congestion and fuel cost savings benefit metric.
- Convert to metric tons.
- Using 2.5% annual inflation and discount rates below, apply range of carbon costs to calculate 20- and 40-year NPV of reduced carbon emissions.

20-Year CO_2 Emissions Reduced: 399M metric tons
40-Year CO_2 Emissions Reduced: 677M metric tons

	6.9% Discount Rate		3% Discount Rate	
	MN PUC (Min)	Federal (Max)	MN PUC (Min)	Federal (Max)
2022$/metric ton	$12.55	$47.80	$12.55	$47.80
20-Year Benefit (2022$, M)	$3,473	$13,438	$4,781	$18,404
40-Year Benefit (2022$, M)	$4,548	$17,364	$7,818	$29,498

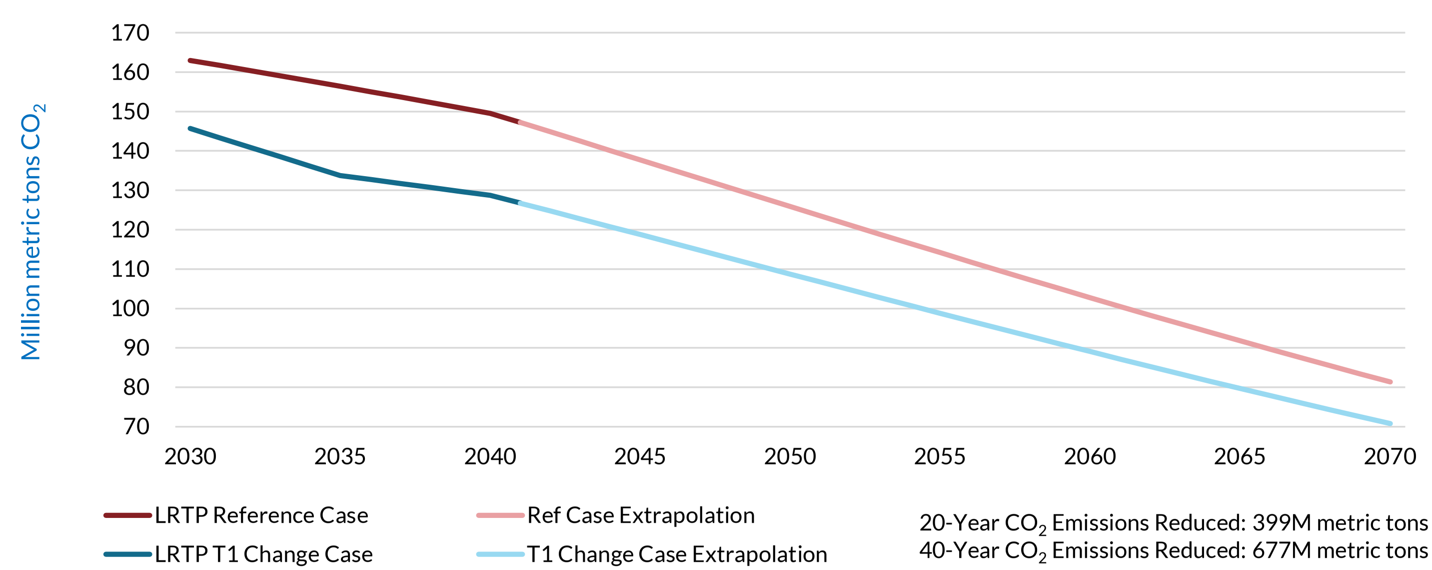
Prices converted to 2022$. Full range of carbon prices demonstrated in previous workshops.
20-year and 40-year benefits = projects' in-service value to 2050 and 2070, respectively.
Emissions data interpolated between PROMOD model years 2030, 2035, and 2040; and extrapolated post-2040.

Minnesota Public Utility Commission (2022 Low)
Federal = Average of 45Q Federal Tax Credit and Federal Social Cost of Carbon

F. Decarbonization

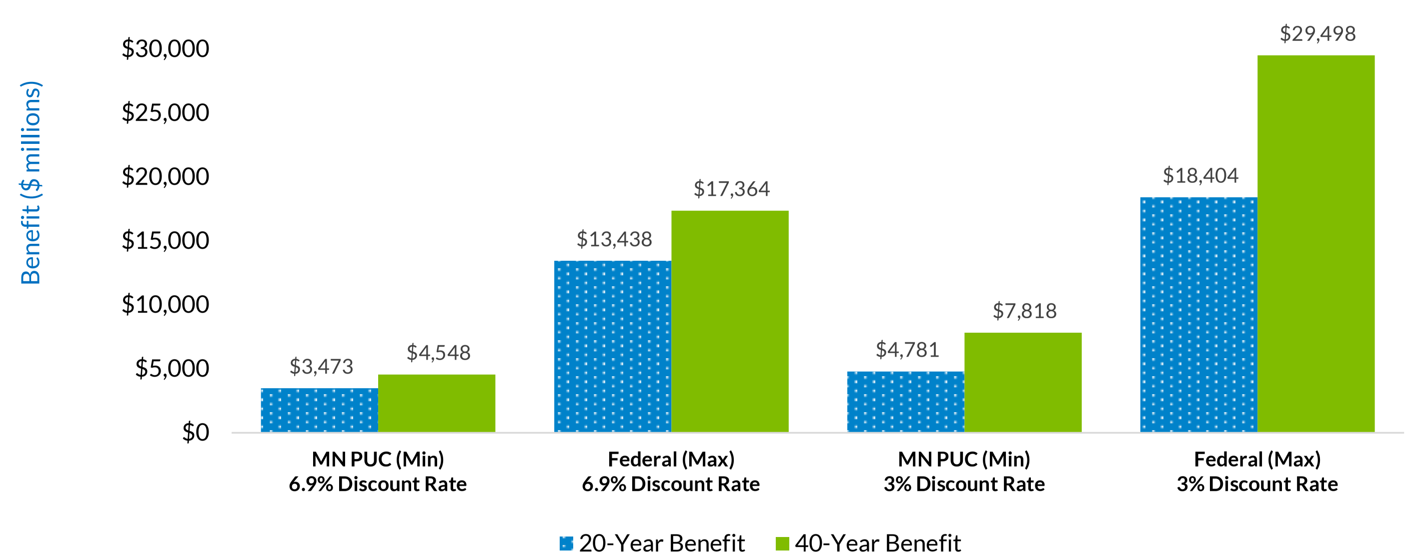
LRTP Change Case illustrates the emissions reduced through enabled resources

40-Year Emissions, LRTP Reference & Tranche 1 Change Cases



With the price range considered, Decarbonization benefits range from $3.5B to $29.5B over 40 years of project life

Range of LRTP T1 Decarbonization 20- & 40-Year Benefits (2022$, M)



G. Reliability issues addressed by LRTP Tranche 1

LRTP Tranche 1 portfolio allows reliable delivery of energy from future resource portfolio to serve load across the footprint

Reliability analysis was performed to assess the impact of the LRTP projects on steady state system performance

- Thermal and voltage issues were mitigated by the LRTP projects under base conditions reflecting varying load and dispatch patterns
- Additional upgrades were identified to mitigate issues resulting from the addition of LRTP projects

Transfer Analysis

- Improvements in transfer capability allows energy requirements to be met under varying dispatch patterns driven by differences in weather conditions across the Midwest subregion
- LRTP projects provides more robust interconnection to improve system stability during periods of heavy power transfers

MN-Dakotas Reliability Needs Addressed

Jamestown - Ellendale 345kV, Big Stone South – Alexandria - Cassie's Crossing 345kV

- Assists in transport of energy out of Dakotas toward central MN and Twin Cities area
- Relieves issues on the 230kV system and improves connections between 345kV systems to improve long distance movement of power
- Relieves 40 elements with excessive thermal loading for N-1 contingencies and 70 elements with excessive loading for N-1-1 contingencies
- Performs better than other six alternatives removing almost all existing congestion with only minimal new congestion.

Iron Range - Benton County – Cassie's Crossing 345kV

- Provides low impedance path from Northern to Central Minnesota improving Voltage stability and transfer performance with >10% increase in Manitoba Import limit performing better with higher capacity and lower cost than the four other alternatives
- Relieves 15 elements with excessive thermal loading for N-1 contingencies and 25 elements with excessive loading for N-1-1 contingencies

MN-WI Reliability Needs Addressed

Wilmarth - N. Rochester – Tremval - Eau Claire - Jump River
Tremval – Rocky Run – Columbia 345kV

- Provides outlet for renewables located in Minnesota
- Congestion relief and raises stability limit by 250MW to increase transfer capability on the MN-WI interface
- Improves connectivity to serve load centers
- Relieves 39 elements with N-1 heavy loading and severe overloads in MN and WI and 96 elements for N-1-1 contingencies

Central Iowa Reliability Needs Addressed

Webster-Franklin-Marshalltown-Morgan 345kV
Beverly-Sub92 345kV

- Provides outlet for renewables located in IA and SW Minnesota
- Provides corridor for delivery of energy to load centers in central portions of MISO
- Addresses 21 elements with N-1 heavy thermal loading and severe overloads in Iowa and 34 elements for N-1-1 contingencies

Iowa, Illinois, Indiana, Michigan Reliability Needs Addressed

Madison – Ottumwa – Skunk River – Ipava – Maple Ridge 345kV
Tazewell – Brokaw - Paxton – Gilman – Morrison – Reynolds – Hiple – Duck Lake 345kV
Paxton – Sidney 345kV
Oneida – Nelson Road 345kV

- Delivers significant increase in transfer capability to support generation deficient areas due to unexpected decrease in renewable output
- Mitigates 28 thermal overloads in Michigan, 16 thermal overload in Indiana, 19 thermal overloads in Missouri and Illinois, 14 thermal overloads in Iowa
- Provides more robust performance under large shifts in dispatch of generation across the region

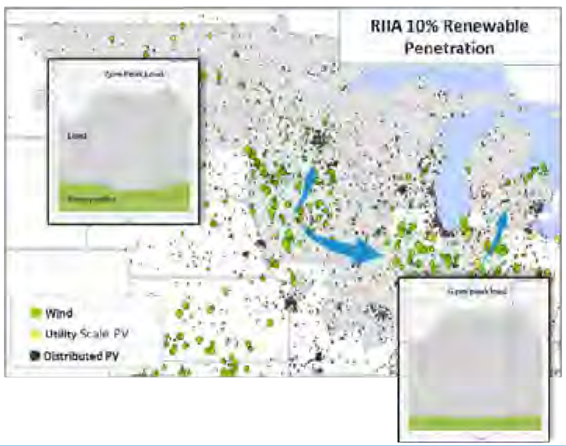
Missouri Reliability Needs Addressed

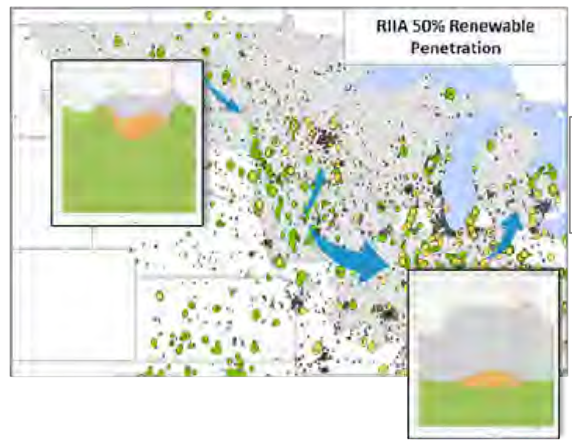
Orient – Fairport – Zachary – Maywood – Meredosia 345kV
Zachary – Thomas Hill 345kV

- Provides increased transfer capability of 250MW West-to-East and 438MW MISO-to-Michigan to address voltage collapse conditions in Missouri
- Mitigates heavy loading and severe overloads on 19 elements for N-1 and N-1-1 contingencies
- Provides more robust performance under large shifts in dispatch of generation across the region addressing 14 thermal overloads

Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

- An increasingly connected system is needed to balance generation resource variability across an increasingly heterogeneous footprint.
- Additional transmission reinforcements provided by LRTP increases the ability of the system to manage the increasing different regional flows and operational events without adverse impacts to system performance



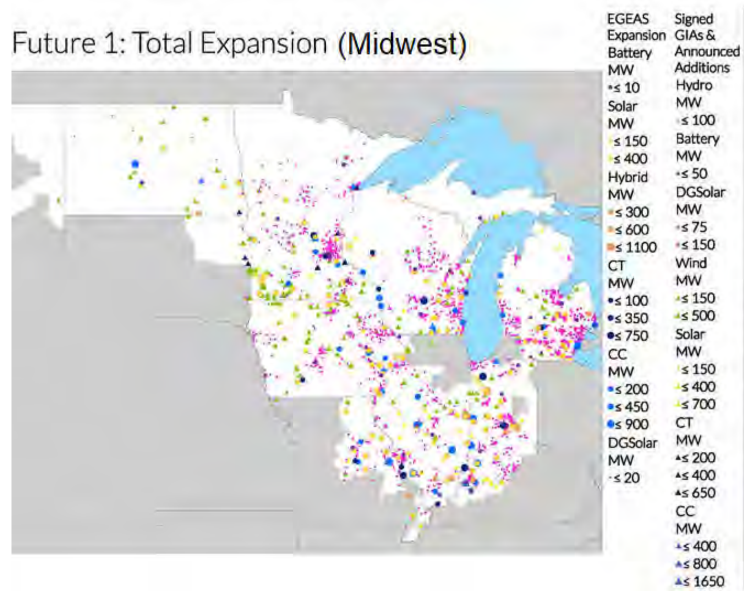


Regional energy transfers increase in magnitude and becomes more variable, leading to a need for increased extra-high voltage transfer capabilities

Illustration of flow changes with increasing renewable penetration spread throughout the MISO footprint (MISO Renewable Integration Impact Assessment (RIIA) Summary Report, February 2021 https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf)

Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

- Increased transmission capacity better leverages the geographic and fuel diversity of the broader footprint to more effectively manage dispatch variability due to changing weather patterns



MISO Futures Report (December 2021) https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

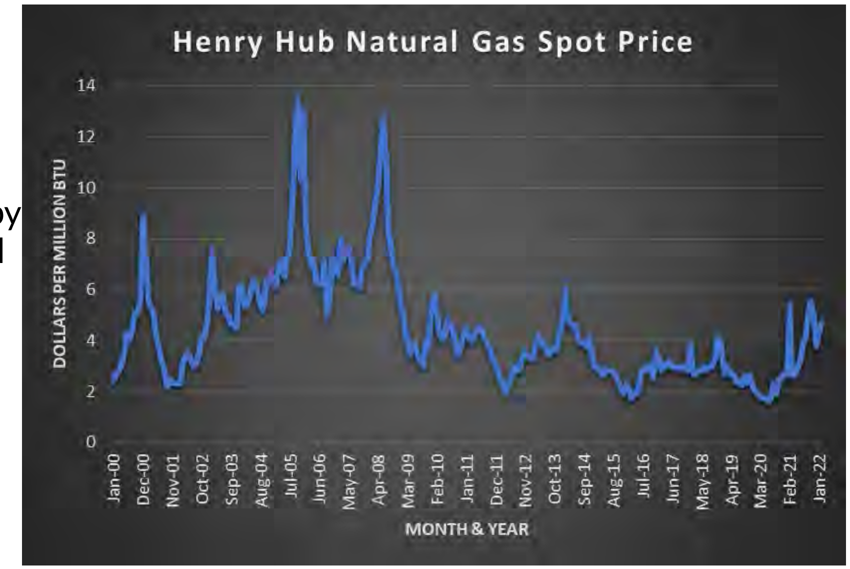
Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

- Transmission expansion provides additional operational flexibility and allows more opportunity for planning of transmission and generation outages with less risk of operational issues or rescheduling of outages
- Transmission expansion allows better use of the transmission network and provides more flexibility to meet changing customer needs and diverse policy goals

Congestion and Fuel Savings Natural Gas Price Sensitivity

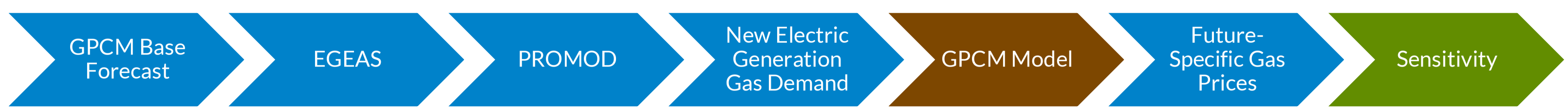
LRTP projects decrease system-wide impacts of natural gas volatility

- Local transmission investment cannot completely insulate electric consumers from the risks associated with fuel price volatility
- However, LRTP projects offset the risk by providing additional congestion and fuel savings benefits under high natural gas prices by enabling renewable energy
- Congestion and fuel savings benefits were analyzed through a series of production cost analyses, with higher natural gas cost assumptions

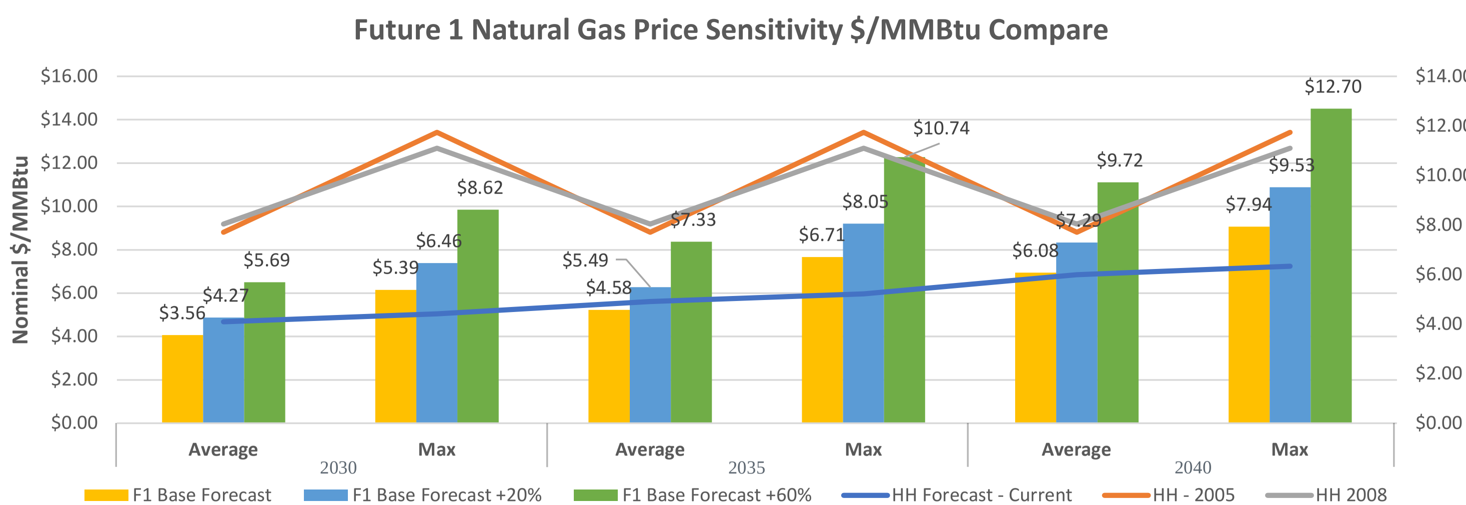


MISO Futures used for the LRTP study utilized new natural gas price forecast methodology

- GPCM Natural Gas Market Forecasting System was used to develop forecasts instead of locked-down Henry Hub (HH) and blend of three different forecasts
- Use on base forecast gas price in EGEAS for all Futures
- Using the same assumptions, but referencing PROMOD output, create Future-specific and area-specific gas prices for use in PROMOD models
- A range of gas prices were tested on LRTP Reference and Change Case PROMOD models



Future 1 Natural Gas prices were increased by 20 – 60% for sensitivity evaluation

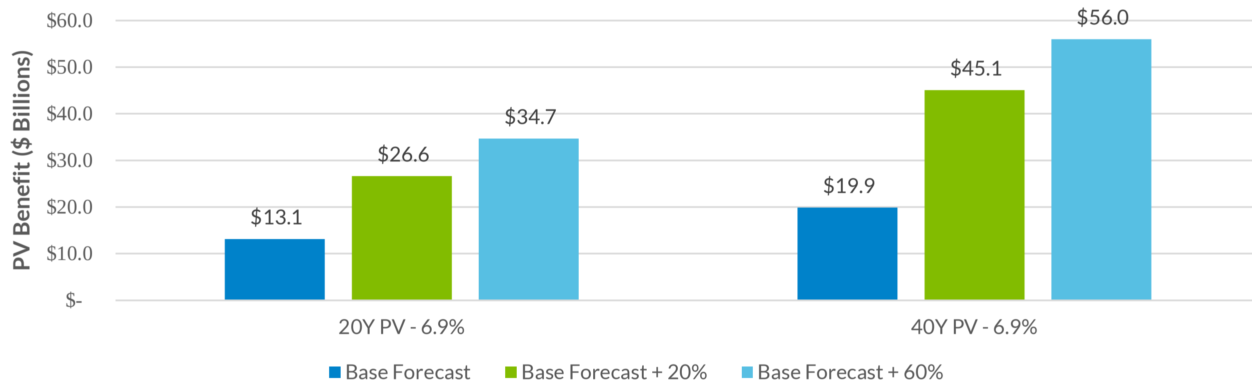


- When comparing to HH prices, a 20% increase was found to facilitate the best starting point, which ensures year 2040 average price is greater than HH projected price
- A 60% increase was selected as the endpoint, to create a year 2040 value that represented HH highest sale prices historically (2005 and 2008)

A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

LRTP Tranche 1 transmission will provide greater congestion and fuel savings as natural gas price increases

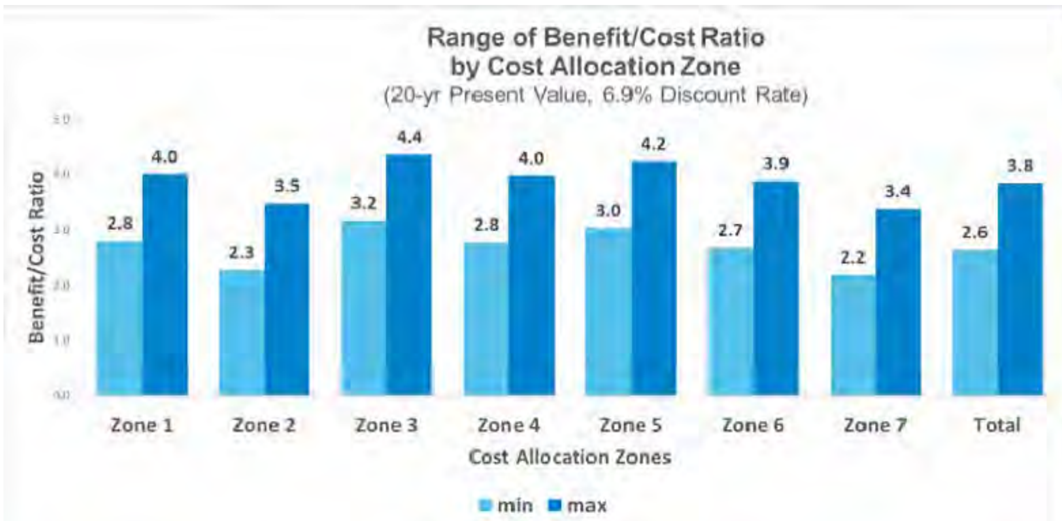
MISO Midwest Congestion and Fuel Savings Natural Gas Price Sensitivity PV Benefits



- 20% price increase generates a $13.4B congestion and fuel savings increase
- 60% price increase generates a $21.5B congestion and fuel savings increase

Distribution of Benefits for Midwest Subregion

The benefits provided by the LRTP Tranche 1 Portfolio are distributed across the Midwest subregion in a manner commensurate with the costs



For the lower range of quantifiable benefits, benefit to cost ratio for the cost allocation zones is at least 2.2 where VOLL=$3,500 and with a carbon price of $12.55 per metric ton

Footprint Benefits (minimum)- 20 Year NPV, 6.9%, 2022$		($M)							
Benefit Metric	CAZ Allocation Method	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Total
Congestion and Fuel Savings	Derived directly from PROMOD resutls	$3,169	$1,049	$2,195	$1,352	$1,471	$2,884	$1,006	**$13,125**
Avoided Capital Cost of Local Resource Investment	Based on load share ratio	$3,481	$2,358	$1,864	$1,707	$1,351	$3,280	$3,460	**$17,501**
Avoided Transmission Investment	Based on the zonal location of upgrade	$278	$283	$201	$305	$125	$45	$74	**$1,312**
Resource Adequacy Savings	Based on zonal capacity savings	$0	$0	$0	$0	$0	$0	$624	**$624**
Avoided Risk of Load Loss*	Based on load ratio share	$248	$168	$133	$121	$96	$233	$246	**$1,246**
Decarbonization**	Based on load ratio share	$691	$468	$370	$339	$268	$651	$687	**$3,473**
Total Benefits		$7,867	$4,326	$4,763	$3,824	$3,311	$7,094	$6,096	**$37,281**
Total Costs		$2,806	$1,901	$1,502	$1,376	$1,089	$2,644	$2,789	**$14,107**
B/C		2.8	2.3	3.2	2.8	3.0	2.7	2.2	**2.6**

For the upper range of quantifiable benefits, benefit to cost ratio for the cost allocation zones is at least 3.4 where VOLL=$23,000 and with a carbon price of $47.80 per metric ton

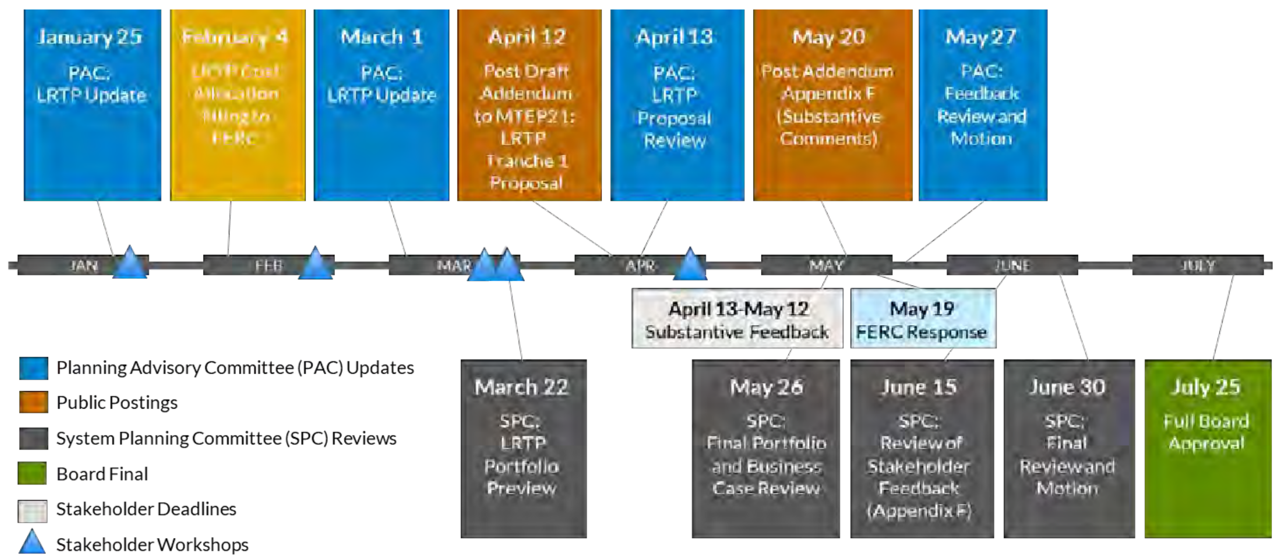
Footprint Benefits (maximum)- 20 Year NPV, 6.9%, 2022$		($M)							
Benefit Metric	CAZ Allocation Method	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Total
Congestion and Fuel Savings	Derived directly from PROMOD resutls	$3,169	$1,049	$2,195	$1,352	$1,471	$2,884	$1,006	**$13,125**
Avoided Capital Cost of Local Resource Investment	Based on load share ratio	$3,481	$2,358	$1,864	$1,707	$1,351	$3,280	$3,460	**$17,501**
Avoided Transmission Investment	Based on the zonal location of upgrade	$278	$283	$201	$305	$125	$45	$74	**$1,312**
Resource Adequacy Savings	Based on zonal capacity savings	$0	$0	$0	$0	$0	$0	$624	**$624**
Avoided Risk of Load Loss*	Based on load ratio share	$1,629	$1,103	$872	$798	$632	$1,534	$1,618	**$8,186**
Decarbonization**	Based on load ratio share	$2,673	$1,811	$1,431	$1,311	$1,037	$2,519	$2,656	**$13,438**
Total Benefits		$11,231	$6,604	$6,563	$5,472	$4,616	$10,262	$9,438	**$54,187**
Total Costs		$2,806	$1,901	$1,502	$1,376	$1,089	$2,644	$2,789	**$14,107**
B/C		4.0	3.5	4.4	4.0	4.2	3.9	3.4	**3.8**

Conclusion

The LRTP Tranche 1 portfolio provides a regional transmission solution to addressing future energy needs

- For a capital investment of $10.3B, the LRTP portfolio provides $37.0B in financially quantifiable benefits over 20 years
- LRTP transmission projects enhance system performance to maintain reliable operation in the future with more variability and uncertainty in energy supply
- The LRTP Tranche 1 portfolio reflects a cost-effective set of solutions that enable delivery of energy to support future energy requirements of the MISO customers
- The LRTP Tranche 1 portfolio provides economic and reliability benefits that exceed the cost of the investment and are broadly distributed across the MISO Midwest subregion

The timeline for approval of Tranche 1 is targeted for July 25



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Appendix G-3

MISO Futures Report (April 2021, Updated December 2021)

MISO Futures Report

\- Published April 2021 -

Updated December 2021

Highlights

- Electric utilities in the MISO region are responding to the energy industry's ongoing transition in different ways. At an aggregate level, there is a dramatic and rapid transformation underway of the resource mix in MISO's footprint.

- The three MISO Futures encompass scenarios that bookend the fleet resource mix over the next twenty years and are intended to be used for several years with minimal updates.

- Analysis of three scenarios allows for insights to the MISO system once it transforms to dual summer and winter peaking as renewable energy and projected demand increase.

- December 2021 updates include revised expansion results for Futures 2 and 3. Explanation and details of these results can be found in the September, October, and November 2021 PAC presentations in the Presentation Materials section of this report.

misoenergy.org

Executive Summary

MISO is tasked with delivering safe, reliable, and cost-effective power across 15 states and the Canadian province of Manitoba. Within MISO's diverse regional footprint, utility members are making future plans, committing to near and long-term retirements and investments, and announcing increasingly advanced decarbonization goals. Although MISO's role is to remain policy- and resource-agnostic, there is a clear fleet transition underway that has implications for system operations.

As the fleet transforms, the need to keep the system operating reliably and efficiently is driving what MISO refers to as a regional "Reliability Imperative." MISO, our member utilities, and state regulators all share the responsibility to address this Reliability Imperative. A key element of MISO's response to the Reliability Imperative is our Long-Range Transmission Planning (LRTP) initiative. The "Futures" defined in this document will be a key driver of those efforts and other elements of the Reliability Imperative.

How can MISO, as a regional grid operator, support its member utilities and state policy makers as they continuously refine how to serve the 42 million people in the MISO footprint? One tool at MISO's disposal is the use of forward-looking planning scenarios to provide outlooks of the future. These Future planning scenarios establish different ranges of economic, policy, and technological possibilities – such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas price, and generation capital cost – over a twenty-year period. This information is used to model a capacity expansion, which forecasts the fleet mix that meets MISO's planning reserve margin at the lowest cost while adhering to policy objectives. Using the range of resource generation modeled, MISO will then apply the Futures' expansion results to the development of transmission plans, the LRTP, and other MISO initiatives that ensure continued reliability and economic energy delivery.

This report captures an eighteen-month collaboration between MISO and stakeholders to develop three Future scenarios that bookend the uncertainty over the next twenty years. When carried forward into the transmission planning models, this set of Futures will enable the diverse goals and policies of MISO's states and utilities.

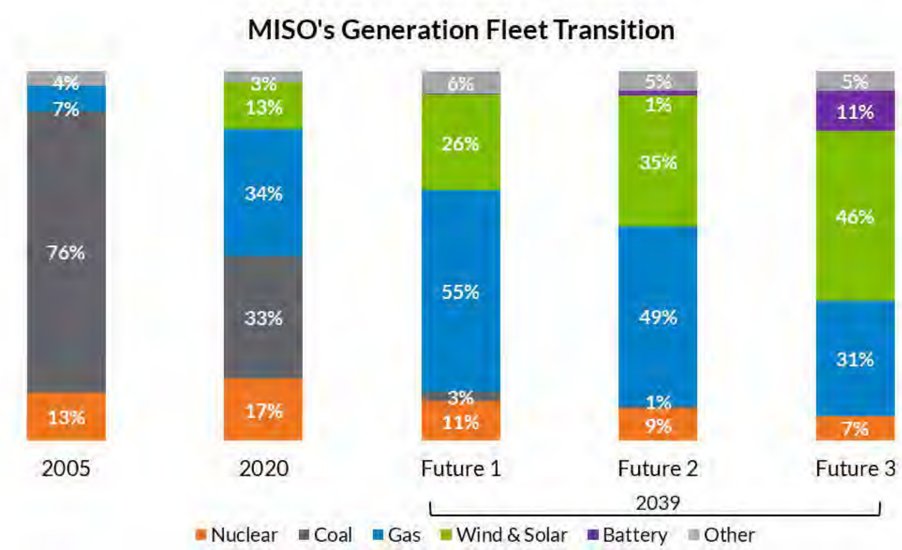


Figure 1: Overview of MISO's Generation Fleet Mix Transition [82]

Future 1 Assumptions – This Future reflects substantial achievement of state and utility announcements and includes a 40% carbon dioxide reduction trajectory.[1] While Future 1 incorporates 100% of utility integrated resource plan (IRP) announcements, state and utility goals that are not legislated are applied at 85% of their respective announcements to hedge the uncertainty of meeting these announced goals and respective timelines. Future 1 assumes that demand and energy growth are driven by existing economic factors, with small increases in EV adoption, resulting in an annual energy growth rate[2] of 0.5%.

Future 2 Assumptions – This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including a 60% carbon dioxide reduction. Future 2 introduces an increase in electrification, driving an approximate 1.1% annual energy growth rate.

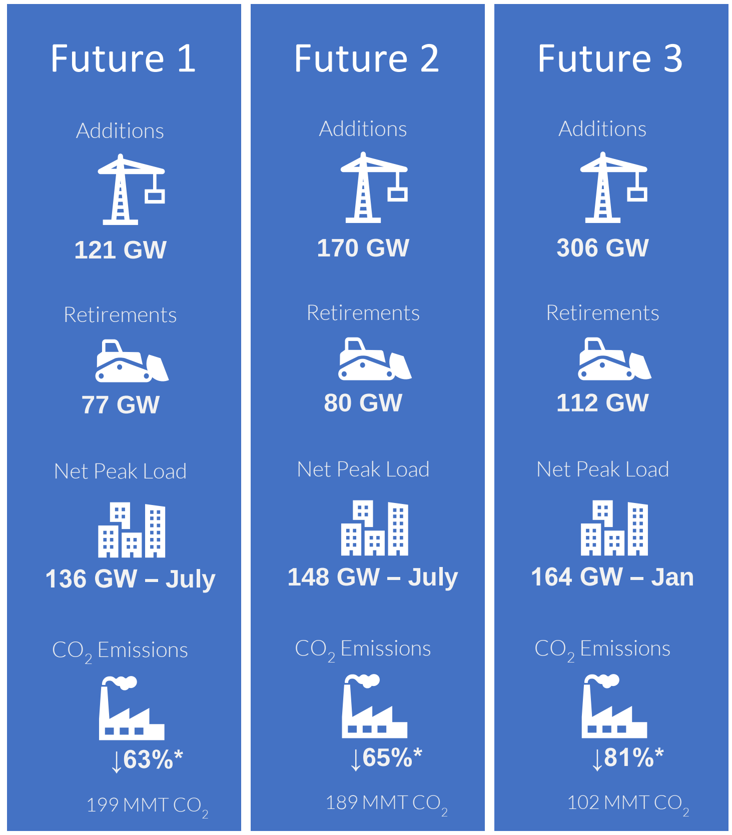


Figure 2: Summary of Future Scenario Impacts, 2039

Future 3 Assumptions – This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including an 80% carbon dioxide reduction. Future 3 requires a minimum penetration of 50% wind and solar and introduces a larger electrification scenario, driving an approximate 1.7% annual energy growth rate.[82]

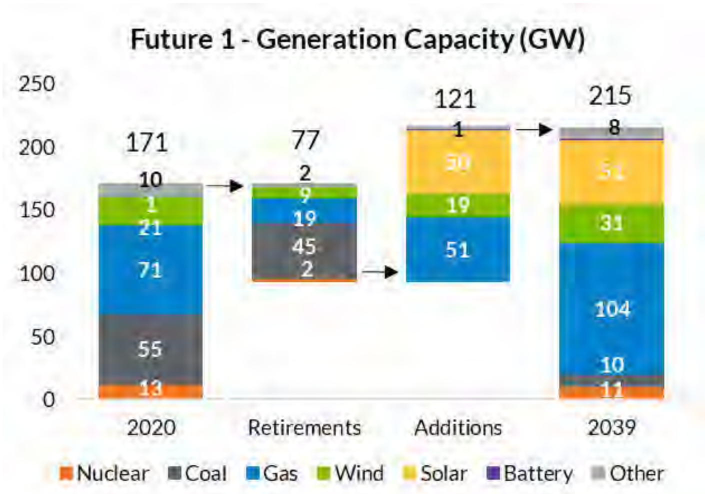
The Futures utilized announced goals and other input assumptions through September 2020 to represent a snapshot in time. Since the modeling of the Future scenarios, new announcements and updates to utility and state goals have been publicized. While the Futures Assumptions above summarize each scenario's inputs, Figure 2 details several key results of the modeling. For example, Future 1 included a 40% carbon reduction trajectory, and the model resulted in 63% carbon reduction. Additionally, "net peak load" results refer to peak load values, net of load modifying resources.

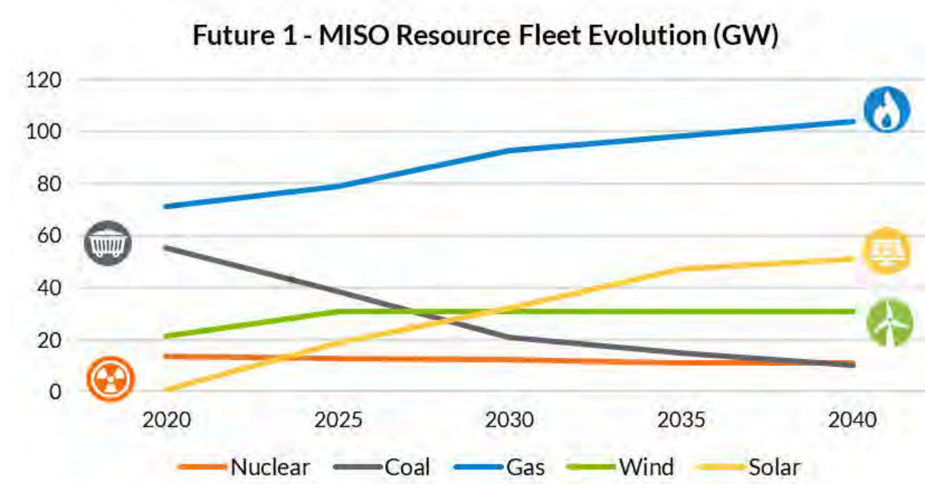
[1] Carbon emission reduction in Future scenarios refer to power sector emissions across the MISO footprint from a 2005 baseline.

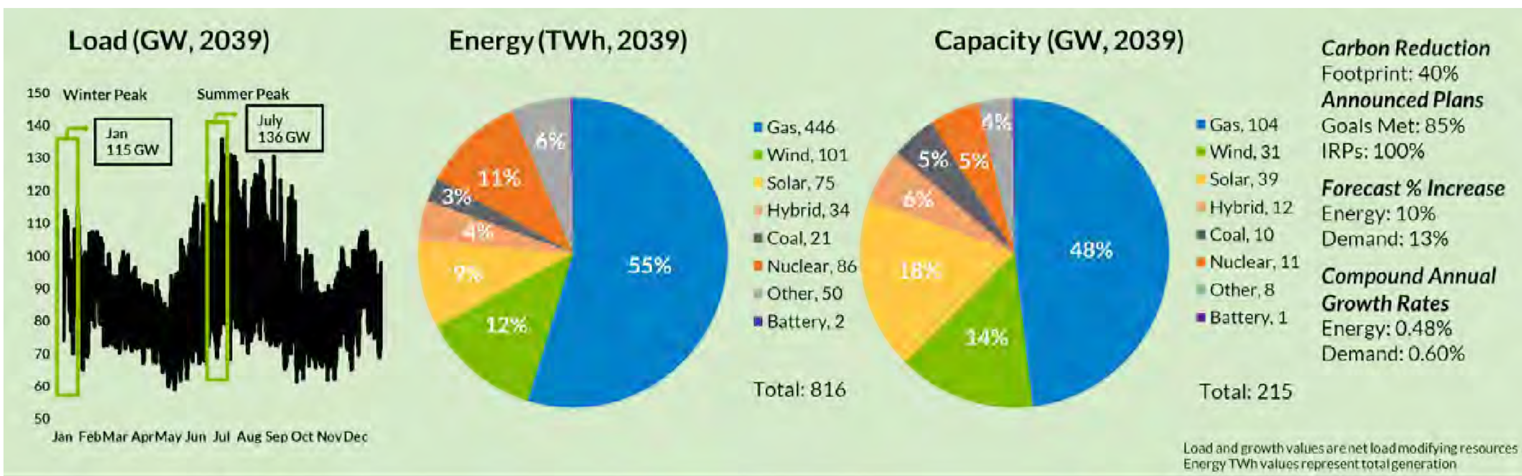
[2] Futures energy growth rates are compound annual growth rates (CAGR).

Future 1 Results

This Future assumes demand and energy growth are driven by existing economic factors, with small increases in EV adoption. Modeling for Future 1 results in the retirement of 77 GW and the addition of 121 GW of resources to the MISO footprint.

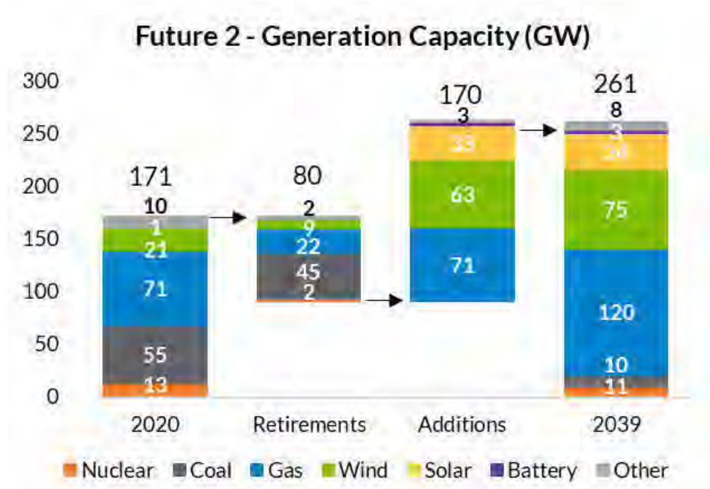


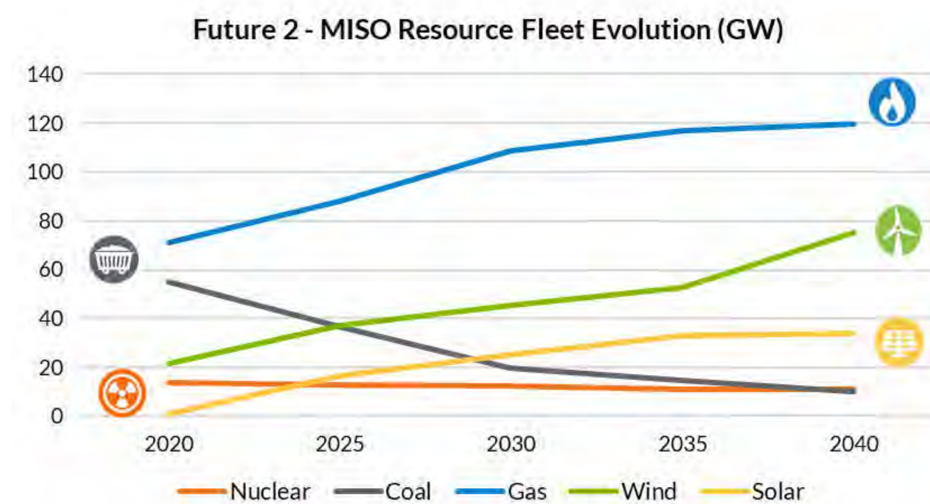


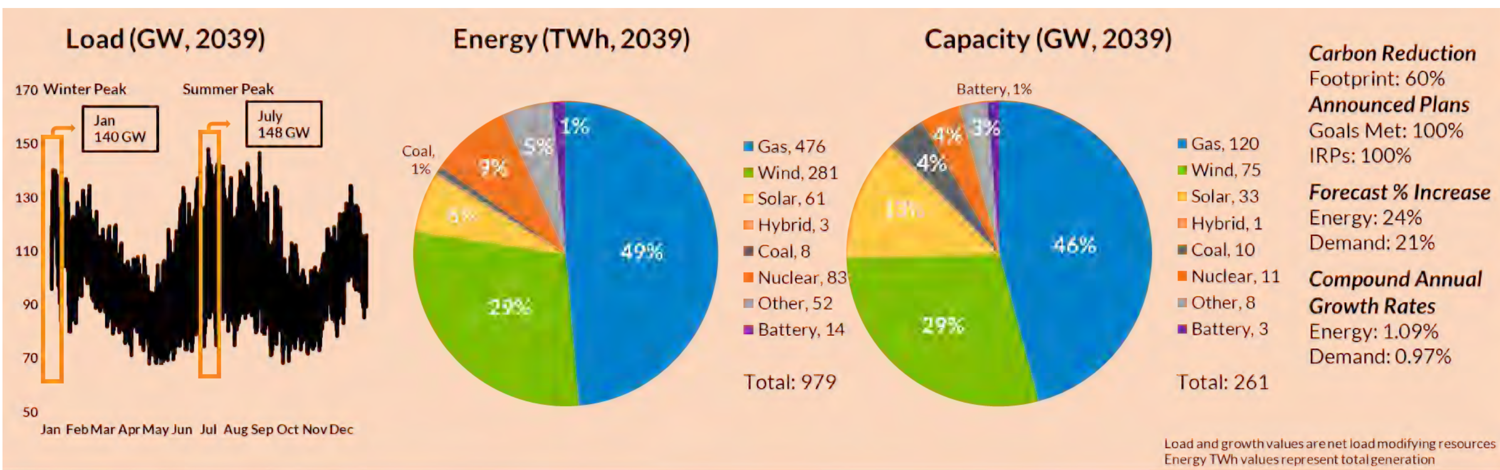


Future 2 Results

Due to retirements and increased electrification, moderate increases in demand and energy cause Future 2's load shape to have a larger peak in the summer but remain relatively dual peaking. Modeling of Future 2 results in the retirement of 80 GW and the addition of 170 GW of resources to the MISO footprint.



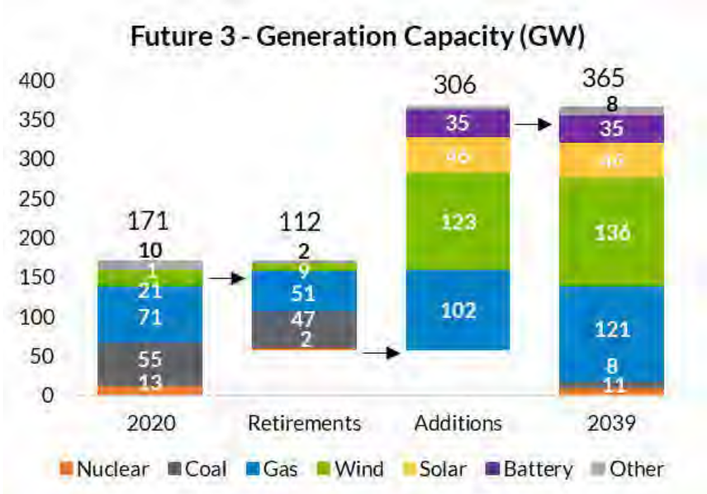


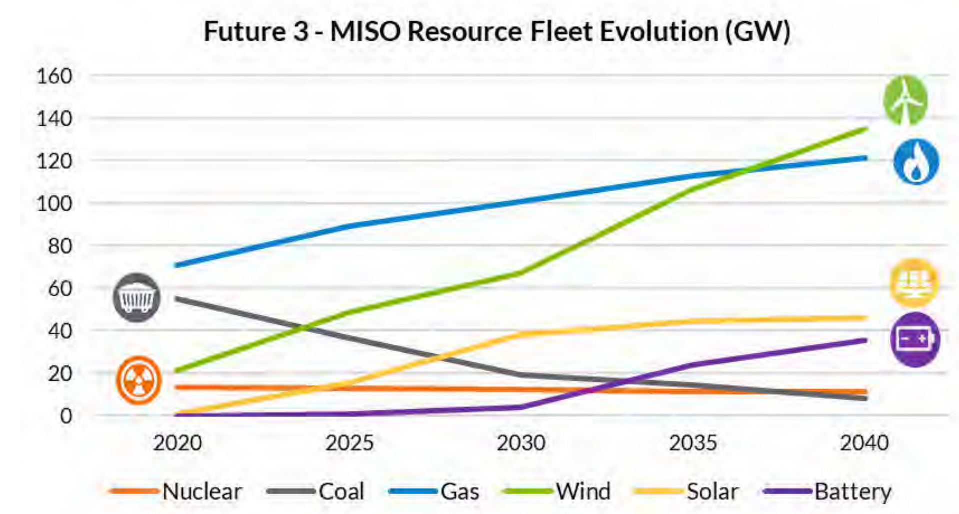


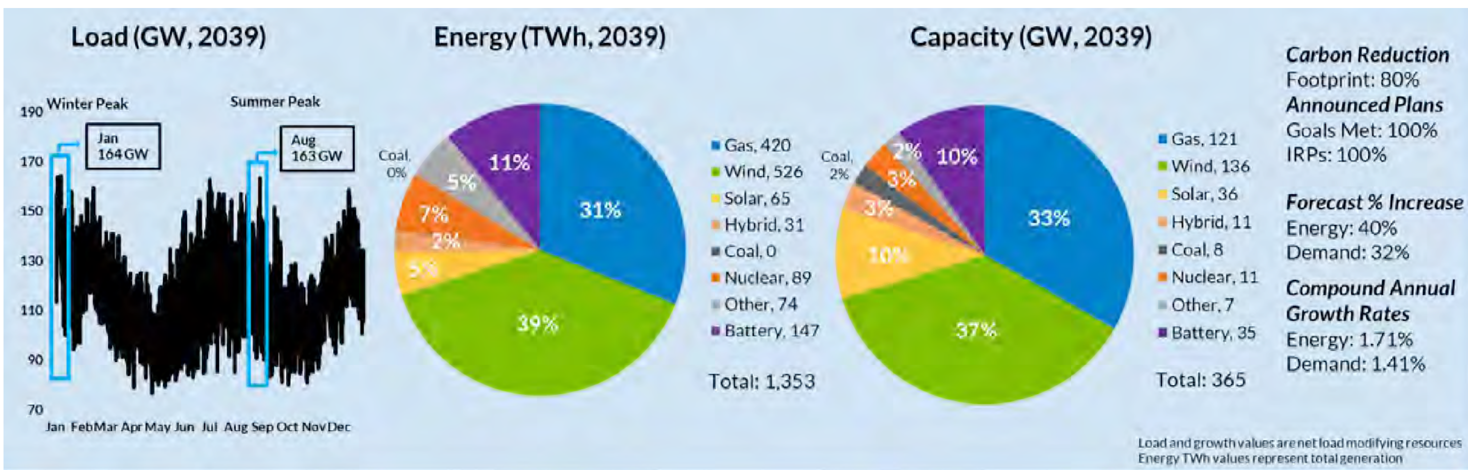
Appendix G-3
Mankato – Mississippi River Transmission Project
Certificate of Need and Route Permit Application
E002/CN-22-532 and E002/TL-23-157

Future 3 Results

Due to retirements, decarbonization, and electrification, large increases in demand and energy produce a prominent dual peaking load shape in the later years of the study period. Modeling of Future 3 results in the retirement of 112 GW and the addition of 306 GW of resources to the MISO footprint.







MISO Futures Purpose and Assumptions

In order to perform analysis on the bulk electric system twenty years into the future, many assumptions must be made to bridge what is known about the system today to what it could be in the future. Complicating matters is the uncertainty of future developments.

A tool that MISO has developed to address this uncertainty is the use of multiple forward-looking scenarios to provide a range of future outlooks. Within MISO, the collection of assumptions defining these multiple forward-looking scenarios are called the “Futures”. These Future scenarios establish different ranges of economic, policy, and technological possibilities – such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas price, and generation capital cost – over a twenty-year period.

One of the core components of analyzing the grid twenty years into the future is an understanding of what the electric generation resource fleet will be. Since MISO is not an integrated resource planner, MISO relies on its stakeholders, policy direction, and industry trends to bridge the gap between what the generation fleet is today and what it will be in the future. The Futures are used to hedge uncertainty by utilizing an economic resource expansion analysis, which forecasts the fleet mix that meets MISO’s planning reserve margin at the lowest cost while adhering to policy objectives.

As the fleet transforms, the need to keep the system operating reliably and efficiently is driving changes within the Futures process, and throughout MISO more broadly as part of the Reliability Imperative. As the 2019 MISO FORWARD Report identified, three major trends that are changing the energy landscape have emerged – demarginalization, decentralization, and digitalization. Electric utilities in the MISO region are responding to the energy industry’s ongoing transition in different ways. At an aggregate level, there is a dramatic and rapid transformation underway of the resource mix in MISO’s footprint.

MISO received a clear message of urgency from its stakeholders including member utilities, policy makers, and large end-users asking MISO to move quickly from identifying high-level needs to providing solutions that allow states and utilities to reach their energy transition goals. In response, MISO initiated a public stakeholder process to update the Futures process to align with the ongoing rapid transformation and to better incorporate the plans of MISO’s members and states, while also creating a bookended range of future scenarios that could be utilized in multiple study cycles. The public stakeholder process kicked off in August 2019, included thirteen different public stakeholder meetings, and concluded in December 2020.

MISO is not an integrated resource planner. The MISO Futures reflect resource plans announced by member utilities and states and forecast additional resources to meet forecasted energy demand, policy objectives, and reserve margins.

The Future scenarios in this document are a product of continued collaboration between MISO and its stakeholders. They represent challenges and compromises enabling member utilities to achieve significant fleet transition goals with diverse approaches or a more traditional resource portfolio. This report describes three Futures that are intended to be used as inputs for multiple MISO Transmission Expansion Plan (MTEP) cycles, the Long-Range Transmission Plan (LRTP) initiative, and other planning studies. These Futures will form the basis for all components of the Reliability Imperative, such that MISO and its stakeholders can plan to a consistent set of scenarios across transmission, markets, and operations.

Assumptions within the three Future scenarios vary to encompass reasonable bookends of the MISO footprint over the next twenty years. Future 1 represents a scenario driven by state and members' plans, with demand and energy growth driven by existing economic factors. Future 2 builds upon Future 1 by fully incorporating state and members' plans and includes a significant increase in load driven by electrification (discussed in the Electrification section of this report). In the final scenario analyzed, Future 3 advances from Future 2, evaluating the effects of large load increases due to electrification, 50% penetration of wind and solar, and an 80% carbon reduction across the footprint by 2039.

MISO conducted the Renewable Integration Impact Assessment (RIIA) to evaluate the impact of large installations of wind and solar to the system. This assessment found that managing MISO's grid, particularly beyond the 30% system-wide renewable level, will require transformational change in planning, markets, and operations. RIIA concludes that renewable penetration of at least 50% can be achieved through additional coordinated action. MISO members have continued to update their goals and look to MISO to help integrate these resources within the grid. With the analysis of the Future scenarios, wind and solar penetrations reach 26% in Future 1 and 46% in Future 3.[82]

Figure 3 shows the resulting wind and solar energy generation in each Future. Since load forecasts differ, the energy required of wind and solar to reach these penetrations is larger in each scenario. Futures 1, 2, and 3 reach maximum wind and solar penetrations of 26%, 35%, and 46% respectively.

Resulting Wind and Solar Penetration Levels

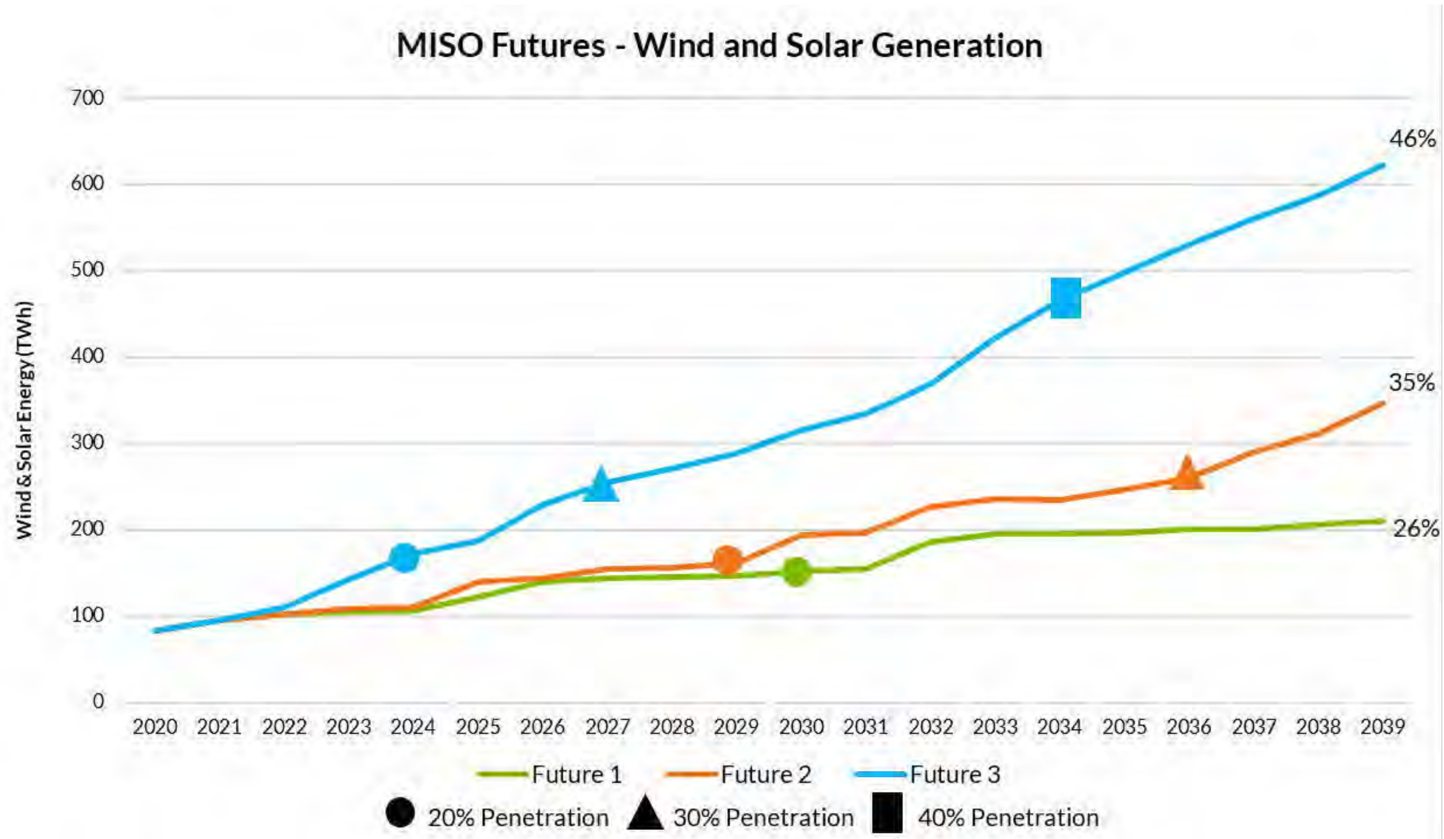


Figure 3: Wind and Solar Energy Generation Throughout Study[82]

Changing Energy Across MISO

Cities, states, large commercial and industrial corporations, and utilities are exploring and setting decarbonization goals that often include reaching 100% renewable energy supply or net zero carbon by 2050. Although not all states and utilities share these clean energy goals, a fleet transition of this magnitude will have implications on what resources will be needed across the MISO footprint to ensure reliability of the grid. The role of MISO is to remain resource-agnostic and to ensure a reliable and economic Bulk Electric System in an ever-changing energy, regulations, and economics environment.

Throughout the analysis of each Future scenario, MISO incorporated specific state and utility goals relative to carbon and renewable energy percentages into the models. Carbon was broken out into two segments per Future: a footprint-wide reduction applied to all resources and site-specific reductions applicable to carbon-emitting resources within states and utilities with announced carbon goals.

Renewable goals were modeled differently than those of carbon emissions. This was done by converting utility/state goals into relative percentages of MISO and taking the summation of these values to create footprint trajectories. As costs for wind and solar have decreased, the model surpassed these goals in Futures 1 and 2. Resources were assigned to their respective areas in the siting process.

Internal analysis indicates the MISO footprint has decarbonized by 29% since 2005. Early thermal retirements, public announcements, and evolving IRPs support MISO's preparation for a broad range of Future scenarios, enabling continual adaptation to the changing energy landscape while ensuring better grid reliability.

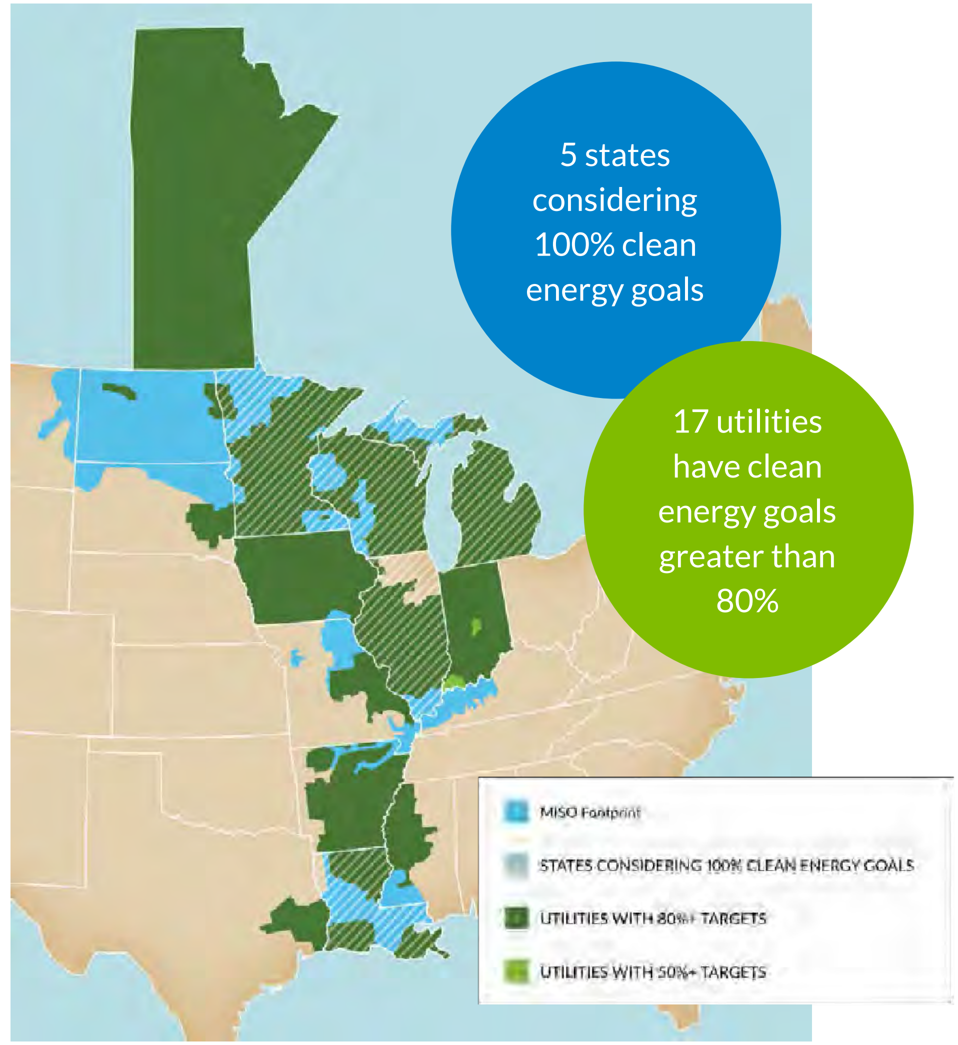


Figure 4: Clean Energy Goals above 50% Across Footprint[3]

State and Utility Clean Energy Goals

Today, state and utility policies and goals are changing rapidly and continued to do so during the Futures process, regarding carbon reductions, renewable energy targets, and unit retirement assumptions. To best account for these changes, MISO continuously updated these announced goals until the final Future scenario models were complete in October 2020. Since then, several members have updated or announced their plans, noted with asterisks in Table 1.

When collecting goal announcements, MISO staff examined companies' IRPs, state publications, and results from the MISO/OMS State Data Survey. (OMS refers to the Organization of MISO States). Once this information was compiled, MISO compared unit addition announcements with signed generation interconnection agreements (GIA) in its queue to ensure that these units would not be double counted. MISO then added IRP units into the base model to account for the announced goals of states and utilities. These units had a variety of fuel types and contained announced additions throughout the study period (2020-2039).

From Figure 4, it is apparent that much of the footprint has a clean energy goal greater than 50% (either from a carbon reduction or renewable energy target).[3] Some goals displayed in the table below were not included in the Futures analysis because their announcement came after the models were complete in October of 2020.[4,5] Table 1 displays state and utility goals within the model, overlapping by service area. In this analysis, MISO considered current trends but also had the opportunity to look beyond and plan for a range of Future scenarios to bookend plausible possibilities over the next 20 years.

[3] Utility goals are represented with green shading while state goals of 100% are given white stripes.

[4] Any goal denoted with an asterisk (*) was updated or announced following the modeling of the Futures.

[5] Entities who announced or updated their goals after Future scenario modeling was complete are listed here in their respective categories. Carbon reduction goals not modeled: Madison Gas, Vectren, Vistra, IPL, and OTP. Renewable energy targets not modeled: Alliant, CLECO, Vistra, IPL, and Entergy. Entities whose carbon reduction was modeled but a modification to the goal was made: Michigan (28% by 2025), Ameren (80% by 2050), and Minnesota Power (50% by 2021).

<table>
<tr><th>State Clean Energy Goals & RPS[6]
(source linked)</th><th>State</th><th>Utility</th><th>Utility Carbon Reduction Goals (2005 Baseline)[7]</th><th>Utility Renewable Energy Goals</th></tr>
<tr><td>RPS: 15% RE by 2021 (IOUs)</td><td>Missouri</td><td rowspan="2">Ameren</td><td rowspan="2">Net Zero by 2050*</td><td rowspan="2">100% by 2050</td></tr>
<tr><td rowspan="2">100% Clean Energy by 2050 (Governor)
RPS: 25% by 2025-2026</td><td rowspan="2">Illinois</td></tr>
<tr><td rowspan="2">MidAmerican Energy</td><td rowspan="2">-</td><td rowspan="2">100% by 2021</td></tr>
<tr><td rowspan="3">RPS: 105 MW (completed 2007)</td><td rowspan="3">Iowa</td></tr>
<tr><td>Alliant Energy</td><td>Carbon Free by 2050</td><td>30% by 2030*</td></tr>
<tr><td rowspan="2">Dairyland Power</td><td rowspan="2">-</td><td rowspan="2">29% by 2029</td></tr>
<tr><td rowspan="3">Carbon Free by 2050 (Governor)
RPS: 10% by 2020</td><td rowspan="3">Wisconsin</td></tr>
<tr><td>WEC Energy Group</td><td>Carbon Neutral by 2050</td><td>-</td></tr>
<tr><td>Madison Gas & Electric</td><td>Net Zero by 2050*</td><td>30% by 2030</td></tr>
<tr><td rowspan="3">Carbon Neutral by 2050*
RPS: 15% by 2021 (standard), 35% by 2025 (goal, including EE & DR)</td><td rowspan="3">Michigan</td><td>Consumers Energy</td><td>Net Zero by 2040</td><td>56% by 2040</td></tr>
<tr><td>DTE Energy</td><td>Net Zero by 2050</td><td>25% by 2030</td></tr>
<tr><td>Upper Peninsula Power</td><td>-</td><td>50% by 2025</td></tr>
<tr><td rowspan="4">Voluntary clean energy PS,
10% RE by 2025</td><td rowspan="4">Indiana</td><td>Duke Energy</td><td>Net Zero by 2050</td><td>16,000 MW by 2025</td></tr>
<tr><td>Hoosier Energy</td><td>80% by 2040</td><td>10% by 2025</td></tr>
<tr><td>Vectren</td><td>75% by 2035*</td><td>62% by 2025</td></tr>
<tr><td>NIPSCO</td><td>90% by 2028</td><td>65% by 2028</td></tr>
<tr><td rowspan="4">Carbon Free by 2050 (Governor)
RPS: 26.5% by 2025 (IOUs),
25% by 2025 (other utilities)</td><td rowspan="4">Minnesota</td><td>Xcel Energy</td><td>Carbon Free by 2050</td><td>100% by 2050</td></tr>
<tr><td>SMMPA</td><td>90% by 2030</td><td>75% by 2030</td></tr>
<tr><td>Minnesota Power</td><td>100% Clean Energy by 2050*</td><td>50% by 2021</td></tr>
<tr><td>Great River Energy</td><td>95% by 2023</td><td>50% by 2030</td></tr>
<tr><td>Net Zero GHG by 2050 (Governor)</td><td>Louisiana</td><td>Entergy</td><td>Net Zero by 2050
(2000 baseline)</td><td>12% by 2030*</td></tr>
</table>

Table 1: State & Utility Goals – Service Area Overlay

System-Wide Carbon Modeling

In addition to state and utility renewable goals, each Future scenario had a carbon emission reduction (CER) applied across the entire footprint. Carbon reduction trajectories were made from a total MISO 2005 CO_2 baseline, with linear reductions of 40%, 60%, and 80% (for Futures 1, 2, and 3, respectively) applied through the end of the study period. These trajectories were modeled within EGEAS (Electric Generation Expansion Analysis System). As well as the footprint-wide total CER for each Future, MISO also entered more specific trajectories for states and utilities as applicable.

6 DR: demand response; EE: energy efficiency; GHG: greenhouse gas; IOU: investor-owned utility; PS: portfolio standard; RE: renewable energy; RPS: renewable portfolio standard

7 Any goal denoted with an asterisk (*) was updated or announced following the modeling of the Futures.

All utility and state carbon trajectories used a 2005 CO_2 emissions baseline except for Entergy, which used a 2000 baseline in accordance with utility-specific goals. Each CER trajectory was given an approximate 2020 CO_2 starting value and then decreased to a target reduction percentage of the baseline. Consistent with Futures assumptions, CER trajectories reflected 100% of IRPs and 85% of other announced goals for Future 1, while trajectories for Futures 2 and 3 reflected 100% of both.

From analysis of the current fleet in 2005, MISO emitted 543 million (M) tons of CO_2. Figure 5 below illustrates CER for each Future scenario, displaying the tons of carbon emitted (bars) and the percentage of carbon reduction from the 2005 baseline (lines). The dotted line projects the historical trend of carbon emissions that MISO is assumed to have for comparison. From the trend of MISO, it is evident that the carbon emissions of the system will continue to decrease and will be accelerated as members' goals continue to change. Futures 2 and 3 emit more carbon than Future 1 in 2020 due to the increased load assumptions met by the existing fleet. The Future scenarios in this document allow for insights on how quickly carbon reduction across the footprint may occur. By the end of the study period, emissions reduced by 63% in Future 1, 65% in Future 2, and 81% in Future 3.

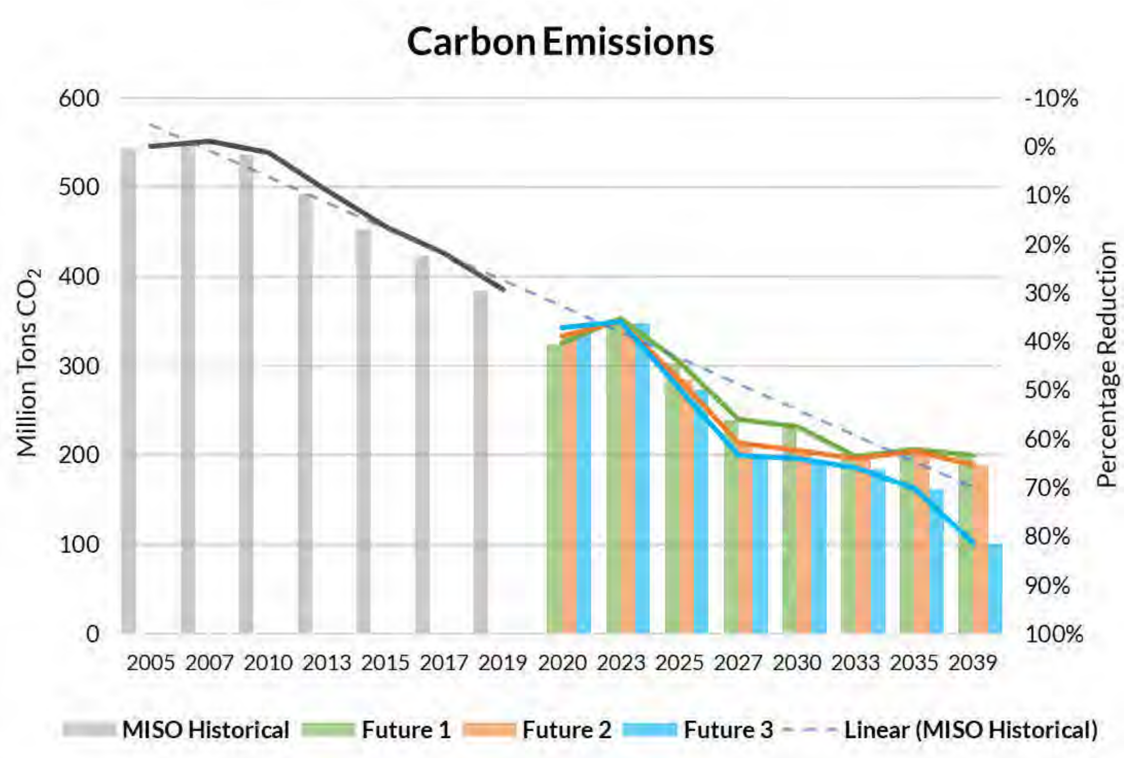


Figure 5: CO_2 Reduction Results (from 2005 Baseline)

Retirement and Repowering Assumptions

Base Retirement Assumptions

Nuclear and Hydroelectric – Retirement of nuclear and hydroelectric units will occur when a unit has a publicly announced retirement plan or is listed to retire in an IRP. Otherwise, these units will remain active throughout the study across all Futures.

Age-Based Retirement Assumptions

Age-based assumptions will be applied to all the units that fall into any of the categories listed below. However, in cases where these assumptions cause older units in the MISO system to retire before the start of the study period (2020), units will be retired by 2025.

Coal – Retirement ages of coal units progressively decrease with each Future. It is assumed that with changing policies and emission standards, coal usage will decline further. The coal retirement ages modeled in the three Futures respectively are: 46, 36, and 30 years. The Future 1 retirement age of 46 years is based on the average age of coal units noted by the Energy Information Administration (EIA).

- Coal retirements in each Future are approximately a 50/50 split between base and age-based retirement assumptions. The amount of coal retired results in similar capacity due to the average coal unit within the MISO fleet being 46 years of age.

Gas – Retirements for gas units were split into two categories, Combined Cycle (CC) and Other-Gas (e.g., Combustion Turbine [CT], IC [Internal Combustion] Renewable, and Integrated Gasification Combined Cycle [IGCC]). Both unit types were given retirement ages that decreased across the Futures scenarios; retirement ages for CC gas units are: 50, 45, and 35 years and retirements for Other-Gas units are: 46, 36, and 30 years respectively.

Oil – Retirement ages of oil units decrease across each Future scenario and are 45, 40, and 35 years respectively.

Wind and Solar – Retirements for utility-scale wind and solar will occur once a unit reaches 25 years of age. However, wind units will be repowered within the same year of retirement. These will be replaced by a new 100m hub height wind turbine with the same capacity as the previous unit but will receive new wind profiles, dependent on location. New profiles have updated capacity factors that are higher than existing wind turbines.

	Future 1	*Future 2*	*Future 3*
Coal	46	36	30
Natural Gas – CC	50	45	35
Natural Gas – Other	46	36	30
Oil	45	40	35
Nuclear & Hydro	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
Solar – Utility-Scale	25	25	25
Wind – Utility-Scale	25	25	25

Table 2: Age-Based Retirement Assumptions

Figure 6 through Figure 8 display the results of differing retirement assumptions across each of the three Future scenarios. Retirement totals were calculated by applying age-based assumptions, announced retirements, and adjusting generation units per stakeholder feedback provided to MISO. Age-based assumptions are the product of Future-specific retirement assumptions, while base retirements are announced by the generator owner, stated in an IRP, or filed with MISO's Attachment Y.[8]

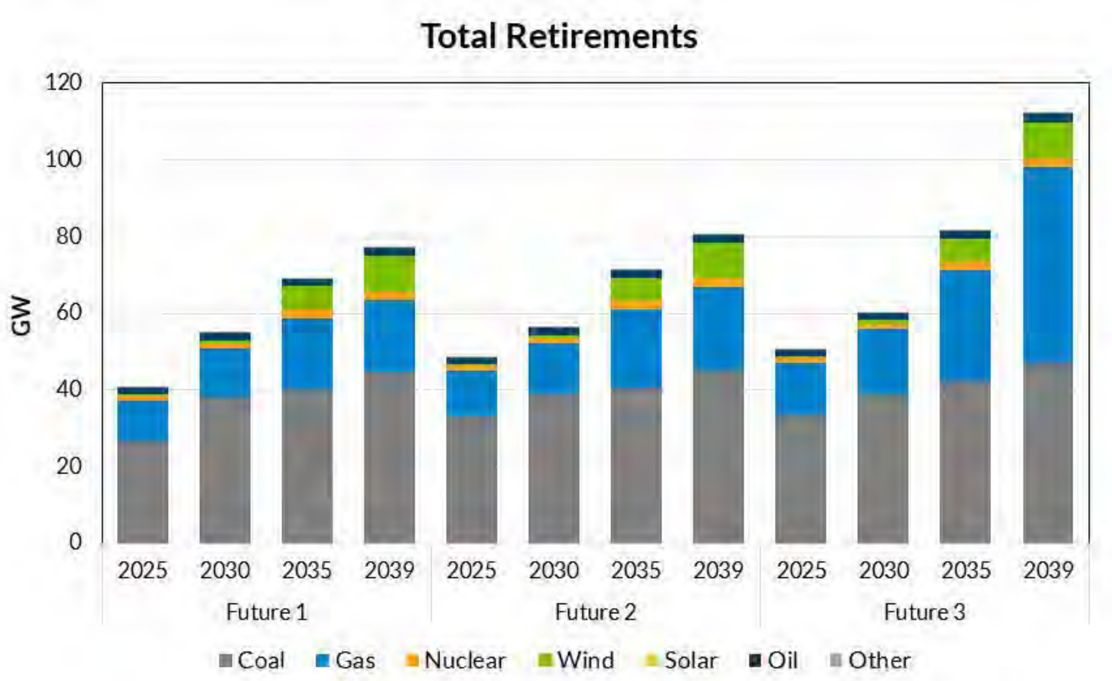


Figure 6: Total Retirements per Future (Cumulative by Year), Equal to Age-Based + Base

[8] MISO's retirement notification process

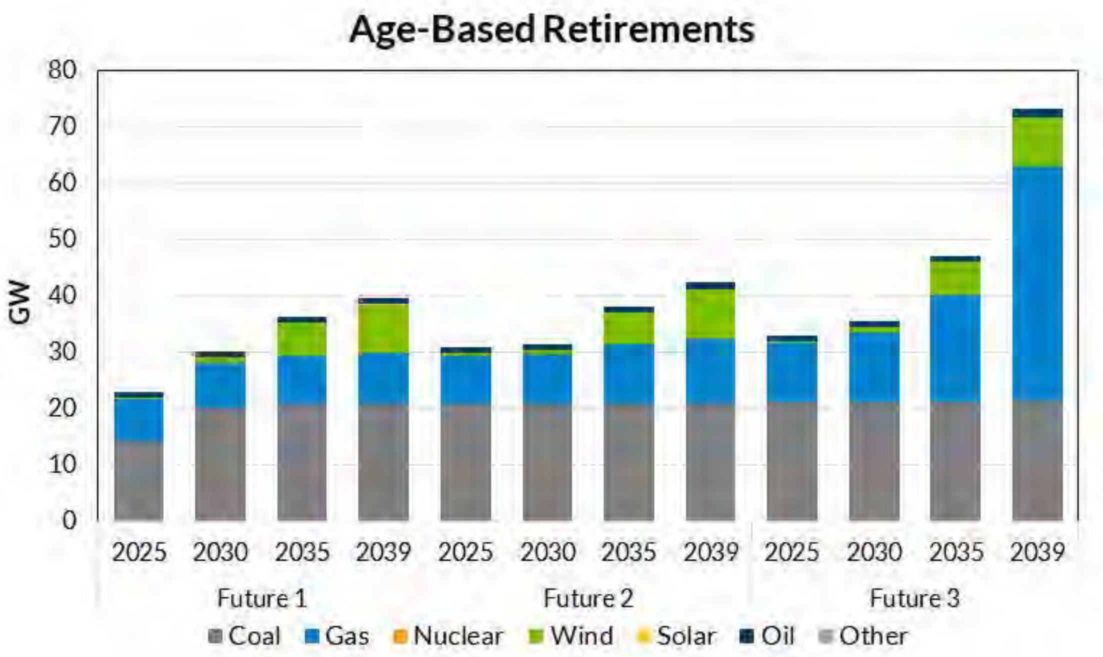


Figure 7: Age-Based Retirements per Future (Cumulative per Year)

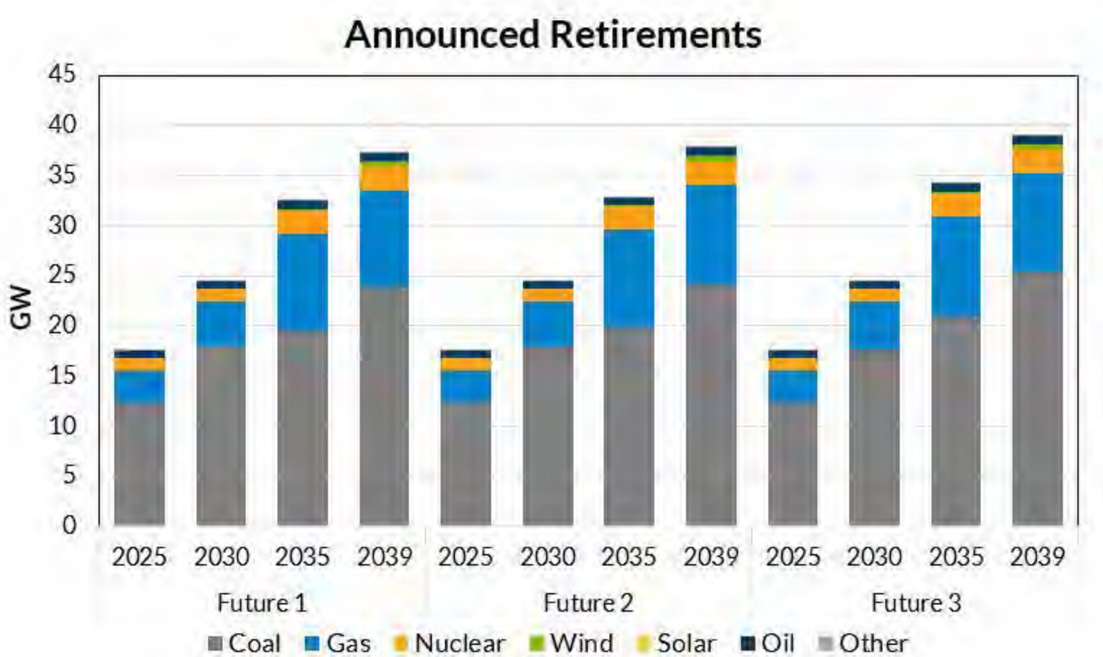


Figure 8: Base Retirements per Future (Cumulative per Year)

Figure 9 through Figure 11 display the results of the Future scenarios' retirement assumptions geographically throughout the MISO footprint. It is important to note that the wind units seen in these figures are assumed to be repowered with the same capacity, albeit with an updated profile that includes a higher capacity factor.

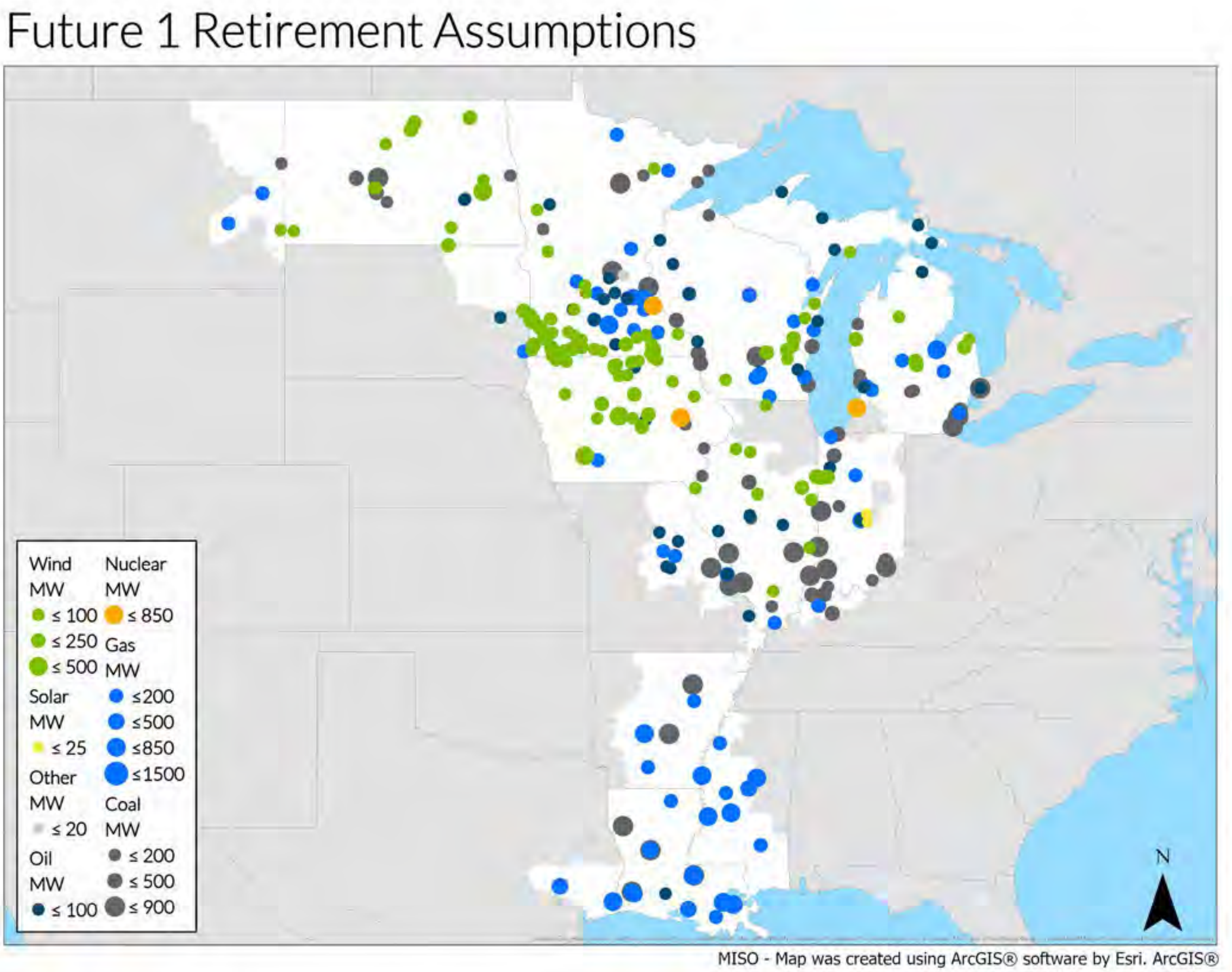


Figure 9: Future 1 Retirements by Fuel Type

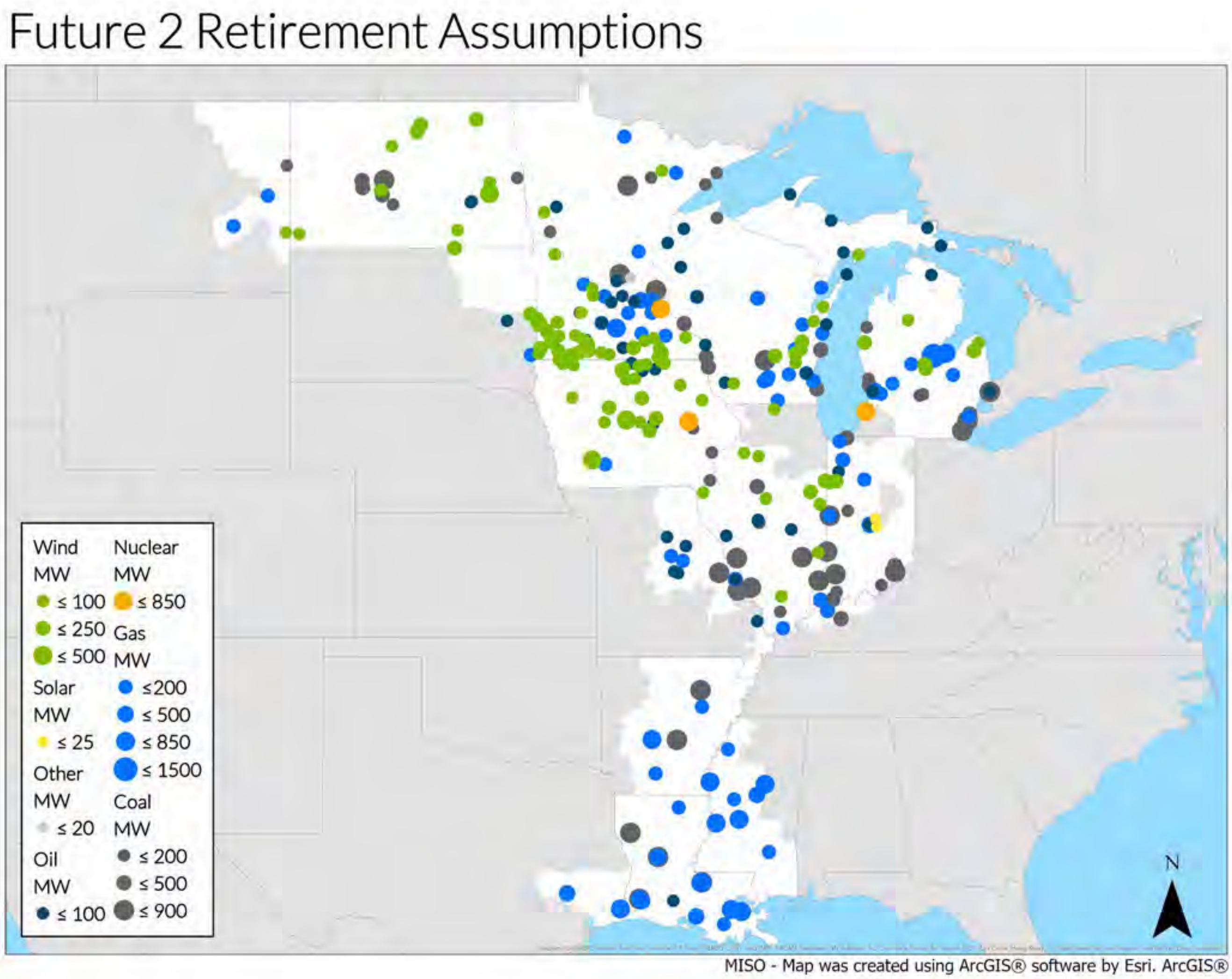


Figure 10: Future 2 Retirements by Fuel Type

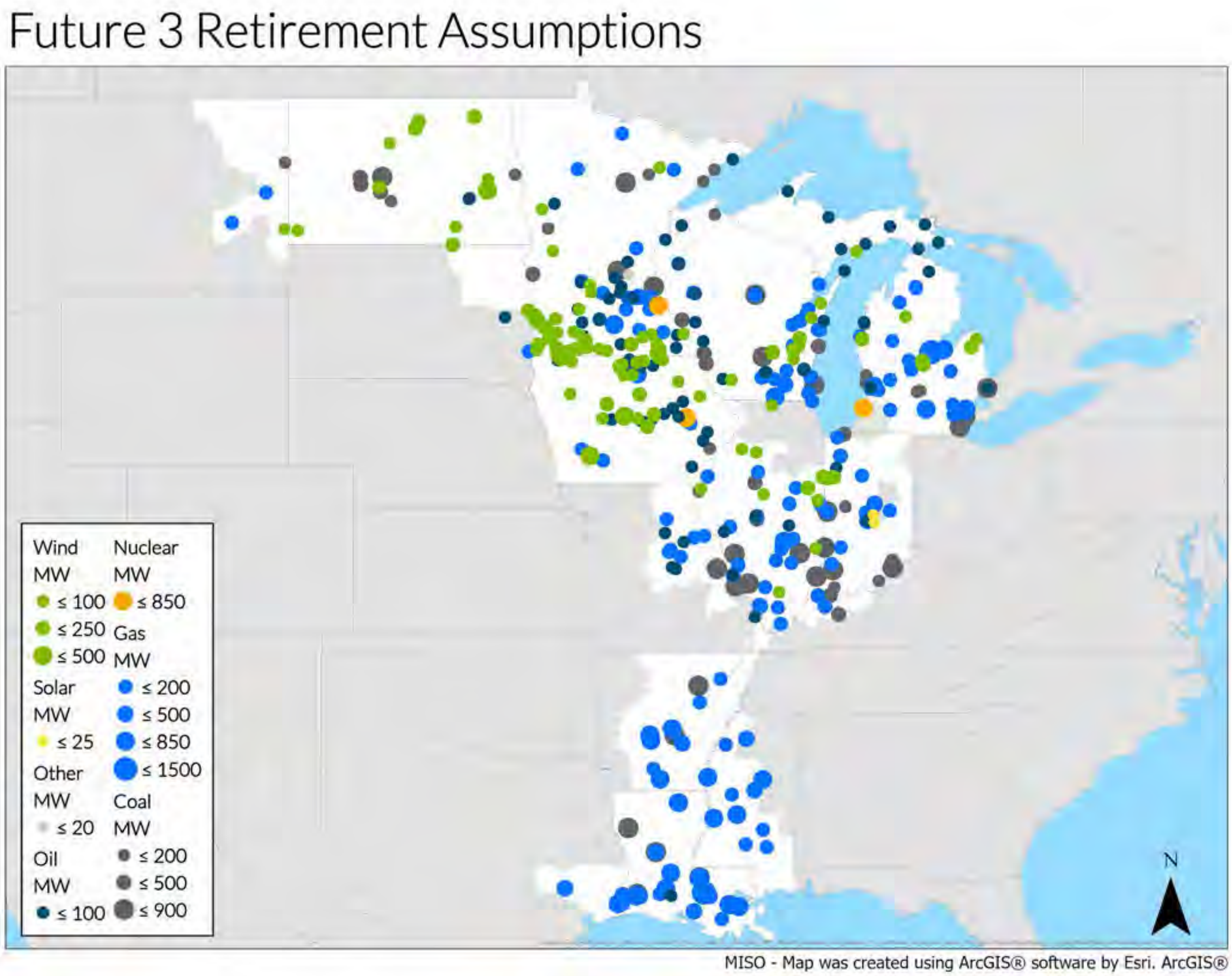


Figure 11: Future 3 Retirements by Fuel Type

Load Assumptions

To analyze what new generation and load modifying resources may be necessary 20 years into the future, assumptions were made regarding the load during that same 20-year period for each Future planning scenario. The three Futures each have differing assumptions representing a wide range of compound annual growth rates (CAGR) during the study period.

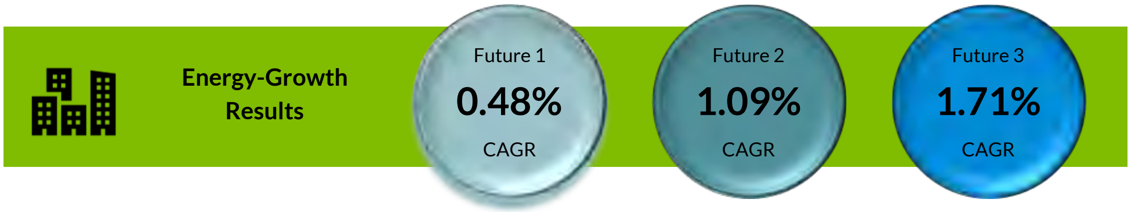


Figure 12: Annual Energy-Growth Rates

Future 1 assumed a load growth[9] consistent with recent trends; 0.48%, including currently low electric vehicle adoption as modeled by Lawrence Berkeley National Laboratory's (LBNL) 'Low' scenario projection.

Future 2 assumed an annual energy growth rate[9] of 1.09% to reach a targeted 30% energy increase by 2040, largely driven by electrification.

Future 3 assumed an annual energy growth rate[9] of 1.71% to reach a targeted 50% energy increase by 2040, driven by additional electrification.

A primary driver of load growth in Futures 2 and 3 is electrification. Electrification is the conversion of an end-use device to be powered with electricity, such that it displaces another fuel, (e.g., natural gas or propane). The increased energy assumptions of 30% and 50% were selected by MISO to create a wide but plausible range of growth scenarios. Although electrification drives the load increase in two of the Futures, it is not the sole source of each scenario's load growth. A more detailed discussion of each Future's load growth and electrification assumptions is provided below and in the Electrification Section of this report.

The resulting Future-specific Demand (MW) and Energy (GWh) forecasts are further detailed in the proceeding sections of this report.

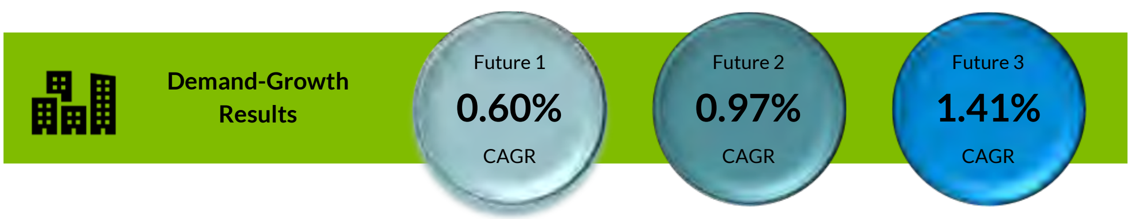


Figure 13: Annual Demand-Growth Rates

[9] Net annual energy and demand growth rates result from reducing the hourly load shape by the energy from energy efficiency (EE) programs.

MISO Forecast Development

The development of the EGEAS-Ready Coincident Peak (CP) Demand and Energy Forecasts for each Future began with MISO's load serving entities' 20-year demand and energy forecasts[10] and ended with the application of the various Future-driven assumptions, creating Future- and year-specific forecasts.

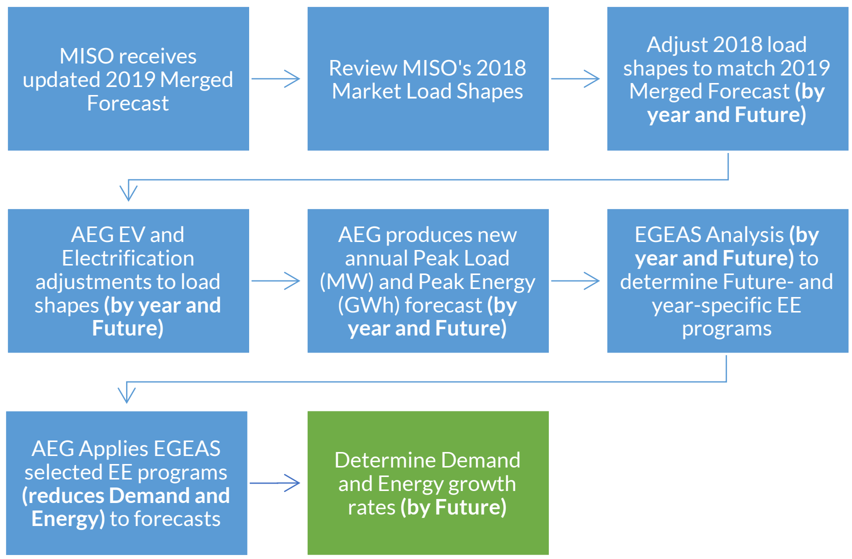


Figure 14: MISO's Forecast Development High-Level Process Flow Chart[11]

Base Forecast and Load Shapes

The 2019 Merged Load Forecast for Energy Planning forecast was reviewed for updates by stakeholders December 17, 2019 through January 10, 2020, and the updates received were incorporated. To accompany the forecast, MISO evaluated its 2018 load shapes for the impact of abnormal outages in operational load shape data due to weather anomalies. MISO evaluated the impact of Atlantic Tropical Cyclones which entered the MISO footprint according to the National Oceanic and Atmospheric Administration and determined that the 2018 shapes are suitable for MISO Futures.[12] MISO's 2018 load shapes also align with wind and solar shapes based on the most current data.

As a Futures process improvement, MISO used PROMOD to adjust each Load Balancing Authority's (LBA) 2018 load shape to meet Peak Load (MW) and Annual Energy (GWh) requirements set by the updated 2019 Merged Load Forecast for Energy Planning forecast. The benefit of this improvement was to create 20 years' worth of unique load shapes for the EGEAS analysis, as well to establish a common load shape for the EGEAS and Market Congestion Planning Studies (MCPS) analyses.

[10] If a particular MISO Load-Serving Entity (LSE) did not provide a 20-year demand and energy forecast, data from the State Utility Forecasting Group's Independent Load Forecast was used for it, creating the 2019 Merged Load Forecast for Energy Planning CP.

[11] Demand and Energy forecast process currently at box highlighted green.

[12] https://www.nhc.noaa.gov/data/tcr/index.php?season=2018&basin=atl

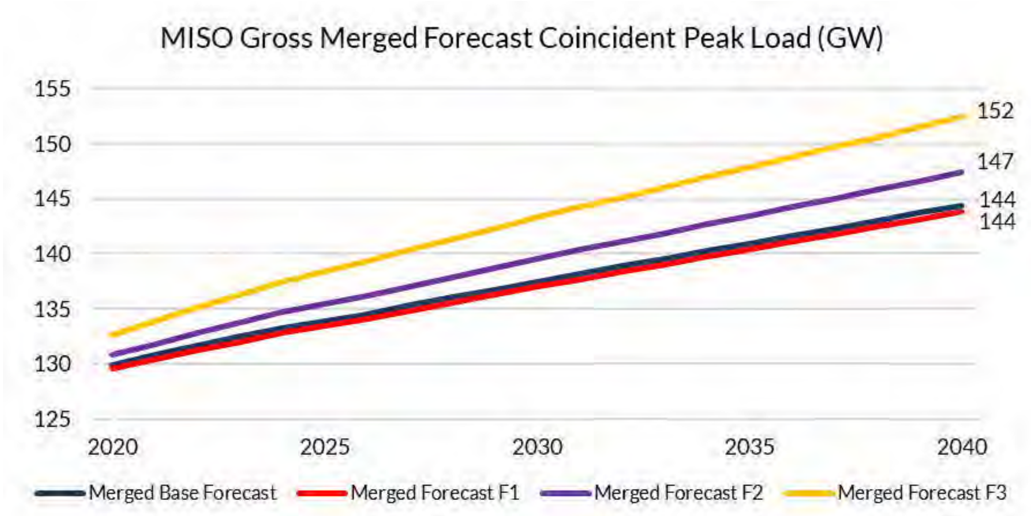


Figure 15: 2019 Merged Load Forecast Peak Load (GW)

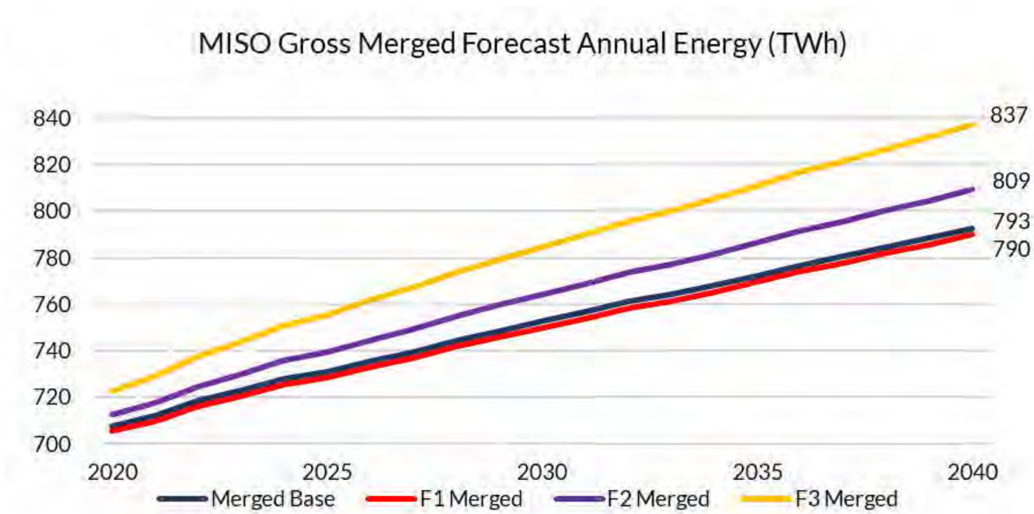


Figure 16: 2019 Merged Load Forecast Annual Energy (TWh)

Future-Specific Forecasts and Load Shapes

Applied Energy Group (AEG) used PROMOD-adjusted load shapes for their base input assumptions and then further modified these load shapes to achieve Future-specific electrification assumptions (EV growth and charging assumptions, residential electrification, and commercial and industrial electrification), ultimately creating 20 years of load shapes for each Future. A representation of the load shape modification is shown in Figure 24.

These Future-specific load shapes were used to calculate the associated Peak Load (MW) and Annual Energy (GWh) forecast for each year to be used in the EGEAS analysis. Refer to the following figures for MISO Footprint and Local Resource Zone (LRZ) representation of this forecast.

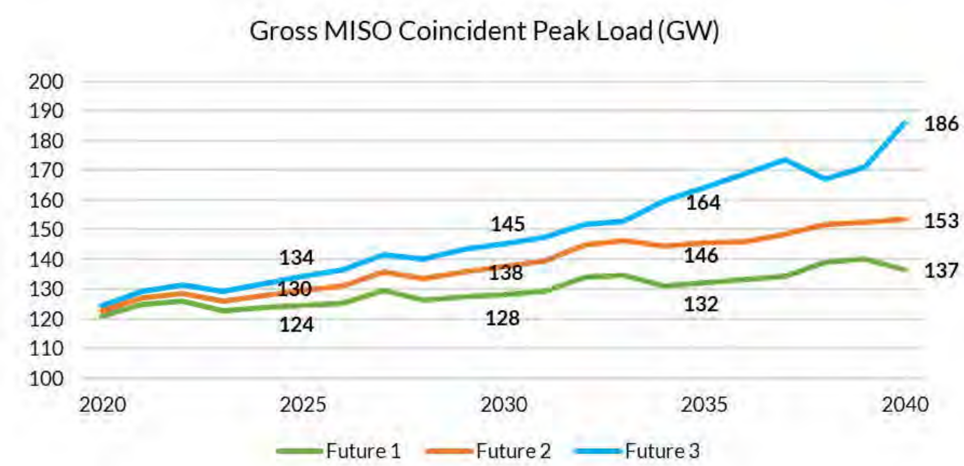


Figure 17: Final AEG Modified MISO Gross Coincident Peak Load (GW) Forecast by Future[13,14]

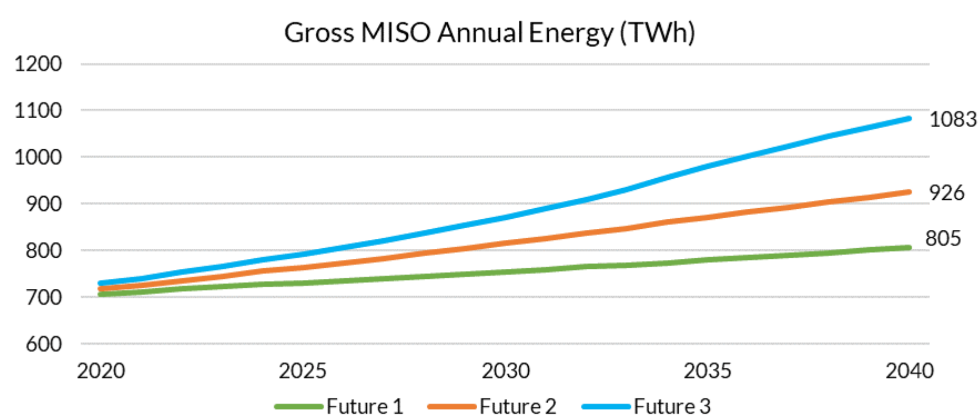


Figure 18: Final AEG Modified MISO Gross Annual Energy (TWh) Forecast by Future

[13] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[14] Dips in Future 3 are due to different peak times of reference, EV charging, and electrification load forecasts.

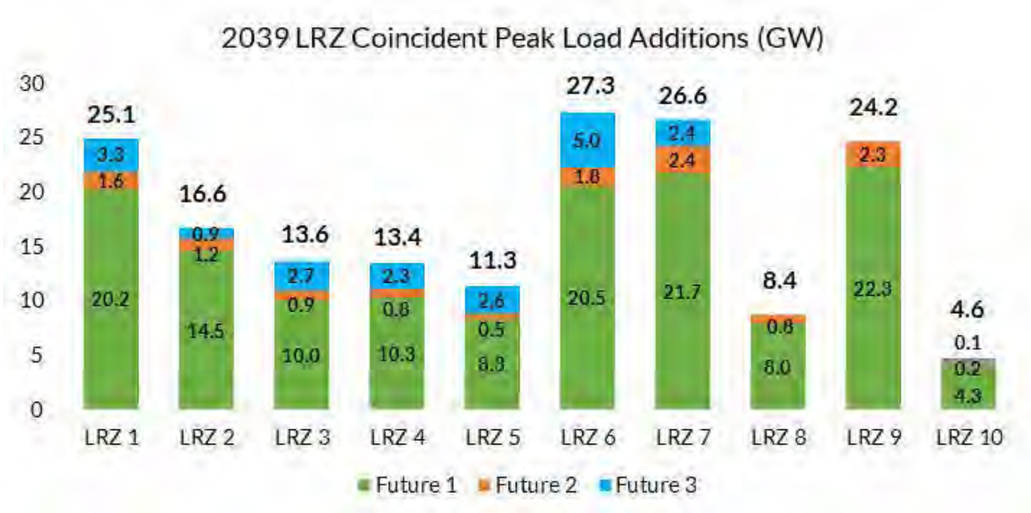


Figure 19: Final AEG Modified LRZ Coincident Peak Load (GW) Forecast [15,16]

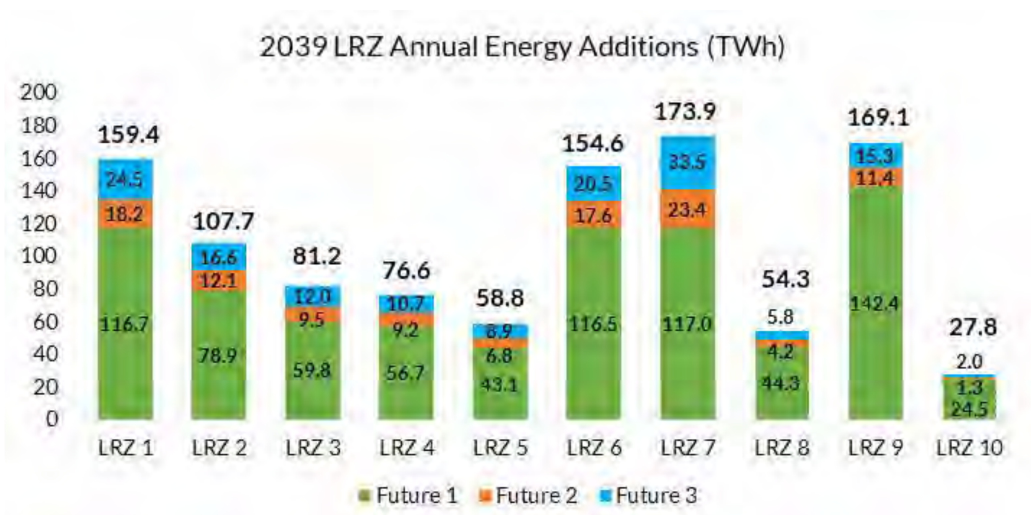


Figure 20: Final AEG Modified LRZ Annual Energy (TWh) Forecast [16]

[15] In LRZs 8 and 9, CP values decrease in Future 3, making the total shown less than the sum of values for Futures 1 and 2.

[16] Values shown do not include load and energy modifiers determined by EGEAS analysis.

Forecast Growth Assumptions

Demand and energy growth values are based on Futures assumptions and were determined once the analysis was finalized; EGEAS having selected hourly load (MW) and energy (GWh) modifiers and programs applied to each Future scenario's Coincident Peak forecast. The following figures represent compound annual growth rates (CAGR) and forecast increases pre- and post-analysis.

Figure 21: Final AEG Modified MISO Footprint Forecast Compound Annual Growth Rates (CAGR)

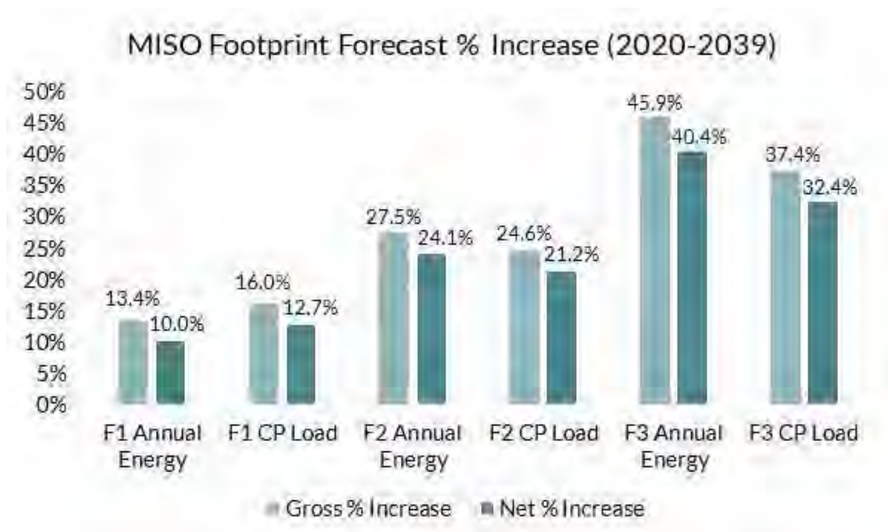


Figure 22: Final AEG Modified MISO Footprint Forecast % Increase[17]

[17] Gross values do not include load and energy modifiers determined by EGEAS analysis, while Net values include EE programs that were selected during modeling.

Forecast Evolution

To ensure the Futures update has effectively created broad and realistic bookends, especially with demand and energy assumptions as key drivers, MISO has compared the 2019 Merged Forecast (pre-application of EV and Electrification assumptions), MTEP21 Coincident Peak (CP) Future-specific forecasts (post-application of EV and Electrification assumptions), and MTEP19 Future forecasts.

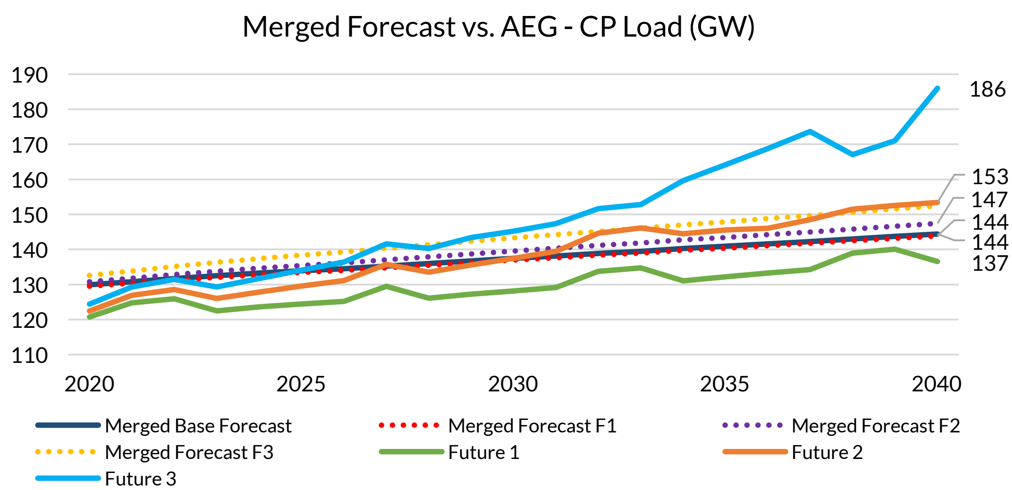


Figure 23: Merged Forecast vs. Future-Specific Adjustments – CP Load (GW) [18,19]

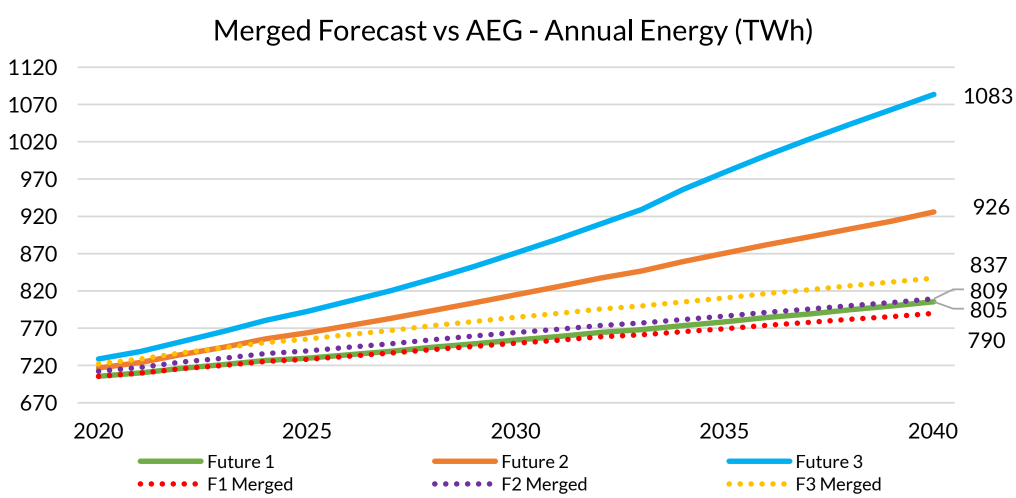


Figure 24: Merged Forecast vs. Future-Specific Adjustments – Annual Energy (TWh)

[18] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[19] Merged Forecast CP Load (GW) values are calculated from monthly peak data while the AEG Peak Load (GW) values are calculated from hourly data. This has the illusory effect of the Merged Forecast CP Load (GW) being reduced.

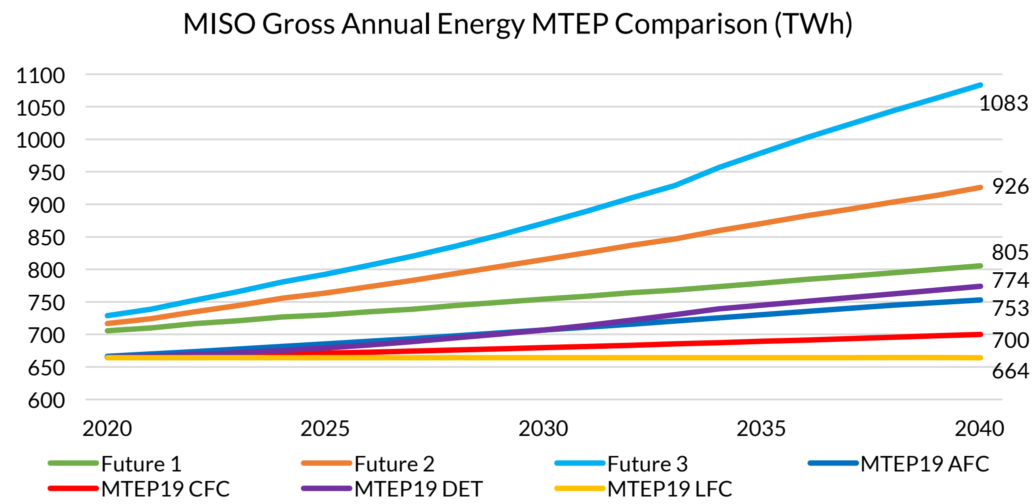


Figure 25: MTEP19 & MTEP21 MISO Annual Energy (TWh) Compare[20]

Final Load Shapes

Upon conclusion of the EGEAS analysis, MISO removed energy proportionate with selected energy efficiency programs in each Future scenario's load shape to produce final net load shapes. In Figure 27 through Figure 29, the evolution of each Future load shape is shown, starting with the initial 2020 load shape developed by SUFG,[21] the final input load shape for year 2039 from AEG that includes electrification assumptions, and then the 2039 load shape post modeling of each scenario that nets out EE programs selected. Figure 26 displays each Future scenario's post-modeling load shape in the final year of the study, for comparison.

[20] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[21] Purdue University's State Utility Forecasting Group

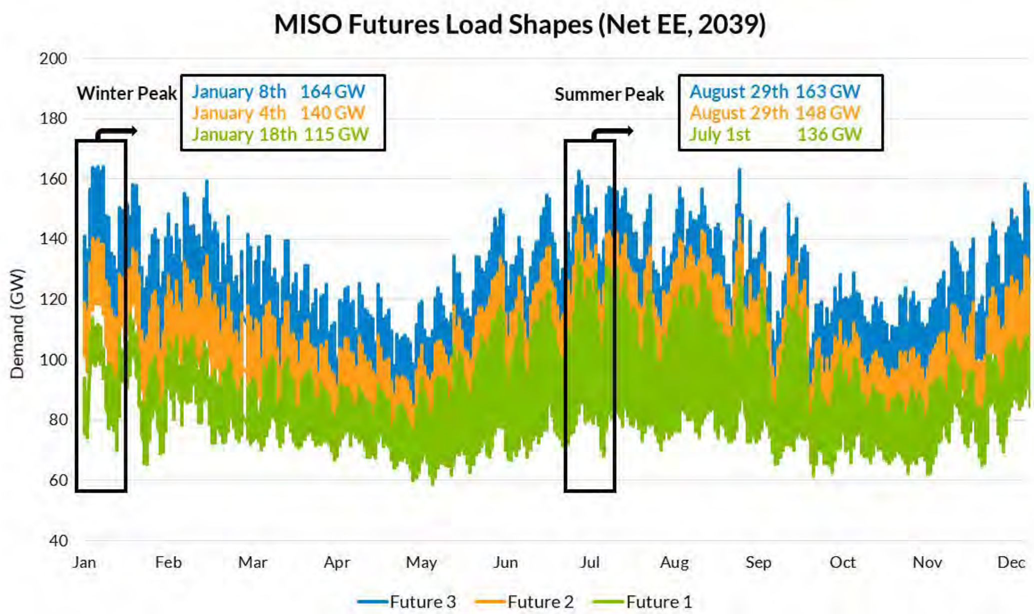


Figure 26: All Futures Final Load Shapes

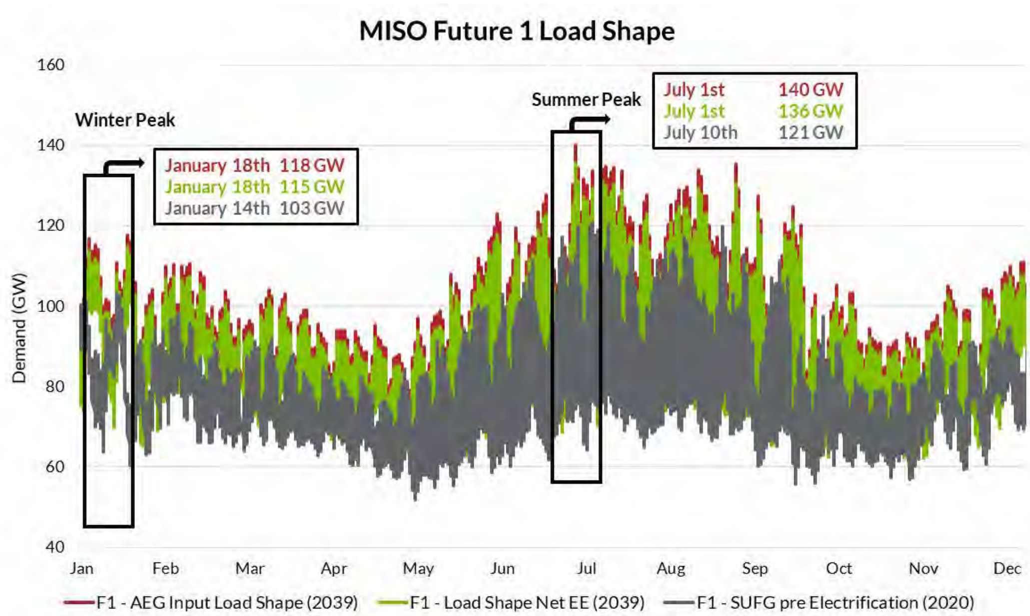


Figure 27: Future 1 Load Shape Evolution

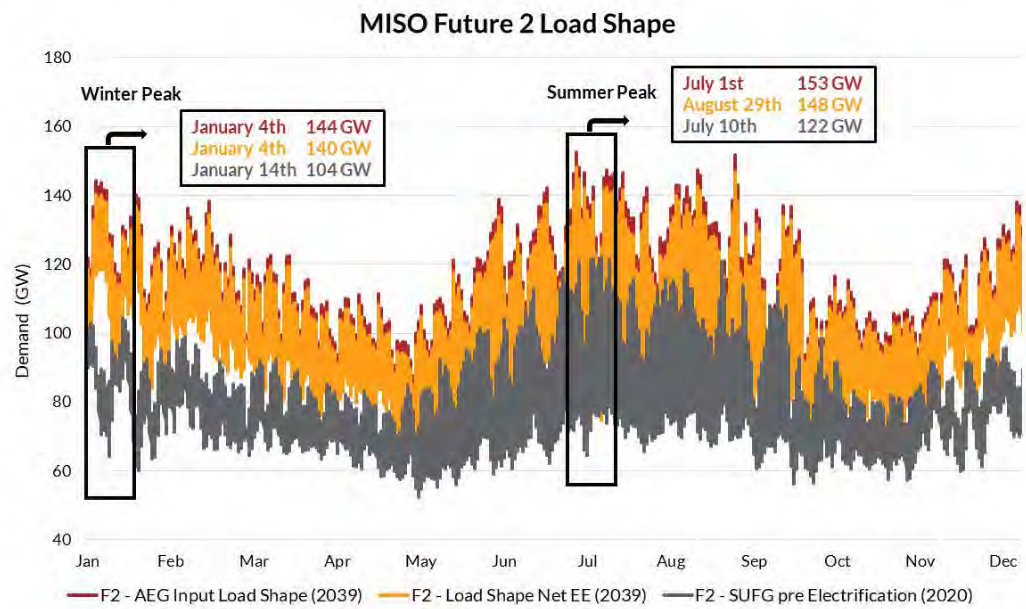


Figure 28: Future 2 Load Shape Evolution

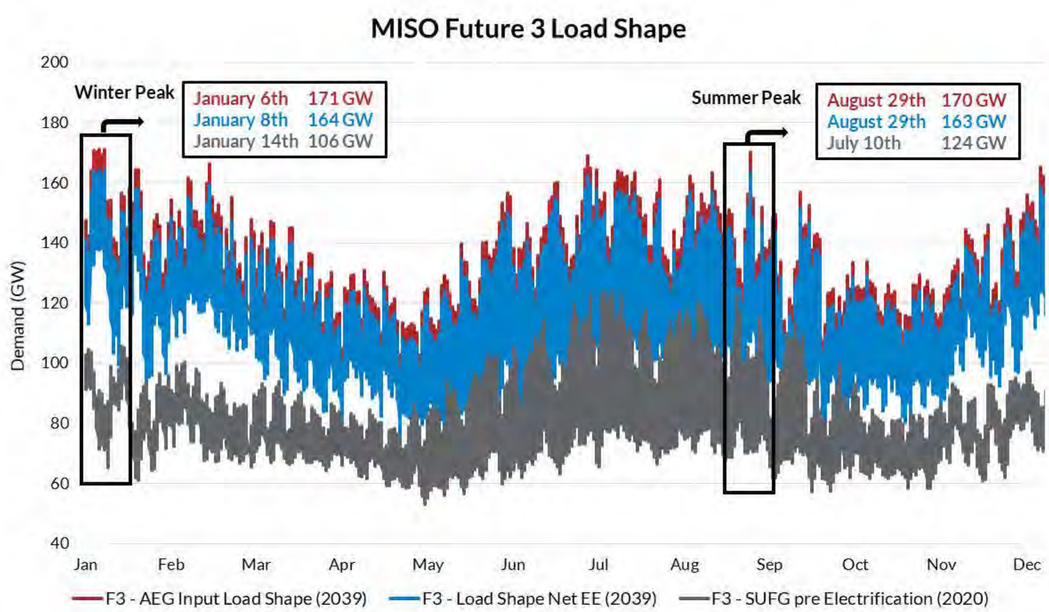


Figure 29: Future 3 Load Shape Evolution

Electrification

MISO contracted Applied Energy Group (AEG) to evaluate the MISO footprint on its potential to electrify. Electrification is the conversion of an end-use device to be powered with electricity, such that it displaces another fuel, (e.g., natural gas or propane). In this study, electrification is calculated as a percentage of technical potential that a given LRZ could achieve. The figure to the right shows the categories of electrification and what percentages of the technical potential they comprise. More details on the assumptions for the categories are included below.

Figure 30: Electrification Categories

To estimate the available market for electrification, AEG started with the end-use load forecasting models developed for MTEP20 (previous set of MISO Futures), which include market data for each state in the MISO footprint. These market data included estimates of the penetration of many types of electric equipment. To estimate the total technical electrifiable load, AEG assumed that 90% of a particular end-use customer load was capable of being electrified, and then subtracted the electric equipment saturations (the load that is already electrified) from that value.

Electrification Categories

AEG identified each electrifiable technology and considered how likely or feasible it would be to be adopted before assigning it to one of four categories: mature technologies, emerging, high, and very high.[22] AEG considered how widespread the technology currently is, whether there are utility EE programs, and whether or not there are known market barriers. Since both mature and emerging versions of known technologies (e.g., traditional air-source heat pumps vs. cold-climate heat pumps) can coexist, AEG distributed the electrification potential for different technologies over more than one category. These are represented by the percentages below.

Additionally, AEG considered the certainty around each assumption. For example, industrial process loads are very customizable and would require a "bottom-up" approach to implementation, considering each industry and state individually. To capture this uncertainty, electrification of industrial process loads was assigned to higher electrification levels.

Each category is described below however, additional insights into the details of these categories may be found in MISO's Electrification Insights Report.

Mature Technologies

The "Mature Technologies" electrification category includes technologies that are widely available on the market today and are the most likely to electrify in the future. One example is an air-source heat pump, which is already found in many homes throughout the United States. Electric cooking equipment, such as induction ovens, is another example of an existing technology that is popular and relatively straightforward to install. Technologies in this category include:

- Air-Source Heat Pumps (50% of single-family [SF], 50% of multi-family [MF], 50% of Commercial and Industrial [C&I])
- Geothermal Heat Pumps (50% of SF, 50% of C&I)
- Heat Pump Water Heaters (50% of SF)
- Clothes Dryers

[22] AEG's 2019 Presentation on Electrification

- Dishwashers
- Stoves

To better understand how much of these technologies are being electrified in each category, it is best to give an example. For air-source heat pumps, this section is saying that 50% of single-family, multi-family, and commercial and industrial heat pumps that can electrify will be electrified in this category.

Emerging Technologies

The "Emerging Technologies" category represents electrification load that is beginning to become available or is more mature but limited by known market barriers. For example, while air-source heat pumps are a mature technology, they may not be easily installable without reconfiguring the ductwork. Gas forced-air furnaces provide hotter air and require smaller ducts, requiring an invasive modification to expand the ductwork to keep a home warm in the winter. Process loads also begin to appear in this category. Technologies in this category include:

- Air-Source Heat Pumps (50% of SF, 50% of MF, 50% of C&I)
- Geothermal Heat Pumps (50% of SF, 50% of MF, 50% of C&I)
- Heat Pump Water Heaters (50% of SF, 50% of MF, 50% of C&I)
- Industrial Process (25% of C&I)

High Electrification Scenario Technologies

This category represents the point where substantial market barriers exist or where technologies are new or still in development. An example is a large-scale air-source heat pump that would be necessary to replace a large gas boiler heating a hospital. These are not readily available—gas is the most common fuel source in large-scale applications. However, if high levels of electrification are to be achieved, electrification using these new and in-development technologies would need to take place. Technologies in this category include:

- Air-Source Heat Pump (50% of C&I)
- Geothermal Heat Pump (50% of MF, 50% of C&I)
- Heat Pump Water Heaters (50% of MF, 50% of C&I)
- Industrial Process (25% of C&I)

Very High Electrification Scenario Technologies

This category represents the highest levels of uncertainty in the analysis and is only applied in the highest-growth cases. As noted above, much of the industrial process electrification is present in this category. The only technology in this category is noted below:

- Industrial Process (50% of C&I)

Technologies Electrified

HVAC Heat Pumps - Air-source and geothermal heat pumps

- Lower-growth scenarios electrify many residential homes and some businesses, where this technology is already available (rooftop units and residential systems)
- Higher-growth scenarios assume large-scale replacements are available for technologies like gas boilers

Heat Pump Water Heaters - Efficient water heaters with a vapor-compression refrigeration cycle

- Lower-growth scenarios electrify tanks in both the residential and commercial sectors
- Higher-growth scenarios include the electrification of large-scale gas water heaters

Residential Appliances - Clothes dryers, dishwashers, and stoves

- Dishwasher electrification occurs when no existing dishwasher is present

Industrial Process - High growth potential, but only certain processes can be electrified

- Due to the complexity involved in electrifying industrial processes, AEG assumed that most of this occurs in the higher-growth scenarios
- Examples of technologies that may be electrified within industrial processes include ultraviolet (UV) curing and drying, machine drives, and process-specific heating and cooling
- Electric boiler, industrial heat pump, resistance heating industrial heat pump, induction furnace, etc.

LBNL PEV Forecasts[23] - All four forecasts were used in development of these scenarios

- These include combinations of uncontrolled and V2G versions of the: Low, Base, High, and Very High scenarios
- Merged PEV forecasts were selected for each growth scenario – adoption curves and load shapes specific to the selected forecast were used

Figure 32 through Figure 37 display the results of these electrification assumptions across each Future scenario in the MISO footprint. The charts present a detailed view of the results showing yearly cumulative increases in energy from electrification for the footprint, electrification totals for each Local Resource Zone for the entire study, and the proportion of electrification from each technology. Similar charts for external region electrification results are found in the Appendix, Figure 80 through Figure 87.

[23] Lawrence Berkeley National Lab EV Forecast Report

Electrification Potential Across MISO Footprint

This analysis was conducted at the state level in the MISO footprint then aggregated by LRZ. AEG's end-use forecasting and Demand-Side Management (DSM) potential model was used to conduct this analysis, providing estimates of electric equipment penetrations as well as consumption for MISO's fraction of each state. Since local weather and equipment penetration data were used in this analysis, each state will have different end-use consumption patterns and a different electrifiable load, as shown in Figure 31. These are high-level findings based on the end-use models and a result of the differences noted above. The three main drivers of technical potential for electrification are:

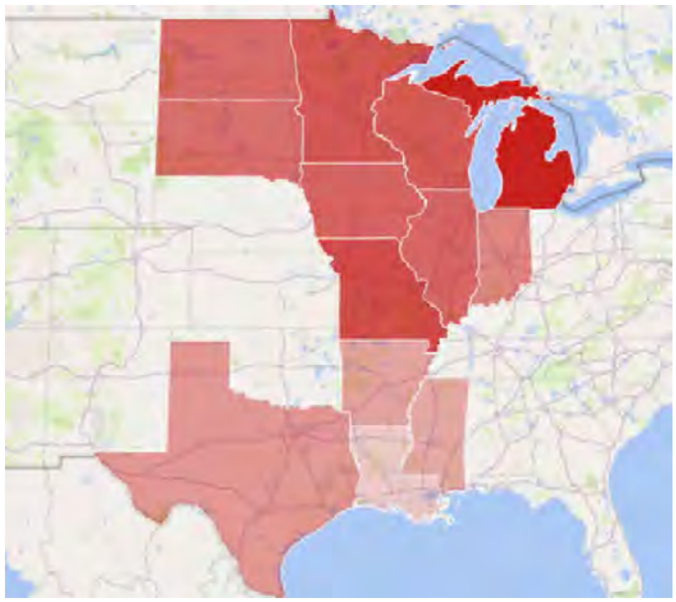


Figure 31: Electrification Potential by State

- **Latitude:** The northern states in the MISO footprint are generally colder than the southern states, resulting in larger space-heating loads. Since the heating end-uses represent some of the largest electrification potential, additional new loads are expected in the northern MISO states.
- **Gas Infrastructure:** Along with latitude, existing gas infrastructure heavily influences the electrifiable load. AEG utilized the state-level market data listed above to estimate gas equipment penetrations by state. If the load in a state is already mostly electric, there would be fewer non-electric units to convert, lowering potential.
- **Cooling Presence:** The final notable factor is the presence of existing cooling equipment. Similar to the gas infrastructure note above, high penetrations of existing cooling equipment limit electrification potential since the remaining non-electric market is smaller. In the warmer southern states, many homes already have cooling equipment installed, so their potential is lower.

Future 1 Electrification

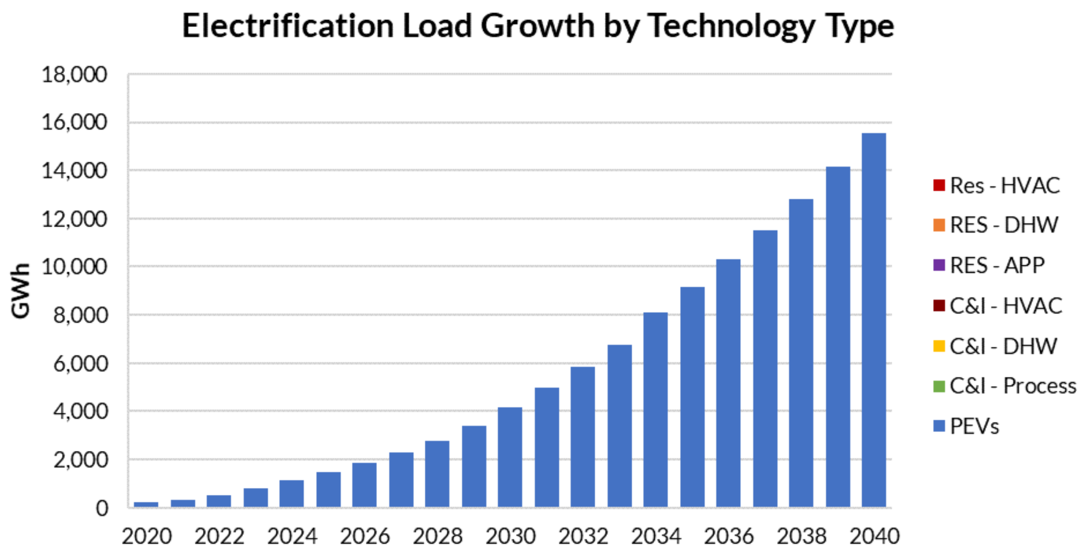


Figure 32: Future 1 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

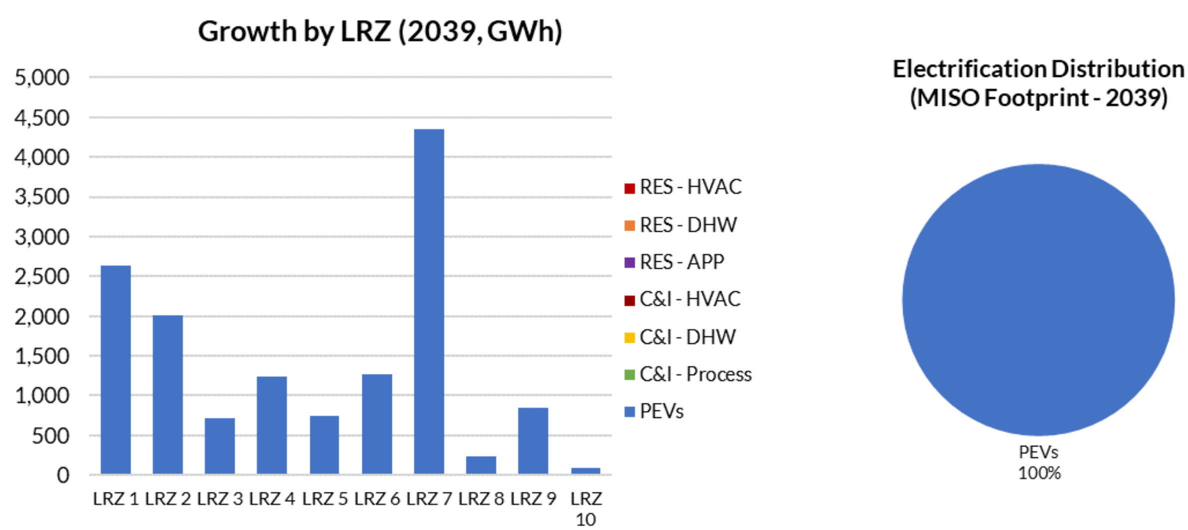


Figure 33: Future 1 Electrification Broken Down by End-Use

Future 2 Electrification

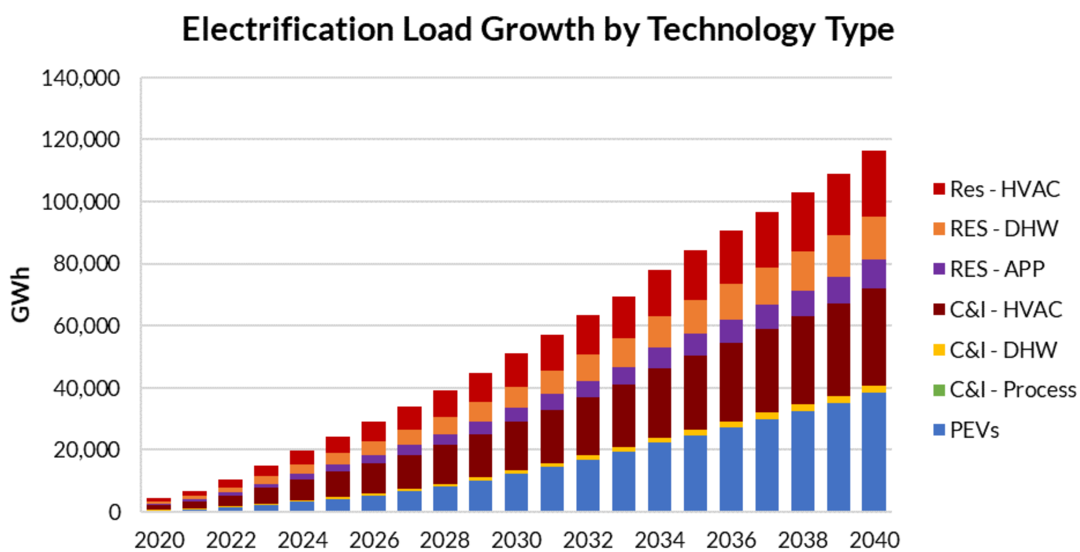


Figure 34: Future 2 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

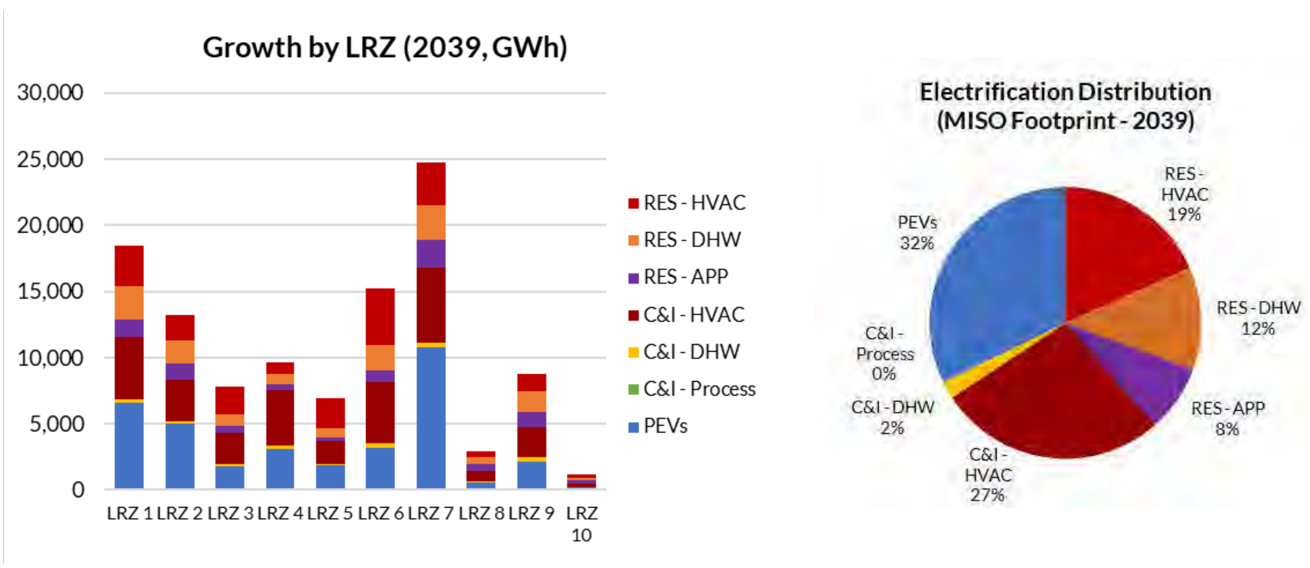


Figure 35: Future 2 Electrification Broken Down by End-Use

Future 3 Electrification

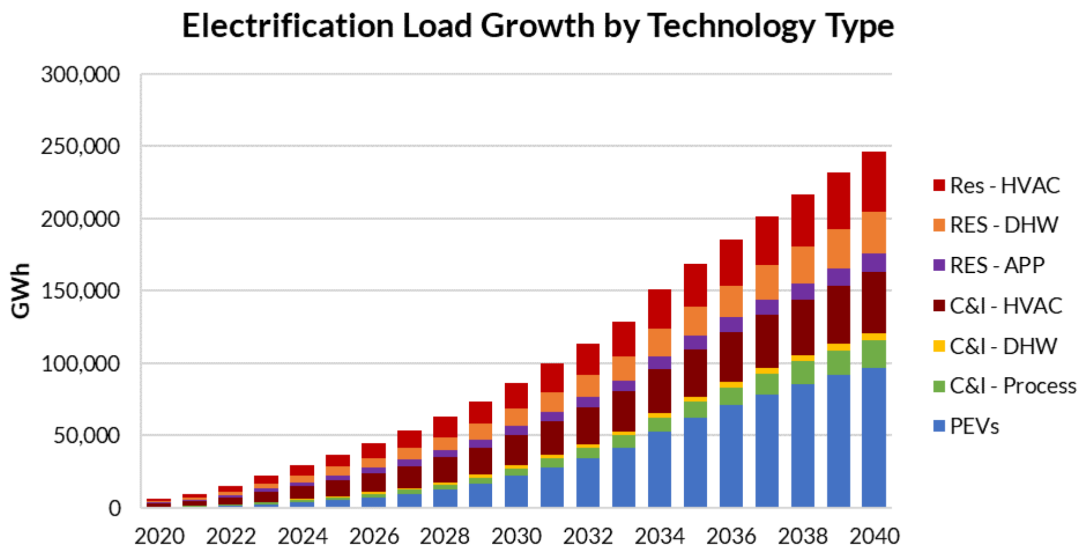
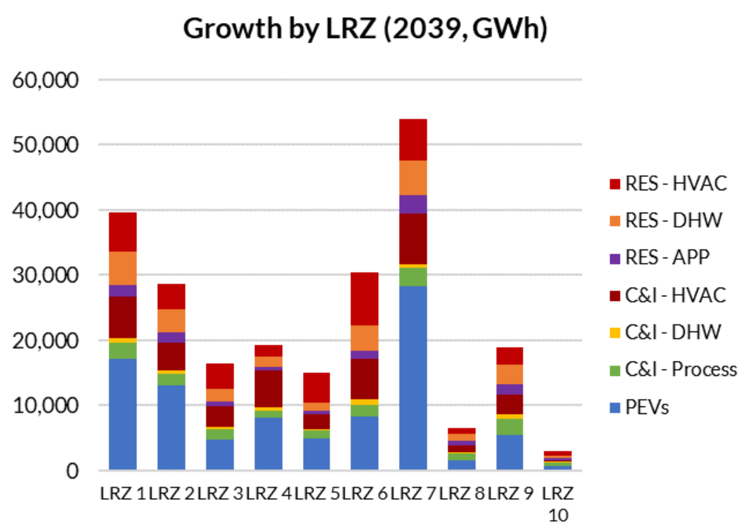


Figure 36: Future 3 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint



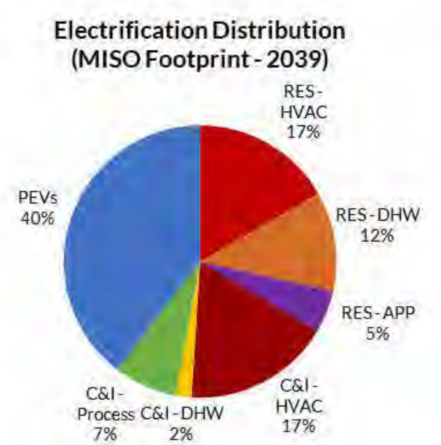
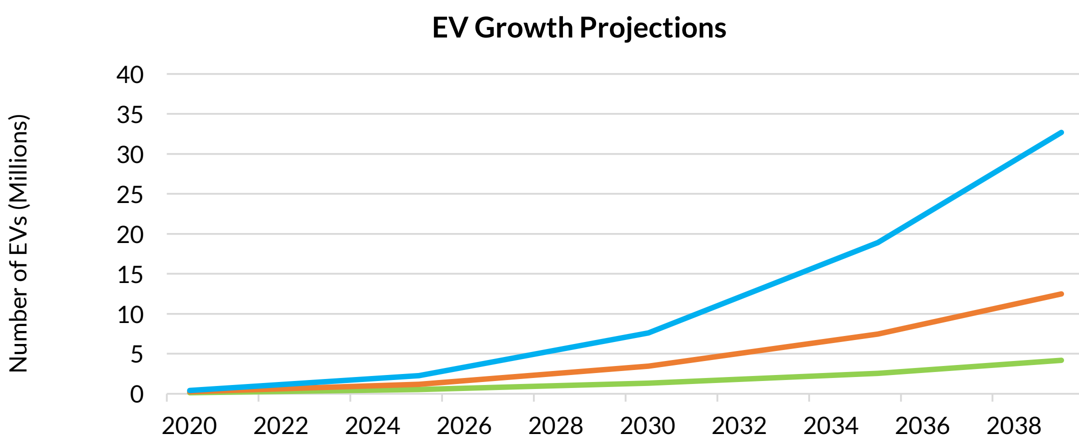


Figure 37: Future 3 Electrification Broken Down by End-Use

Electric Vehicle Forecasts

MISO collaborated with Lawrence Berkeley National Laboratory (LBNL) on a study to determine the potential for EVs within the MISO footprint. This study categorized the projected growth of EVs in into four scenarios: low, base, high, and very high. Each of the three Futures used merged forecasted EV growth scenarios to include different amounts of light-duty EVs. All Futures explored a variety of EV growth and charging scenarios within every LRZ across the 20-year study period.

Future 1 evaluated only uncontrolled charging methods, Future 2 included vehicle-to-grid (V2G) charging after 2035, and Future 3 incorporated V2G charging after 2030. Figure 38 through Figure 41 detail the number of EVs in each scenario, MISO footprint and LRZ.



	2020	2025	2030	2035	2039
Future 1	0.135	0.53	1.33	2.57	4.19
Future 2	0.26	1.205	3.47	7.455	12.49
Future 3	0.416	2.272	7.598	18.91	32.686

Figure 38: EV Growth per Future (MISO footprint)

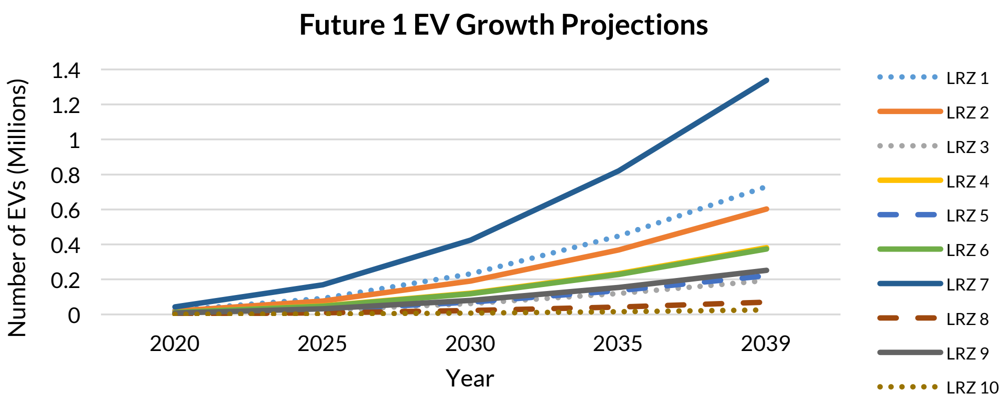


Figure 39: Future 1 EV Growth per LRZ

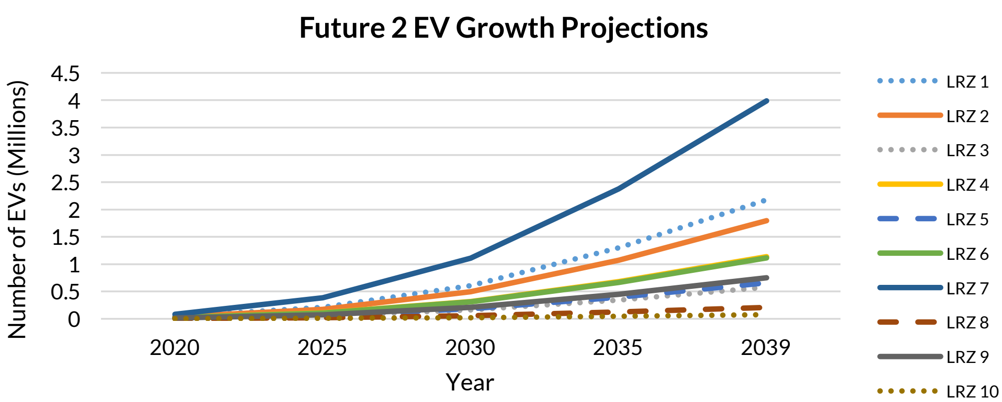


Figure 40: Future 2 EV Growth per LRZ

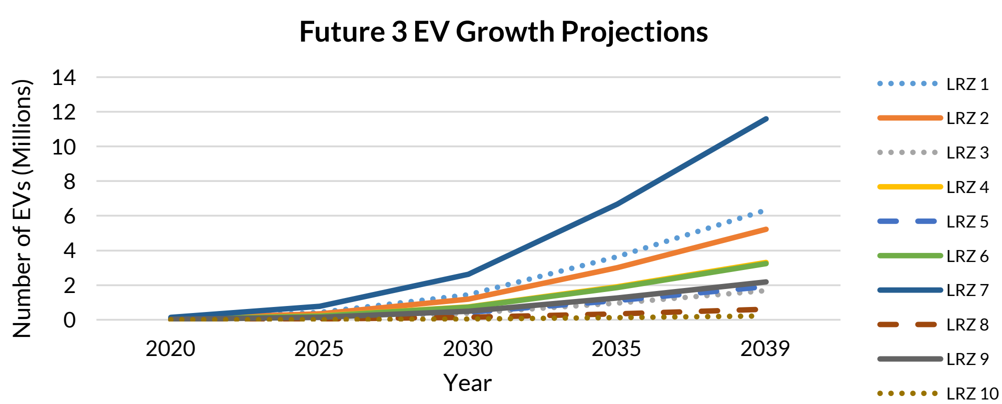


Figure 41**: Future 3 EV Growth per LRZ**

New Resource Additions

Regional Resource Forecast Units (RRF Units) are various resource types that are defined in and selected by MISO's capacity expansion tool, EGEAS, to achieve each of the Futures scenarios. The RRF units used in MISO Futures are discussed in further detail below.

Wind

Vibrant Clean Energy (VCE) 2018 hourly profiles were used as the base data. New RRF units were built at 100m hub height throughout the study period. Existing units used representative 80m hub height hourly profile and all wind units assumed 16.6% capacity credit.

Solar

Vibrant Clean Energy (VCE) 2018 hourly profiles were used as the base data. Existing units used a representative hourly profile and all solar units assumed 50% capacity credit at the beginning of the study period and decreased by 2% starting in year 2026, until the capacity factor reached a minimum of 30%.

Hybrid: Utility-Scale Solar PV + Storage

Hybrid solar profiles were created by modifying VCE 2018 hourly profiles for solar units. Hybrid units were modeled as a 1200 MW inverter attached to 1500 MW of solar panels, resulting in an over-panel of 25%. When solar output exceeded the inverter capacity, the battery charged. Once solar output reached 20% or lower of the max capacity (max capacity is 1500 MW making 20%, 300 MW), the battery discharged until empty. Hybrid units assumed a 60% capacity factor.

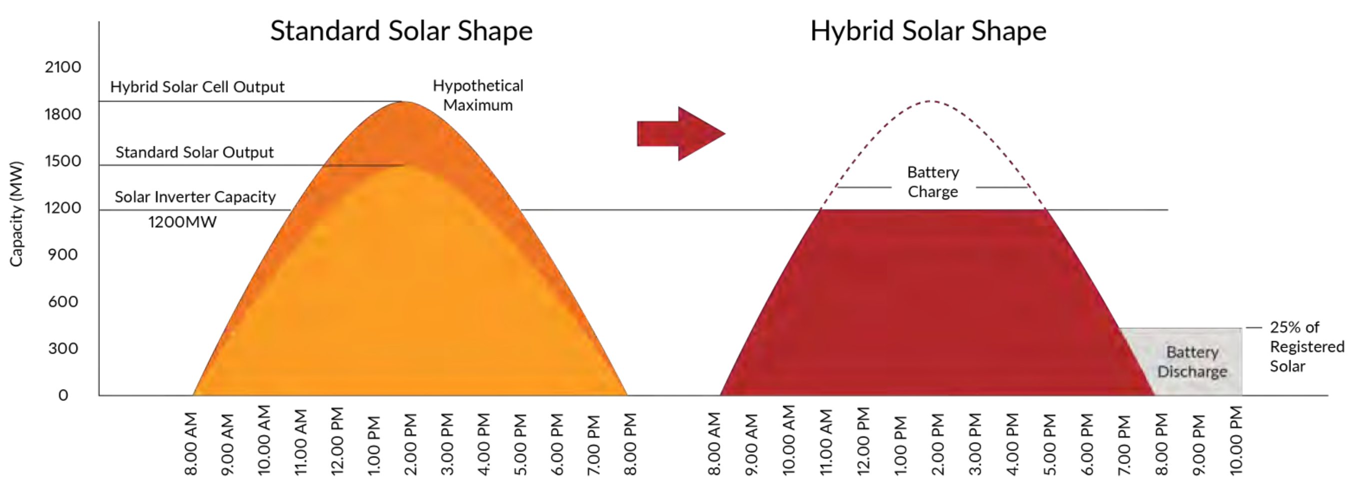


Figure 42: Solar + Storage Hybrid Profile

Storage: Lithium-Ion Battery (4-hour)

Batteries modeled in the capacity expansion were 4-hour duration lithium-ion batteries. Units were sited with a minimum capacity of 5 MW and a maximum capacity of 500 MW across all Future scenarios.

Distributed Energy Resources (DERs)

As in previous Futures cycles, MISO commissioned Applied Energy Group (AEG) to develop new DER technical potential. AEG developed estimates of DER impacts through survey of load-serving entities (LSE) and secondary research. Based on analysis for MTEP20, with updated utility information and Futures narratives for this cycle, technical potential represents feasible potential under each scenario. To support modeling, AEG compiled DER programs by type and cost into program blocks for EGEAS.

Previously referred to as demand-side additions or management (DSM), these resources were modeled as program blocks in three main categories: Demand Response (DR), Energy Efficiency (EE), and Distributed Generation (DG). Programs also fall into two sectors: Residential and Commercial and Industrial (C&I).

During the program selection phase for the models, each block was offered against supply-side alternatives to determine economic viability. For all three Futures, EGEAS selected the following program blocks, all within the C&I group: Customer PV, Utility Incentive PV, and Low-Cost Energy Efficiency. Additionally, Future 3 selected Residential Low-Cost Energy Efficiency. “Customer PV” indicates market-driven, naturally occurring solar panel adoption, whereas “Utility Incentive PV” indicates a utility incentive program for solar PV. Specific EE programs were grouped by cost into three tiers for C&I and two tiers for Residential. A complete list of detailed AEG programs mapped to EGEAS program blocks is below in Table 5.

Announced resources were included in Futures base assumptions. Several stakeholders submitted feedback detailing DERs they intend to add to their systems; these are also included in the totals below. Only selected programs and stakeholder additions were implemented in the Futures models. Table 3 and Table 4 show total DER technical potential and additions modeled in MISO by the end of the study period.

MTEP21 DERs Capacity (GW) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	5.2	0.9	5.9	0.9	5.9	0.9
Energy Efficiency (EE)	13.3	7.8	14.5	8.1	14.5	11.7
Distributed Generation (DG)	14.7	3.5	14.7	3.5	21.8	6.2

Table 3: DER Capacity (GW): 20-Year Technical Potential & Additions in MISO

MTEP21 DERs Energy (GWh) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	442	118	498	118	498	118
Energy Efficiency (EE)	86,886	30,801	94,313	31,393	94,313	49,145
Distributed Generation (DG)	26,119	5,709	26,119	5,709	36,934	9,837

Table 4: DER Energy (GWh): 20-Year Technical Potential & Additions in MISO

DER Type	EGEAS Program Block	DER Program(s) Included
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable
DR	C&I Price Response	C&I Price Response
DR	Residential Direct Load Control	Res. Direct Load Control
DR	Residential Price Response	Res. Price Response
EE	C&I High-Cost EE	Customer Incentive High, New Construction High
EE	C&I Low-Cost EE*	Customer Incentive Low, Lighting Low, New Construction Low, Prescriptive Rebate Low, Retro commissioning Low
EE	C&I Mid-Cost EE	Customer Incentive Mid, Lighting Mid, New Construction Mid, Prescriptive Rebate Mid, Retro commissioning Mid
EE	Residential High-Cost EE	Appliance Incentives High, Appliance Recycling, Low Income, Multifamily High, New Construction High, School Kits, Whole Home Audit High
EE	Residential Low-Cost EE*	Appliance Incentives Low, Behavioral Programs, Lighting, Multifamily Low, New Construction Low, Whole Home Audit Low
DG	C&I Customer Solar PV*	C&I Customer Solar PV
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Utility Incentive Battery Storage
DG	C&I Utility Incentive Solar PV*	C&I Utility Incentive Solar PV
DG	Residential Customer Solar PV	Res. Customer Solar PV
DG	Residential Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Utility Incentive Battery Storage
DG	Residential Utility Incentive Solar PV	Res. Utility Incentive Solar PV

Table 5: EGEAS Program Block/Specific DER Program Mapping

* Program was selected as economically viable and utilized by EGEAS in the resource expansion.

Natural Gas Resources

Combined Cycle (CC) and Combustion Turbine (CT) were the two gas resource types modeled. Site priority levels for these units remained the same when selecting a site. However, CC units were given a higher priority over CT units.

CC + Carbon Capture Sequestration

Futures analysis modeled Combined Cycle plus Carbon Capture and Sequestration (noted as CC+CCS in report documentation) due to the need for a low-carbon resource with a high-capacity factor. This was found to be the case when modeling the high carbon reduction in Future 3 (80%) after 2035 and in 2039 of Future 2 (60%). While there are no large-scale CC+CCS plants in operation today, there are several states and utilities testing this resource.

In modified Futures studies to come, MISO will continue to investigate other forms of energy that could include small modular reactors (SMRs) and green hydrogen, for example. Recent announcements show that members are looking into SMRs and hydrogen resources for electricity production.[24,25,26] Due to such recent developments and MISO's role to remain resource-agnostic, MISO used CC+CCS units in modeling to serve as a proxy for a high-capacity factor, low-carbon-emitting resource.

New Resource Addition Siting Process

RRF unit siting processes were developed to help identify where future generation would likely be located. While different RRF unit types need their own siting processes, there are universal criteria that apply to each resource type's unique siting process. These universal siting criteria and resource-specific processes are discussed below.[27]

Universal Siting Criteria

To help improve siting measures, the following criteria underlie all resource-specific siting processes.

1. The same sites were used for each Future and site differences only occurred due to Future-specific renewable capacity needs. This included only using sites that were found in both the Year 5 and Year 10 MTEP Powerflow models.
2. Radial lines and associated buses were identified in the MTEP Powerflow models and excluded from potential resource sites.
3. Sited capacity could not exceed a site's N-1 capacity amount. This means the summation of all the transmission elements, excluding the highest rated capacity element, could not have a lower capacity than the resource capacity.
4. Units were only sited on MISO-owned transmission elements.

Wind and Solar PV

Resources of this type were modeled as a collector system, representing an aggregated capacity potential that can be installed within 10-30 miles of each site. These collector sites were identified by two methods:

1. Compilation of Generation Interconnection (GI) queue projects:
   - 80% of Future-determined capacity was distributed to GI sites.
   - GI projects were ranked based on GI queue status (projects further along in the GI study process were ranked higher) and grouped by project state location, creating a capacity by state penetration percentage.
   - GI projects within 10 miles of each other were identified and combined into a collector system.
   - The capacity by state penetration percentage was applied to the 80% capacity expansion results, creating a state-up siting processes driven by GI Queue activity.
2. Vibrant Clean Energy[28] (VCE) results:
   - VCE sites receive the remaining 20% of Future-determined capacity.
   - Collector buses represent a 20- to 30-mile aggregated capacity potential.

[24] Mitsubishi Power and Entergy Collaboration
[25] Xcel Energy and INL
[26] Xcel Energy
[27] All capacities referenced on this page are (MW).
[28] VCE Report

Utility-Scale Solar PV + Storage (Hybrid)

Hybrid units were sited the same as Solar PV units and utilized the GI Queue only. Due to low GI queue activity for hybrid units not all Hybrid capacity (MW) was able to be distributed. As a result, the remaining balance was sited at unutilized Solar PV GI sites for the respective Future.

Distributed Solar PV Generation (DGPV)

Distributed solar PV resources (DGPV) siting methodology utilized the National Renewable Energy Laboratory's (NREL) Distributed Generation Market Demand Model (dGen) and consisted of the following:

- Using dGen, identify top 25 counties by DGPV potential within each LRZ.
- Identify (up to) top 20 load buses for each county.
- Distribute county capacity using dGen results weighting.
- Use top 20 load buses' Load Ratio Share (LRS) to distribute dGen-weighted capacity to each bus.

Lithium-Ion Battery (4-hour)

Batteries were restricted to a minimum capacity of 5 MW and capped at a maximum capacity of 500 MW (PROMOD performance reasons) and sited in a way to create geographical distribution for each LBA. The geographical distribution process follows:

- Each LBA's LRS was determined using Future-specific forecast data; LRS was then used to determine each LBA's Battery Capacity (MW) allocation.
- Top load buses for each LBA were identified, and the nearest, highest N-1 capacity bus greater than 100kV was selected to site the capacity.
- If an LBA needed more than one battery site, the next bus selected would be at least 10-20 miles away from the previously used bus to maintain geographical distribution.

Combined Cycle and Combustion Turbine

Combined Cycle and Combustion Turbine siting largely remained the same as in past MTEP cycles with site rankings as follows:

- Combined Cycle units got higher priority sites over Combustion Turbine
- Priority 1: Active Definitive Planning Phase (DPP) Phase 1, 2, 3 Generator Interconnection Queue
- Priority 2: Brownfield – Existing and Retired Sites
    - Retired sites ranked by earliest commission date
    - Retired sites had to be 50 MW and greater
- Priority 3.1: SPA or Canceled/Postponed GI Queue
- Priority 3.2: Greenfield Siting Criteria

CC + Carbon Capture Sequestration

Combined Cycle plus Carbon Capture Sequestration (CC+CCS) sites were limited to sites suitable to this technology type. Desirable basins for these resources were determined using the results of the U.S. Geological Survey's (USGS) National Geologic CO_2 Storage Assessment. Potential sites were screened to ensure that their geographic location fell within the boundary of a geologic storage resource. Sedimentary basin locations were overlayed onto Priority Sites for Combined Cycle and Combustion Turbine. Priority sites were then ranked by suitability and reserved for CC+CCS resources.

MISO Expansion Results

While comparing the expansion results of the MISO footprint across each Future scenario, there are several key findings of note:

- All scenarios have relatively large amounts of gas additions; this is due to increasing amounts of coal and gas retirements and the system's need for base generation to replace retired units. CC and CT gas units emit approximately half the amount of CO_2 that coal units emit. Decarbonization and load growth allow for gas to comprise 40% of the total expansion in Future 1, while CC+CCS comprises 40% of the gas units built in Future 3's expansion, illustrating the model's need for a low-carbon, high-capacity factor proxy resource.
- Wind, solar, and hybrid resource expansion is largely driven by decarbonization and each underlying load shape. In Future 3 there is significantly more wind than the other two cases; this is primarily due to the increase in load, 80% carbon reduction, and dual peaking system.
- Battery installation is driven by increased load and decarbonization.
- Age-based retirement assumptions for nuclear, wind, solar, and "other" resources remain the same across all scenarios. Additionally, all retired wind is repowered and reflected in the resource addition totals.
- Distributed solar and energy efficiency (EE) resources are composed of both selected DER programs and specific member feedback. No demand response (DR) resources were selected in the model, but are present in the expansion due to member feedback.

Future Resource Additions (MW)												
	CC	CT	CC+CCS	Wind	Solar	Hybrid	Battery	Distributed Solar	Hydro	EE	DR	Totals
Future 1	37,126	14,094	0	18,704	34,696	12,000	600	3,475	82	7,824	939	129,540
Future 2	58,725	10,494	1,201	63,104	28,696	1,200	3,400	3,475	82	8,053	939	179,368
Future 3	41,923	17,695	42,001	123,104	28,696	10,800	35,400	6,168	82	11,722	939	318,530

Future Resource Retirements (MW)								
	Coal	Gas	Nuclear	Oil	Wind	Solar	Other	Totals
Future 1	44,827	18,627	2,359	1,996	9,223	21	36	77,089
Future 2	45,109	21,611	2,359	2,027	9,223	21	36	80,386
Future 3	46,963	51,368	2,359	2,295	9,223	21	36	112,265

Table 6: MISO Resource Additions and Retirement Totals

Figure 43 details the results from each Future scenario's resource additions as displayed in the table above. Solar resources are comprised of utility-scale solar PV, solar hybrid, and distributed solar resources. Wind totals include expansion wind units and repowered wind assumptions. The other resource categorey includes energy efficiency and demand side management programs selected within each future. Gas resources include both CC and CT units for Futures 1, while Future 2 and 3 additionally include CC+CCS expansion units. In Future 3, the CC+CCS resource proxy units (42 GW) are needed in the later years of the study period to serve base load with low CO_2 emissions.

Over the course of the following pages (Figure 44 through Table 12) the detailed expansion results of each Future scenario and the siting locations are displayed. Following the figures in each section are resource-specific additons and retirement (R&A) tables; each table details R&A capacities applicable for each LRZ and MISO per milestone year.

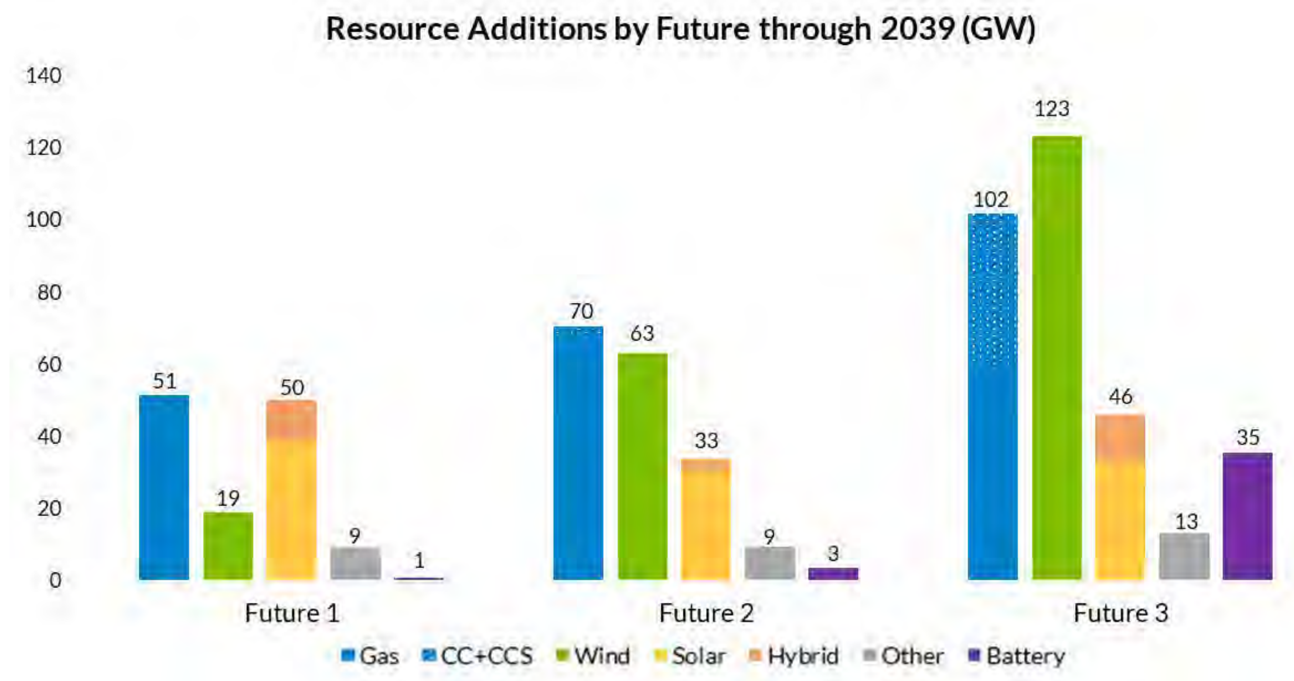


Figure 43: MISO Resource Addition Summary by Future

MISO – Future 1

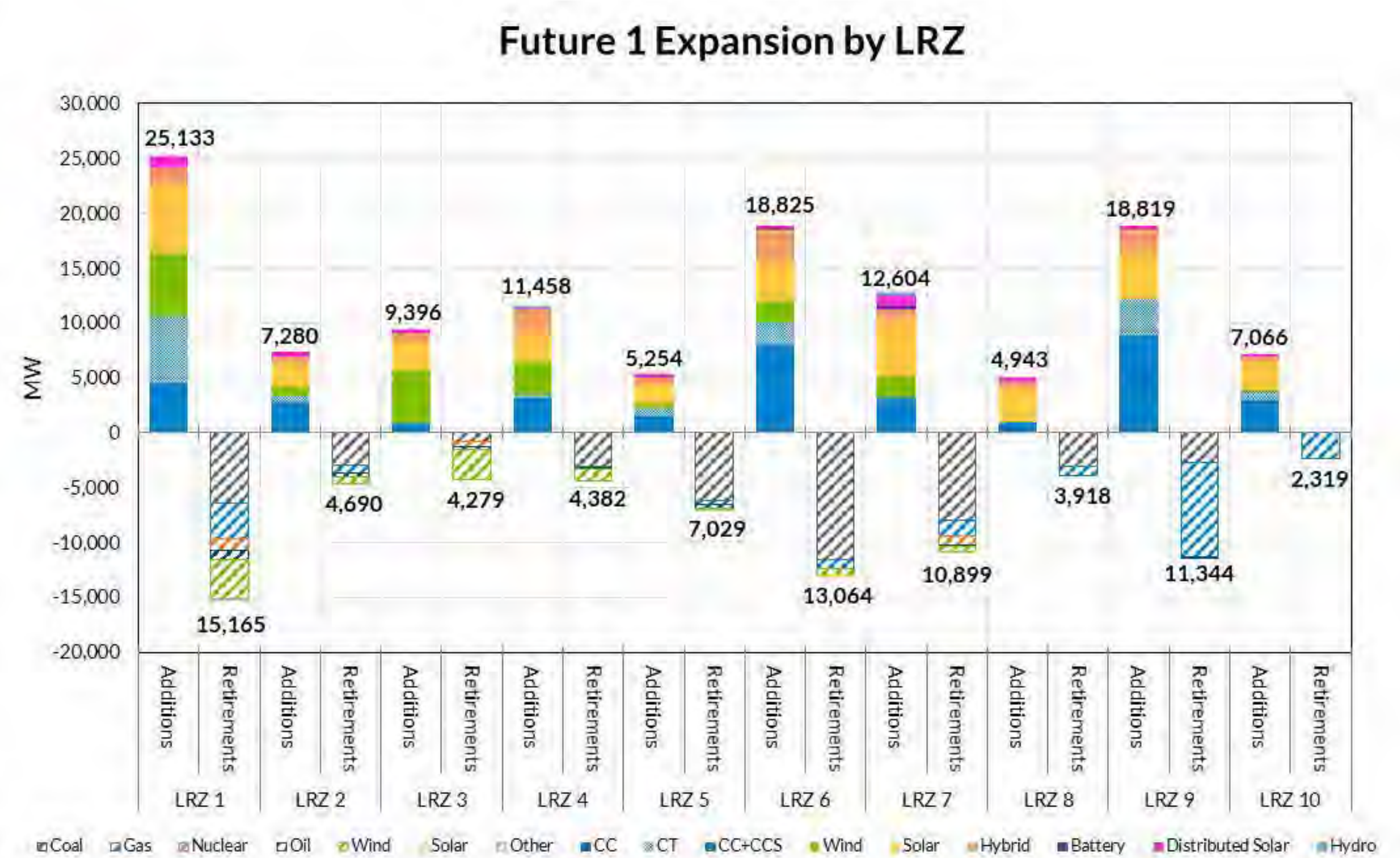


Figure 44: MISO Future 1 Resource Retirement and Addition Summary

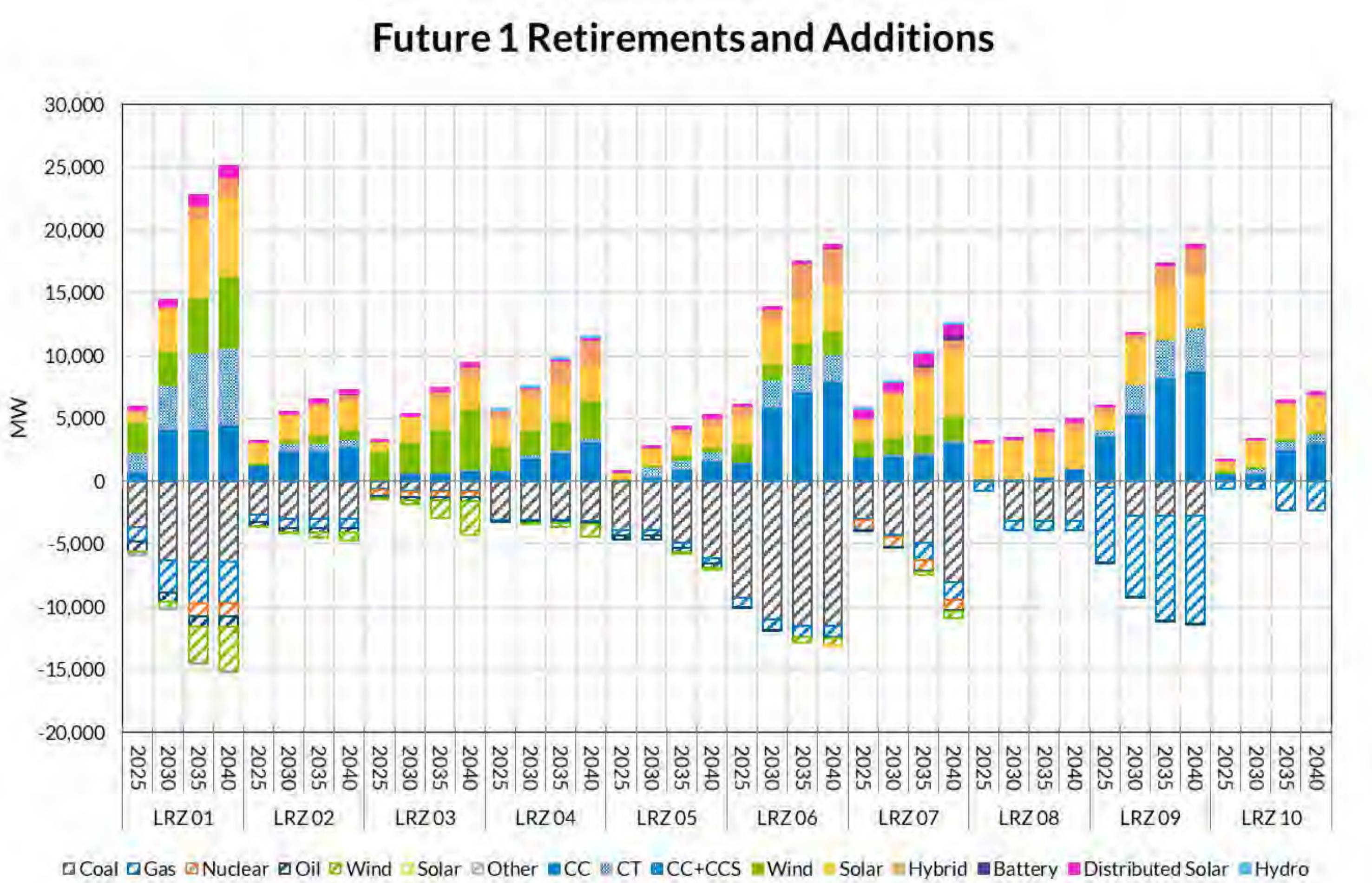


Figure 45: Future 1 Resource Additions per Milestone Year (Cumulative)

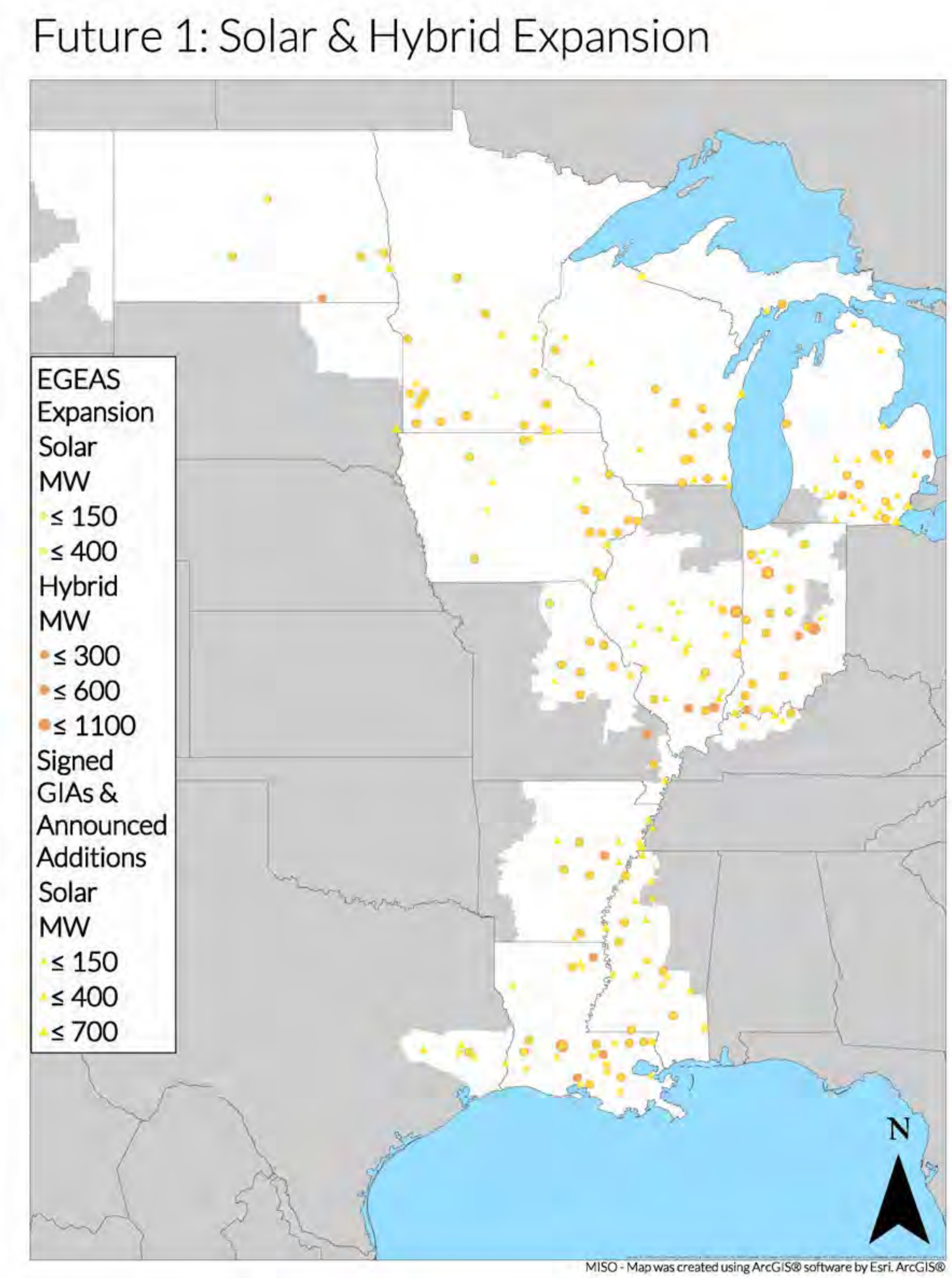


Figure 46: MISO Future 1 Solar and Hybrid Siting

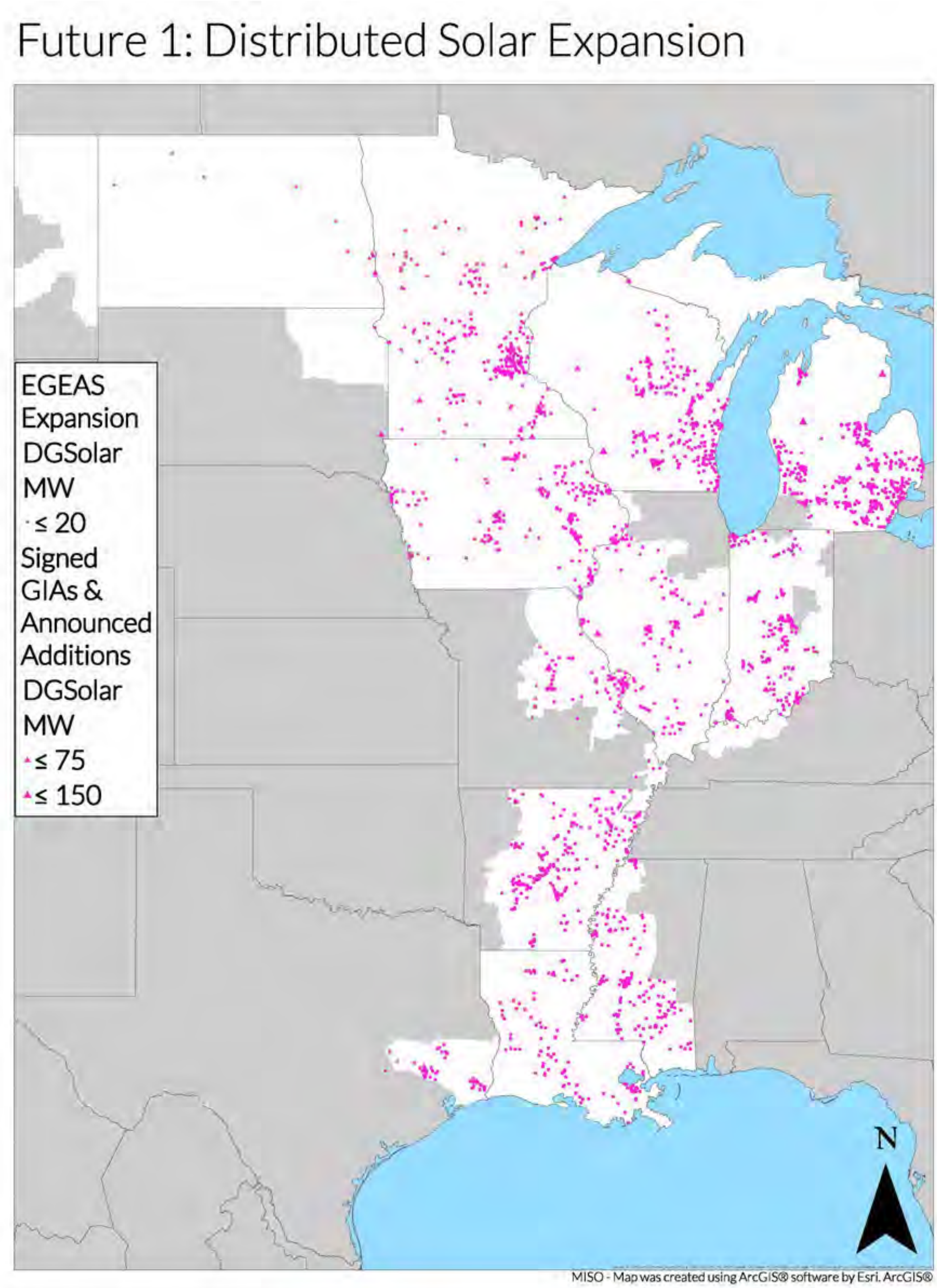


Figure 47: MISO Future 1 Distributed Solar Siting

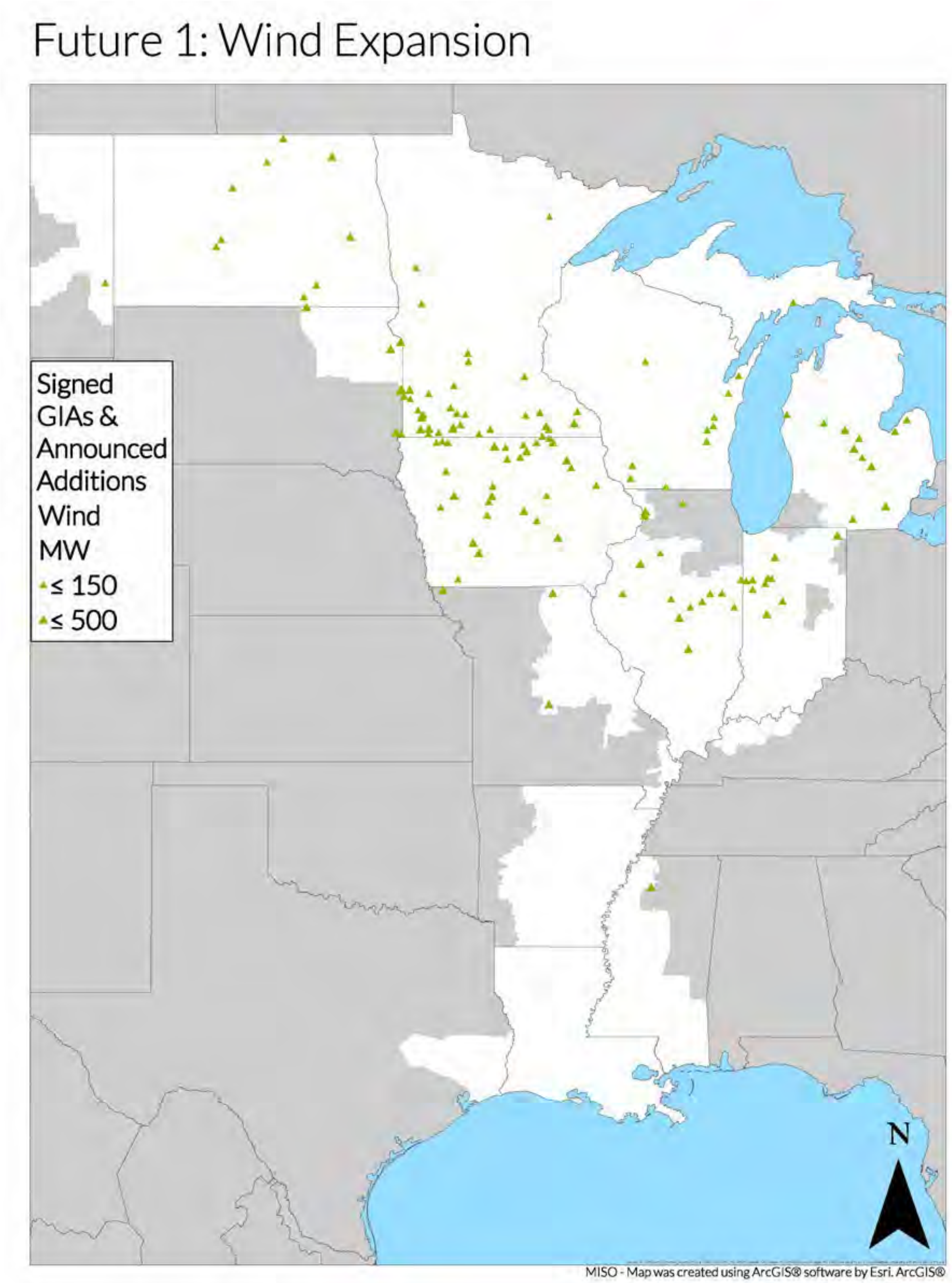


Figure 48: MISO Future 1 Wind Siting

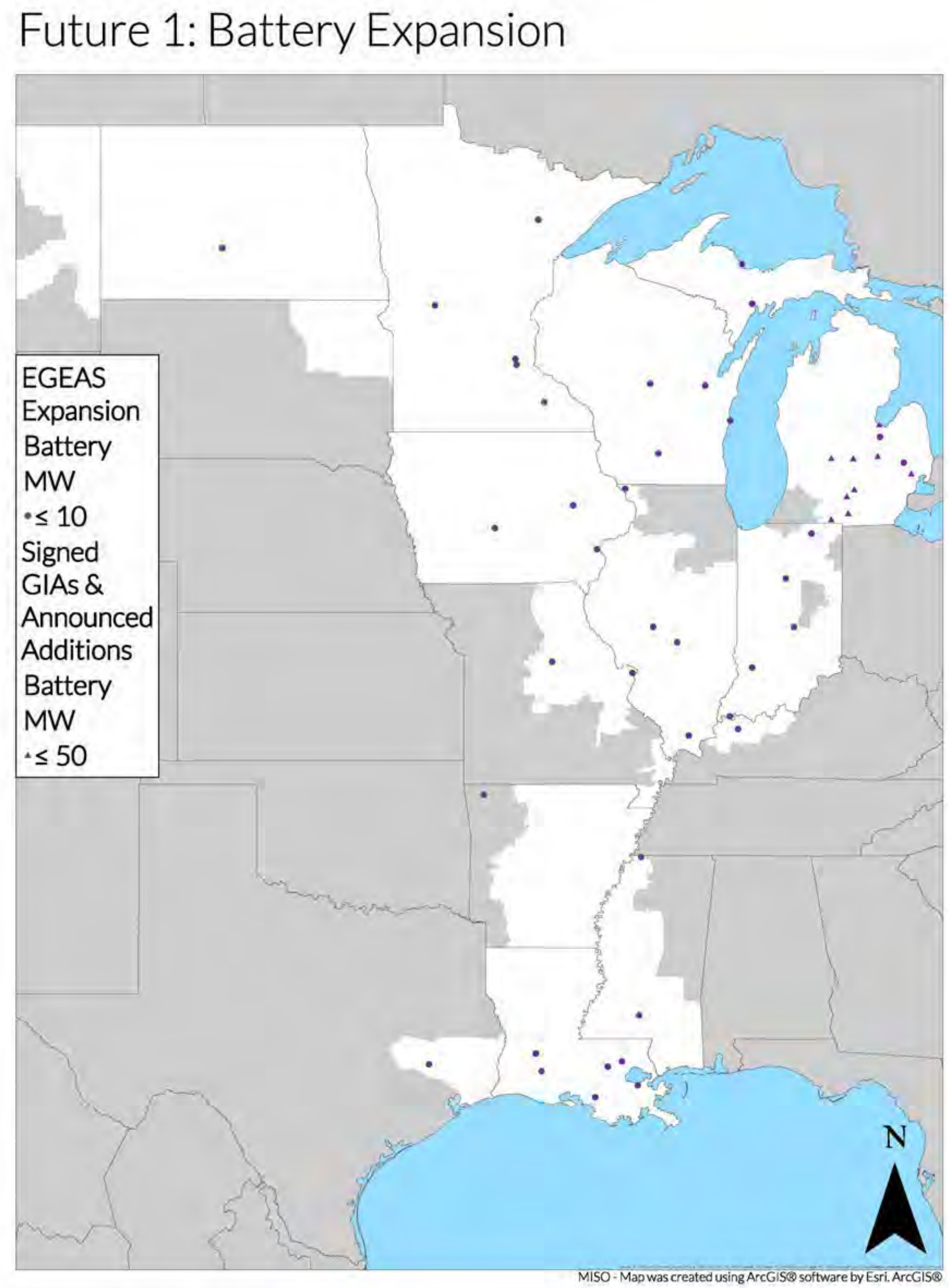


Figure 49: MISO Future 1 Battery Siting

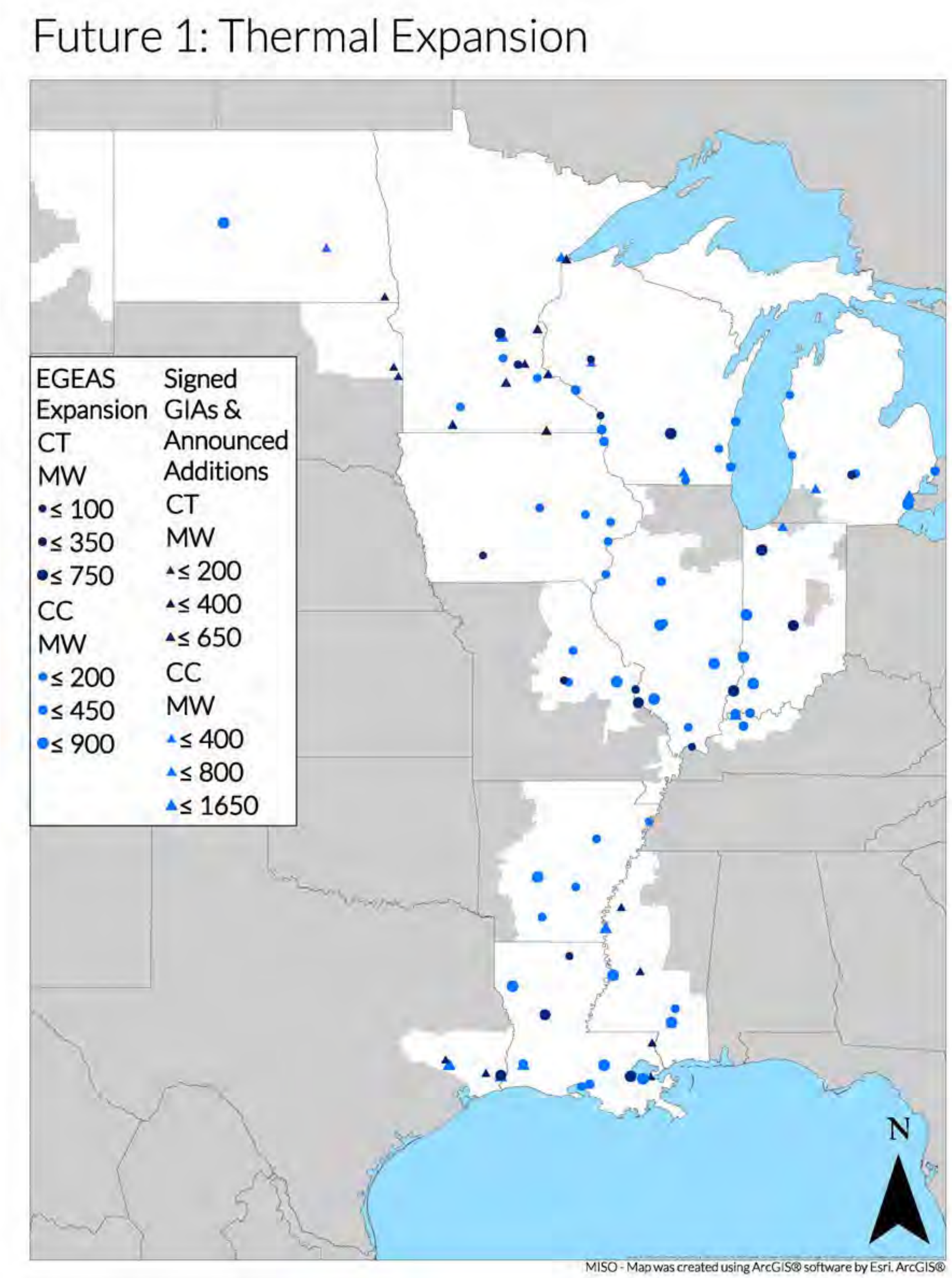


Figure 50: MISO Future 1 Thermal Siting

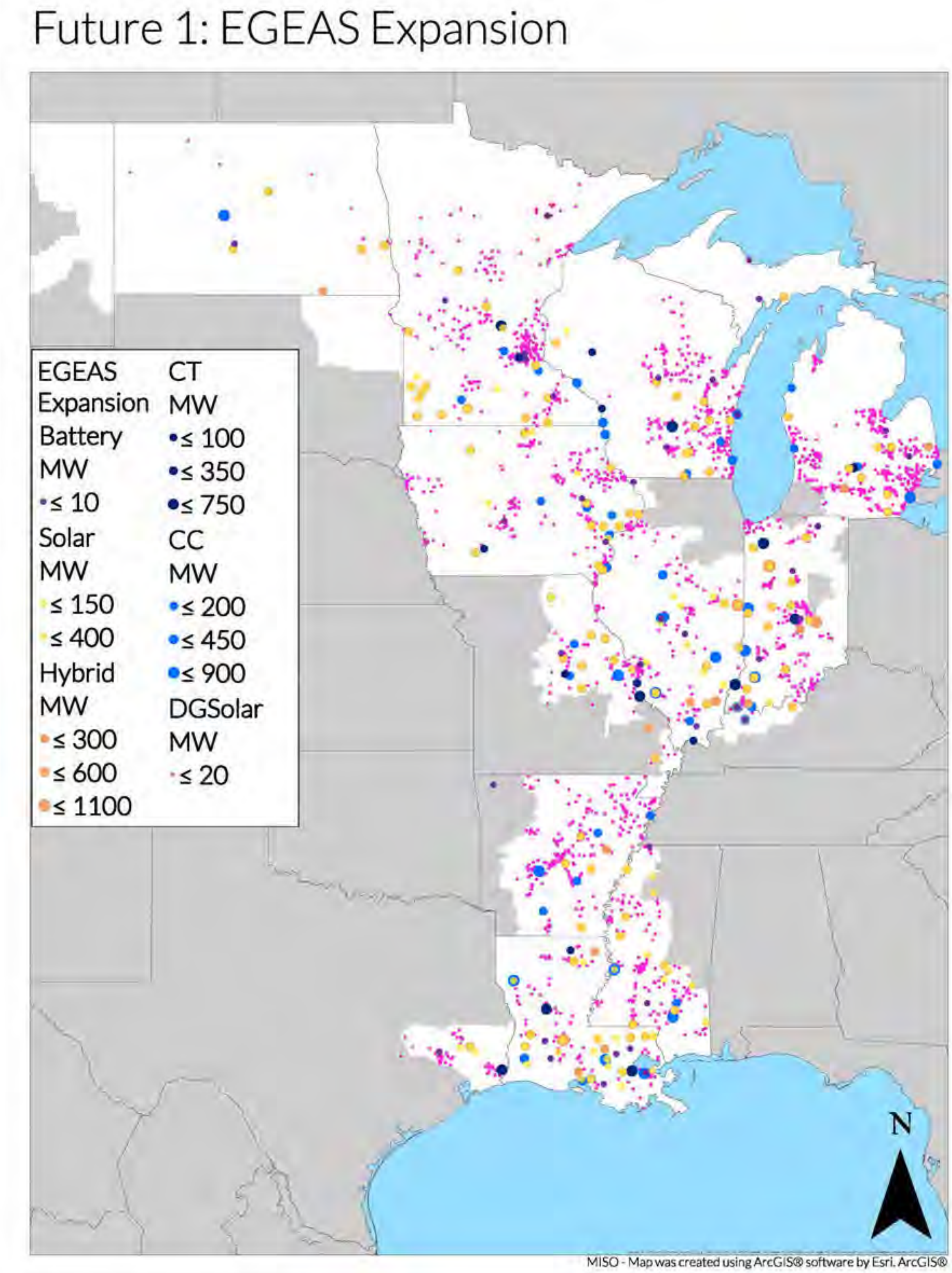


Figure 51: MISO Future 1 Complete EGEAS Expansion Siting

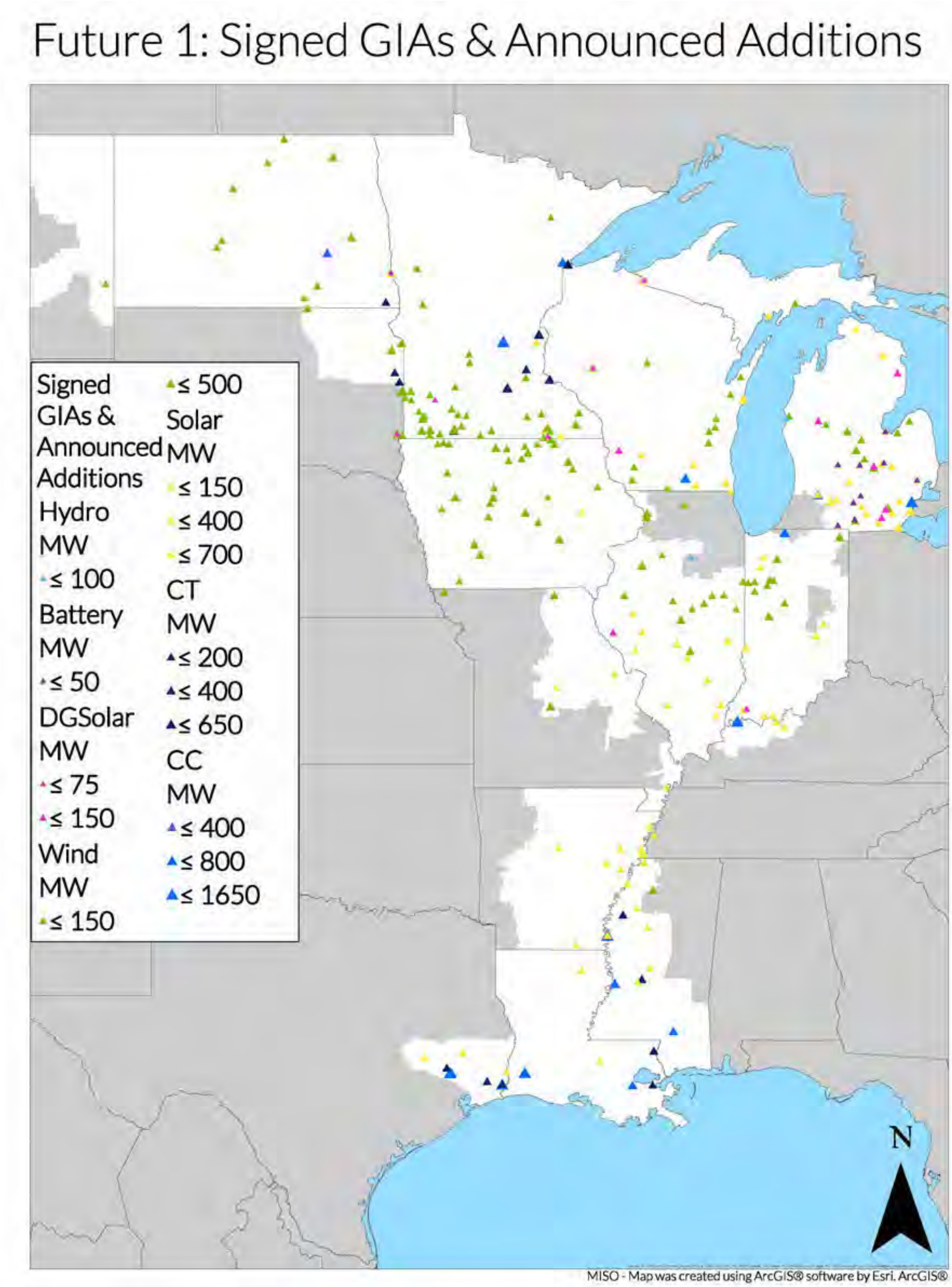


Figure 52: MISO Future 1 Non-EGEAS Expansion Siting

Future 1: Total Expansion

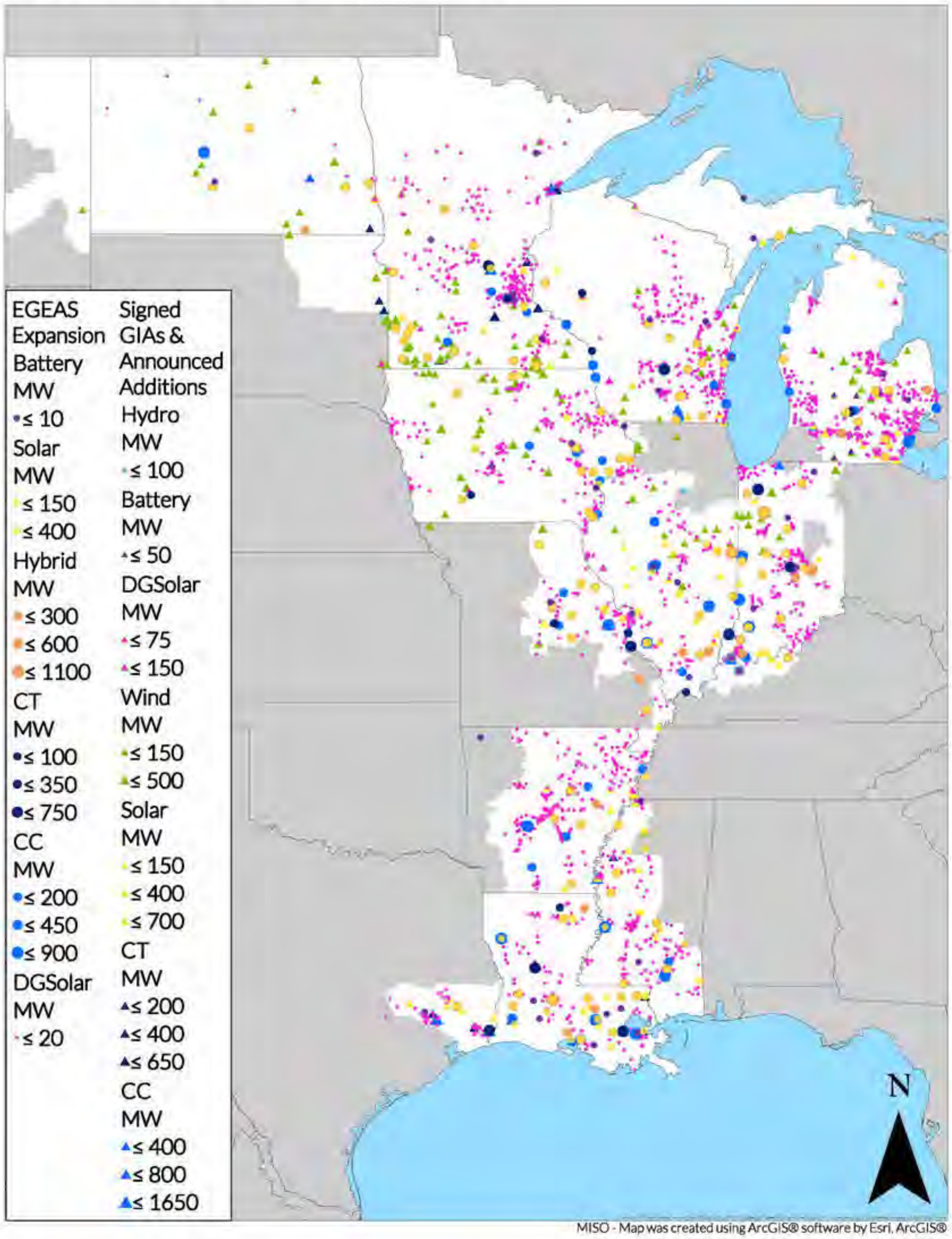


Figure 53: MISO Future 1 Non-EGEAS and EGEAS Expansion Siting

Future 1 Resource Additions (MW) - *Cumulative*												
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	850	1,453	0	2,402	771	198	0	283	0	5,957
	2030	4,171	3,520	0	2,669	3,384	198	0	499	0	14,442
	2035	4,171	6,088	0	4,379	6,225	1,129	0	772	0	22,764
	2039	4,560	6,088	0	5,734	6,225	1,547	36	942	0	25,133
LRZ 2	**2025**	1,268	0	0	240	1,585	0	0	38	0	3,131
	2030	2,432	572	0	270	2,099	0	0	122	0	5,495
	2035	2,484	572	0	636	2,304	242	0	246	0	6,484
	2039	2,795	572	0	846	2,304	422	30	311	0	7,280
LRZ 3	**2025**	150	0	0	2,198	875	0	0	33	0	3,256
	2030	608	92	0	2,424	2,103	0	0	104	0	5,331
	2035	608	92	0	3,510	2,522	475	0	210	0	7,417
	2039	881	92	0	4,783	2,522	838	15	265	0	9,396
LRZ 4	**2025**	900	0	0	1,966	2,152	628	0	52	10	5,709
	2030	1,868	240	0	1,986	2,693	628	0	80	10	7,504
	2035	2,285	240	0	2,345	2,871	1,839	0	120	10	9,710
	2039	3,231	240	0	2,979	2,871	1,971	15	141	10	11,458
LRZ 5	**2025**	64	0	0	200	500	0	0	25	0	789
	2030	382	747	0	200	1,381	0	0	80	0	2,790
	2035	979	747	0	369	1,755	322	0	162	0	4,333
	2039	1,596	747	0	369	1,768	560	10	205	0	5,254
LRZ 6	**2025**	1,594	0	0	1,325	2,282	853	0	69	0	6,123
	2030	5,956	2,136	0	1,325	3,466	853	0	103	0	13,839
	2035	7,189	2,136	0	1,702	3,685	2,626	0	153	0	17,491
	2039	7,989	2,136	0	1,907	3,685	2,899	30	179	0	18,825
LRZ 7	**2025**	1,954	0	0	1,322	1,550	189	0	749	72	5,835
	2030	2,051	153	0	1,322	3,421	189	0	781	72	7,988
	2035	2,116	153	0	1,551	4,715	638	200	829	72	10,274
	2039	3,156	153	0	1,887	5,315	755	412	854	72	12,604
LRZ 8	**2025**	250	0	0	0	2,688	155	0	26	0	3,119
	2030	250	0	0	0	2,985	155	0	83	0	3,473
	2035	384	0	0	0	3,059	536	0	168	0	4,147
	2039	1,038	0	0	0	3,059	628	5	212	0	4,943
LRZ 9	**2025**	3,601	493	0	0	1,465	378	0	28	0	5,965
	2030	5,439	2,328	0	0	3,540	378	0	91	0	11,776
	2035	8,287	3,020	0	0	4,238	1,640	0	184	0	17,369
	2039	8,833	3,366	0	0	4,238	2,113	37	232	0	18,819
LRZ 10	**2025**	672	0	0	200	730	0	0	16	0	1,619
	2030	672	350	0	200	2,070	0	0	52	0	3,345
	2035	2,531	700	0	200	2,709	153	0	106	0	6,399
	2039	3,046	700	0	200	2,709	267	10	134	0	7,066
MISO Total	**2025**	11,303	1,946	0	9,853	14,600	2,400	0	1,320	82	41,504
	2030	23,829	10,138	0	10,396	27,144	2,400	0	1,995	82	75,984
	2035	31,035	13,748	0	14,691	34,082	9,600	200	2,950	82	106,388
	2039	37,126	14,094	0	18,704	34,696	12,000	600	3,475	82	120,777

Table 7: MISO Future 1 Resource Additions by LRZ and Footprint

Future 1 Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2025**	3,619	1,214	0	698	240	0	36	5,807
	2030	6,303	2,567	0	698	519	0	36	10,123
	2035	6,413	3,281	1,092	771	2,946	0	36	14,539
	2039	6,413	3,281	1,092	771	3,572	0	36	15,165
LRZ 2	**2025**	2,650	599	0	351	11	0	0	3,611
	2030	2,981	736	0	351	41	0	0	4,109
	2035	2,981	741	0	351	427	0	0	4,500
	2039	2,981	741	0	351	617	0	0	4,690
LRZ 3	**2025**	596	92	448	196	122	0	0	1,454
	2030	757	92	448	196	348	0	0	1,841
	2035	757	92	448	196	1,434	0	0	2,927
	2039	757	92	448	275	2,707	0	0	4,279
LRZ 4	**2025**	3,056	134	0	90	0	0	0	3,281
	2030	3,056	134	0	117	20	0	0	3,327
	2035	3,056	134	0	117	379	0	0	3,686
	2039	3,118	134	0	117	1,013	0	0	4,382
LRZ 5	**2025**	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	384	0	345	169	0	0	5,796
	2039	6,132	384	0	345	169	0	0	7,029
LRZ 6	**2025**	9,268	788	0	50	0	0	0	10,106
	2030	11,002	853	0	50	0	0	0	11,905
	2035	11,537	853	0	50	377	0	0	12,816
	2039	11,537	853	0	71	582	21	0	13,064
LRZ 7	**2025**	2,956	155	819	45	0	0	0	3,974
	2030	4,223	161	819	59	0	0	0	5,261
	2035	4,878	1,444	819	59	230	0	0	7,429
	2039	8,013	1,444	819	59	565	0	0	10,899
LRZ 8	**2025**	0	788	0	0	0	0	0	788
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	788	0	0	0	0	0	3,918
	2039	3,130	788	0	0	0	0	0	3,918
LRZ 9	**2025**	515	5,919	0	7	0	0	0	6,441
	2030	2,746	6,438	0	7	0	0	0	9,191
	2035	2,746	8,361	0	7	0	0	0	11,114
	2039	2,746	8,591	0	7	0	0	0	11,344
LRZ 10	**2025**	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	2,319	0	0	0	0	0	2,319
	2039	0	2,319	0	0	0	0	0	2,319
MISO Total	**2025**	26,553	10,648	1,267	1,782	373	0	36	40,658
	2030	38,091	12,727	1,267	1,822	928	0	36	54,871
	2035	40,397	18,397	2,359	1,896	5,960	0	36	69,044
	2039	44,827	18,627	2,359	1,996	9,223	21	36	77,089

Table 8: MISO Future 1 Resource Retirements by LRZ and Footprint

MISO – Future 2

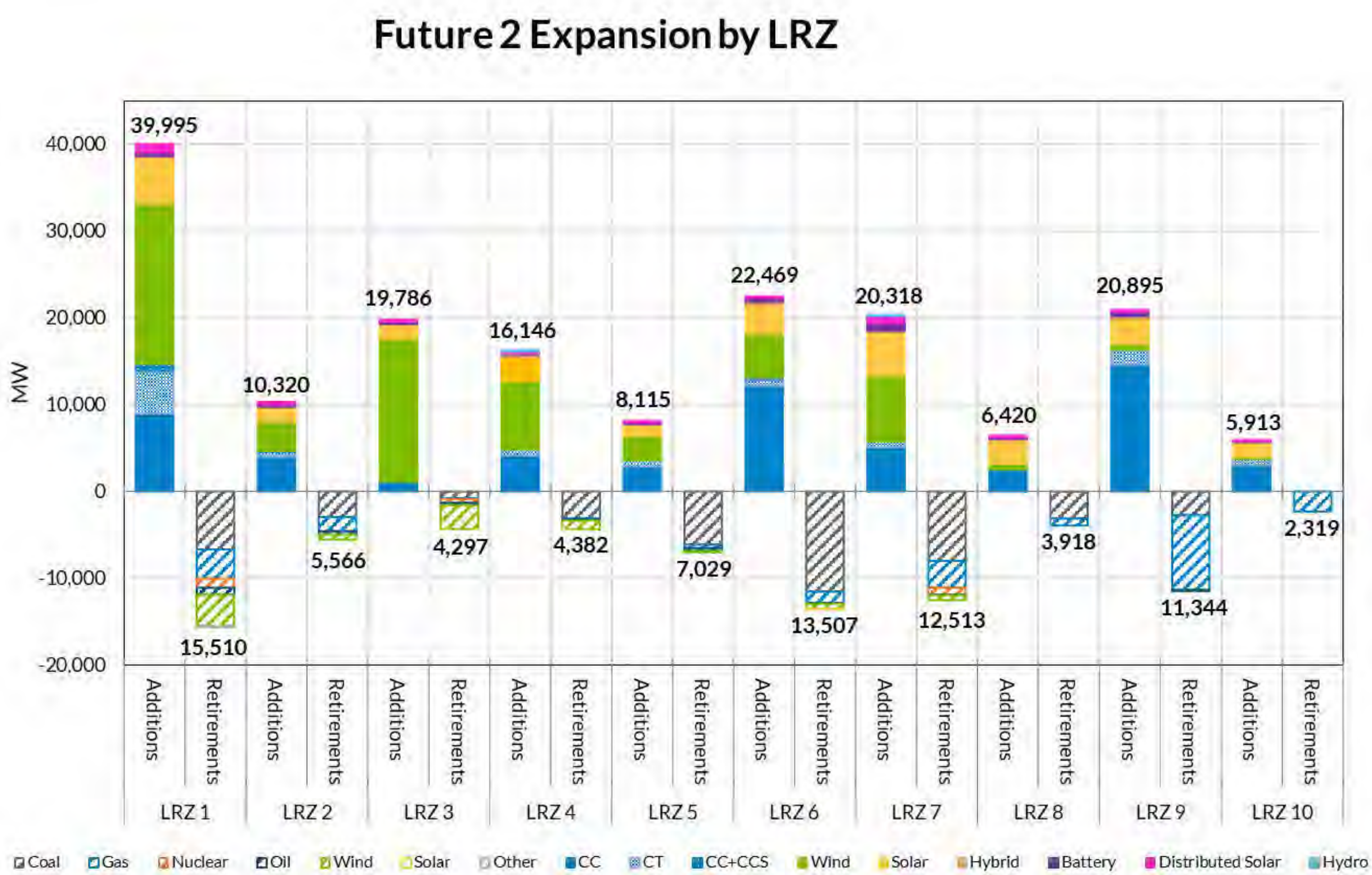


Figure 54: MISO Future 2 Resource Retirement and Addition Summary

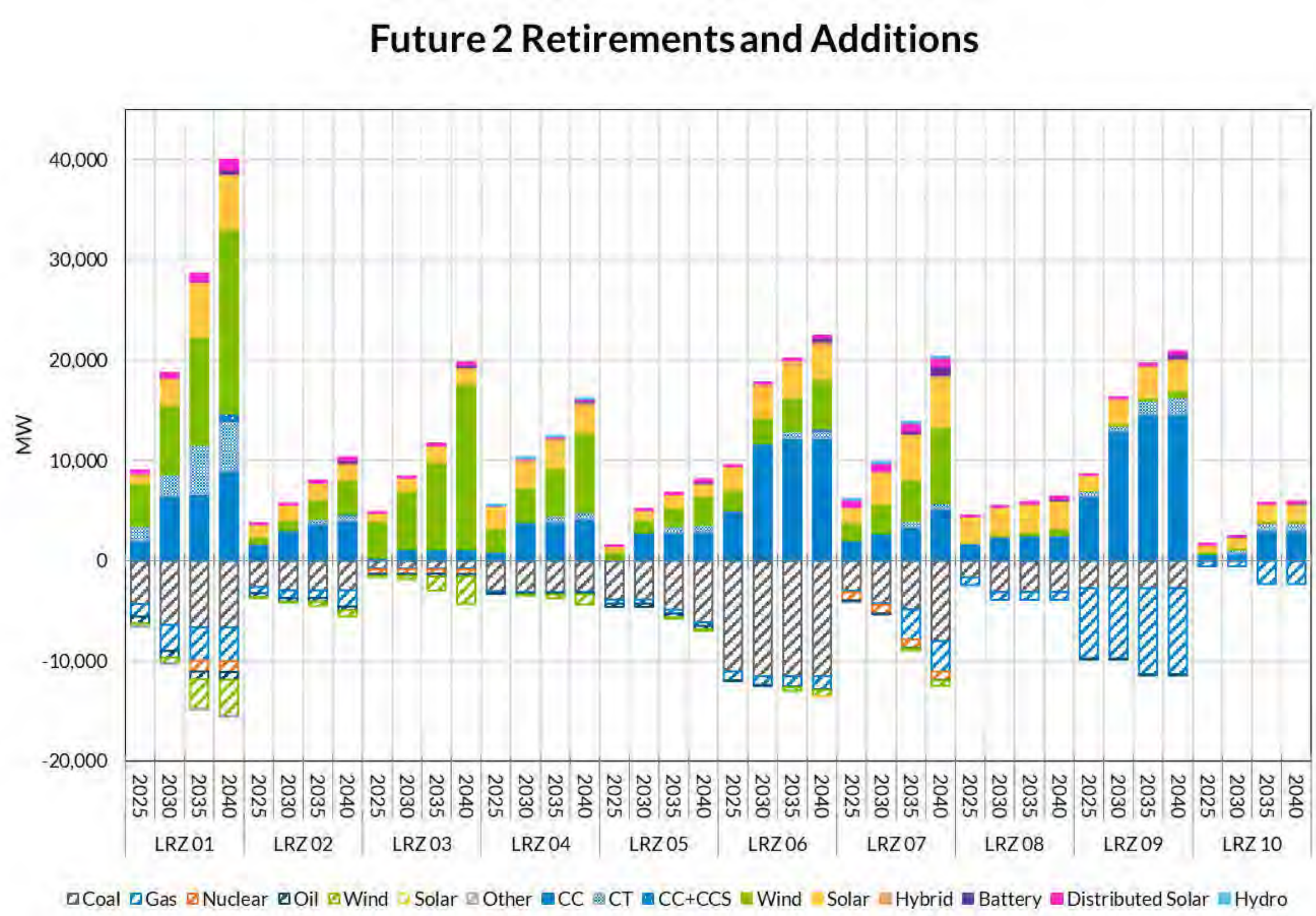


Figure 55: MISO Future 2 Resource Additions per Milestone Year (Cumulative)

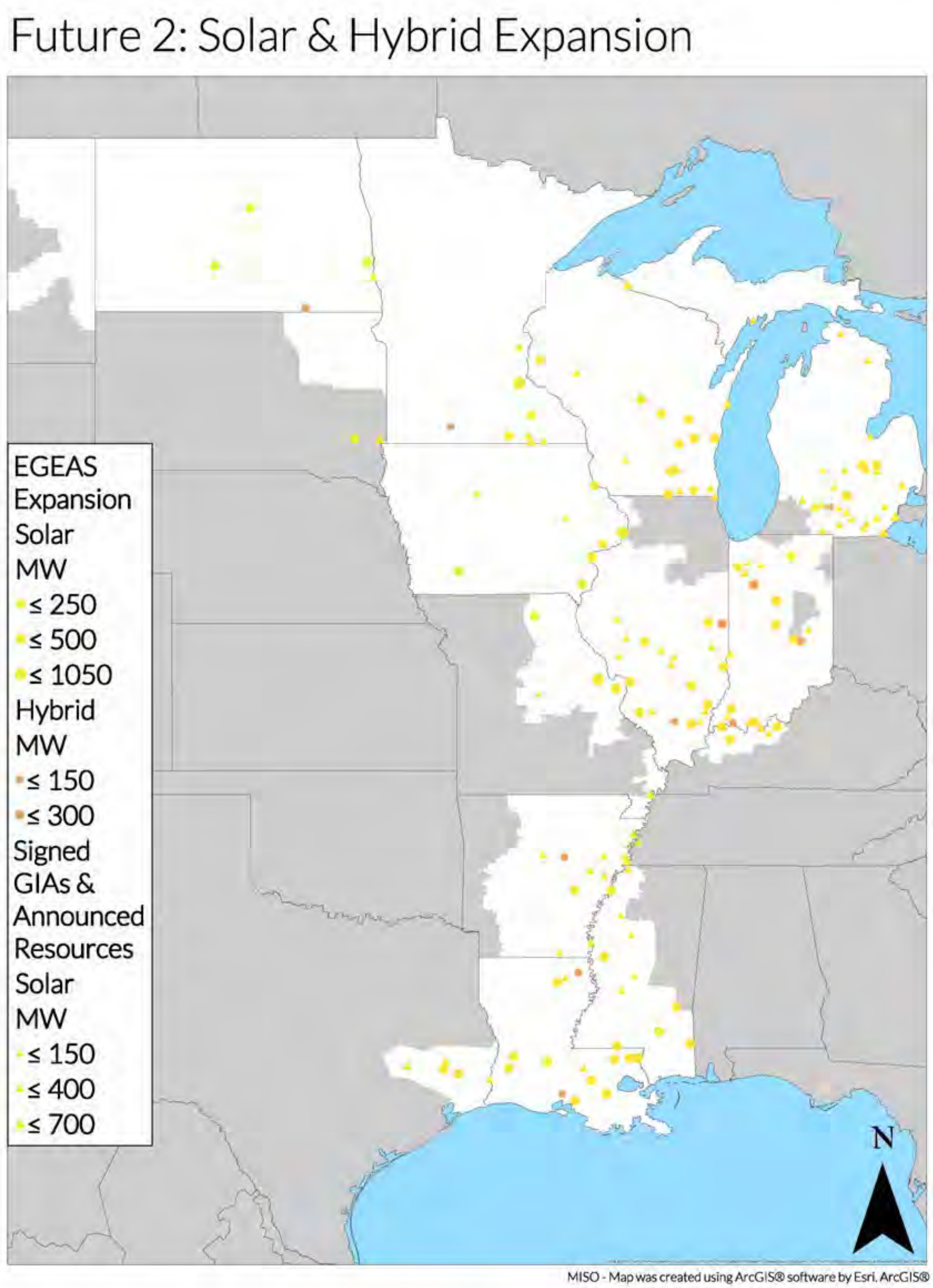


Figure 56: MISO Future 2 Solar and Hybrid Siting

Future 2: Distributed Solar Expansion

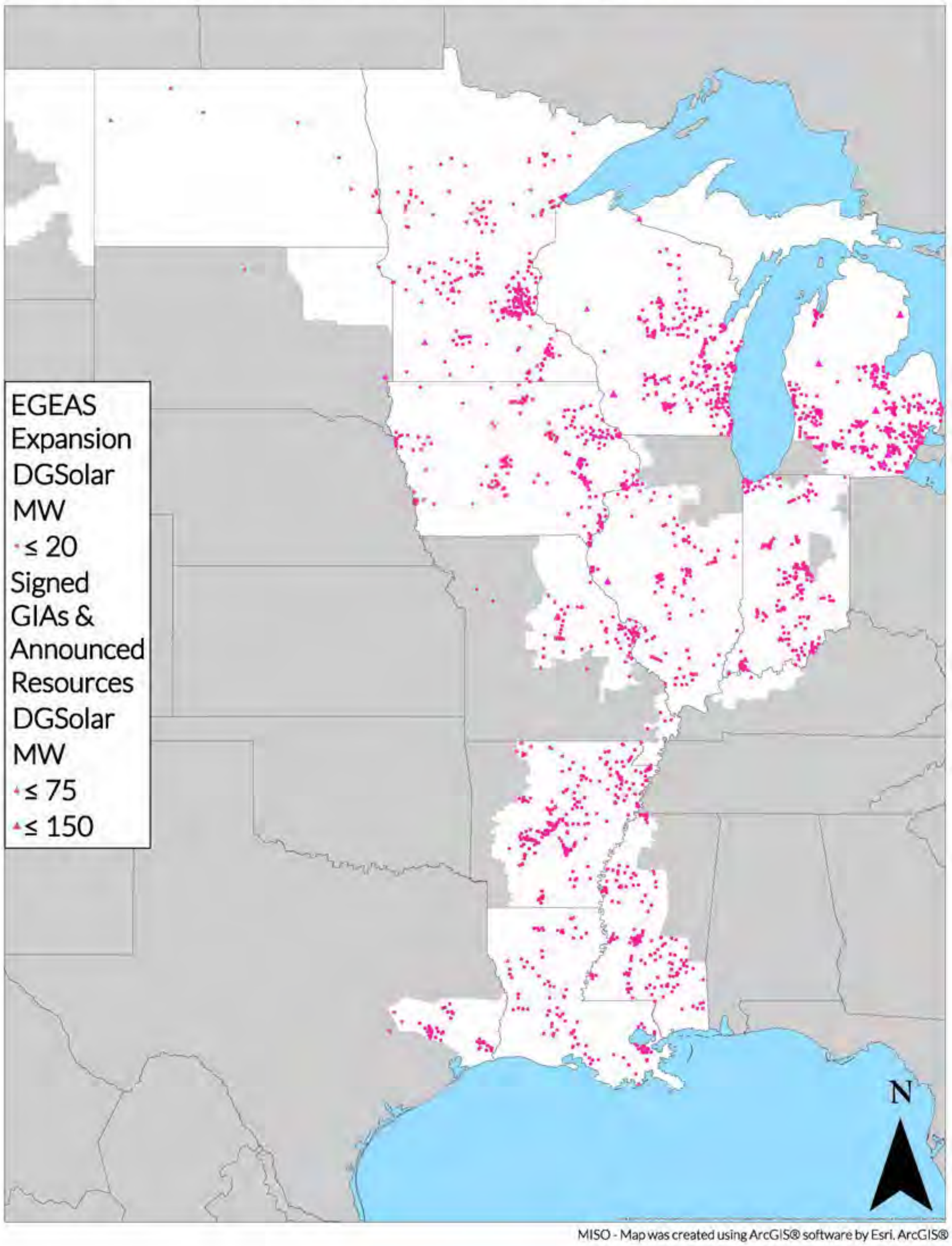


Figure 57: MISO Future 2 Distributed Solar Siting

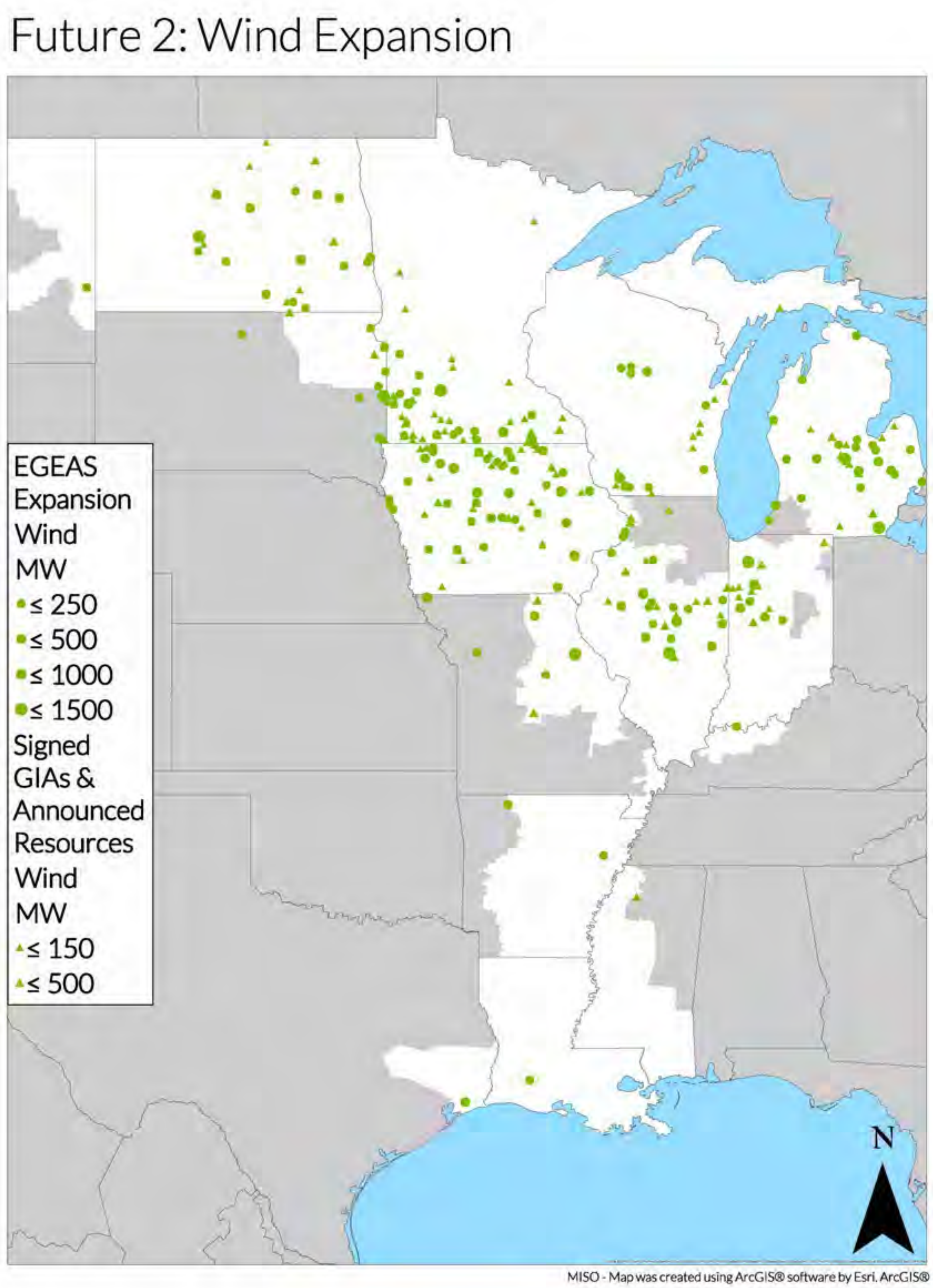


Figure 58: MISO Future 2 Wind Siting

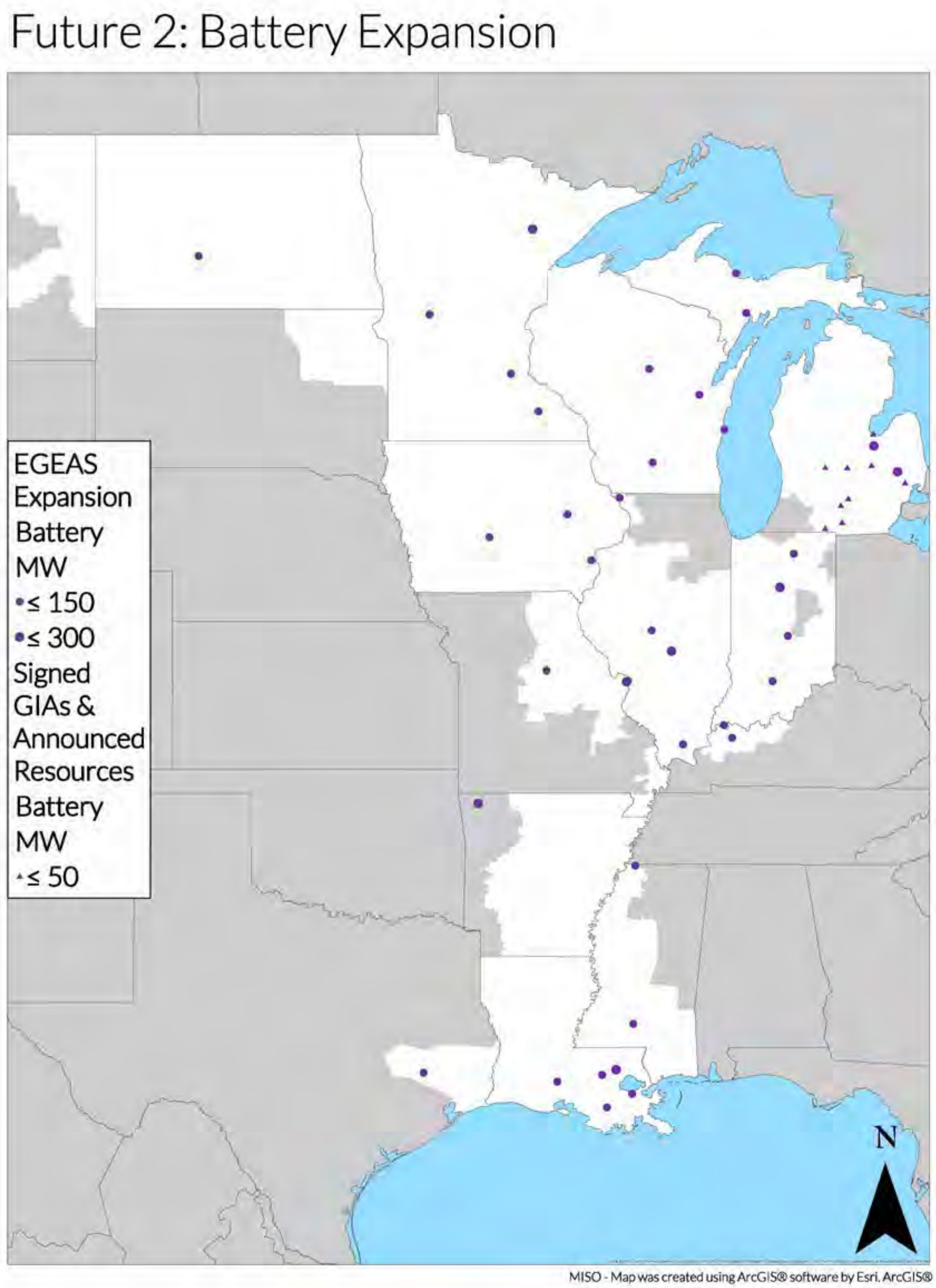


Figure 59: MISO Future 2 Battery Siting

Future 2: Thermal Expansion

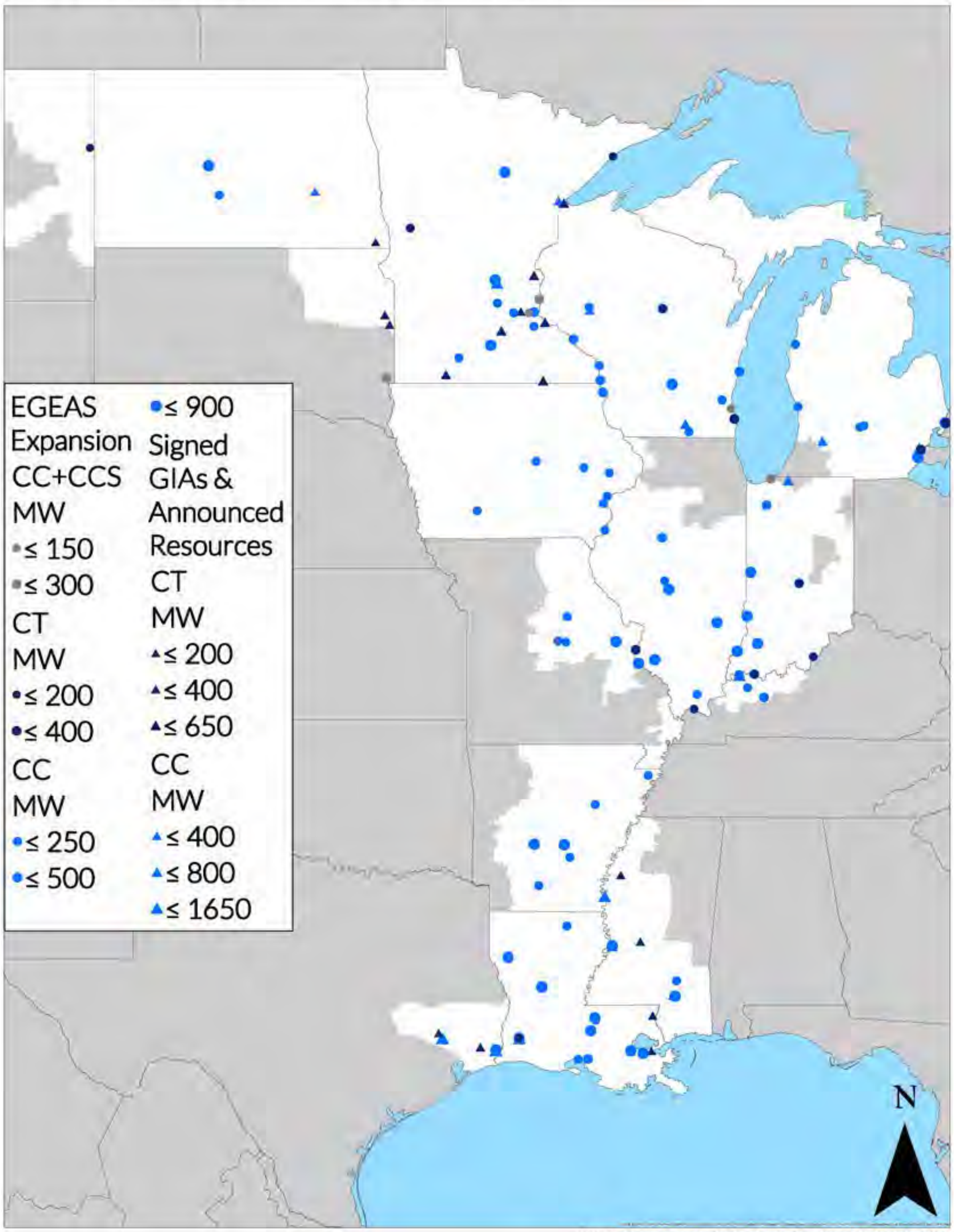


Figure 60: MISO Future 2 Thermal Siting

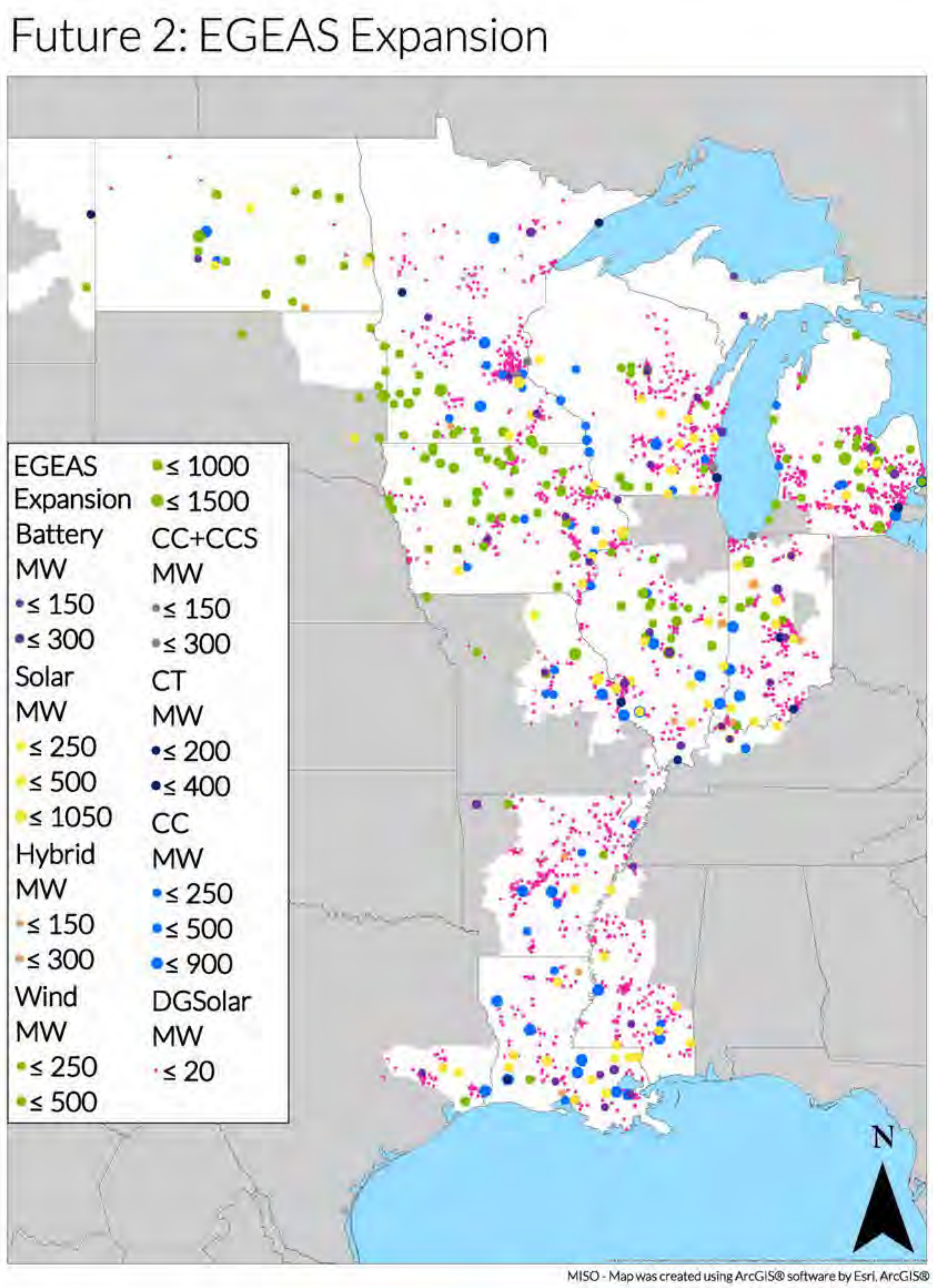


Figure 61: MISO Future 2 Complete EGEAS Expansion Siting

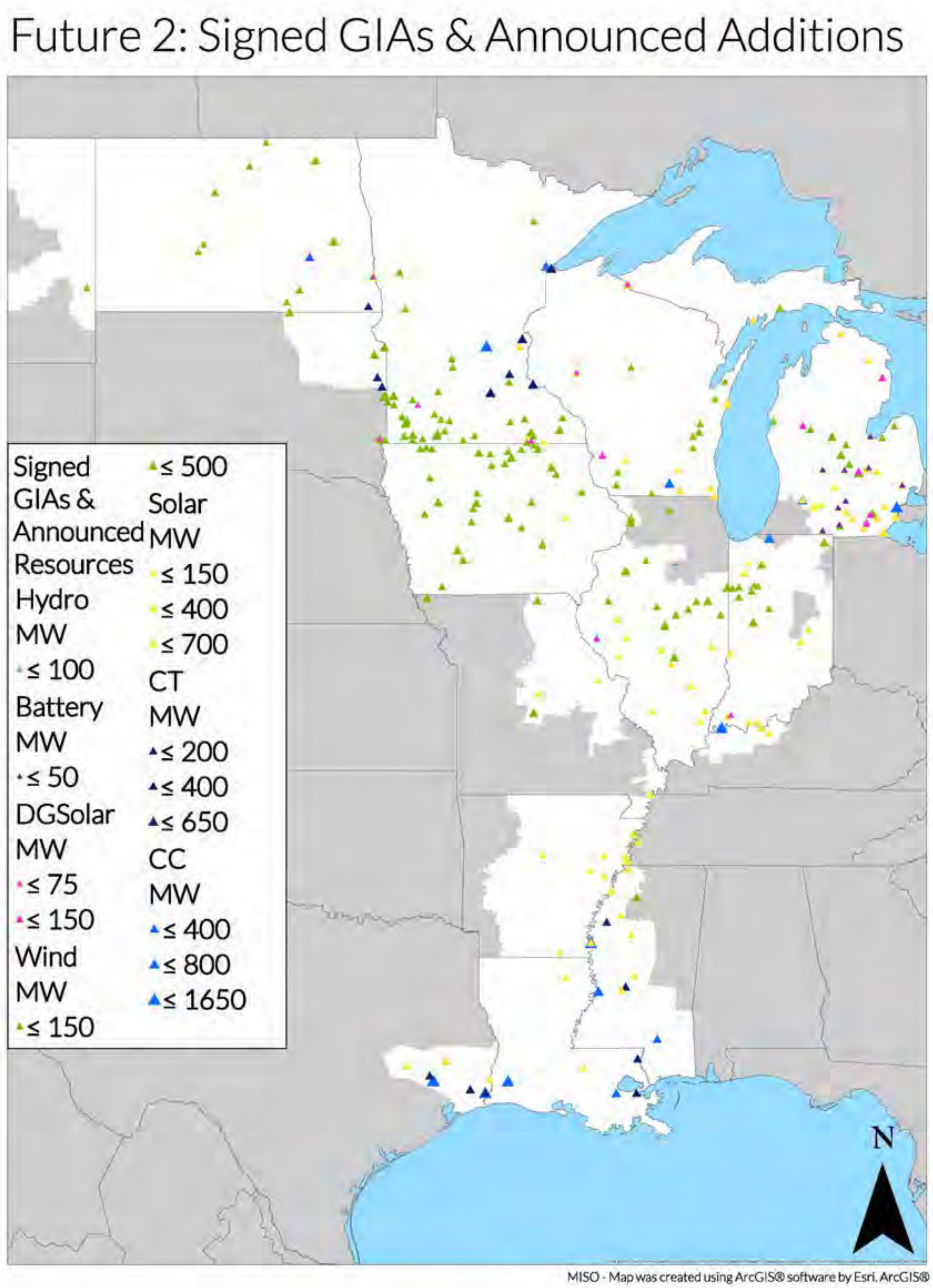


Figure 62: MISO Future 2 Non-EGEAS Expansion Siting

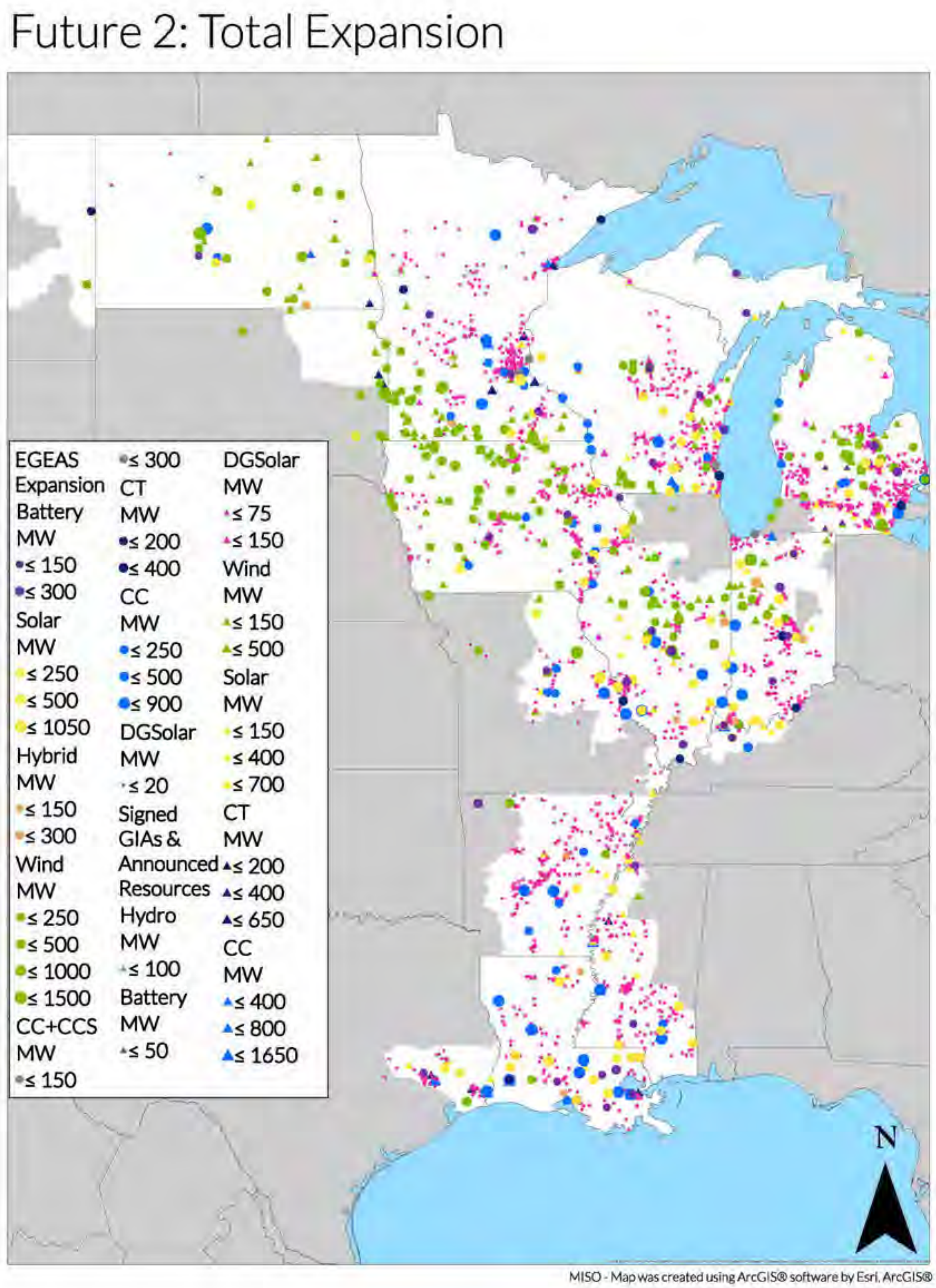


Figure 63: MISO Future 2 Non-EGEAS and EGEAS Expansion Siting

Future 2 Resource Additions (MW) - *Cumulative*											
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	2,020	1,453	0	4,219	1,032	0	0	283	0	9,007
	2030	6,491	2,095	0	7,006	2,550	99	0	499	0	18,740
	2035	6,641	4,928	0	10,797	5,380	99	33	772	0	28,650
	2039	8,986	4,928	774	18,435	5,380	99	451	942	0	39,995
LRZ 2	**2025**	1,686	0	0	657	1,270	0	0	38	0	3,650
	2030	3,056	0	0	1,041	1,471	0	0	122	0	5,689
	2035	3,673	511	0	1,903	1,680	0	0	246	0	8,012
	2039	4,004	511	138	3,408	1,680	0	268	311	0	10,320
LRZ 3	**2025**	311	0	0	3,630	821	0	0	34	0	4,796
	2030	1,134	0	0	5,850	1,295	0	0	109	0	8,388
	2035	1,134	0	0	8,682	1,666	0	0	220	0	11,701
	2039	1,134	0	0	16,484	1,666	0	224	277	0	19,786
LRZ 4	**2025**	900	0	0	2,328	2,225	0	0	51	10	5,514
	2030	3,850	0	0	3,424	2,557	314	0	75	10	10,230
	2035	3,850	668	0	4,671	2,771	314	0	111	10	12,396
	2039	4,184	668	0	7,862	2,771	314	207	129	10	16,146
LRZ 5	**2025**	64	0	0	881	498	0	0	25	0	1,468
	2030	2,783	0	0	1,358	901	0	0	80	0	5,122
	2035	2,783	660	0	1,905	1,273	0	0	162	0	6,783
	2039	2,909	660	0	2,879	1,287	0	174	205	0	8,115
LRZ 6	**2025**	5,009	0	0	2,002	2,410	0	0	69	0	9,490
	2030	11,699	0	0	2,552	3,027	426	0	103	0	17,807
	2035	12,209	699	0	3,384	3,309	426	0	153	0	20,180
	2039	12,209	699	289	4,935	3,309	426	423	179	0	22,469
LRZ 7	**2025**	2,051	0	0	1,758	1,537	0	0	749	72	6,166
	2030	2,718	0	0	2,937	3,211	94	0	781	72	9,813
	2035	3,378	601	0	4,106	4,498	94	267	829	72	13,845
	2039	5,133	601	0	7,576	5,098	94	889	854	72	20,318
LRZ 8	**2025**	1,734	0	0	93	2,578	0	0	26	0	4,431
	2030	2,400	0	0	222	2,681	77	0	83	0	5,464
	2035	2,522	0	0	334	2,750	77	0	168	0	5,851
	2039	2,522	0	0	686	2,750	77	172	212	0	6,420
LRZ 9	**2025**	6,457	493	0	86	1,512	0	0	28	0	8,577
	2030	12,965	493	0	207	2,360	189	0	91	0	16,305
	2035	14,597	1,381	0	310	3,031	189	0	184	0	19,692
	2039	14,597	1,727	0	638	3,031	189	481	232	0	20,895
LRZ 10	**2025**	672	0	0	200	718	0	0	16	0	1,606
	2030	731	350	0	200	1,091	0	0	52	0	2,425
	2035	3,046	700	0	200	1,723	0	0	106	0	5,776
	2039	3,046	700	0	200	1,723	0	109	134	0	5,913
MISO Total	**2025**	20,903	1,946	0	15,853	14,600	0	0	1,320	82	54,704
	2030	47,828	2,938	0	24,796	21,144	1,200	0	1,995	82	99,983
	2035	53,834	10,148	0	36,291	28,082	1,200	300	2,950	82	132,887
	2039	58,725	10,494	1,201	63,104	28,696	1,200	3,400	3,475	82	170,376

Table 9: MISO Future 2 Resource Additions by LRZ and Footprint

Future 2 Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2025**	4,324	1,255	0	698	240	0	36	6,553
	2030	6,413	2,584	0	698	519	0	36	10,250
	2035	6,676	3,281	1,092	771	2,946	0	36	14,802
	2039	6,676	3,332	1,092	803	3,572	0	36	15,510
LRZ 2	**2025**	2,650	2,650	0	351	11	0	0	5,663
	2030	2,981	741	0	351	41	0	0	4,114
	2035	2,981	741	0	351	427	0	0	4,500
	2039	2,981	1,617	0	351	617	0	0	5,566
LRZ 3	**2025**	757	92	448	196	122	0	0	1,615
	2030	757	92	448	196	348	0	0	1,841
	2035	757	92	448	275	1,434	0	0	3,006
	2039	776	92	448	275	2,707	0	0	4,297
LRZ 4	**2025**	3,056	134	0	117	0	0	0	3,307
	2030	3,118	134	0	117	20	0	0	3,389
	2035	3,118	134	0	117	379	0	0	3,748
	2039	3,118	134	0	117	1,013	0	0	4,382
LRZ 5	**2025**	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	384	0	345	169	0	0	5,796
	2039	6,132	384	0	345	169	0	0	7,029
LRZ 6	**2025**	11,068	853	0	50	0	0	0	11,970
	2030	11,537	853	0	50	0	0	0	12,439
	2035	11,537	1,008	0	71	377	0	0	12,992
	2039	11,537	1,296	0	71	582	21	0	13,507
LRZ 7	**2025**	2,991	161	819	59	0	0	0	4,029
	2030	4,258	168	819	59	0	0	0	5,303
	2035	4,878	2,973	819	59	230	0	0	8,958
	2039	8,013	3,059	819	59	565	0	0	12,513
LRZ 8	**2025**	1,647	788	0	0	0	0	0	2,435
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	788	0	0	0	0	0	3,918
	2039	3,130	788	0	0	0	0	0	3,918
LRZ 9	**2025**	2,746	7,013	0	7	0	0	0	9,766
	2030	2,746	7,013	0	7	0	0	0	9,766
	2035	2,746	8,591	0	7	0	0	0	11,344
	2039	2,746	8,591	0	7	0	0	0	11,344
LRZ 10	**2025**	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	2,319	0	0	0	0	0	2,319
	2039	0	2,319	0	0	0	0	0	2,319
MISO Total	**2025**	33,132	13,904	1,267	1,822	373	0	36	50,534
	2030	38,833	13,331	1,267	1,822	928	0	36	56,217
	2035	40,722	20,311	2,359	1,996	5,960	0	36	71,383
	2039	45,109	21,611	2,359	2,027	9,223	21	36	80,386

Table 10: MISO Future 2 Resource Retirements by LRZ and Footprint

MISO – Future 3

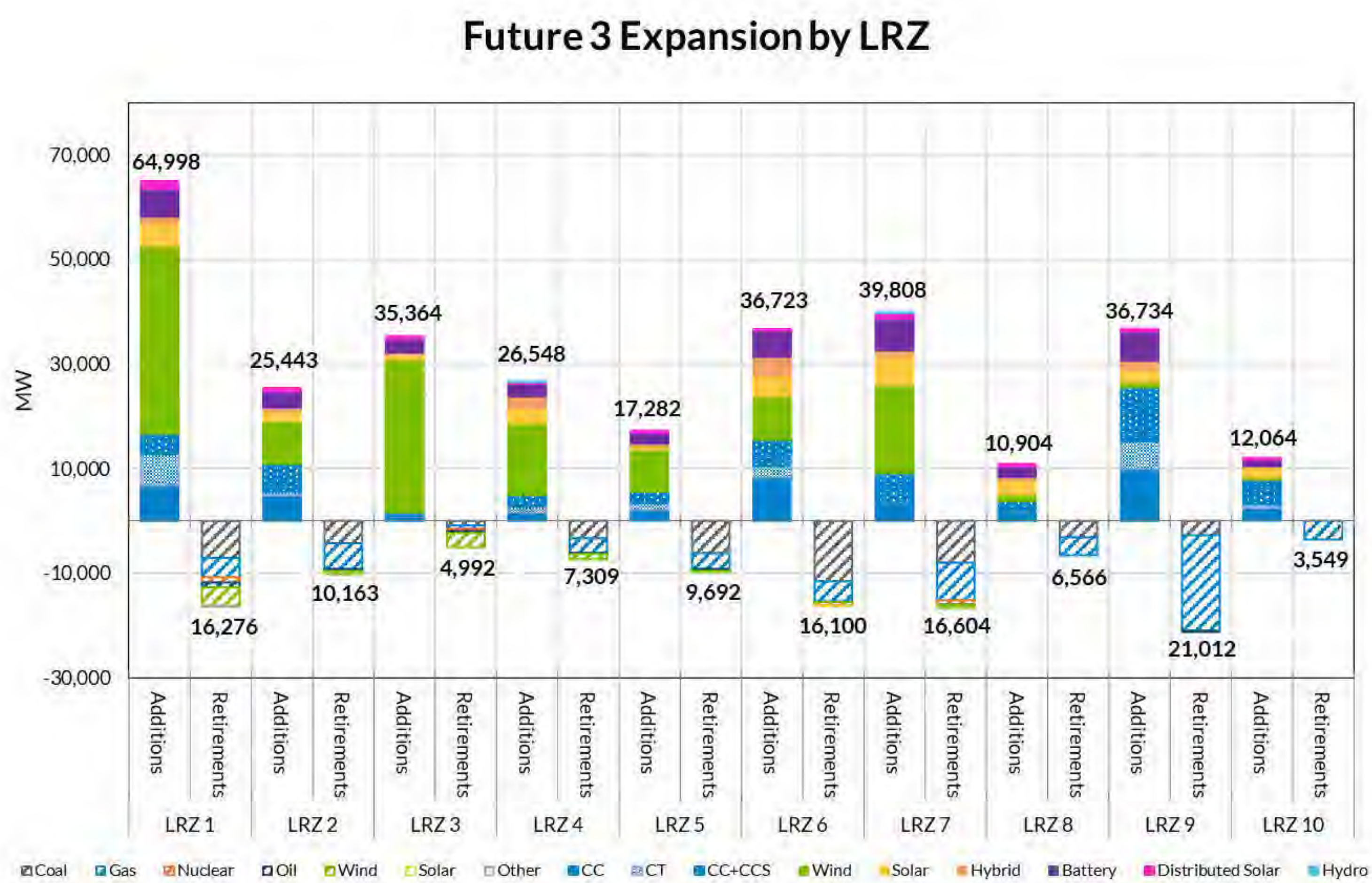


Figure 64: MISO Future 3 Resource Retirement and Addition Summary

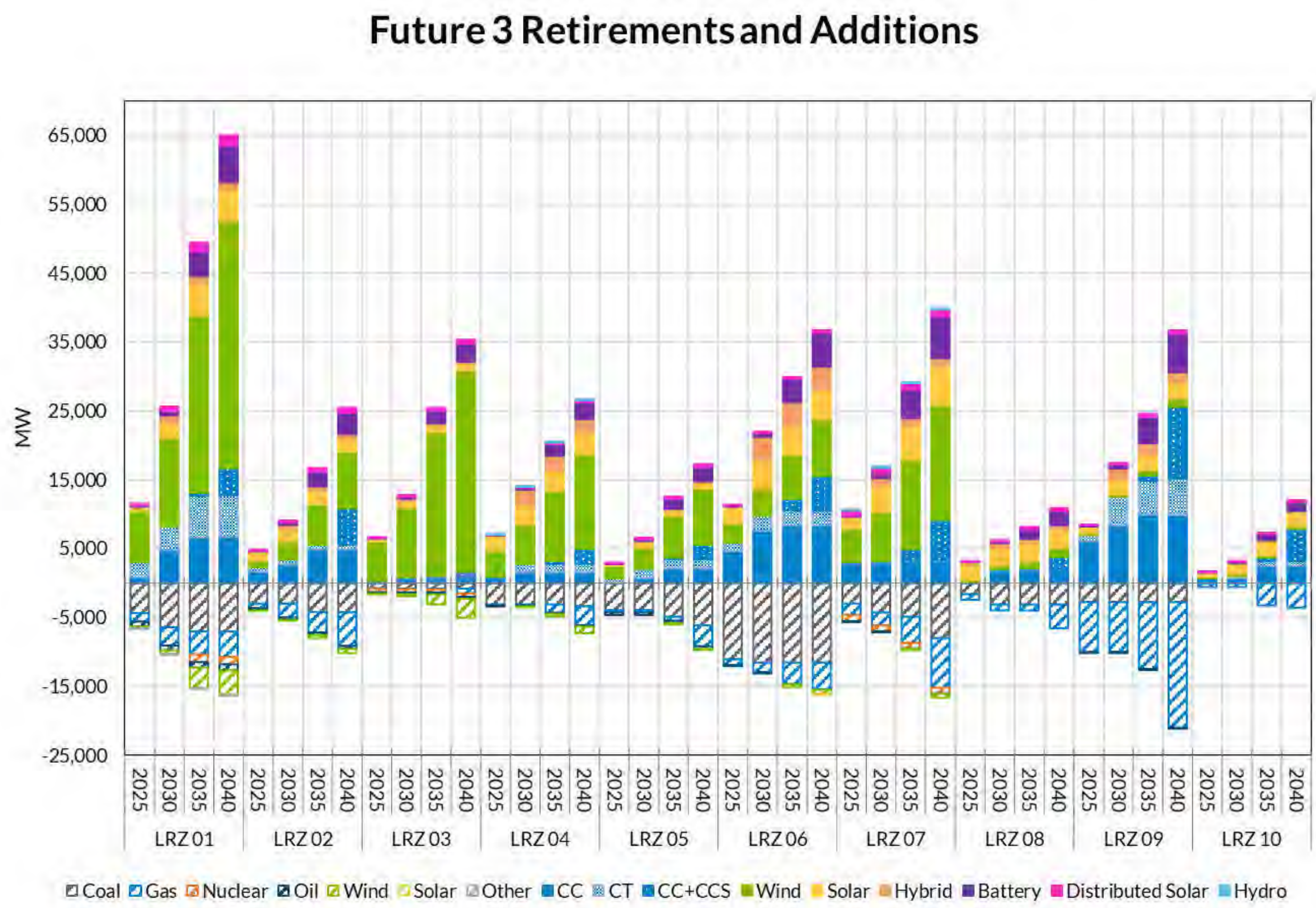


Figure 65: MISO Future 3 Resource Additions per Milestone Year (Cumulative)

Future 3: Solar & Hybrid Expansion

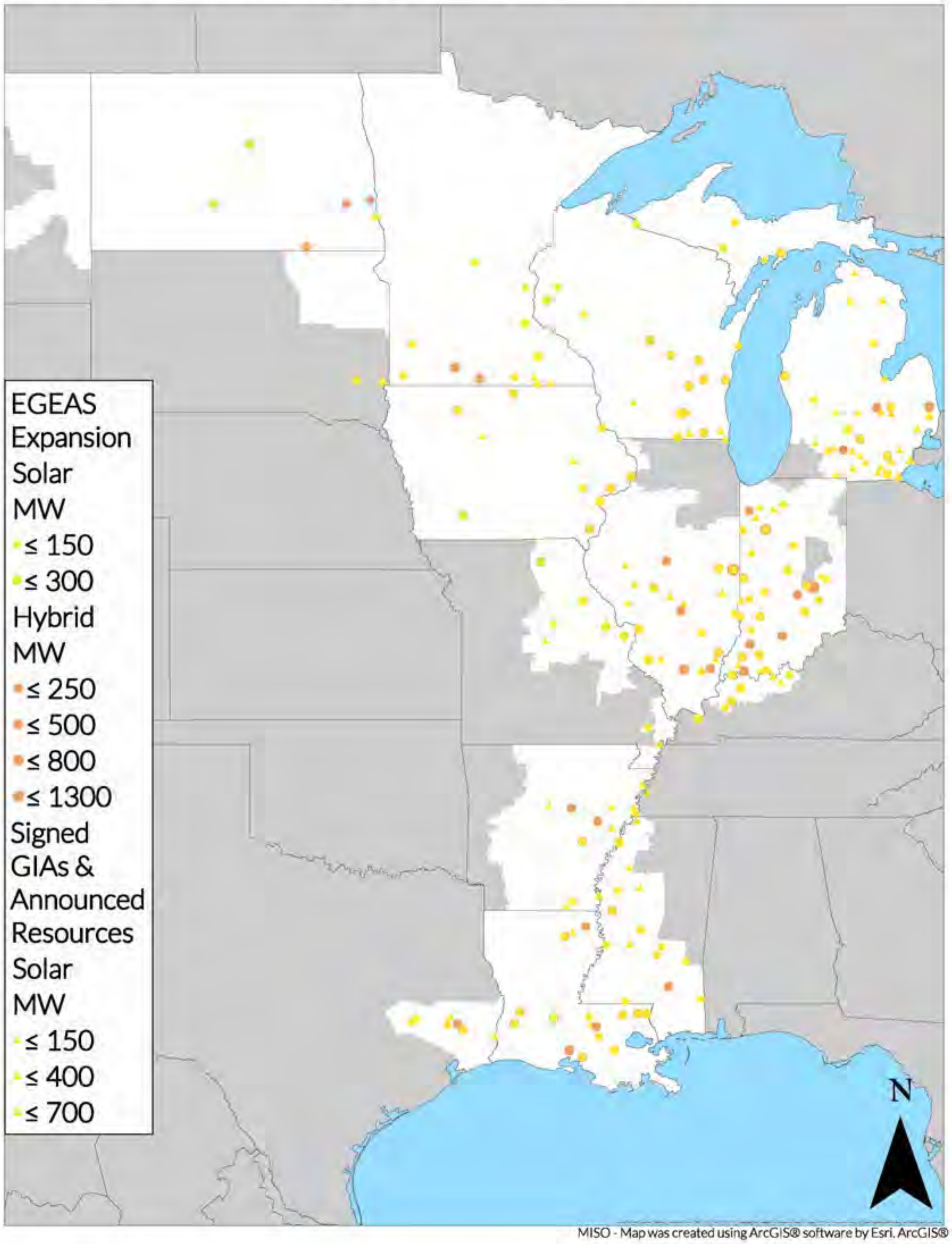


Figure 66: MISO Future 3 Solar and Hybrid Siting

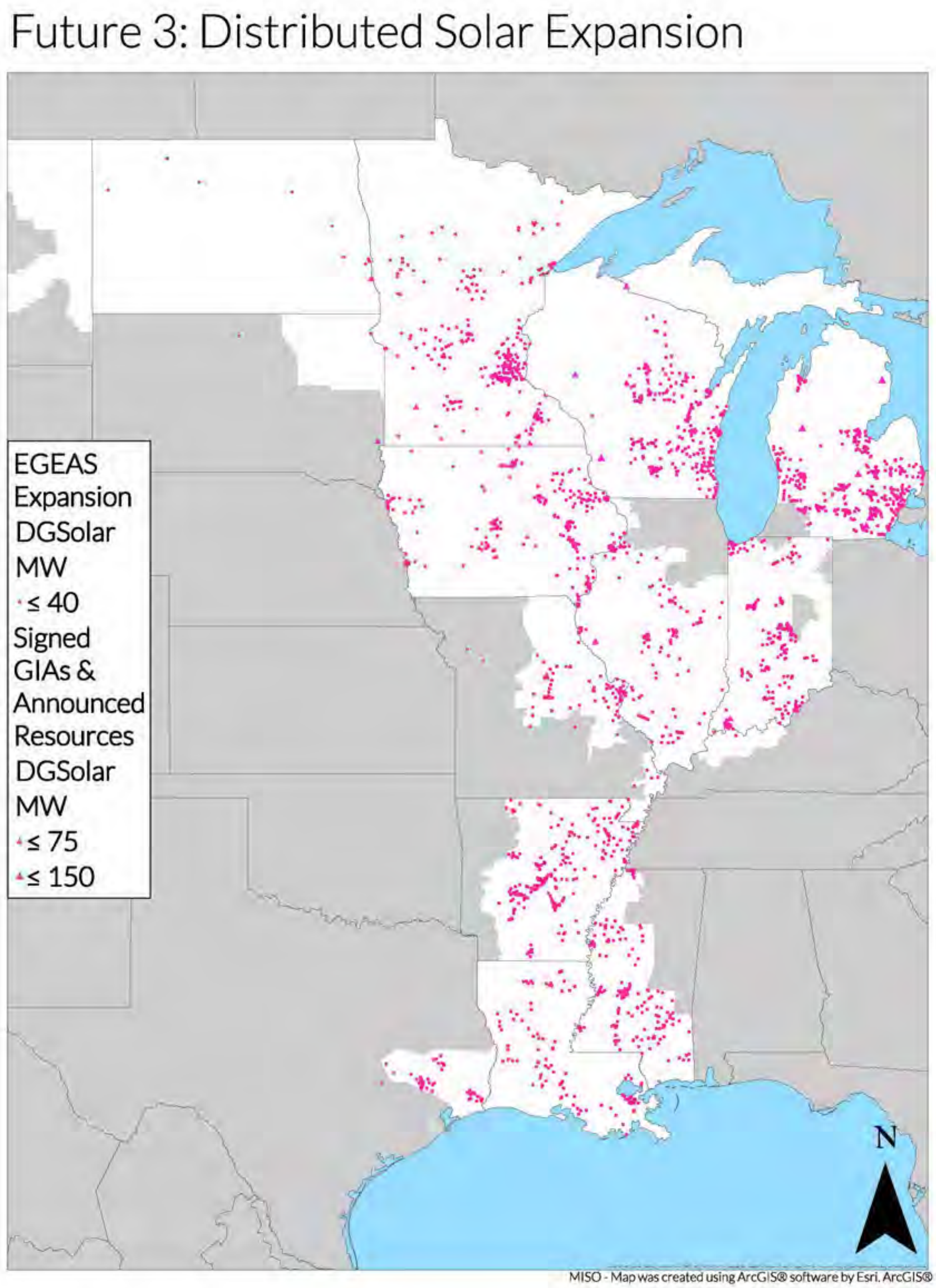


Figure 67: MISO Future 3 Distributed Solar Siting

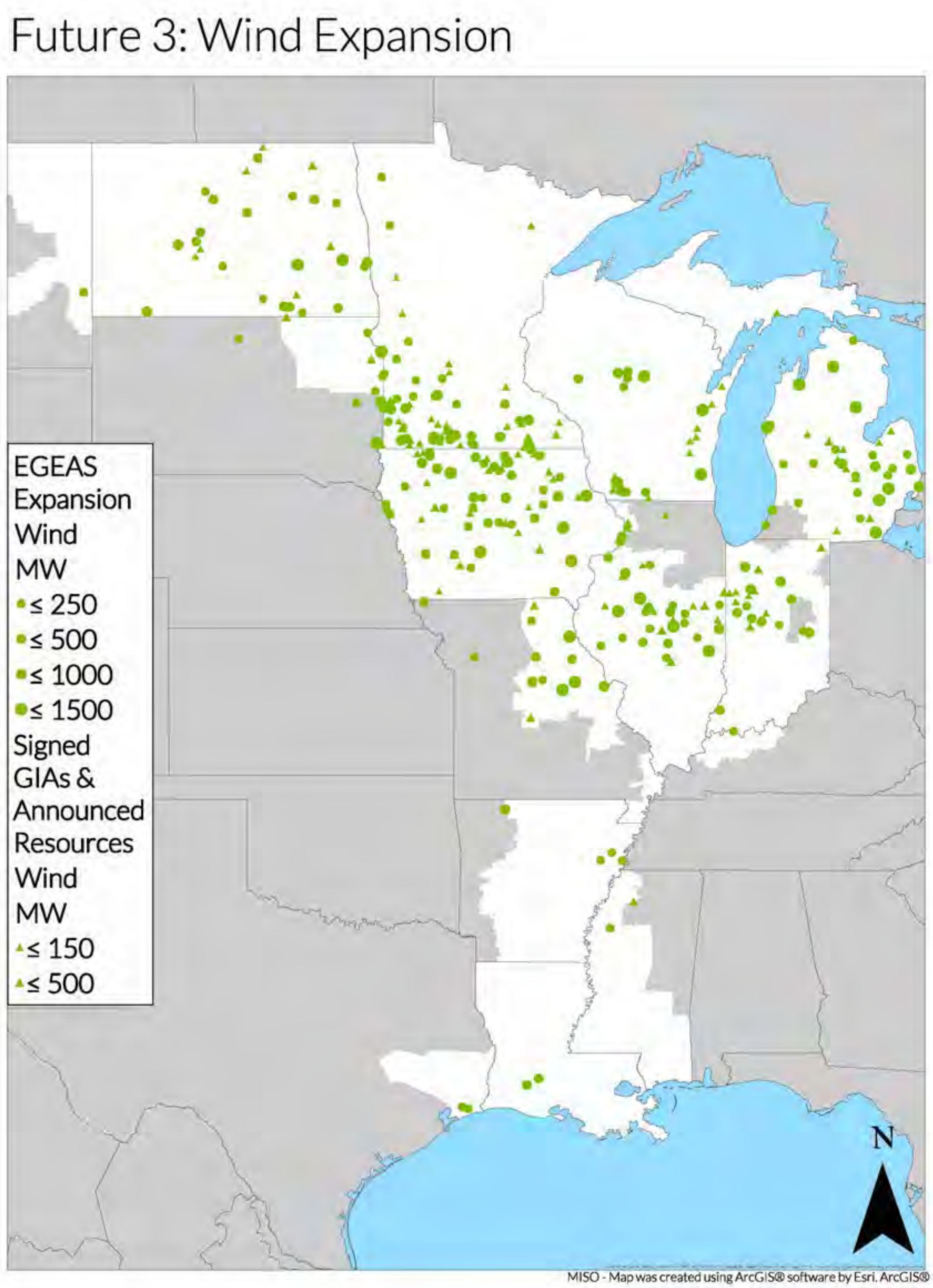


Figure 68: MISO Future 3 Wind Siting

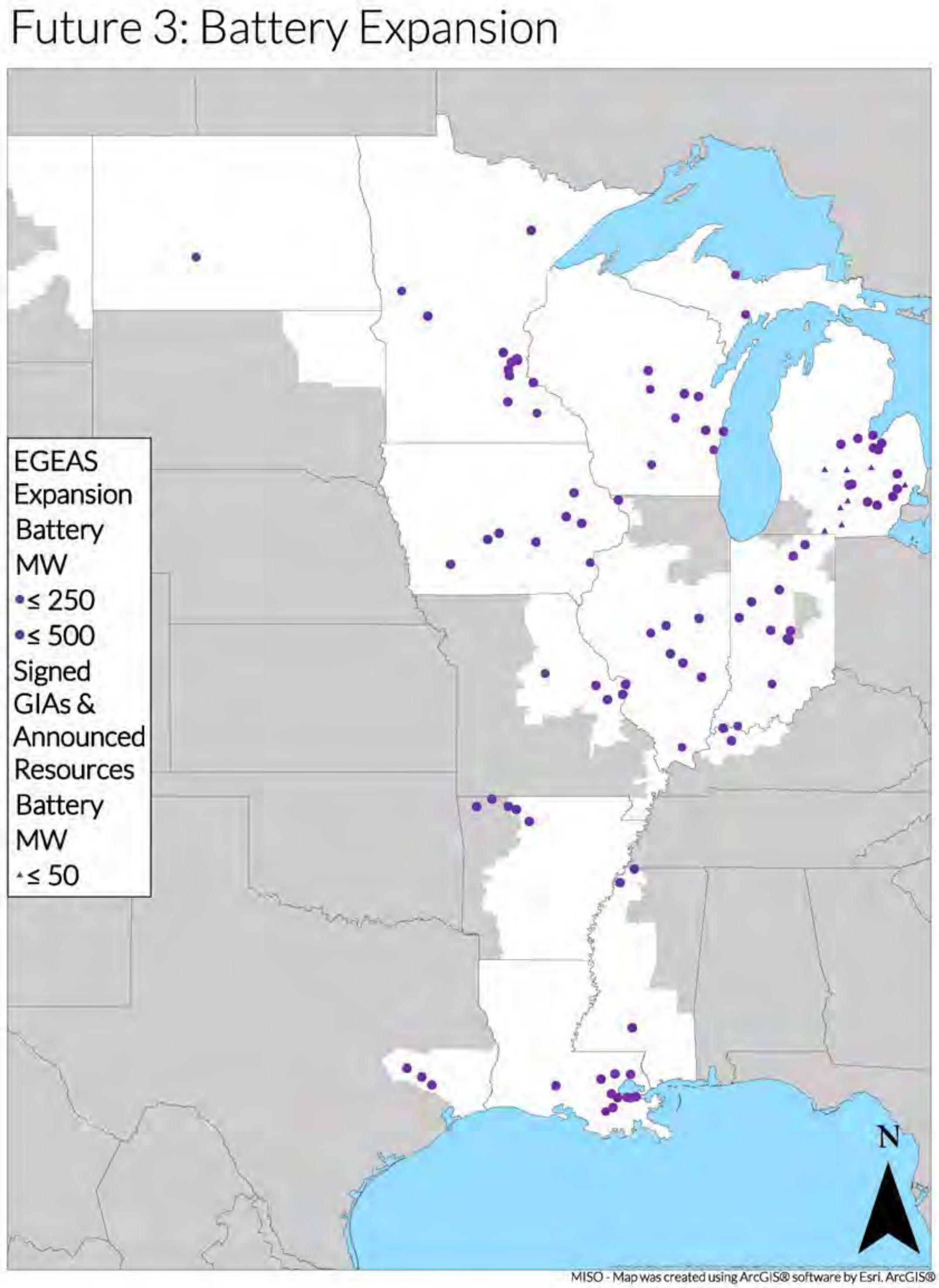


Figure 69: MISO Future 3 Battery Siting

Future 3: Thermal Expansion

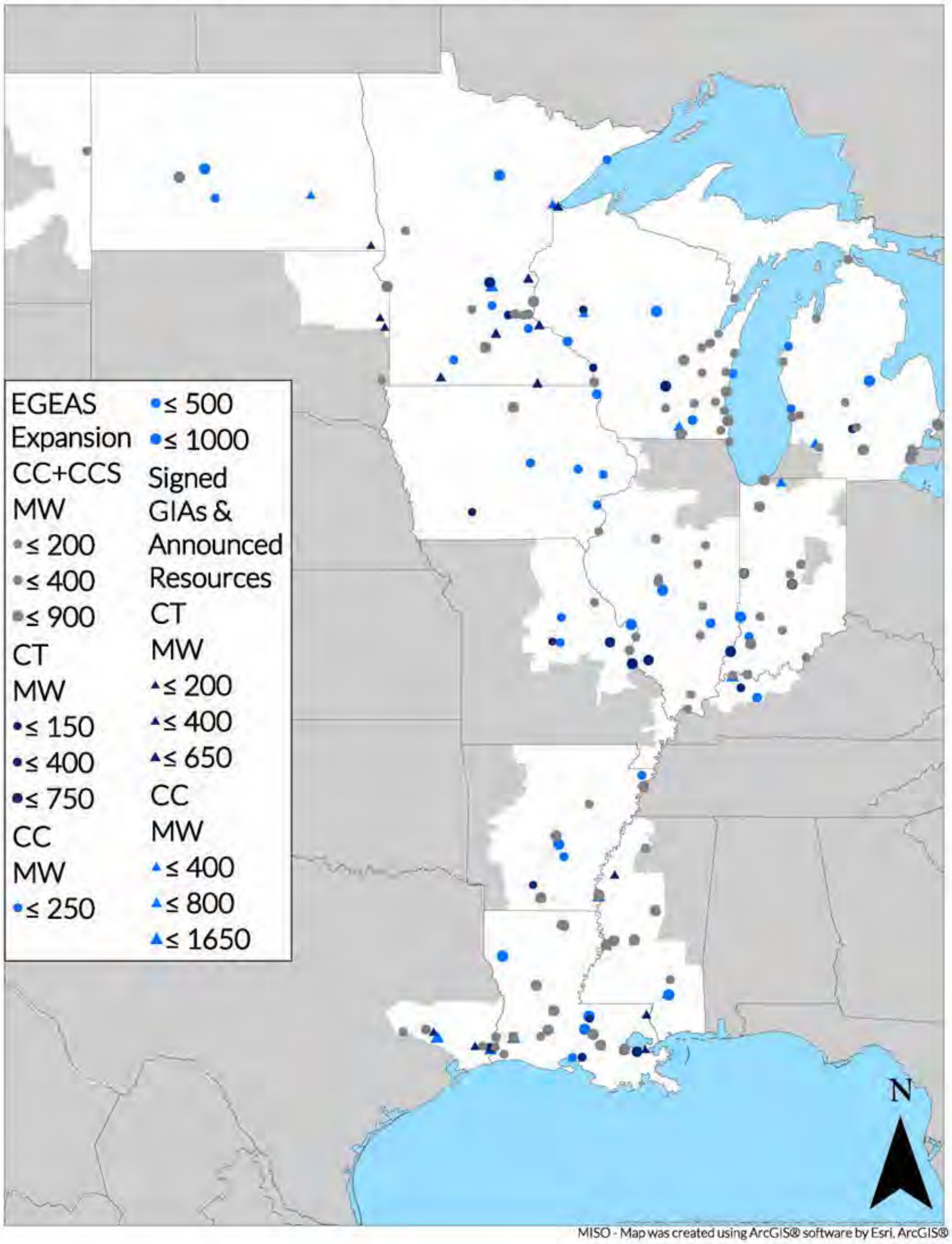


Figure 70: MISO Future 3 Thermal Siting

Future 3: EGEAS Expansion

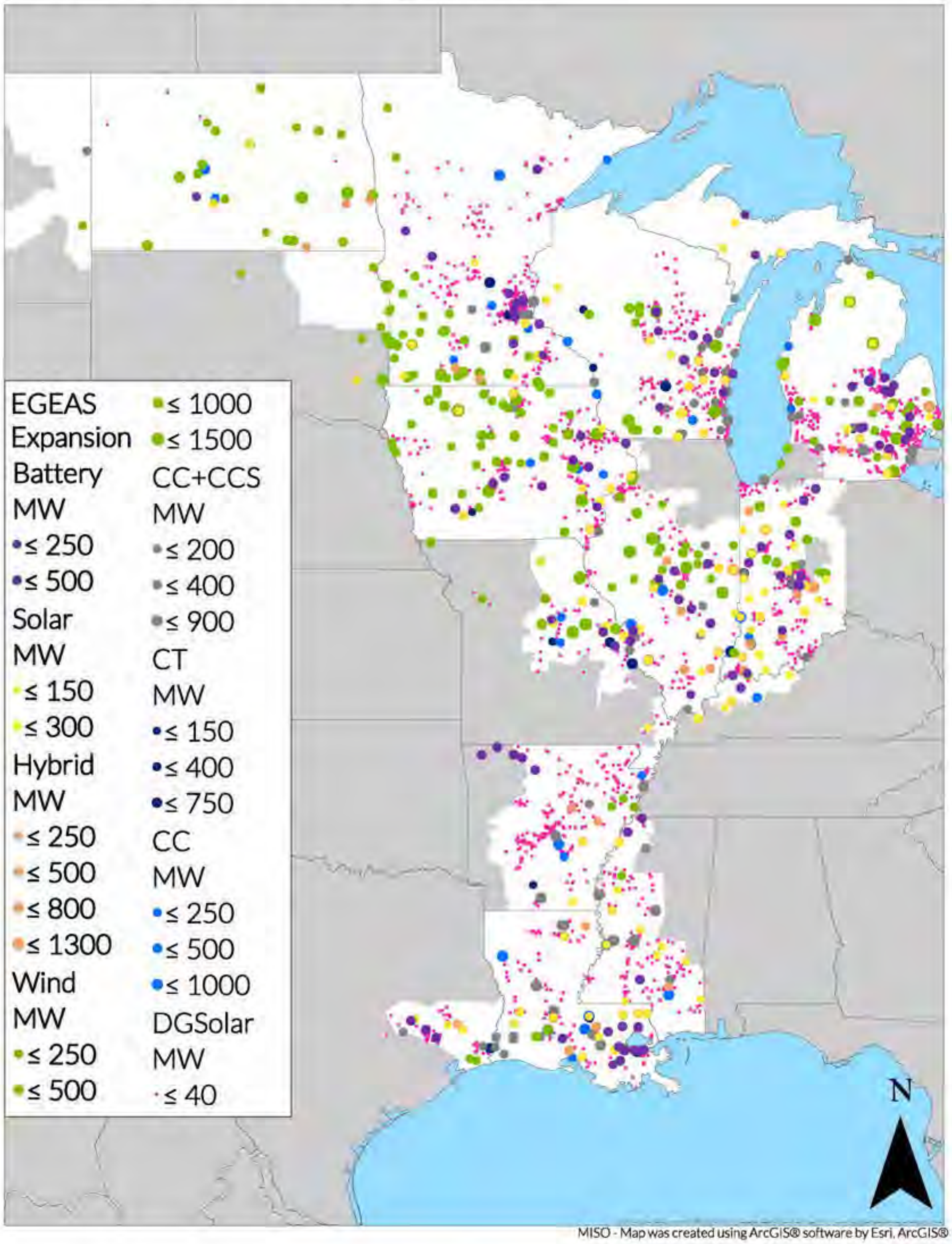


Figure 71: MISO Future 3 Complete EGEAS Expansion Siting

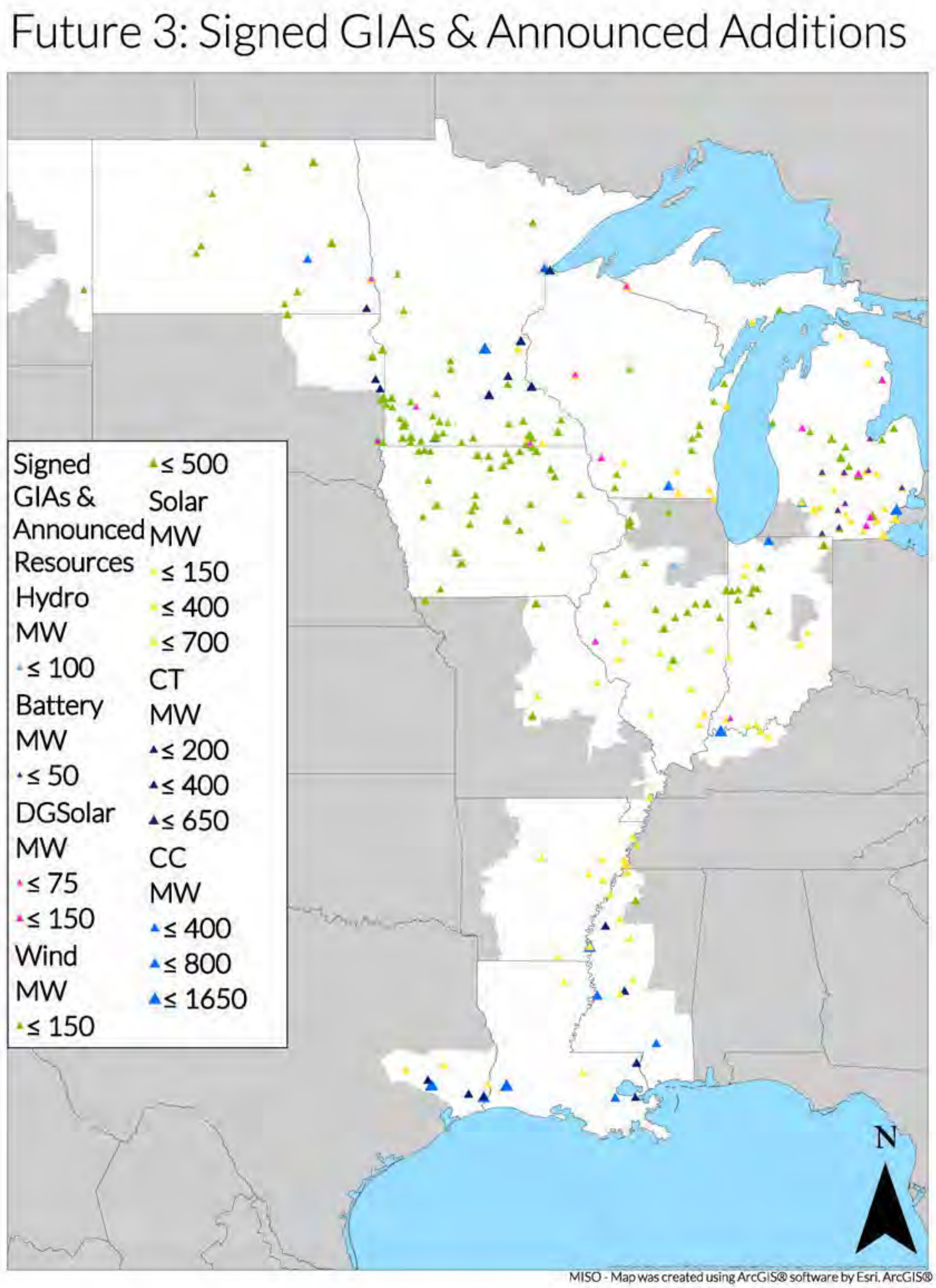


Figure 72: MISO Future 3 Non-EGEAS Expansion Siting

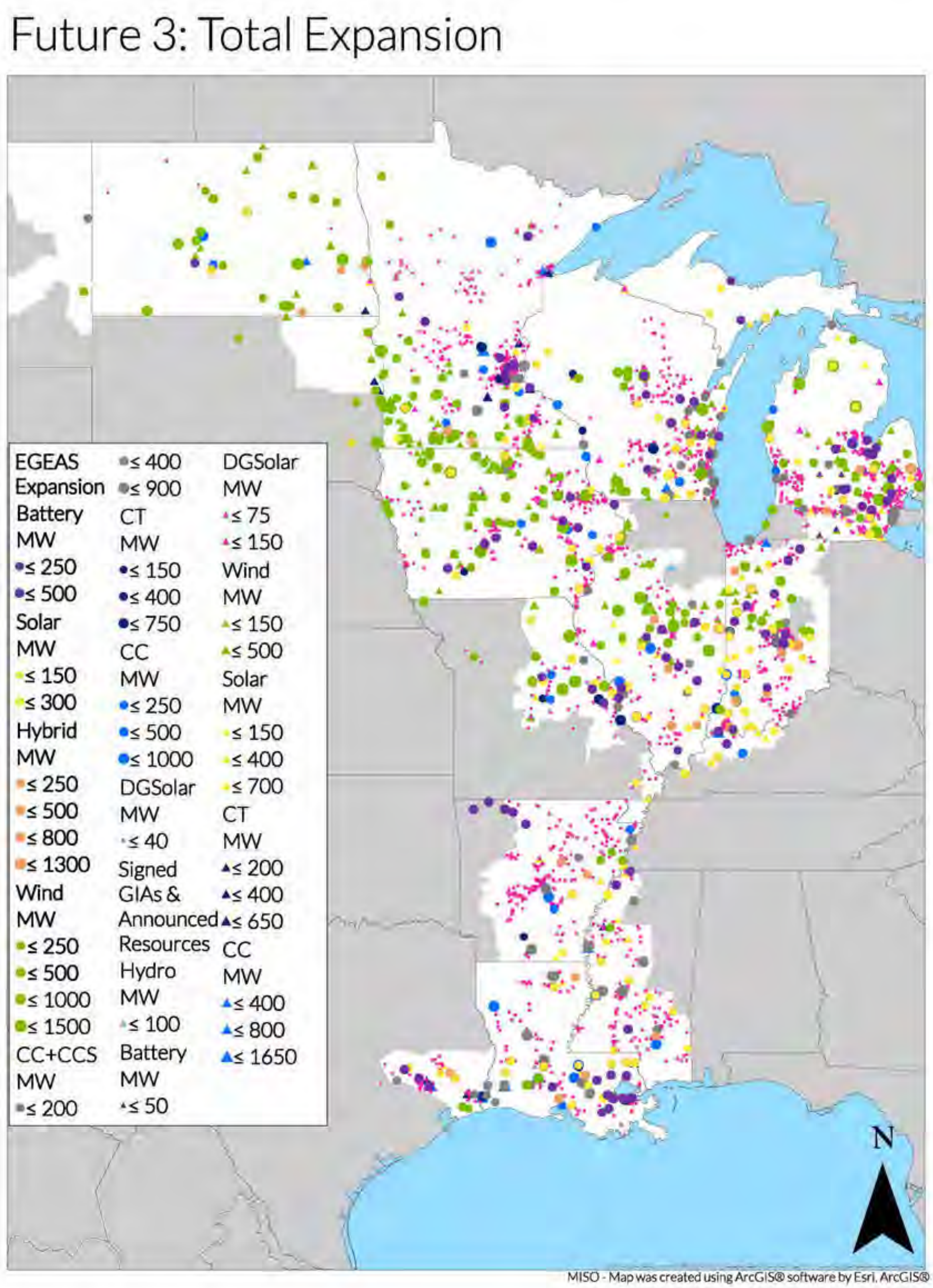


Figure 73: MISO Future 3 Non-EGEAS and EGEAS Expansion Siting

Future 3 Resource Additions (MW) - *Cumulative*											
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	850	2,179	0	7,398	640	0	149	350	0	11,565
	2030	4,766	3,486	0	12,897	2,228	969	606	712	0	25,664
	2035	6,641	6,054	409	25,786	4,728	969	3,635	1,202	0	49,425
	2039	6,731	6,054	3,881	35,848	4,728	969	5,302	1,486	0	64,998
LRZ 2	**2025**	1,686	620	0	949	1,332	0	91	86	0	4,764
	2030	2,762	673	0	2,532	1,991	516	356	275	0	9,105
	2035	4,880	673	0	5,898	2,066	516	2,133	556	0	16,722
	2039	4,880	673	5,363	8,132	2,066	516	3,111	703	0	25,443
LRZ 3	**2025**	311	0	0	5,669	513	0	74	74	0	6,640
	2030	769	92	0	10,102	1,019	264	298	235	0	12,779
	2035	769	92	200	20,874	1,019	264	1,786	475	0	25,479
	2039	769	92	766	29,249	1,019	264	2,605	600	0	35,364
LRZ 4	**2025**	900	0	0	3,768	2,240	0	72	68	10	7,059
	2030	1,612	1,134	0	5,745	2,957	2,122	278	130	10	13,988
	2035	1,612	1,134	459	10,219	2,957	2,122	1,668	221	10	20,403
	2039	1,612	1,134	2,203	13,808	2,957	2,122	2,432	269	10	26,548
LRZ 5	**2025**	64	609	0	1,793	283	0	62	57	0	2,868
	2030	748	1,344	0	3,091	728	251	234	181	0	6,577
	2035	2,114	1,344	266	6,029	791	251	1,402	366	0	12,565
	2039	2,114	1,344	2,117	8,143	805	251	2,045	463	0	17,282
LRZ 6	**2025**	4,659	1,223	0	2,765	2,467	0	142	89	0	11,345
	2030	7,629	2,158	0	3,805	4,259	3,401	566	164	0	21,982
	2035	8,375	2,158	1,661	6,410	4,259	3,401	3,398	277	0	29,940
	2039	8,375	2,158	4,988	8,251	4,259	3,401	4,955	336	0	36,723
LRZ 7	**2025**	3,051	0	0	4,837	1,722	0	159	767	72	10,609
	2030	3,051	153	0	7,079	3,936	1,054	648	841	72	16,832
	2035	3,120	153	1,642	12,888	5,136	1,054	4,087	949	72	29,100
	2039	3,120	153	5,870	16,730	5,736	1,054	6,068	1,006	72	39,808
LRZ 8	**2025**	250	0	0	227	2,544	0	57	59	0	3,137
	2030	1,897	134	0	454	2,753	571	229	188	0	6,226
	2035	1,897	134	122	954	2,753	571	1,377	379	0	8,187
	2039	1,897	134	1745	1,317	2,753	571	2,008	479	0	10,904
LRZ 9	**2025**	6,061	915	0	201	1,031	0	160	64	0	8,432
	2030	8,321	4,215	0	401	2,156	1,529	639	205	0	17,466
	2035	9,953	4,907	726	842	2,356	1,529	3,836	415	0	24,564
	2039	9,953	5,253	10,361	1,163	2,356	1,529	5,594	524	0	36,734
LRZ 10	**2025**	672	0	0	245	627	0	34	37	0	1,616
	2030	672	350	0	291	1,517	123	146	119	0	3,217
	2035	2,472	700	515	390	2,017	123	877	240	0	7,334
	2039	2,472	700	4,707	463	2,017	123	1,280	303	0	12,064
MISO Total	**2025**	18,503	5,546	0	27,853	13,400	0	1,000	1,650	82	68,034
	2030	32,228	13,739	0	46,396	23,544	10,800	4,000	3,049	82	133,837
	2035	41,833	17,349	6,000	90,291	28,082	10,800	24,200	5,081	82	223,719
	2039	41,923	17,695	42,001	123,104	28,696	10,800	35,400	6,168	82	305,869

Table 11: MISO Future 3 Resource Additions by LRZ and Footprint

Future 3 Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2025**	4,324	1,272	0	698	240	0	36	6,569
	2030	6,420	2,635	0	698	519	0	36	10,307
	2035	7,040	3,337	1,092	824	2,946	0	36	15,275
	2039	7,040	3,651	1,092	885	3,572	0	36	16,276
LRZ 2	**2025**	2,981	604	0	351	11	0	0	3,947
	2030	2,981	2,017	0	351	41	0	0	5,390
	2035	4,173	3,010	0	351	427	0	0	7,961
	2039	4,232	4,906	0	409	617	0	0	10,163
LRZ 3	**2025**	757	92	448	196	122	0	0	1,615
	2030	776	107	448	275	348	0	0	1,954
	2035	776	135	448	275	1,434	0	0	3,068
	2039	808	702	448	328	2,707	0	0	4,992
LRZ 4	**2025**	3,118	134	0	117	0	0	0	3,369
	2030	3,118	134	0	117	20	0	0	3,389
	2035	3,118	1,199	0	117	379	0	0	4,813
	2039	3,326	2,794	0	176	1,013	0	0	7,309
LRZ 5	**2025**	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	582	0	345	169	0	0	5,994
	2039	6,132	3,047	0	345	169	0	0	9,692
LRZ 6	**2025**	11,068	853	0	50	0	0	0	11,970
	2030	11,537	1,398	0	71	0	0	0	13,005
	2035	11,537	3,102	0	71	377	0	0	15,086
	2039	11,537	3,889	0	71	582	21	0	16,100
LRZ 7	**2025**	2,991	1,697	819	59	0	0	0	5,565
	2030	4,258	1,906	819	59	0	0	0	7,041
	2035	4,878	3,760	819	59	230	0	0	9,745
	2039	8,013	7,134	819	74	565	0	0	16,604
LRZ 8	**2025**	1,647	788	0	0	0	0	0	2,435
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	882	0	0	0	0	0	4,012
	2039	3,130	3,436	0	0	0	0	0	6,566
LRZ 9	**2025**	2,746	7,243	0	7	0	0	0	9,996
	2030	2,746	7,243	0	7	0	0	0	9,996
	2035	2,746	9,711	0	7	0	0	0	12,464
	2039	2,746	18,259	0	7	0	0	0	21,012
LRZ 10	**2025**	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	3,248	0	0	0	0	0	3,248
	2039	0	3,549	0	0	0	0	0	3,549
MISO Total	**2025**	33,525	13,640	1,267	1,822	373	0	36	50,663
	2030	38,858	17,185	1,267	1,922	928	0	36	60,196
	2035	42,297	28,965	2,359	2,049	5,960	0	36	81,665
	2039	46,963	51,368	2,359	2,295	9,223	21	36	112,265

Table 12: MISO Future 3 Resource Retirements by LRZ and Footprint

Appendix

EGEAS Modeling

Description

The Electric Generation Expansion Analysis System (EGEAS) is a program developed by EPRI which MISO uses to conduct its expansion analysis studies. The primary function of EGEAS is the creation of a generation expansion plan that meets system requirements specified by several inputs, assumptions, and constraints.

Modeling Procedure

The modeling process can be broken down into three main stages: definition of the model through inputs, computational analysis and solution processing, and consolidation of the results in the output file.

Inputs

Listed below are some of the key input parameters that EGEAS uses when selecting the optimal expansion solution. EGEAS allows users to input a variety of variables however, the inputs below include some of the more important parameters when setting up an economic expansion model.

- Hourly load shape files for the system and NDTs
- Projected peak yearly values of demand and energy
- Planning Reserve Margin (PRM) percentage requirement
- Renewable Portfolio Standard (RPS) percentage trajectories
- Decarbonization trajectories, may be input in short tons or $/short ton
- Existing unit data including planned additions and retirements
- Cost of unserved energy
- Available expansion resources and respective cost and emission data

Computational Analysis

To find the optimal resource expansion plan, EGEAS solves two objective functions:

1. Present value of the revenue requirements
2. The levelized average system rates ($/MWh)

The bulk of the work done by EGEAS is in solving these functions. It is an iterative process that progresses through the study year by year. Retaining only the feasible solutions each year, a single expansion plan that satisfies all input constraints and limitations over the study period is selected after the final year of study.

Output

The final report file is a text output file containing a report on the generic units EGEAS built to meet the system constraints in every year of the study. Metrics such as PRM, RPS, systemwide CO_2 emissions, resource generation, and cost data are also included in the report file.

From this information, MISO staff acquires its resource expansion and sites these resources throughout the footprint based on generator availability and other criteria discussed in the New Resource Addition Siting Process section of this report.

An important metric used in the Futures process is the RPS which EGEAS calculates as the ratio of Renewable Energy Generation (from wind, solar, and solar hybrid resources) to Net System Energy. In this calculation, net system energy is the sum of forecasted and storage charging energy minus energy from demand side management programs. While this may be how EGEAS calculated required contribution from renewable resources when defining an economic expansion, MISO displays these results differently so that energy generation from all resources may be seen. The calculation used by MISO is (Renewable Energy GWh / Total Generation GWh).

Shown below is an example of the EGEAS and MISO calculation to meet the RPS in Future 3 year 2039. MISO values appear less than EGEAS calculated values because total generation includes energy from DSM programs and curtailed renewable energy from low demand periods.

EGEAS Calculation

Forecasted System Energy (GWh)	Storage Charging (GWh)	DSM Energy (GWh)	Net System Energy (GWh)	Renewable Energy Generation (GWh)	RPS %
1,063,465	176,423	56,665	1,183,223	622,241	53%

$$\left(\frac{Renewable}{Forecasted + Storage - DSM}\right) \times 100 = RPS\%$$

$$\left(\frac{622{,}241}{1{,}063{,}465 + 176{,}423 - 56{,}665}\right) \times 100 = 52.59$$

MISO Calculation

Total Energy Generation (GWh)	Renewable Energy Generation (GWh)	RPS %
1,352,519	622,241	46%

$$\left(\frac{Renewable}{Total\ Generation}\right) \times 100 = RPS\%$$

$$\left(\frac{622{,}241}{1{,}352{,}519}\right) \times 100 = 46.01$$

Additional MISO Assumptions

Futures Assumptions Summary

Table 13 and Table 14 detail Future-specific input assumptions. Many of these variables were direct inputs to the model; however, selected DERs, retirements, and addition totals are results of the analysis.

Variables	Future 1	Future 2	Future 3
Gross Load[29] Total Growth	Low-Base EV Growth 94,275 GWh	30% Total Energy Growth by 2040 196,996 GWh	50% Total Energy Growth by 2040 334,692 GWh
Energy (CAGR) Input/*Result* **Demand (CAGR)** Input/*Result*	0.63% / *0.48%* 0.75% / *0.60%*	1.22% / *1.09%* 1.11% / *0.97%*	1.91% / *1.71%* 1.60% / *1.41%*
Electrification Growth & Technologies Growth from Electrification	2% of Total Growth 14,147 GWh	15.2% of Total Growth 109,101 GWh	31.8% of Total Growth 231,513 GWh
Electrification Technologies	PEVs	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process
Selected DERs DR EE DG	0.94 GW 7.82 GW 3.47 GW	0.94 GW 8.05 GW 3.47 GW	0.94 GW 11.72 GW 6.17 GW
Carbon Reduction *(2005 baseline)* MISO Footprint currently at 29%	40% *63% realized in results*	60% *65% realized in results*	80% *81% realized in results*
Wind & Solar Generation Percentage[82]	Resulted in 26% with No Minimum Enforced	Resulted in 35% with No Minimum Enforced	46%
Utility Announced Plans	85% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met

Table 13: MISO Futures Assumptions

[29] Total Growth is based on 2039 values due to the study period ending on 12/31/2039.

Variables		Future 1	Future 2	Future 3
Retirement Age-Based Criteria	Coal	46 years[30]	36 years	30 years
	Natural Gas-CC	50 years	45 years	35 years
	Natural Gas-Other	46 years	36 years	30 years
	Oil	45 years	40 years	35 years
	Nuclear	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
	Wind & Solar - Utility Scale	25 years	25 years	25 years
Retirements	Coal	44.8 GW	45.1 GW	47 GW
	Gas	18.6 GW	21.6 GW	51.4 GW
	Oil	2 GW	2.03 GW	2.3 GW
	Nuclear	2.4W	2.4GW	2.4GW
	Wind	9.2 GW	9.2 GW	9.2 GW
	Solar	0.02 GW	0.02 GW	0.02 GW
	Other	0.04 GW	0.04 GW	0.04 GW
	Total	77.1 GW	80.4 GW	112.3 GW
Additions	CC	37.1 GW	58.7 GW	41.9 GW
	CT	14.1 GW	10.5 GW	17.7 GW
	CC+CCS	0 GW	1.2 GW	42 GW
	Wind[31]	18.7 GW	63.1 GW	123.1 GW
	Solar	34.7 GW	28.7 GW	28.7 GW
	Hybrid	12 GW	1.2 GW	10.8 GW
	Battery	0.6 GW	3.4 GW	35.4 GW
	Hydro	0.1 GW	0.1 GW	0.1 GW
	Total (Including DERs)	129.5 GW	179.4 GW	318.5 GW

Table 14: MISO Futures Assumptions and Expansion Results

[30] EIA Source for Coal Retirement Age, Future 1: https://www.eia.gov/todayinenergy/detail.php?id=40212

[31] All Futures include 9.2 GW of repowered wind and 9.5 GW of wind from signed GIAs.

Capital Costs

MISO used the 2020 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[32] to calculate the capital costs for all resources except for oil,[33] storage compressed air energy storage (CAES),[34] and internal combustion (IC) renewable[35] costs. MISO utilized moderate cost values within the 2020 ATB, which are in 2018 dollars. These values were converted to 2020 dollars and projected into the 20-year study period to create cost trajectories. For Hybrid unit costs, 2020 ATB Solar PV + Battery costs are included.

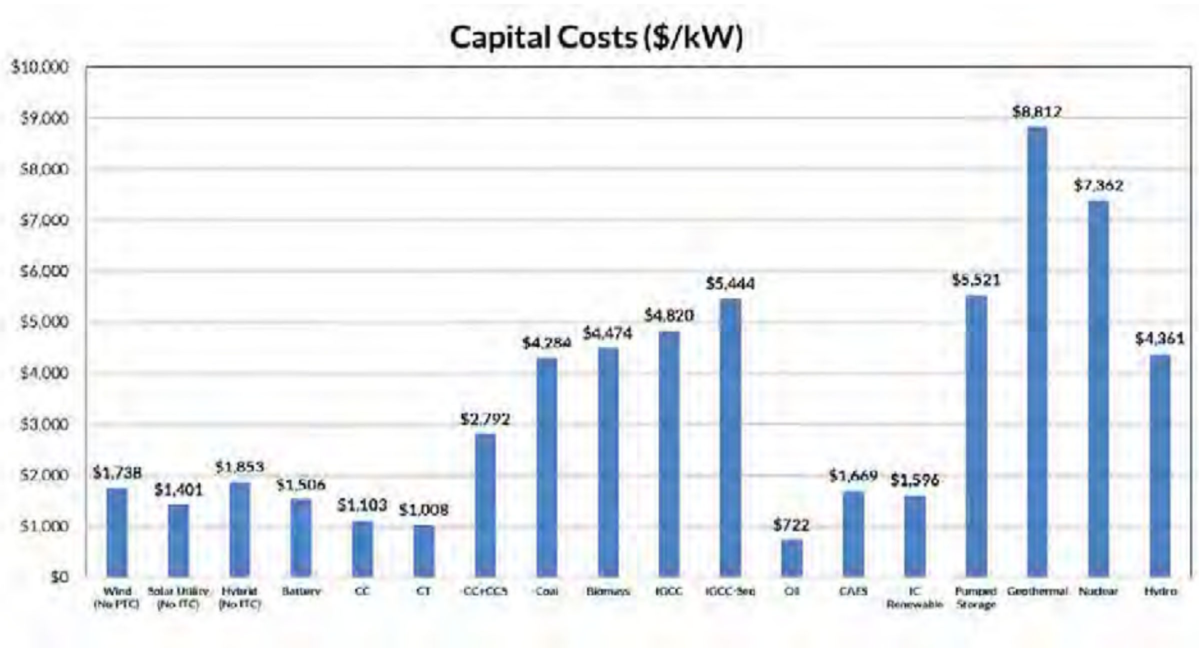


Figure 74: Annual Capital Cost Assumptions by Fuel Type

[32] NREL 2020 ATB: https://atb.nrel.gov/electricity/2020/data.php

[33] EIA costs were used and adjusted for 2020 dollars: https://www.eia.gov/electricity/generatorcosts/

[34] Costs from the DOE Energy Storage Technology and Cost Characterization Report of July 2019: https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf

[35] Costs from EIA Annual Energy Outlook: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

Production Tax Credits (PTC) and Investment Tax Credits (ITC)

Production Tax Credit (PTC) and Investment Tax Credit (ITC) effects on wind, utility-scale solar PV, and hybrid units are displayed below. Since the battery in the hybrid unit modeled is charged from solar resources 100% of the time, it may qualify for 100% of ITC benefits.[36,37]

Actual and Modeled Schedule of Wind and Solar Tax Credits

Consolidated Appropriations Act of 2016 PTC with 2020 Extensions	2016	2017	2018	2019	2020	2021	2022	2023 & onward
Utility Wind PTC	Full	80%	60%	40%	60%	0%	0%	0%
Utility Solar ITC	30%	30%	30%	30%	26%	22%	10%	10%
Model Representation	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023 & onward**
Utility Wind PTC	Full	Full	Full	Full	Full	Full	Full	0%
Utility Solar ITC	30%	30%	30%	30%	30%	26%	22%	10%
Hybrid ITC (Battery charged by solar 100% of the time)	30%	30%	30%	30%	30%	26%	22%	10%

Table 15: PTC and ITC Schedule

Accreditations of PTC and ITC benefits are seen for wind, solar, and hybrid units since extensions and changes were issued in the spring of 2020. The model representation differs due to the assumed construction time of each of these units, in order to ensure their safe harbor provisions. MISO used the values in the model representation section to build cost trajectories for these resources in EGEAS.

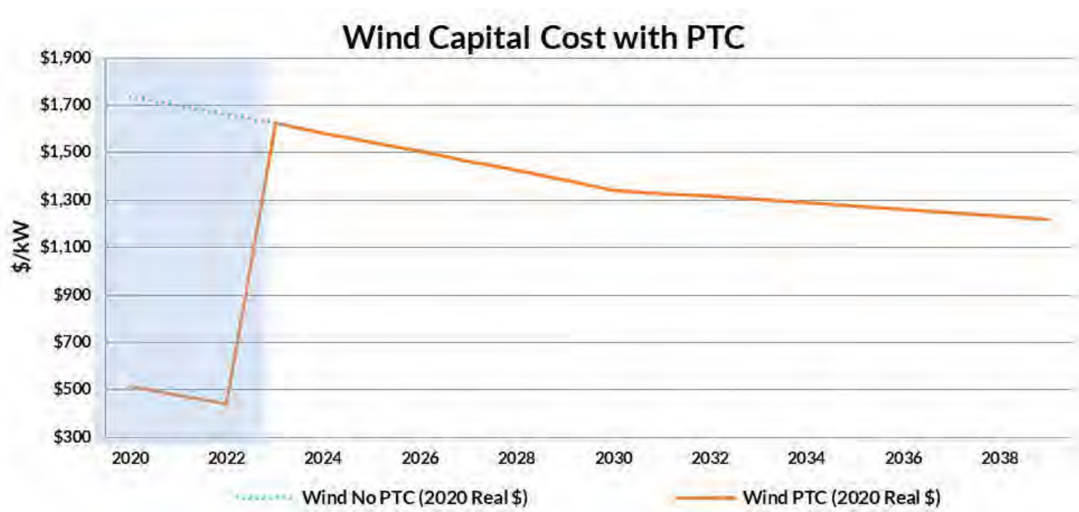


Figure 75: Wind with PTC

[36] Source for PTC and ITC for Wind & Solar PV: https://fas.org/sgp/crs/misc/R43453.pdf

[37] NREL - ITC accreditation for Hybrids: https://www.nrel.gov/docs/fy18osti/70384.pdf

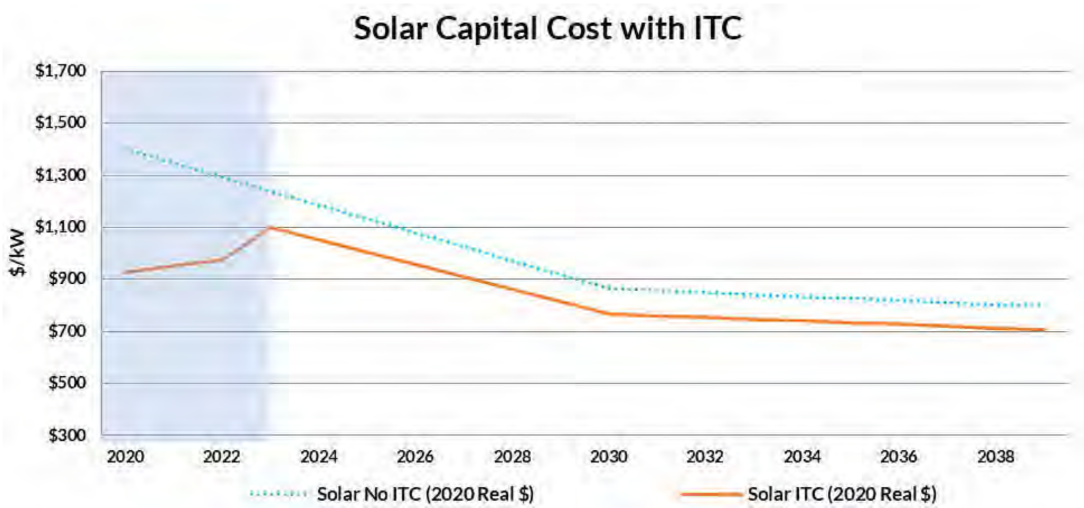


Figure 76: Solar PV with ITC

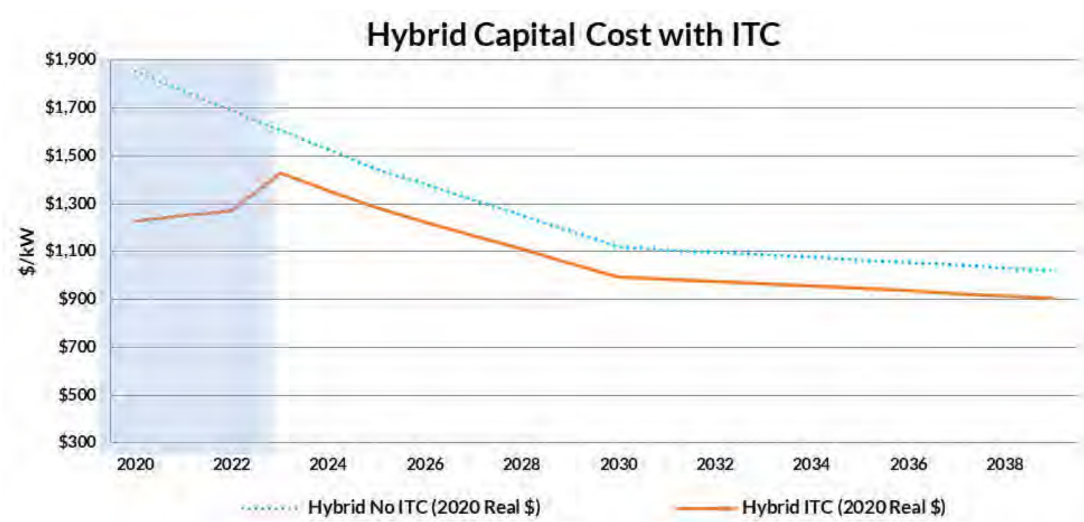


Figure 77: Hybrid with ITC

Electrification and Energy Growth Values

Although the energy growth in Futures 2 and 3 reaches 30% and 50% by 2040 respectively, not all growth is from electrification. Table 16 details the amounts of growth resulting from the reference forecast (SUFG) and electrification (AEG). By the end of the study period (12/31/2039), energy in Futures 1, 2, and 3 increases by 13%, 27%, and 46% respectively. On the following page, Table 17 presents the granular energy values for each technology that was electrified. These numbers represent the total energy growth from electrification in each Future scenario by LRZ.

Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	705,604	716,734	728,773
2039 Reference Growth	80,128	87,895	103,179
Electrification Growth	14,147	109,101	231,513
2039 Energy Forecast	799,879	913,730	1,063,465
Total Energy Increase, 2020-2039	**13%**	**27%**	**46%**
Energy Increase from Reference Forecast	11%	12%	14%
Energy Increase from Electrification	2%	15%	32%
Electrification Technologies	PEVs	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process

Table 16: Future-Specific Growth Assumptions (GWh)

Energy Growth by Technology Type from Electrification (GWh)								
F1	RES_HVAC	RES_DHW	RES_App	C&I_HVAC	C&I_DHW	C&I_Process	PEVs	Total
LRZ 1	0	0	0	0	0	0	2,636	2,636
LRZ 2	0	0	0	0	0	0	2,016	2,016
LRZ 3	0	0	0	0	0	0	719	719
LRZ 4	0	0	0	0	0	0	1,237	1,237
LRZ 5	0	0	0	0	0	0	747	747
LRZ 6	0	0	0	0	0	0	1,264	1,264
LRZ 7	0	0	0	0	0	0	4,352	4,352
LRZ 8	0	0	0	0	0	0	238	238
LRZ 9	0	0	0	0	0	0	851	851
LRZ 10	0	0	0	0	0	0	87	87
Total	0	0	0	0	0	0	14,147	14,147
F2	RES_HVAC	RES_DHW	RES_App	C&I_HVAC	C&I_DHW	C&I_Process	PEVs	Total
LRZ 1	3,108	2,556	1,266	4,711	307	0	6,542	18,489
LRZ 2	1,973	1,685	1,262	3,113	200	0	5,004	13,238
LRZ 3	2,076	945	451	2,425	137	0	1,784	7,818
LRZ 4	874	805	428	4,172	319	0	3,071	9,669
LRZ 5	2,307	654	332	1,686	129	0	1,855	6,962
LRZ 6	4,264	1,920	944	4,602	374	0	3,136	15,239
LRZ 7	3,265	2,574	2,085	5,710	316	0	10,802	24,751
LRZ 8	506	528	470	791	73	0	591	2,960
LRZ 9	1,330	1,540	1,114	2,276	387	0	2,112	8,760
LRZ 10	345	172	231	217	35	0	215	1,215
Total	20,048	13,378	8,584	29,702	2,277	0	35,112	109,101
F3	RES_HVAC	RES_DHW	RES_App	C&I_HVAC	C&I_DHW	C&I_Process	PEVs	Total
LRZ 1	6,005	5,289	1,723	6,411	594	2,573	17,078	39,673
LRZ 2	3,812	3,498	1,718	4,237	387	1,834	13,062	28,548
LRZ 3	4,012	1,967	614	3,300	264	1,662	4,657	16,476
LRZ 4	1,690	1,611	583	5,678	616	1,056	8,017	19,250
LRZ 5	4,457	1,334	452	2,295	249	1,303	4,842	14,931
LRZ 6	8,242	3,806	1,284	6,263	722	1,932	8,186	30,437
LRZ 7	6,308	5,301	2,838	7,771	611	2,878	28,198	53,905
LRZ 8	978	1,050	640	1,076	142	1,116	1,543	6,545
LRZ 9	2,570	3,043	1,516	3,098	749	2,340	5,513	18,829
LRZ 10	666	341	315	295	68	674	562	2,921
Total	38,741	27,240	11,683	40,423	4,400	17,368	91,658	231,513

Table 17: Quantification of Electrified Technologies (2020-2039)

Natural Gas Price Forecasting

MISO used the Gas Pipeline Competition Model (GPCM) base price forecast across the three Futures, instead of the Henry Hub price (HH) as in past cycles. GPCM outputs the gas price at a level of monthly granularity and produces unit-specific gas prices. The gas forecast per unit remained the same for all Futures modeled in EGEAS.

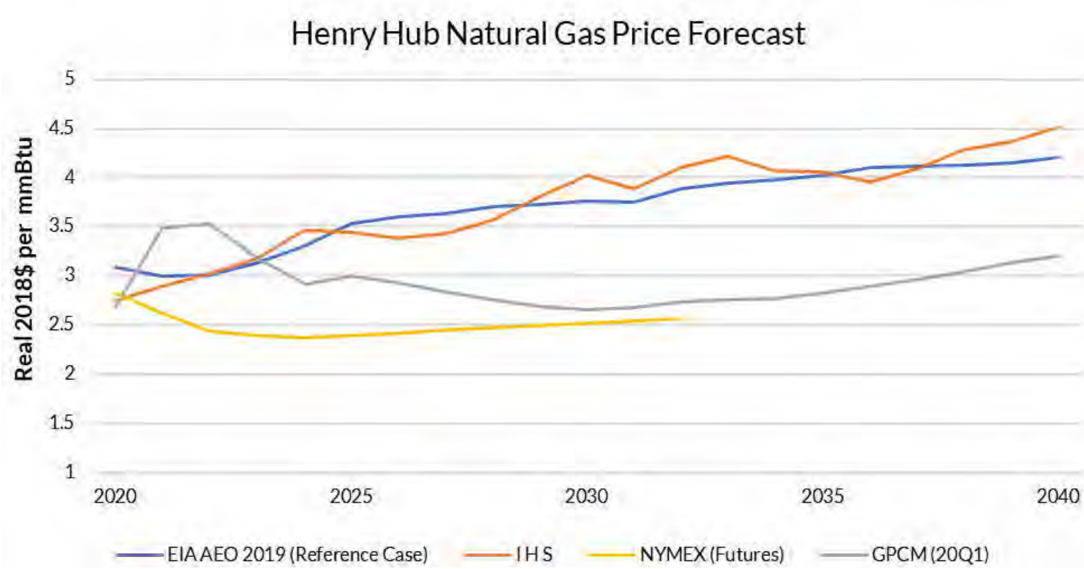


Figure 78: Henry Hub Natural Gas Price Forecast

General Assumptions

Study Period

The study period of the EGEAS resource expansion analysis is 20 years, beginning on 1/1/2020 and ending on 12/31/2039. An extension period of 40 years is added to the end of the simulation, with no new units forecasted during this time. This extension ensures that the generation selected in the last few years of the forecasting period (i.e., Years 15-20) is based on cost of generation spread out over the total tax/book life of the new resources (i.e., beyond Year 20) and does not bias to the cheapest generation in those final years.

Discount Rate

The discount rate of 7.22% is based upon the after-tax weighted average cost of capital of the Transmission Owners that make up the Transmission Provider Transmission System.

MISO Footprint Study Area

The study area for the updated MISO Futures continued to be the entire MISO footprint. However, the Local Clearing Requirement (LCR) for each zone was evaluated during the siting process to ensure each LRZ met their respective LCR as defined in the 2020/2021 Planning Resource Auction (PRA).

External Assumptions and Modeling

General Assumptions

External Footprint Study Area

From an external-to-MISO (External areas) perspective, MISO increased the EGEAS analysis granularity for External areas/pools represented in the MCPS[38] by increasing the number of representative models.

MISO-Created External Regional Model and Future Assumptions			
EGEAS Models	**Future 1**	**Future 2**	**Future 3**
PJM	Yes	Yes	Yes
SPP	No – Use SPP ITP Future 2 and Results[39]	Yes	Yes
TVA-Other *(includes Southeast, TVA, TVA-Other)*	Yes	Yes	Yes
Manitoba Hydro	No	No	No

Table 18: EGEAS External Model Representation

MISO realizes system flows depend on External areas' representations and the above improvements are intended to help align MISO Future assumptions to MISO's neighbors, as well as provide a Future (Future 1) that utilizes SPP Future assumptions. This Future will be used to help bookmark projected External system flows as decided by External Future assumptions.

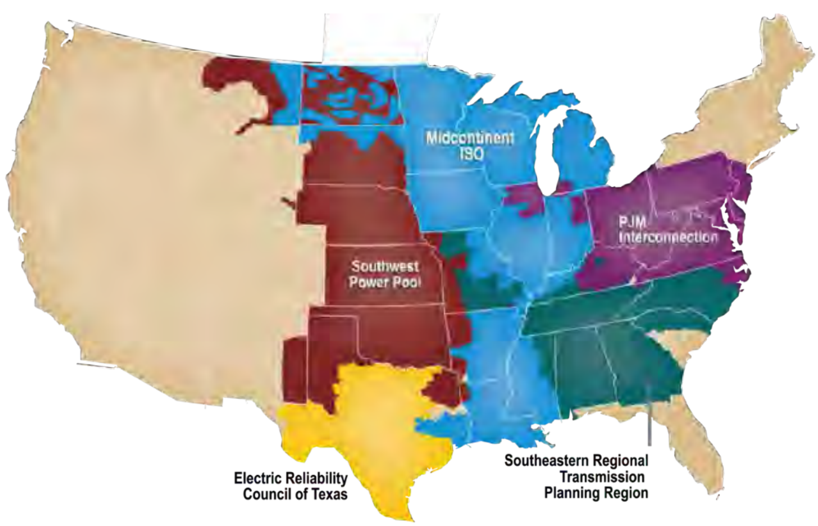


Figure 79: MISO Footprint & Neighboring Systems

[38] MISO Market Congestion Planning Studies (MCPS): https://www.misoenergy.org/stakeholder-engagement/committees/subregional-planning-meeting/market-congestion-planning-studies---south/

[39] https://www.spp.org/documents/61365/2021%20itp%20scope%20mopc%20and%20board%20approved.pdf

External Areas Forecasts Development

The 2019 Merged Load Forecast for Energy Planning forecast did not include External (non-MISO) companies' forecasts, so when available, External areas utilized respective regional model forecasts and when no regional forecast was available, the latest Multiregional Modeling Working Group (MMWG) model was used to create associated forecasts. External forecasts are defined in Table 19 and Future-specific adjustments will follow a similar process as shown in Table 18. Additionally, External areas utilized ABB's Velocity Suite 2018 load shapes.

Peak Load (MW) and Annual Energy (GWh)			
External Area (MCPS-Defined)	**Future 1**	**Future 2**	**Future 3**
PJM	PJM 2020 Long-Term Load Forecast (Base)	Base + Future-Specific Adjustments	Base + Future-Specific Adjustments
SPP	2021 ITP Future 2 Forecast (40% annual EV growth rate applied to energy only)	2021 ITP Future 1 Forecast + Future-Specific Adjustments	2021 ITP Future 1 Forecast + Future-Specific Adjustments
TVA-Other *(includes Southeast, TVA, TVA-Other)*	2019 MMWG Powerflow Model (Base)	Base + Future-Specific Adjustments	Base + Future-Specific Adjustments
Manitoba Hydro	MTEP20 CFC Forecast[40]	MTEP20 CFC Forecast	MTEP20 CFC Forecast

Table 19: External Area Demand & Energy Forecast Source

[40] 2020 MISO Transmission Expansion Planning (MTEP20): https://www.misoenergy.org/planning/planning/mtep20/

Electrification Assumptions

In addition to the electrification assumptions that were developed for the MISO footprint, a set of similar assumptions were made for External areas with the collaboration of AEG. The load growth in External areas came from electrification assumptions and reference load growth. Each area's growth is detailed in Table 20, electrification growth in Future 1 for SPP and PJM is reflected as zero due to this growth being incorporated in their reference load forecasts. Additionally, Figure 80 through Figure 87 detail the electrification of each technology within each External area.

PJM			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	939,546	946,602	949,301
2039 Reference Growth	111,347	111,347	111,347
Electrification Growth	0	172,086	353,105
2039 Energy Forecast	1,050,893	1,230,036	1,413,753
SPP			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	297,320	299,152	299,964
2039 Reference Growth	69,616	53,481	53,481
Electrification Growth	0	41,795	84,889
2039 Energy Forecast	366,936	394,428	438,334
TVA-Other (Southeast, TVA, TVA-Other)			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	698,962	702,206	703,821
2039 Reference Growth	78,303	75,059	73,444
Electrification Growth	7,553	76,817	163,373
2039 Energy Forecast	784,817	854,082	940,638
Electrification Technologies	PEVs (Included in reference forecast for PJM & SPP)	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process

Table 20: External Area Forecast Growth (GWh)

PJM Electrification

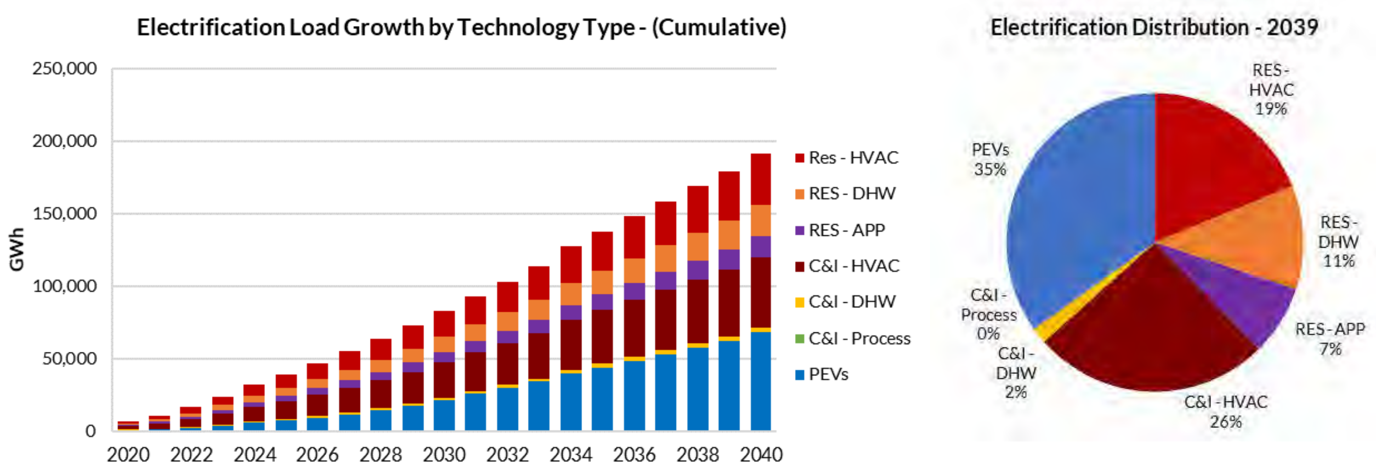


Figure 80: PJM Future 2 Electrification by End-Use

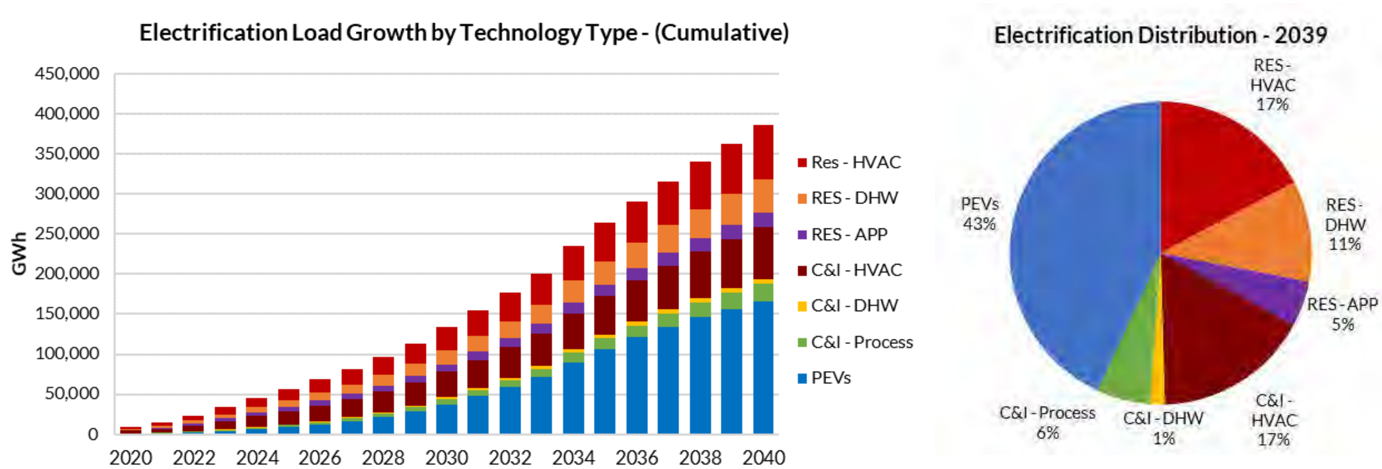


Figure 81: PJM Future 3 Electrification by End-Use

SPP Electrification

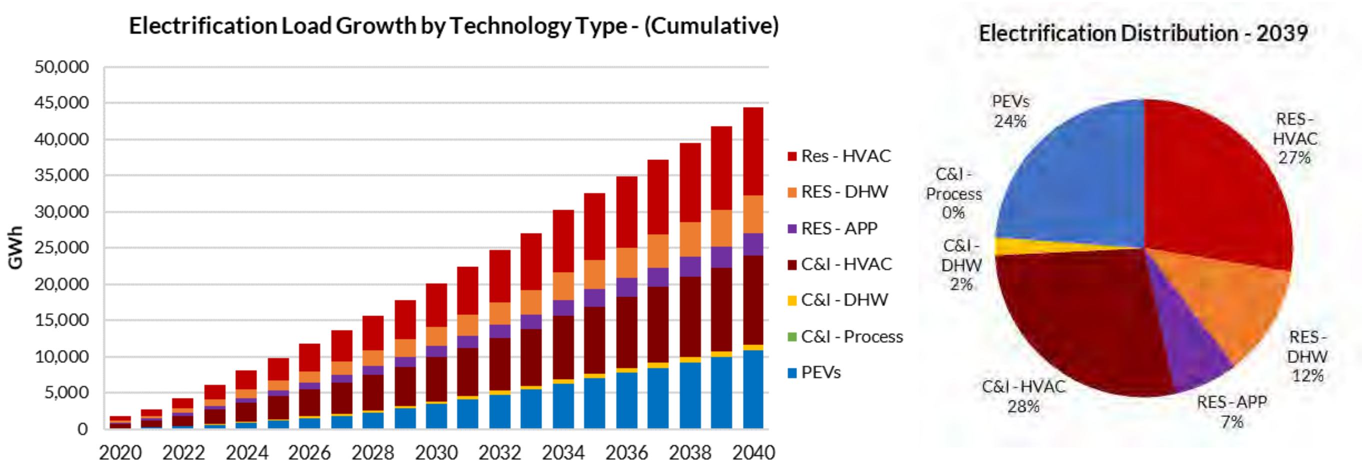


Figure 82: SPP Future 2 Electrification Broken Down by End-Use

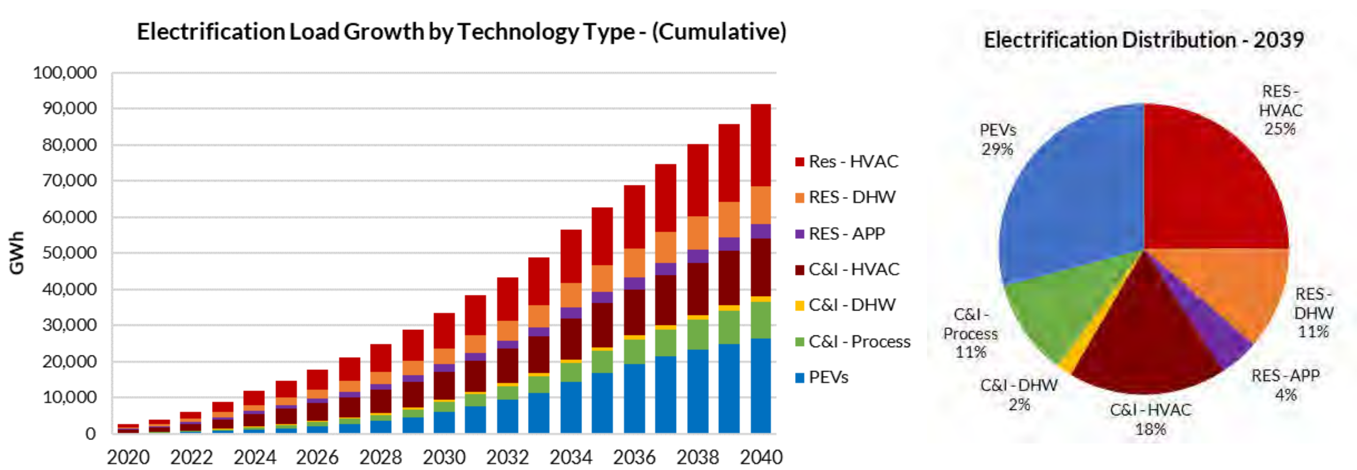


Figure 83: SPP Future 3 Electrification Broken Down by End-Use

TVA-Other Electrification

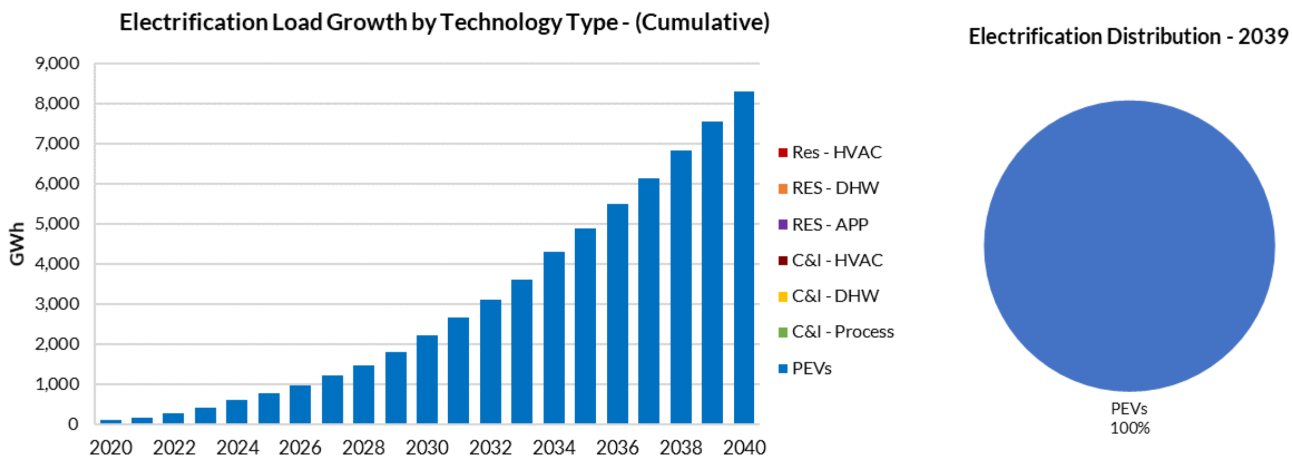


Figure 84: TVA-Other Future 1 Electrification Broken Down by End-Use

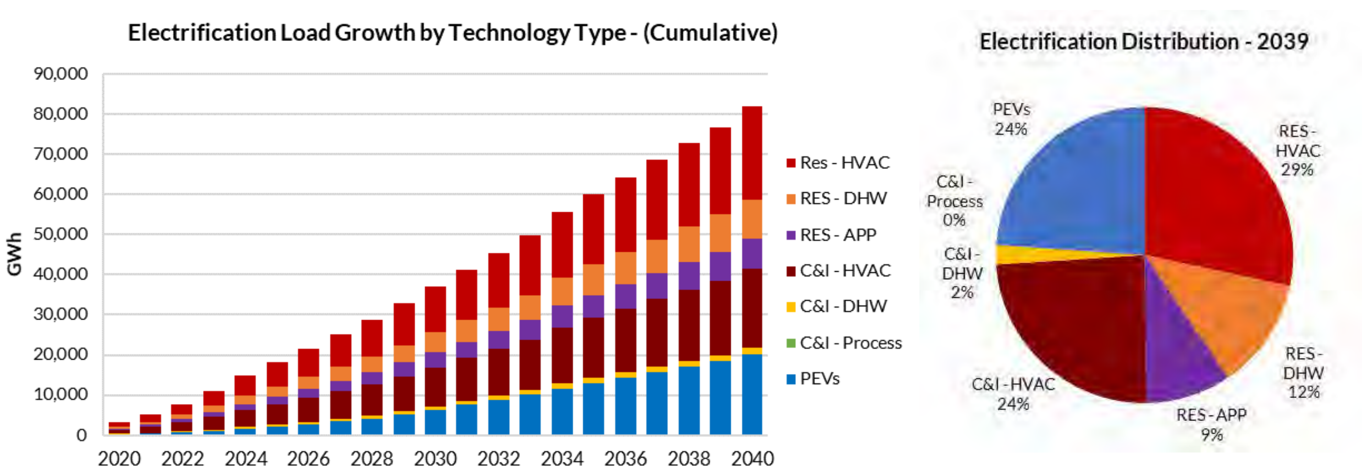


Figure 85: TVA-Other Future 2 Electrification Broken Down by End-Use

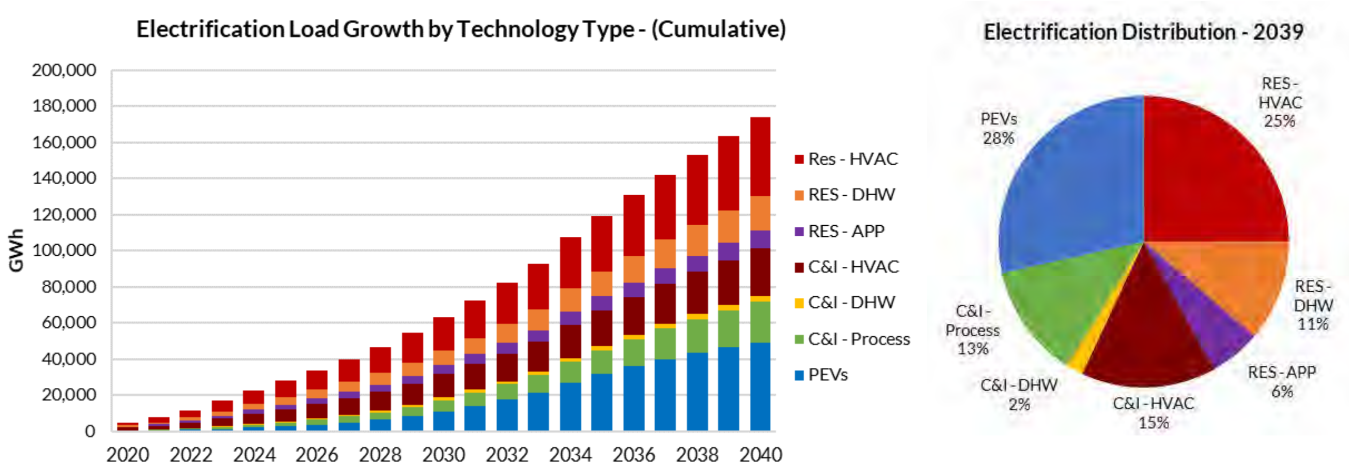


Figure 86: TVA-Other Future 3 Electrification Broken Down by End-Use

External Region Electrification Summary

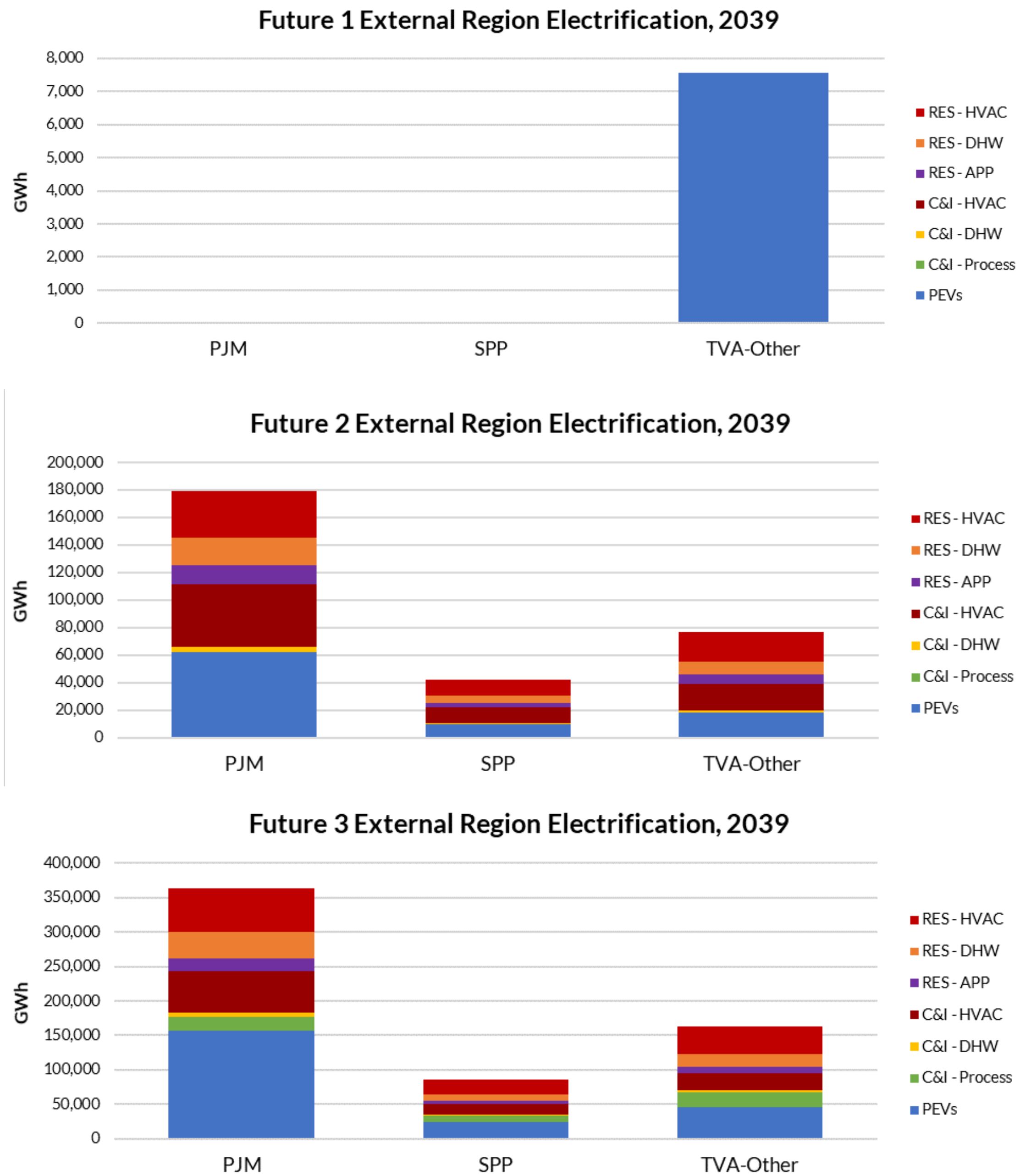


Figure 87: External Region Future Scenario Electrification[41]

[41] The only electrification in Future 1 happens in the external region TVA-Other due to SPP and PJM's Future 1 forecasts already including EVs.

External Expansion Results

While comparing the expansion results of the External regions across each Future scenario, there are several key findings of note:

- All scenarios have very different expansions; this is due to large contrasts among the regions with respect to geography, resource retirements, and current resource mixes.
- Wind, solar, and hybrid resource expansion is largely driven by decarbonization and each underlying load shape. In Future 3 there is significantly more wind than the other two cases; this is primarily due to the increase in load and 80% carbon reduction.
- Battery installation is driven by increased load and decarbonization.
- Age-based retirement assumptions for nuclear, wind, solar, and "other" resources remain the same across scenarios, with the exception of SPP Future 1. In this future, MISO incorporated retirement assumptions in SPP's Future 2. Additionally, all retired wind is repowered and reflected in the resource addition totals.
- In Future 3, the CC+CCS resource proxy units are needed in the later years of the study to serve base load with low CO_2 emissions, while maintaining a high capacity factor.
- Distributed solar (DGPV) and energy efficiency (EE) programs selected by EGEAS for TVA-Other (TVAO) remained the same across all scenarios. SPP Future 2 selected an additional EE program compared with Futures 1 and 3. Lastly, PJM's first two Futures both selected two DGPV and EE programs, while Future 3 selected one of each. A list of EGEAS-offered and selected programs for External regions is found below in Table 22.

Over the course of the following pages (Table 21 through Table 24) the detailed expansion results of each External Future scenario are displayed. Following the figures in each section are resource-specific additions and retirement (R&A) tables, each table details R&A capacities applicable for each region and milestone year.

Future Resource Additions (MW)											
Area	Future	CC	CT	CC+CCS	Wind	Solar	Hybrid	Battery	Distributed Solar	EE	Total
PJM	Future 1	14,400	21,600	0	6,641	3,600	10,800	0	2,954	35,919	95,915
	Future 2	25,200	18,000	0	42,641	21,600	21,600	2,000	2,954	38,110	172,106
	Future 3	21,600	7,200	32,400	175,841	3,600	79,200	20,000	295	17,291	357,427
SPP	Future 1	9,600	14,400	0	15,600	2,400	6,000	8,500	1,100	1,197	58,797
	Future 2	21,600	9,600	0	24,256	4,800	2,400	6,000	1,100	3,253	73,009
	Future 3	18,000	12,000	10,800	38,656	1,200	6,000	9,500	1,100	1,332	98,588
TVA-Other	Future 1	16,800	1,200	0	14,405	0	26,400	0	118	346	59,269
	Future 2	16,800	7,200	0	60,005	13,200	25,200	300	118	370	123,193
	Future 3	18,000	18,000	28,800	123,605	39,600	14,400	32,000	118	382	274,905

Future Resource Retirements (MW)									
Area	Future	Coal	Gas	Nuclear	Oil	Wind	Solar	Other	Total
PJM	Future 1	53,068	9,312	0	7,002	6,641	251	0	76,275
	Future 2	54,680	15,348	0	7,136	6,641	251	0	84,055
	Future 3	55,737	57,793	0	7,502	6,641	251	0	127,924
SPP	Future 1	18,361	5,631	0	1,260	0	0	0	25,252
	Future 2	19,842	13,205	0	1,361	9,856	50	0	44,314
	Future 3	20,524	24,516	0	1,392	9,856	50	0	56,337
TVA-Other	Future 1	42,295	7,350	0	1,910	1,205	165	276	53,201
	Future 2	43,840	9,117	0	1,910	1,205	165	276	56,513
	Future 3	45,040	55,246	0	1,990	1,205	165	276	103,922

Table 21: External Resource Additions and Retirements Summary

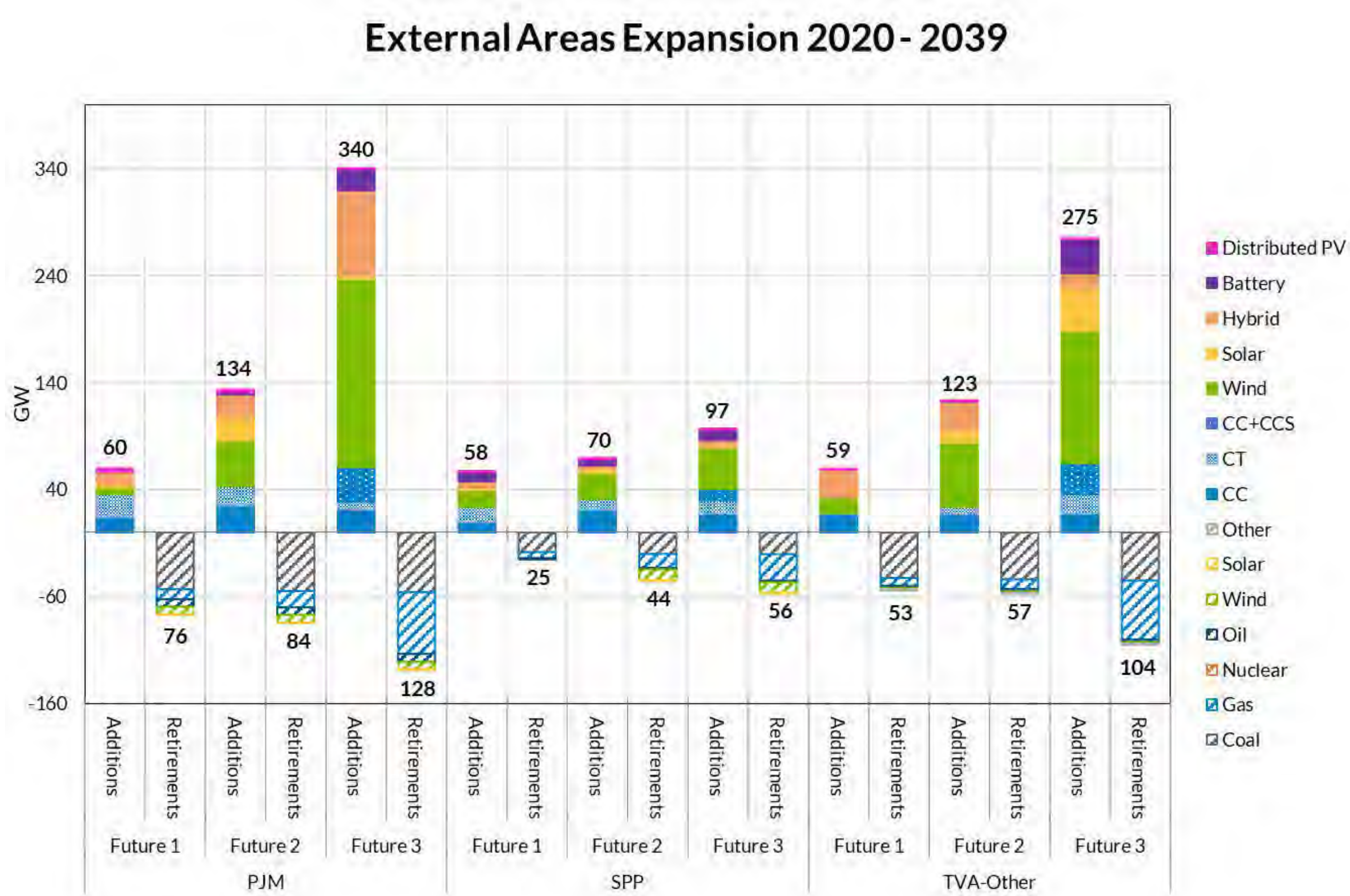


Figure 88: External Region Expansion Summary

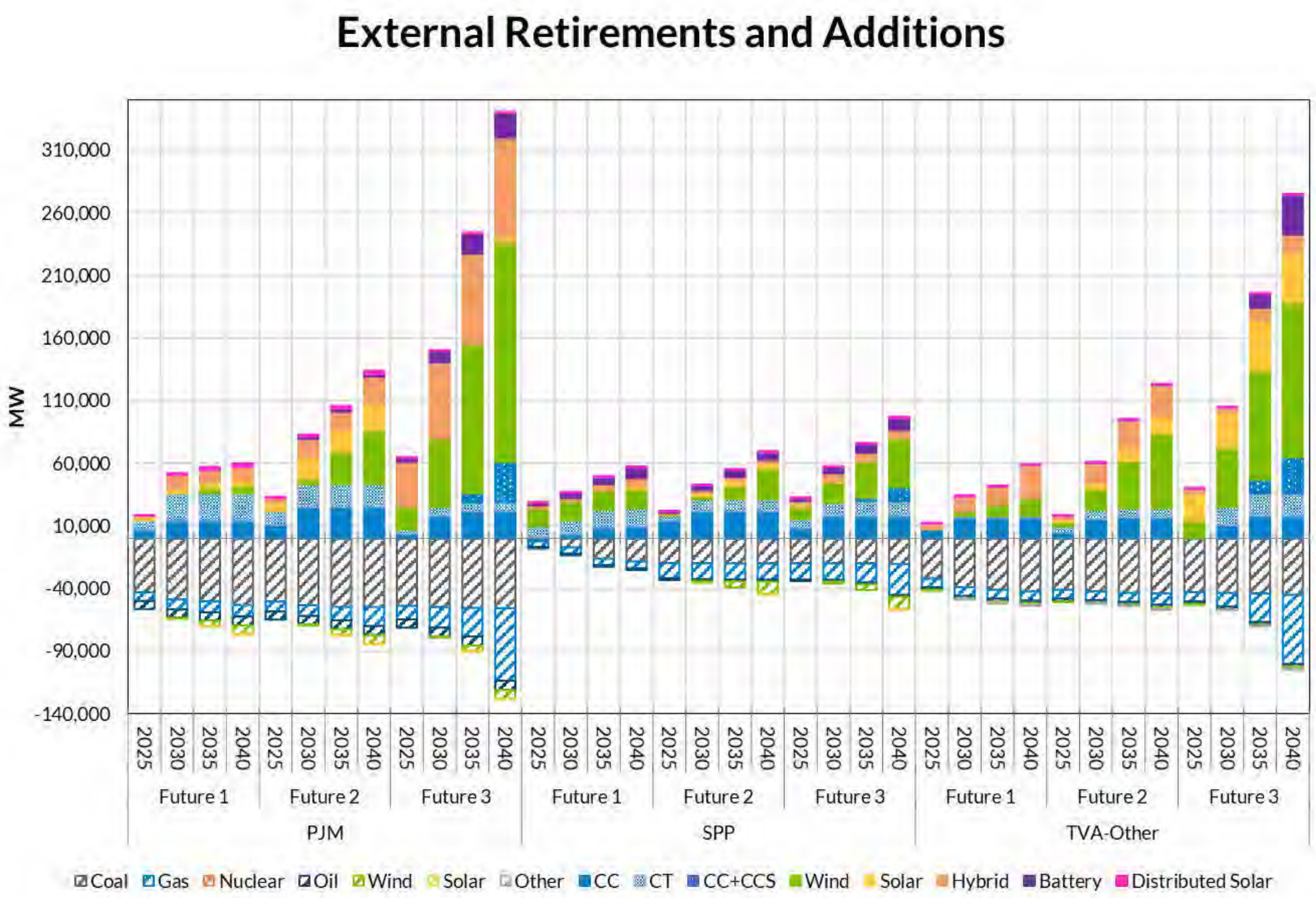


Figure 89: External Resource Additions and Retirements per Milestone Year (Cumulative)

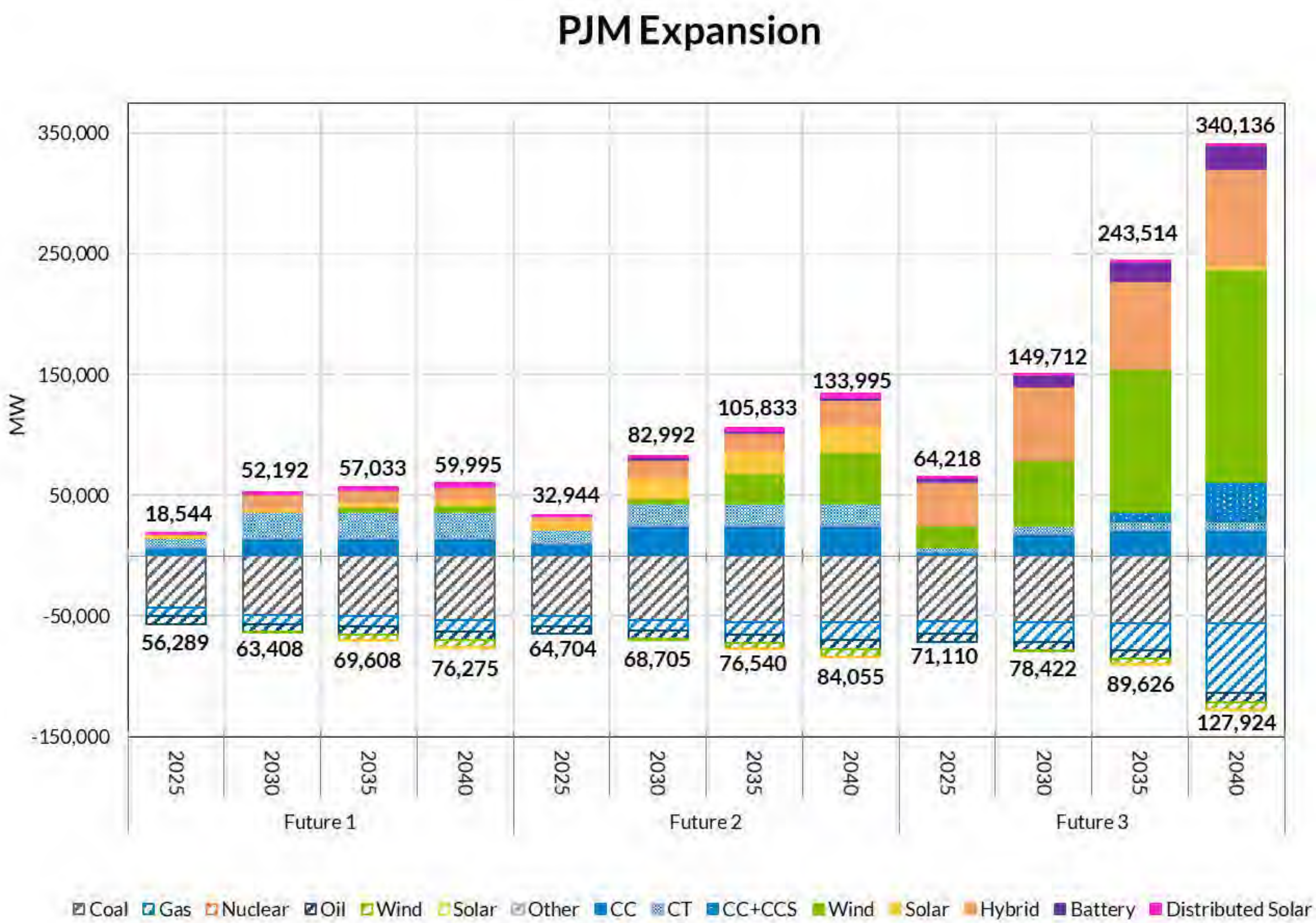


Figure 90: PJM Resource Additions and Retirements per Milestone Year (Cumulative)

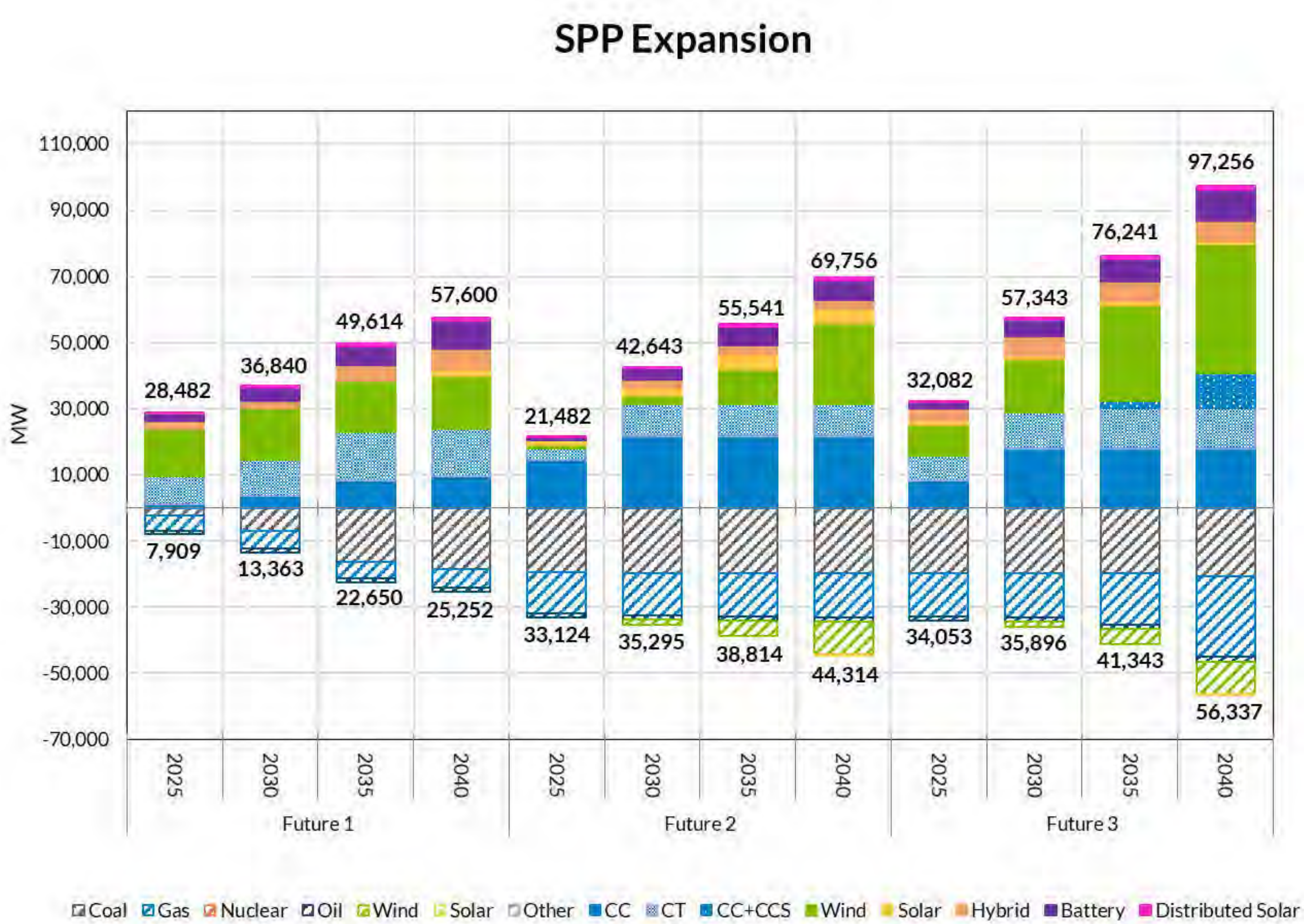


Figure 91: SPP Resource Additions and Retirements per Milestone Year (Cumulative)

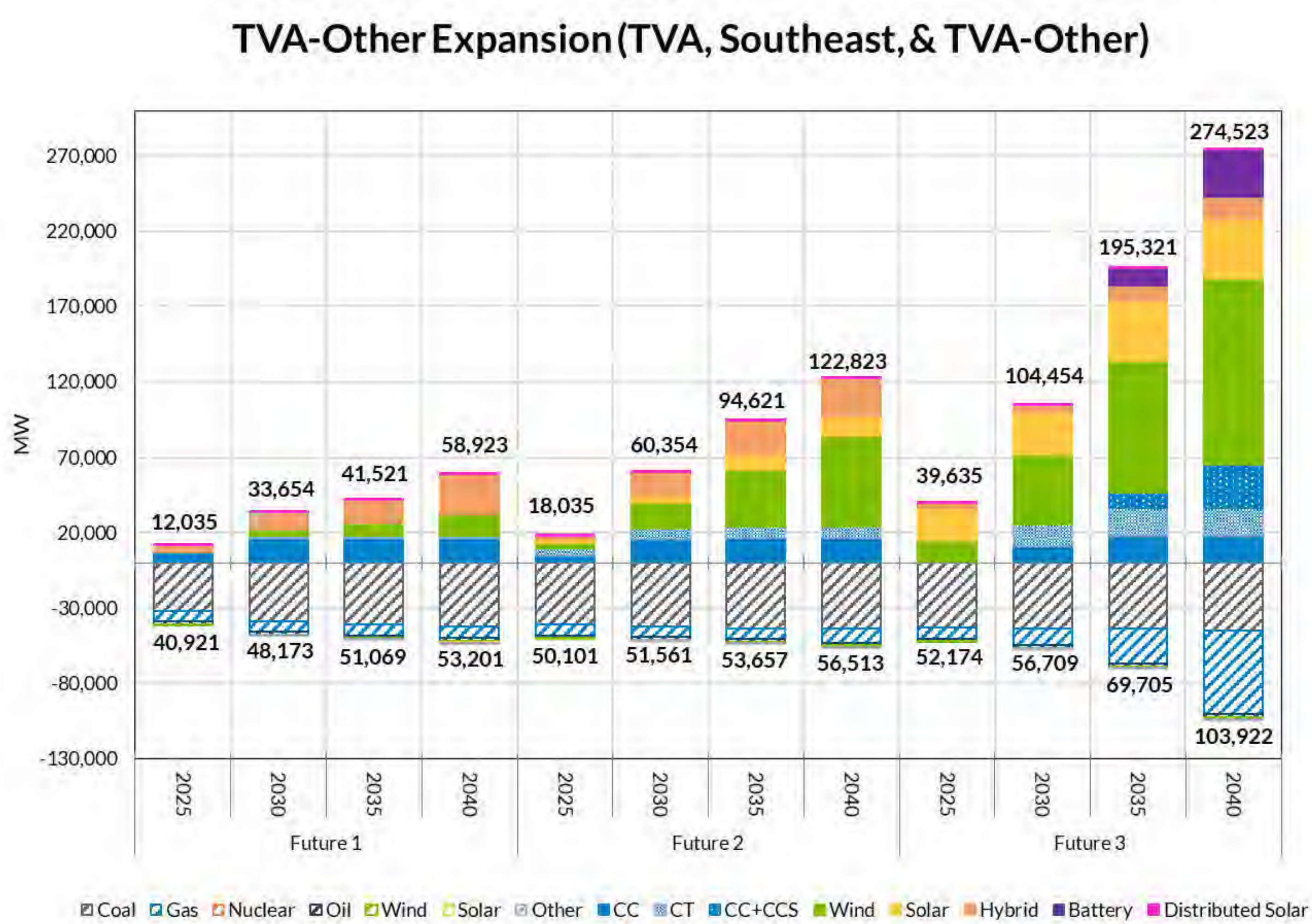


Figure 92: TVA-Other Resource Additions and Retirements per Milestone Year (Cumulative)

External DER Programs: Respective Offerings and Selections

DER Type	EGEAS Program Block	DER Program(s) Included	PJM	SPP	TVAO
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable	*Offered*	*Offered*	*Offered*
DR	C&I Price Response	C&I Price Response	*Offered*	*Offered*	*Offered*
DR	Res. Direct Load Control	Res. Direct Load Control	*Offered*	*Offered*	-
DR	Res. Price Response	Res. Price Response	*Offered*	*Offered*	-
EE	C&I EE	Custom Incentive, Lighting, New Construction, Prescriptive Rebate, Retro commissioning	F1, F2, F3	F2	F1, F2, F3
EE	Res. EE	Appliance Incentives, Appliance Recycling, Behavioral Programs, Lighting, Low Income, Multifamily, New Construction, School Kits, Whole Home Audit	F1, F2	F1, F2, F3	F1, F2, F3
DG	C&I Customer Solar PV	C&I Customer Solar PV	F1, F2	F1, F2, F3	F1, F2, F3
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Util Incentive Batt Storage	*Offered*	*Offered*	*Offered*
DG	C&I Utility Incentive Solar PV	C&I Utility Incentive Solar PV	F1, F2, F3	F1, F2, F3	-
DG	Res. Customer Solar PV	Res. Customer Solar PV	*Offered*	*Offered*	*Offered*
DG	Res. Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Util Incentive Batt Storage	*Offered*	*Offered*	*Offered*
DG	Res. Utility Incentive Solar PV	Res. Utility Incentive Solar PV	*Offered*	*Offered*	-

Table 22: External DER Program Mapping, with Respective Offerings and Selection by Future in EGEAS

External Area Resource Additions per Future (MW) - *Cumulative*										
Future/Area	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Total**
PJM Future 1	**2025**	7,200	7,200	0	0	3,600	0	0	544	18,544
	2030	14,400	21,600	0	245	3,600	10,800	0	1,547	52,192
	2035	14,400	21,600	0	4,129	3,600	10,800	0	2,504	57,033
	2040	14,400	21,600	0	6,641	3,600	10,800	0	2,954	59,995
PJM Future 2	**2025**	10,800	10,800	0	0	7,200	3,600	0	544	32,944
	2030	25,200	18,000	0	3,845	18,000	14,400	2,000	1,547	82,992
	2035	25,200	18,000	0	25,729	18,000	14,400	2,000	2,504	105,833
	2040	25,200	18,000	0	42,641	21,600	21,600	2,000	2,954	133,995
PJM Future 3	**2025**	3,600	3,600	0	18,000	0	36,000	3,000	18	64,218
	2030	18,000	7,200	0	54,245	0	61,200	9,000	68	149,712
	2035	21,600	7,200	7,200	119,329	0	72,000	16,000	185	243,514
	2040	21,600	7,200	32,400	175,841	3,600	79,200	20,000	295	340,136
SPP Future 1	**2025**	1,200	8,400	0	14,400	0	2,400	2,000	82	28,482
	2030	3,600	10,800	0	15,600	0	2,400	4,000	440	36,840
	2035	8,400	14,400	0	15,600	0	4,800	5,500	914	49,614
	2040	9,600	14,400	0	15,600	2,400	6,000	8,500	1,100	57,600
SPP Future 2	**2025**	14,400	3,600	0	1,200	1,200	0	1,000	82	21,482
	2030	21,600	9,600	0	2,703	2,400	2,400	3,500	440	42,643
	2035	21,600	9,600	0	10,727	4,800	2,400	5,500	914	55,541
	2040	21,600	9,600	0	24,256	4,800	2,400	6,000	1,100	69,756
SPP Future 3	**2025**	8,400	7,200	0	9,600	1,200	3,600	2,000	82	32,082
	2030	18,000	10,800	0	15,903	1,200	6,000	5,000	440	57,343
	2035	18,000	12,000	2,400	28,727	1,200	6,000	7,000	914	76,241
	2040	18,000	12,000	10,800	38,656	1,200	6,000	9,500	1,100	97,256
TVA-Other Future 1	**2025**	7,200	0	0	29	0	4,800	0	7	12,035
	2030	16,800	1,200	0	3,629	0	12,000	0	25	33,654
	2035	16,800	1,200	0	9,055	0	14,400	0	66	41,521
	2040	16,800	1,200	0	14,405	0	26,400	0	118	58,923
TVA-Other Future 2	**2025**	4,800	4,800	0	3,629	2,400	2,400	0	7	18,035
	2030	15,600	7,200	0	16,829	4,800	15,600	300	25	60,354
	2035	16,800	7,200	0	37,855	10,800	21,600	300	66	94,621
	2040	16,800	7,200	0	60,005	13,200	25,200	300	118	122,823
TVA-Other Future 3	**2025**	0	0	0	14,429	21,600	3,600	0	7	39,635
	2030	10,800	14,400	0	46,829	28,800	3,600	0	25	104,454
	2035	18,000	18,000	10,800	87,055	39,600	10,800	11,000	66	195,321
	2040	18,000	18,000	28,800	123,605	39,600	14,400	32,000	118	274,523

Table 23: External Resource Additions by Milestone Year

External Area Resource Retirements per Future (MW) - *Cumulative*									
Future/Area	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Total**
PJM Future 1	**2025**	43,061	6,829	0	6,400	0	0	0	56,289
	2030	48,723	7,981	0	6,460	245	0	0	63,408
	2035	50,263	8,569	0	6,604	4,129	43	0	69,608
	2040	53,068	9,312	0	7,002	6,641	251	0	76,275
PJM Future 2	**2025**	50,263	7,981	0	6,460	0	0	0	64,704
	2030	53,287	8,569	0	6,604	245	0	0	68,705
	2035	54,680	10,687	0	7,002	4,129	43	0	76,540
	2040	54,680	15,348	0	7,136	6,641	251	0	84,055
PJM Future 3	**2025**	53,819	10,687	0	6,604	0	0	0	71,110
	2030	54,680	16,495	0	7,002	245	0	0	78,422
	2035	55,469	22,703	0	7,283	4,129	43	0	89,626
	2040	55,737	57,793	0	7,502	6,641	251	0	127,924
SPP Future 1	**2025**	2,318	4,588	0	1,003	0	0	0	7,909
	2030	7,089	5,062	0	1,213	0	0	0	13,363
	2035	16,238	5,200	0	1,213	0	0	0	22,650
	2040	18,361	5,631	0	1,260	0	0	0	25,252
SPP Future 2	**2025**	19,563	12,329	0	1,232	0	0	0	33,124
	2030	19,842	12,649	0	1,301	1,503	0	0	35,295
	2035	19,842	12,938	0	1,307	4,727	0	0	38,814
	2040	19,842	13,205	0	1,361	9,856	50	0	44,314
SPP Future 3	**2025**	19,842	12,938	0	1,273	0	0	0	34,053
	2030	19,842	13,245	0	1,307	1,503	0	0	35,896
	2035	19,842	15,413	0	1,361	4,727	0	0	41,343
	2040	20,524	24,516	0	1,392	9,856	50	0	56,337
TVA-Other Future 1	**2025**	31,981	7,001	0	1,910	29	0	0	40,921
	2030	38,907	7,051	0	1,910	29	0	276	48,173
	2035	41,111	7,051	0	1,910	655	66	276	51,069
	2040	42,295	7,350	0	1,910	1,205	165	276	53,201
TVA-Other Future 2	**2025**	41,111	7,051	0	1,910	29	0	0	50,101
	2030	42,295	7,051	0	1,910	29	0	276	51,561
	2035	43,400	7,350	0	1,910	655	66	276	53,657
	2040	43,840	9,117	0	1,910	1,205	165	276	56,513
TVA-Other Future 3	**2025**	42,885	7,350	0	1,910	29	0	0	52,174
	2030	43,400	11,094	0	1,910	29	0	276	56,709
	2035	43,840	22,878	0	1,990	655	66	276	69,705
	2040	45,040	55,246	0	1,990	1,205	165	276	103,922

Table 24: External Resource Retirements by Milestone Year

Presentation Materials

Futures Workshops & MISO Stakeholder Presentations:

August 15, 2019: MTEP Futures Workshop – Purpose of MISO Futures

September 26, 2019: MTEP Futures Workshop – Drafting of Futures Assumptions

October 17, 2019: MTEP Futures Workshop – Walkthrough of Initial Strawman

December 5, 2019: MTEP Futures Workshop – Detailing Various Assumptions

February 13, 2020: MTEP Futures Workshop – Updated Assumptions

April 27, 2020: MTEP Futures Workshop – Final Assumptions

July 13, 2020: MTEP Futures Workshop – Siting Review

August 12, 2020: PAC Presentation – Draft Expansion and Siting Results

November 11, 2020: PAC Presentation – Final Expansion and Siting Results

September 22, 2021: PAC Presentation – Correction to Futures Resource Expansion

October 13, 2021: PAC Presentation – Revised Future 2 and 3 Expansion Results for MISO

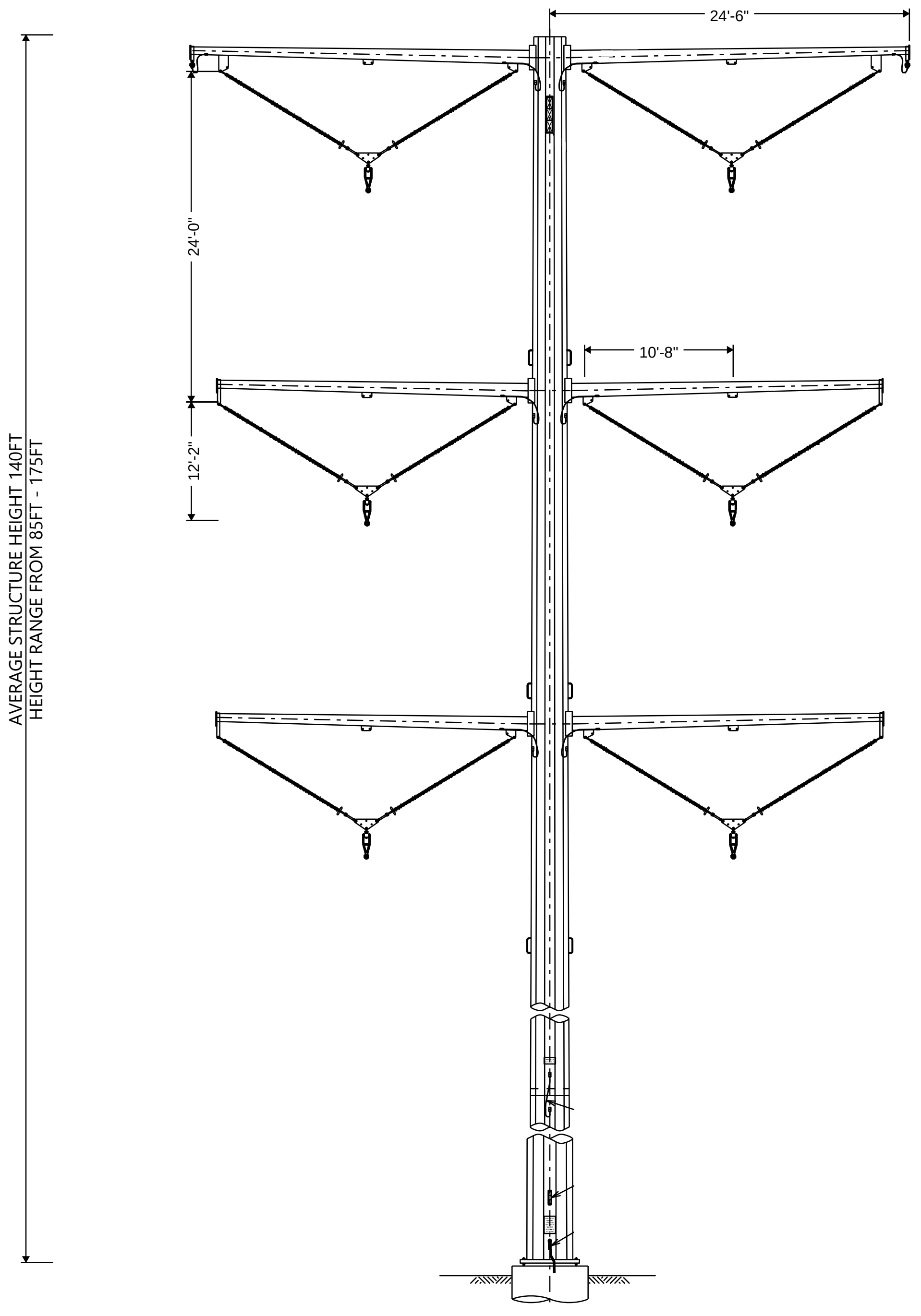
November 10, 2021: PAC Presentation – Revised Futures Siting and External Expansion Results

Full Futures Evolution Material Available at: MISOEnergy.org

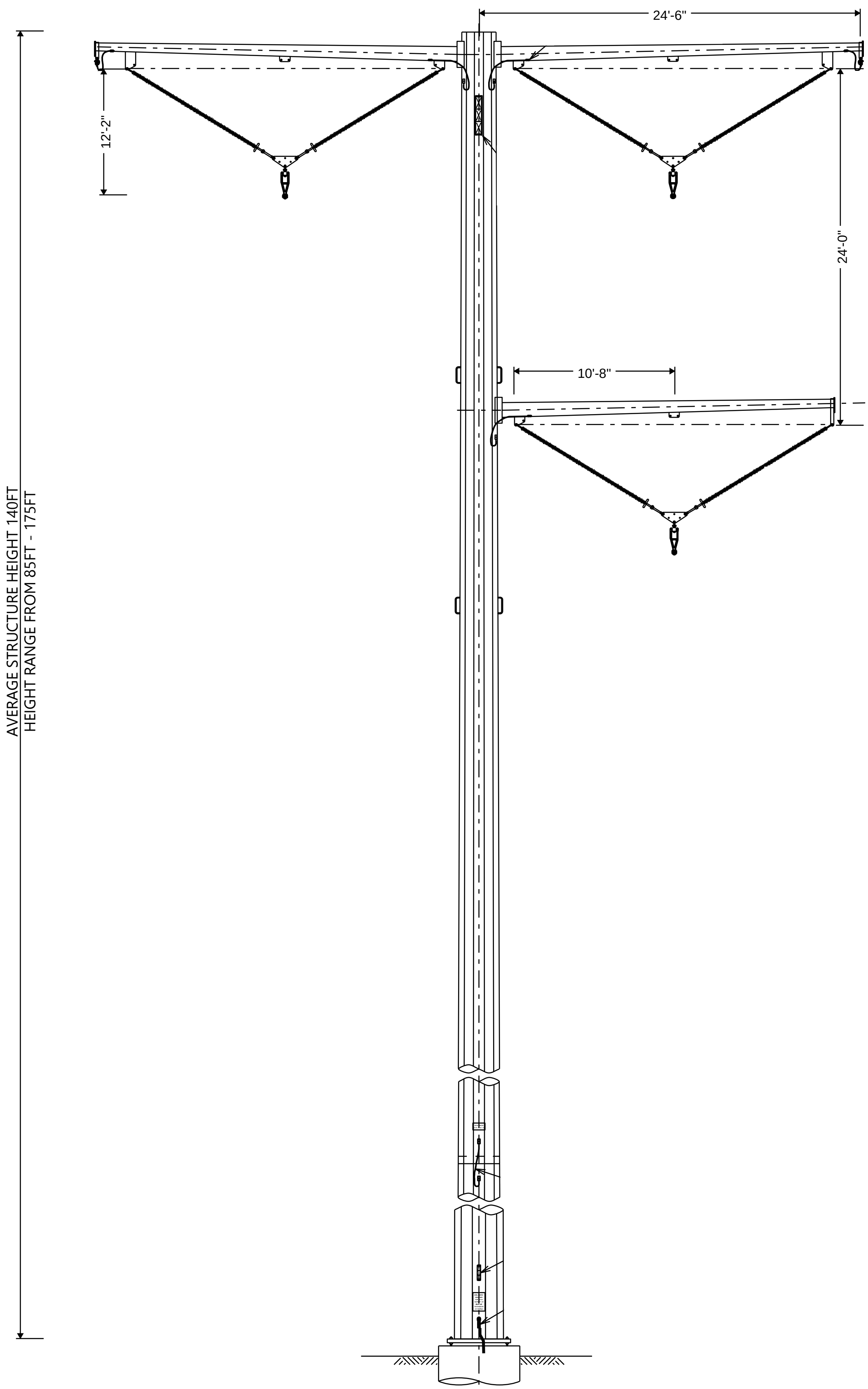
misoenergy.org

Appendix H

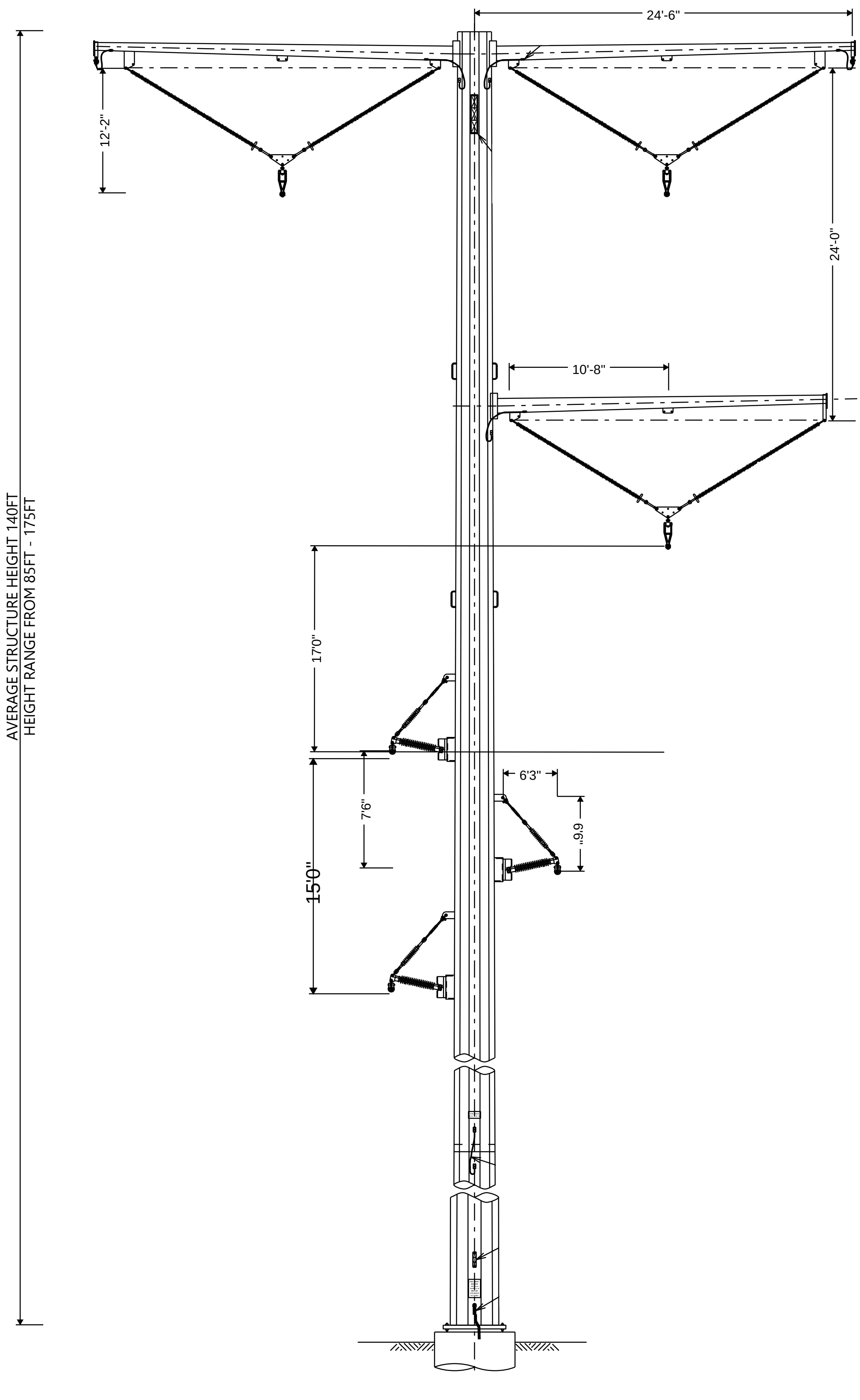
Technical Drawings of Proposed Structures



LOOKING AHEAD
DOUBLE-CIRCUIT MONOPOLE
TANGENT STRUCTURE
STANDARD SPAN

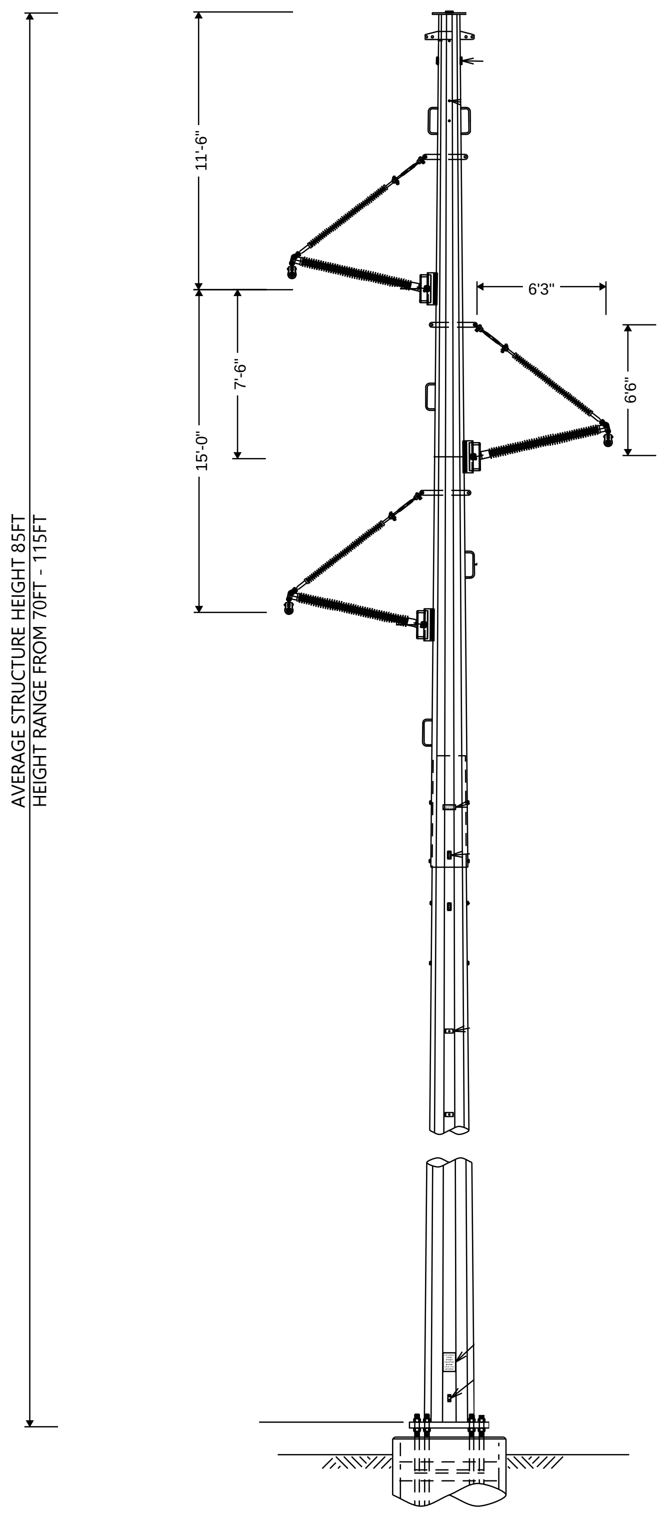


LOOKING AHEAD
SINGLE-CIRCUIT 345kV MONOPOLE
TANGENT STRUCTURE
STANDARD SPAN



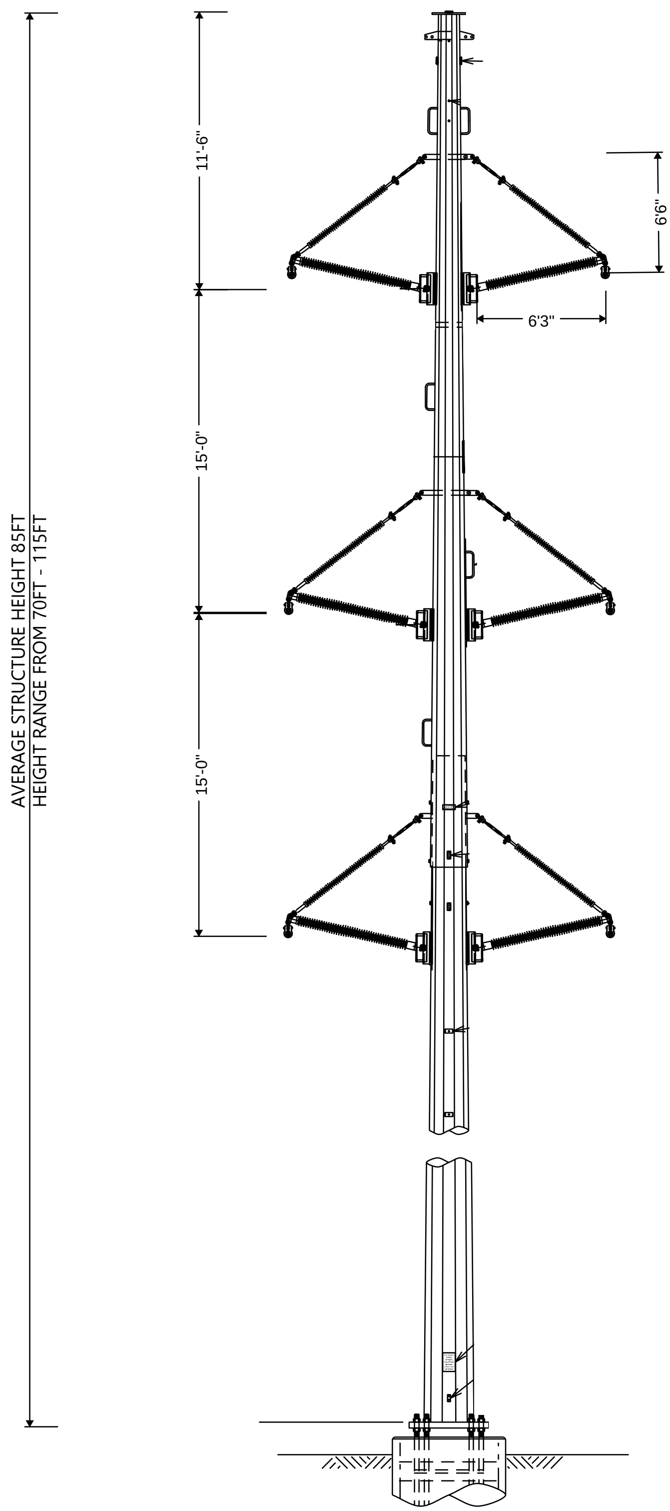
LOOKING AHEAD

SINGLE-CIRCUIT 345kV MONOPOLE
TANGENT STRUCTURE w/
115kV/69kV UB
STANDARD SPAN



LOOKING AHEAD

SINGLE-CIRCUIT 161kV MONOPOLE
TANGENT STRUCTURE
STANDARD SPAN



LOOKING AHEAD
DOUBLE-CIRCUIT 161kV/69kV MONOPOLE
TANGENT STRUCTURE
STANDARD SPAN

Appendix I

Energy Conservation and Efficiency Programs

Minnesota Rule 7849.0290 requires a Certificate of Need application to provide information related to an applicant's energy conservation and efficiency programs and a quantification of the impact of these programs on the forecast information required by Minn. R. 7849.0270. The Applicant requested an exemption from this content requirement, and proposed to provide substitute information related to its conservation programs in Minnesota. The Applicant also proposed to provide information regarding how conservation and energy efficiency was considered by the Midcontinent Independent System Operator, Inc. (MISO) in its evaluation of the Project.[1] In response, the Department agreed that the proposed information will better inform the record as to the need for the proposed Project and recommended that the Commission grant the requested exemption with the provision of the proposed alternative data.[2] The Commission approved the Applicants' requested exemption with provision of the alternative data.[3] The required information is provided below.

For decades, Minnesota has been a national leader in energy efficiency. The state's utility-sponsored energy efficiency programs are among the longest-standing in the country, and Minnesota is the only Midwestern state that is consistently ranked in the top ten on the American Council for an Energy Efficient Economy's (ACEEE) State Energy Efficiency Scorecard. Minnesota utilities' energy savings achievements through demand-side management (DSM) have saved billions of dollars for customers and avoided millions of tons of greenhouse gas and other pollutants while creating and supporting jobs in the state.[4] Xcel Energy provides below information related to their conservation programs, as well as a discussion of how conservation and energy efficiency was considered by MISO in its evaluation and approval of the Project.

---

[1] *See* Docket No. E002/CN-22-532, *In the Matter of the Application for a Certificate of Need for the Mankato to Mississippi River 345 kV Transmission Project*, Request for Exemption from Certain Certificate of Need Application Content Requirements at 8 (Oct. 17, 2023).

[2] *See* Docket No. E002/CN-22-532, Comments of the Minnesota Department of Commerce, Division of Energy Resources at 4-5 (Nov. 13, 2023).

[3] *See* Docket No. E002/CN-22-532, Consent Items at 1 (Dec. 7, 2023).

[4] The Aggregate Economic Impact of the Conservation Improvement Program 2008-2013, Minnesota Department of Commerce, Division of Energy Resources, Cadmus (Oct. 2015), https://mn.gov/commerce-stat/pdfs/card-report-aggregate-eco-impact-cip-2008-2013.pdf.

A. Xcel Energy's Energy Conservation and Efficiency Programs

Xcel Energy has maintained a consistent and high level of DSM achievement. Between 1994 and 2022, Xcel Energy invested nearly $2.2 billion (nominal) resulting in 11,813 gigawatt hours (GWh) of electric energy savings, 3,733 megawatts (MW) of electric demand savings and an estimated 19.92 million dekatherms (Dth) of natural gas savings.[5] In its 2024-2026 Energy Conservation and Optimization Triennial Plan, dated June 29, 2023 (Xcel Energy's ECO Triennial Plan), Xcel Energy continued to strive to provide customers with a wide variety of options for saving energy. Xcel Energy's ECO Triennial Plan proposed ambitious goals of saving 1,734 GWh, 674 MW, and 3,918,970 Dth over the three-year period at a cost of approximately $530 million.[6]

Further, as provided below in **Table I-1** and **Figure I-1**, in the January 29, 2024 Update to Xcel Energy's ECO Triennial Plan, Xcel Energy revised its savings goals outlined above to include 1,871 GWh, 674 MW, and 3,532,624 Dth over the same three-year period at a cost of approximately $588 million.[7] These proposed savings goals also aligned with Xcel Energy's DSM commitments in its most recent Integrated Resource Plan (IRP).[8]

[5] *See* Docket No. E,G002/CIP-23-92, Xcel Energy 2024-2026 Energy Conservation and Optimization Plan (June 29, 2023) at 2.

[6] *See id.* at 1.

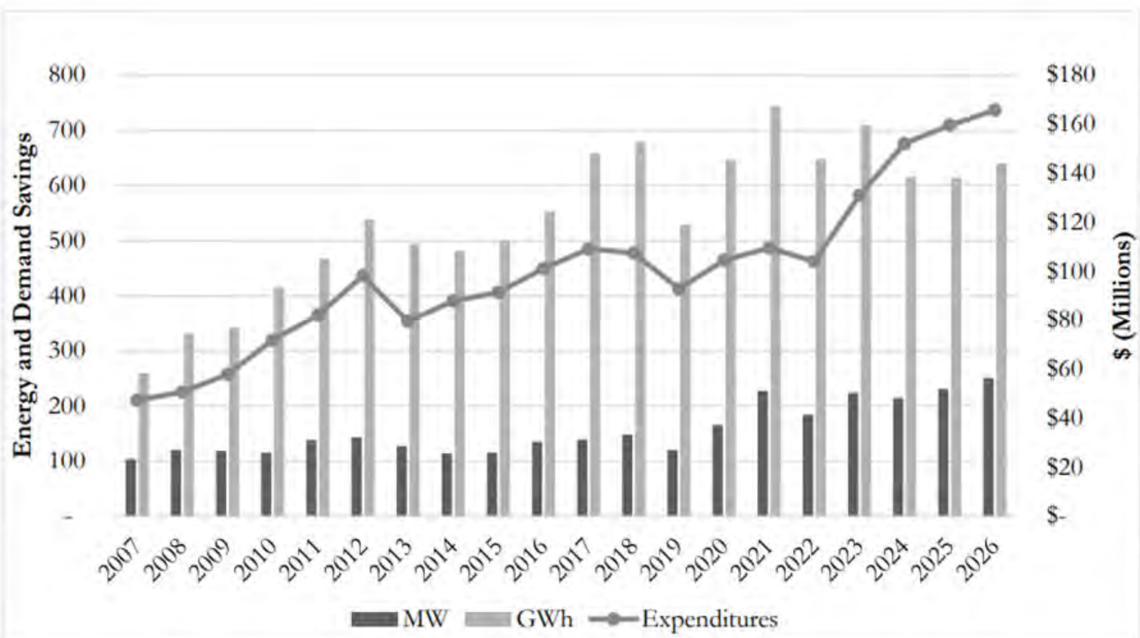
[7] *See* Docket No. E,G002/CIP-23-92, Xcel Energy 2024-2026 Energy Conservation and Optimization Plan Compliance Filing Update (January 29, 2024) at 1.

[8] *See* Docket No. E002/RP-24-67, *In the Matter of Xcel Energy's 2024-2040 Integrated Resource Plan*, 2024-2040 Upper Midwest Integrated Resource Plan (Feb. 1, 2024).

Table I-1
Proposed Xcel Energy Portfolio Budgets and Savings, 2024-2026[9]

		2024	2025	2026
Electric Spending		$135,640,027	$141,047,902	$147,294,579
Natural Gas Spending		$29,820,687	$31,603,116	$35,414,954
Electric Demand Savings (kW)		206,960	223,451	243,149
Electric Energy Savings (MWh)	First-Year	570,375	569,358	595,344
	Lifetime	8,954,889	8,938,924	9,346,905
Natural Gas Energy Savings (Dth)	First-Year	1,091,887	1,169,560	1,271,177
	Lifetime	15,360,340	15,762,865	17,204,888
Lifetime Cost of Saved Energy	Electric ($/kWh)	$0.0151	$0.0158	$0.0158
	Gas ($/Dth)	$1.9414	$2.0066	$2.0584

Figure I-1
Xcel Energy's Energy Conservation and Optimization Electric Achievements, 2007-2026[10]



[9] *See* Docket No. E,G002/CIP-23-92, Xcel Energy 2024-2026 Energy Conservation and Optimization Plan Compliance Filing Update (January 29, 2024) at 1.

[10] *See id.* at 3.

Likewise, Xcel Energy's 2024 IRP filing included energy efficiency (EE) and demand response (DR) investments.[11] Xcel Energy proposed to seek to achieve EE savings levels ranging from 2 to 2.5 percent annually, which, when combined with naturally occurring EE, will achieve average savings of over 780 GWh of energy in each of 2024 through 2040.[12] Further, while Xcel Energy exceeded the Commission's 2019 requirement to secure an incremental 400 MW of DR load by the end of 2023, the 2024 IRP filing also proposed to increase Xcel Energy's DR load to 1,365 MW in the next five years.[13]

B. MISO's Consideration of Conservation and Energy Efficiency in MTEP21

The Mankato – Mississippi River Transmission Project is not needed to support growing peak demand. Rather, the Project is needed to provide additional transmission capacity to reliably transport increasing amounts of renewable generation on the system. More specifically, the existing transmission system in southern Minnesota plays a key role in transporting and delivering renewable energy from Minnesota, North Dakota, and South Dakota to regional load centers of the Twin Cities and areas to the East and South. The Project is needed to provide additional transmission capacity, to mitigate current capacity issues, and to improve electric system reliability throughout the region as more renewable energy resources are added to the electric system in and around the region. Given that the need for this Project is not driven by increases in peak demand, the Commission granted the Applicant's request for exemption from certain forecasting data for Applicants' service areas and systems as required by Minn. R. 7849.0270, subp. 2. Instead, the Applicant committed to provide forecast information utilized by MISO in studying, planning, and analyzing the Project as part of MISO's 2021 Transmission Expansion Plan (MTEP21).

MISO's annual transmission planning process develops multiple future scenarios to study transmission needs under a variety of economic, policy, and technological

[11] *See* Docket No. E002/RP-24-67, *In the Matter of Xcel Energy's 2024-2040 Integrated Resource Plan*, 2024-2040 Upper Midwest Integrated Resource Plan (Feb. 1, 2024).

[12] *See* Docket No. E002/RP-24-67, 2024-2040 Upper Midwest Integrated Resource Plan, Appendix J (Feb. 1, 2024) at 3.

[13] *See id.* at 11.

possibilities. Each future scenario contains assumptions about future fuel costs, environmental regulations, demand and energy levels, and technological possibilities.

As part of the development of these future scenarios, MISO develops forecasts for conservation, energy efficiency, and demand response, collectively referred to as "Distributed Energy Resources" (DER) by MISO. These forecasts are developed by aggregating each MISO member's load forecasts. To consider a broader range of potential DER outcomes, MISO creates forecasts considering varying adoption rates, technological advancements, and economic factors. MISO's forecasts are developed for each of MISO's 10 Local Resource Zones, to consider regional differences, and then are aggregated to a MISO-wide forecast.

Similar to previous MTEPs, MISO commissioned Applied Energy Group (AEG) to develop new DER technical potential for MTEP21. AEG developed estimates of DER impacts through survey of load-serving entities (LSE) and secondary research. Based on analysis for MTEP20, with updated utility information and Futures narratives for this cycle, technical potential represents feasible potential under each scenario. To support modeling, AEG compiled DER programs by type and cost into program blocks for use in MISO's Electric Generation Expansion Analysis System (EGEAS) – an integrated resource planning tool.

The DER resources were modeled as program blocks in three main categories: Demand Response (DR), Energy Efficiency (EE), and Distributed Generation (DG). The DER programs also fall into two sectors: Residential and Commercial and Industrial (C&I). A complete list of the DER programs considered by MISO in MTEP21 is provided below in **Table I-2**.

Table I-2
MTEP21 Distributed Energy Resource Programs[14]

DER Type	EGEAS Program Block	DER Program(s) Included
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable
DR	C&I Price Response	C&I Price Response
DR	Residential Direct Load Control	Res. Direct Load Control
DR	Residential Price Response	Res. Price Response
EE	C&I High-Cost EE	Customer Incentive High, New Construction High
EE	C&I Low-Cost EE*	Customer Incentive Low, Lighting Low, New Construction Low, Prescriptive Rebate Low, Retrocommissioning Low
EE	C&I Mid-Cost EE	Customer Incentive Mid, Lighting Mid, New Construction Mid, Prescriptive Rebate Mid, Retrocommissioning Mid
EE	Residential High-Cost EE	Appliance Incentives High, Appliance Recycling, Low Income, Multifamily High, New Construction High, School Kits, Whole Home Audit High
EE	Residential Low-Cost EE*	Appliance Incentives Low, Behavioral Programs, Lighting, Multifamily Low, New Construction Low, Whole Home Audit Low
DG	C&I Customer Solar PV*	C&I Customer Solar PV
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Utility Incentive Battery Storage
DG	C&I Utility Incentive Solar PV*	C&I Utility Incentive Solar PV
DG	Residential Customer Solar PV	Res. Customer Solar PV
DG	Residential Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Utility Incentive Battery Storage
DG	Residential Utility Incentive Solar PV	Res. Utility Incentive Solar PV

During the program selection phase for the MTEP21 Futures, each block was offered against supply-side alternatives to determine economic viability. For all three MTEP21 Futures, EGEAS selected the following program blocks, all within the C&I group: Customer PV, Utility Incentive PV, and Low-Cost Energy Efficiency. Additionally, Specific EE programs were grouped by cost into three tiers for C&I and two tiers for Residential.

Announced resources were included in Futures base assumptions. Several stakeholders submitted feedback detailing DERs they intend to add to their systems; these are also included in the totals below. Only selected programs and stakeholder additions were

[14] **Appendix G-3** at 42 (MTEP21 Report Addendum).

implemented in the MTEP21 Futures models. **Table I-3** and **Table I-4** show the total DER technical potential and additions modeled in MTEP21 by Future. The additions are those that were found to be economically superior to other alternatives and thus were included in the MTEP21 Futures. All of the values shown in **Table I-3** and **Table I-4** are in addition to the DER included in MISO LSE base forecasts.

Table I-3
DER Capacity (GW): 20-Year Technical Potential and Additions in MISO

MTEP21 DERs Capacity (GW) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	5.2	0.9	5.9	0.9	5.9	0.9
Energy Efficiency (EE)	13.3	7.8	14.5	8.1	14.5	11.7
Distributed Generation (DG)	14.7	3.5	14.7	3.5	21.8	6.2

Table I-4
DER Energy (GWh): 20-Year Technical Potential and Additions in MISO

MTEP21 DERs Energy (GWh) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	442	118	498	118	498	118
Energy Efficiency (EE)	86,886	30,801	94,313	31,393	94,313	49,145
Distributed Generation (DG)	26,119	5,709	26,119	5,709	36,934	9,837

Appendix J

Ratepayer Impacts

Total Project Summary

Line No.	Amounts in dollars	LRTP4 - Years 1 thru 20			
		Line (A)	**Subs (B)**	**ROW (C)**	**Total**
1	**LRTP4 - Revenue Requirement**	**874,669,809**	**55,853,683**	**68,720,251**	**999,243,743**
2					
3					
4	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%
5	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%	86.6%
6					
7	**Net cost to MN Jurisdiction**	**635,496,215**	**40,580,804**	**49,929,080**	**726,006,099**

NOTE: Tax assumptions include 21% corp Fed tax rate

Project Summary - Year 1

Amounts in dollars

Line No.		LRTP4 - Year 1 Revenue Requirement			
		Line (A)	Subs (B)	ROW (C)	Total
1	**LRTP4 - Revenue Requirement**	**57,406,637**	**3,626,601**	**3,880,152**	**64,913,390**
2					
3					
4	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%
5	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%	86.6%
6					
7	**Net cost to MN Jurisdiction**	**41,709,111**	**2,634,927**	**2,819,146**	**47,163,185**

NOTE: Tax assumptions include 21% corp Fed tax rate

Total - Xcel Energy

LRTP4 - Total

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate (MN)	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
1	**Project Spend - Xcel Energy Only**								
2	Line	452,840,000							
3	Sub	29,220,000							
4	ROW	37,450,000							
5	**Total**	519,510,000							
6									
7	Revenue Requirement								
8	Line		57,406,637	55,868,632	54,124,796	52,485,325	50,939,783	49,479,473	48,078,883
9	Sub		3,626,601	3,532,450	3,425,017	3,324,319	3,229,682	3,140,544	3,055,259
10	ROW		3,880,152	3,844,189	3,796,239	3,748,289	3,700,338	3,652,388	3,604,438
11									
12	**Total Revenue Requirements - NSP**		64,913,390	63,245,272	61,346,052	59,557,933	57,869,803	56,272,405	54,738,580
13									
14	FERC Interchange Agreement allocator to NSPM		83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
15	Demand Allocator - MN Jurisdiction		86.6%	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%
16									
17	**Total Revenue Requirements - MN Jurisdiction**		47,163,185	45,951,204	44,571,316	43,272,147	42,045,627	40,885,029	39,770,620
18									
19									
20	**Discount Rate =**	0.06349334							
21									
22	**Present Value of Revenue Requirements - NSP**	589,999,014	61,037,891	55,918,886	51,001,424	46,558,665	42,538,104	38,894,378	35,575,426
23									
24									
25									
26			12.50%	12.17%	11.81%	11.46%	11.14%	10.83%	10.54%

Total - Xcel Energy

LRTP4 - Total

Line No.	Rate Analysis	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
1	**Project Spend - Xcel Energy Only**								
2	Line								
3	Sub								
4	ROW								
5	**Total**								
6									
7	Revenue Requirement								
8	Line	46,697,426	45,315,390	43,933,354	42,551,317	41,169,281	39,787,245	38,405,208	37,023,172
9	Sub	2,971,210	2,887,122	2,803,035	2,718,948	2,634,861	2,550,774	2,466,687	2,382,600
10	ROW	3,556,488	3,508,537	3,460,587	3,412,637	3,364,687	3,316,736	3,268,786	3,220,836
11									
12	**Total Revenue Requirements - NSP**	53,225,123	51,711,050	50,196,976	48,682,902	47,168,829	45,654,755	44,140,681	42,626,607
13									
14	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
15	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%
16									
17	**Total Revenue Requirements - MN Jurisdiction**	38,671,010	37,570,951	36,470,892	35,370,833	34,270,775	33,170,716	32,070,657	30,970,599
18									
19									
20	**Discount Rate =**								
21									
22	**Present Value of Revenue Requirements - NSP**	32,526,586	29,714,634	27,122,506	24,733,976	22,533,974	20,508,502	18,644,562	16,930,086
23									
24									
25									
26		10.25%	9.95%	9.66%	9.37%	9.08%	8.79%	8.50%	8.21%

Total - Xcel Energy

LRTP4 - Total

Line No.	Rate Analysis	Year 16	Year 17	Year 18	Year 19	Year 20
1	**Project Spend - Xcel Energy Only**					
2	Line					
3	Sub					
4	ROW					
5	**Total**					
6						
7	Revenue Requirement					
8	Line	35,812,179	34,943,852	34,246,569	33,549,285	32,852,002
9	Sub	2,309,549	2,258,610	2,218,707	2,178,804	2,138,902
10	ROW	3,172,886	3,124,935	3,076,985	3,029,035	2,981,084
11						
12	**Total Revenue Requirements - NSP**	41,294,614	40,327,397	39,542,261	38,757,124	37,971,988
13						
14	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%	83.9%
15	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%	86.6%	86.6%
16						
17	**Total Revenue Requirements - MN Jurisdiction**	30,002,831	29,300,095	28,729,650	28,159,204	27,588,759
18						
19						
20	**Discount Rate =**					
21						
22	**Present Value of Revenue Requirements - NSP**	15,421,869	14,161,492	13,056,764	12,033,469	11,085,820
23						
24						
25						
26		7.95%	7.76%	7.61%	7.46%	7.31%

Rev Req - Lines

LRTP4 - Line
Based on 62 YEAR LIFE

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate (MN)	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
1	Plant Investment		452,840,000	452,840,000	452,840,000	452,840,000	452,840,000	452,840,000	452,840,000
2	Depreciation Reserve		(10,981,995)	(21,963,990)	(32,945,985)	(43,927,980)	(54,909,975)	(65,891,970)	(76,873,964)
3	Removal Expense		-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(3,351,085)	(12,558,751)	(20,530,027)	(27,395,060)	(33,257,967)	(38,209,851)	(42,732,253)
5			438,506,920	418,317,260	399,363,988	381,516,960	364,672,058	348,738,179	333,233,783
6									
7	Average Rate Base		445,673,460	428,412,090	408,840,624	390,440,474	373,094,509	356,705,118	340,985,981
8									
9	Debt Return		9,314,575	8,953,813	8,544,769	8,160,206	7,797,675	7,455,137	7,126,607
10	Equity Return		21,659,730	20,820,828	19,869,654	18,975,407	18,132,393	17,335,869	16,571,919
11	Current Income Tax Requirement		5,384,540	(810,379)	42,390	787,973	1,450,101	2,039,877	2,161,249
12									
13	Book Depreciation		10,981,995	10,981,995	10,981,995	10,981,995	10,981,995	10,981,995	10,981,995
14	Annual Deferred Tax		3,351,085	9,207,665	7,971,276	6,865,033	5,862,907	4,951,884	4,522,401
15	ITC Flow Thru		-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense		22,642,000	43,019,800	38,717,820	34,868,680	31,381,812	28,211,932	26,717,560
17	Tax Depreciation on Easements		-	-	-	-	-	-	-
18	AFUDC Expenditure		-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating		-	-	-	-	-	-	-
20	Avoided Tax Interest		-	-	-	-	-	-	-
21	Property Tax @ 1.4828%		6,714,712	6,714,712	6,714,712	6,714,712	6,714,712	6,714,712	6,714,712
22									
23	Total Revenue Requirements - NSP		57,406,637	55,868,632	54,124,796	52,485,325	50,939,783	49,479,473	48,078,883
24									
25	Discount Rate =	0.06349334							
26									
27	Present Value of Revenue Requirements	517,656,202	53,979,310	49,396,763	44,997,869	41,029,743	37,444,085	34,199,237	31,247,188
28									
29	**Level Annual Revenue Requirement**	**33,562,038**							
30									
31	**63 Year Life LARR %**	**7.41%**							

Rev Req - Lines

LRTP4 - Line
Based on 62 YEAR LIFE

Line No.	Rate Analysis	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
1	Plant Investment	452,840,000	452,840,000	452,840,000	452,840,000	452,840,000	452,840,000	452,840,000	452,840,000	452,840,000
2	Depreciation Reserve	(87,855,959)	(98,837,954)	(109,819,949)	(120,801,944)	(131,783,939)	(142,765,934)	(153,747,929)	(164,729,924)	(175,711,919)
3	Removal Expense	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(47,254,654)	(51,790,070)	(56,312,472)	(60,847,888)	(65,370,289)	(69,905,705)	(74,428,107)	(78,963,523)	(79,646,611)
5		317,729,386	302,211,975	286,707,579	271,190,168	255,685,772	240,168,361	224,663,965	209,146,554	197,481,471
6										
7	Average Rate Base	325,481,585	309,970,681	294,459,777	278,948,874	263,437,970	247,927,066	232,416,163	216,905,259	203,314,012
8										
9	Debt Return	6,802,565	6,478,387	6,154,209	5,830,031	5,505,854	5,181,676	4,857,498	4,533,320	4,249,263
10	Equity Return	15,818,405	15,064,575	14,310,745	13,556,915	12,803,085	12,049,255	11,295,426	10,541,596	9,881,061
11	Current Income Tax Requirement	1,857,348	1,540,305	1,249,291	932,248	641,234	324,191	33,177	(283,866)	3,302,061
12										
13	Book Depreciation	10,981,995	10,981,995	10,981,995	10,981,995	10,981,995	10,981,995	10,981,995	10,981,995	10,981,995
14	Annual Deferred Tax	4,522,401	4,535,416	4,522,401	4,535,416	4,522,401	4,535,416	4,522,401	4,535,416	683,088
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	26,717,560	26,762,844	26,717,560	26,762,844	26,717,560	26,762,844	26,717,560	26,762,844	13,358,780
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	6,714,712	6,714,712	6,714,712	6,714,712	6,714,712	6,714,712	6,714,712	6,714,712	6,714,712
22										
23	Total Revenue Requirements - NSP	46,697,426	45,315,390	43,933,354	42,551,317	41,169,281	39,787,245	38,405,208	37,023,172	35,812,179
24										
25	Discount Rate =									
26										
27	Present Value of Revenue Requirements	28,537,423	26,039,507	23,738,136	21,618,746	19,667,809	17,872,767	16,221,958	14,704,559	13,374,401
28										
29										
30										
31										

Rev Req - Lines

LRTP4 - Line
Based on 62 YEAR LIFE

Line No.	Rate Analysis	Year 17	Year 18	Year 19	Year 20
1	Plant Investment	452,840,000	452,840,000	452,840,000	452,840,000
2	Depreciation Reserve	(186,693,914)	(197,675,909)	(208,657,903)	(219,639,898)
3	Removal Expense	-	-	-	-
4	Accumulated Deferred Taxes	(76,490,385)	(73,334,160)	(70,177,935)	(67,021,709)
5		189,655,701	181,829,932	174,004,162	166,178,392
6					
7	Average Rate Base	193,568,586	185,742,816	177,917,047	170,091,277
8					
9	Debt Return	4,045,583	3,882,025	3,718,466	3,554,908
10	Equity Return	9,407,433	9,027,101	8,646,768	8,266,436
11	Current Income Tax Requirement	6,950,354	6,796,962	6,643,569	6,490,177
12					
13	Book Depreciation	10,981,995	10,981,995	10,981,995	10,981,995
14	Annual Deferred Tax	(3,156,225)	(3,156,225)	(3,156,225)	(3,156,225)
15	ITC Flow Thru	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-
18	AFUDC Expenditure	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-
20	Avoided Tax Interest	-	-	-	-
21	Property Tax @ 1.4828%	6,714,712	6,714,712	6,714,712	6,714,712
22					
23	Total Revenue Requirements - NSP	34,943,852	34,246,569	33,549,285	32,852,002
24					
25	Discount Rate =				
26					
27	Present Value of Revenue Requirements	12,270,990	11,308,139	10,416,518	9,591,054
28					
29					
30					
31					

Rev Req - Subs

LRTP4 - Subs
Based on 56 YEAR LIFE

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate (MN)	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
1	Plant Investment		29,220,000	29,220,000	29,220,000	29,220,000	29,220,000	29,220,000	29,220,000
2	Depreciation Reserve		(628,455)	(1,256,910)	(1,885,365)	(2,513,820)	(3,142,275)	(3,770,730)	(4,399,185)
3	Removal Expense		-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(239,273)	(856,449)	(1,393,845)	(1,859,860)	(2,261,212)	(2,603,778)	(2,918,632)
5			28,352,272	27,106,641	25,940,790	24,846,320	23,816,513	22,845,492	21,902,183
6									
7	Average Rate Base		28,786,136	27,729,456	26,523,715	25,393,555	24,331,417	23,331,002	22,373,837
8									
9	Debt Return		601,630	579,546	554,346	530,725	508,527	487,618	467,613
10	Equity Return		1,399,006	1,347,652	1,289,053	1,234,127	1,182,507	1,133,887	1,087,368
11	Current Income Tax Requirement		324,962	(73,652)	(17,506)	31,723	75,567	114,743	123,695
12									
13	Book Depreciation		628,455	628,455	628,455	628,455	628,455	628,455	628,455
14	Annual Deferred Tax		239,273	617,176	537,396	466,015	401,352	342,567	314,854
15	ITC Flow Thru		-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense		1,461,000	2,775,900	2,498,310	2,249,940	2,024,946	1,820,406	1,723,980
17	Tax Depreciation on Easements		-	-	-	-	-	-	-
18	AFUDC Expenditure		-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating		-	-	-	-	-	-	-
20	Avoided Tax Interest		-	-	-	-	-	-	-
21	Property Tax @ 1.4828%		433,274	433,274	433,274	433,274	433,274	433,274	433,274
22									
23	Total Revenue Requirements - NSP		3,626,601	3,532,450	3,425,017	3,324,319	3,229,682	3,140,544	3,055,259
24									
25	Discount Rate =	0.06349334							
26									
27	Present Value of Revenue Requirements	32,962,609	3,410,084	3,123,248	2,847,465	2,598,745	2,374,028	2,170,682	1,985,659
28									
29	**Level Annual Revenue Requirement**	**2,161,716**							
30									
31	**57 Year Life LARR %**	**7.40%**							

Rev Req - Subs

LRTP4 - Subs
Based on 56 YEAR LIFE

Line No.	Rate Analysis	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
1	Plant Investment	29,220,000	29,220,000	29,220,000	29,220,000	29,220,000	29,220,000	29,220,000	29,220,000	29,220,000
2	Depreciation Reserve	(5,027,640)	(5,656,095)	(6,284,550)	(6,913,005)	(7,541,460)	(8,169,915)	(8,798,370)	(9,426,825)	(10,055,280)
3	Removal Expense	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(3,233,486)	(3,549,180)	(3,864,034)	(4,179,727)	(4,494,581)	(4,810,275)	(5,125,129)	(5,440,823)	(5,507,941)
5		20,958,874	20,014,725	19,071,416	18,127,268	17,183,959	16,239,810	15,296,501	14,352,352	13,656,780
6										
7	Average Rate Base	21,430,528	20,486,799	19,543,071	18,599,342	17,655,613	16,711,884	15,768,156	14,824,427	14,004,566
8										
9	Debt Return	447,898	428,174	408,450	388,726	369,002	349,278	329,554	309,831	292,695
10	Equity Return	1,041,524	995,658	949,793	903,928	858,063	812,198	766,332	720,467	680,622
11	Current Income Tax Requirement	105,205	85,867	68,209	48,871	31,213	11,875	(5,783)	(25,121)	207,385
12										
13	Book Depreciation	628,455	628,455	628,455	628,455	628,455	628,455	628,455	628,455	628,455
14	Annual Deferred Tax	314,854	315,694	314,854	315,694	314,854	315,694	314,854	315,694	67,118
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	1,723,980	1,726,902	1,723,980	1,726,902	1,723,980	1,726,902	1,723,980	1,726,902	861,990
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	433,274	433,274	433,274	433,274	433,274	433,274	433,274	433,274	433,274
22										
23	Total Revenue Requirements - NSP	2,971,210	2,887,122	2,803,035	2,718,948	2,634,861	2,550,774	2,466,687	2,382,600	2,309,549
24										
25	Discount Rate =									
26										
27	Present Value of Revenue Requirements	1,815,746	1,659,022	1,514,540	1,381,397	1,258,753	1,145,829	1,041,903	946,301	862,523
28										
29										
30										
31										

Rev Req - Subs

LRTP4 - Subs
Based on 56 YEAR LIFE

Line No.	Rate Analysis	Year 17	Year 18	Year 19	Year 20
1	Plant Investment	29,220,000	29,220,000	29,220,000	29,220,000
2	Depreciation Reserve	(10,683,735)	(11,312,190)	(11,940,645)	(12,569,100)
3	Removal Expense	-	-	-	-
4	Accumulated Deferred Taxes	(5,327,323)	(5,146,705)	(4,966,087)	(4,785,469)
5		13,208,943	12,761,105	12,313,268	11,865,431
6					
7	Average Rate Base	13,432,861	12,985,024	12,537,187	12,089,350
8					
9	Debt Return	280,747	271,387	262,027	252,667
10	Equity Return	652,837	631,072	609,307	587,542
11	Current Income Tax Requirement	443,915	435,137	426,359	417,581
12					
13	Book Depreciation	628,455	628,455	628,455	628,455
14	Annual Deferred Tax	(180,618)	(180,618)	(180,618)	(180,618)
15	ITC Flow Thru	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-
18	AFUDC Expenditure	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-
20	Avoided Tax Interest	-	-	-	-
21	Property Tax @ 1.4828%	433,274	433,274	433,274	433,274
22					
23	Total Revenue Requirements - NSP	2,258,610	2,218,707	2,178,804	2,138,902
24					
25	Discount Rate =				
26					
27	Present Value of Revenue Requirements	793,140	732,612	676,484	624,447
28					
29					
30					
31					

Rev Req - ROW

LRTP4 - ROW

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate (MN)	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
1	Plant Investment		37,450,000	37,450,000	37,450,000	37,450,000	37,450,000	37,450,000	37,450,000
2	Depreciation Reserve		-	-	-	-	-	-	-
3	Removal Expense		-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(269,078)	(807,235)	(1,345,391)	(1,883,548)	(2,421,704)	(2,959,861)	(3,498,017)
5			37,180,922	36,642,765	36,104,609	35,566,452	35,028,296	34,490,139	33,951,983
6									
7	Average Rate Base		37,315,461	36,911,844	36,373,687	35,835,531	35,297,374	34,759,218	34,221,061
8									
9	Debt Return		779,893	771,458	760,210	748,963	737,715	726,468	715,220
10	Equity Return		1,813,531	1,793,916	1,767,761	1,741,607	1,715,452	1,689,298	1,663,144
11	Current Income Tax Requirement		462,340	185,351	174,802	164,254	153,706	143,157	132,609
12									
13	Book Depreciation		-	-	-	-	-	-	-
14	Annual Deferred Tax		269,078	538,157	538,157	538,157	538,157	538,157	538,157
15	ITC Flow Thru		-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense		936,250	1,872,500	1,872,500	1,872,500	1,872,500	1,872,500	1,872,500
17	Tax Depreciation on Easements		-	-	-	-	-	-	-
18	AFUDC Expenditure		-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating		-	-	-	-	-	-	-
20	Avoided Tax Interest		-	-	-	-	-	-	-
21	Property Tax @ 1.4828%		555,309	555,309	555,309	555,309	555,309	555,309	555,309
22									
23	Total Revenue Requirements - NSP		3,880,152	3,844,189	3,796,239	3,748,289	3,700,338	3,652,388	3,604,438
24									
25	Discount Rate =	0.06349334							
26									
27	Present Value of Revenue Requirements	39,380,203	3,648,497	3,398,875	3,156,089	2,930,177	2,719,992	2,524,459	2,342,578
28									
29	**Level Annual Revenue Requirement**	**2,553,200**							
30									
31	**63 Year Life LARR %**	**6.82%**							

Rev Req - ROW

LRTP4 - ROW

Line No.	Rate Analysis	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
1	Plant Investment	37,450,000	37,450,000	37,450,000	37,450,000	37,450,000	37,450,000	37,450,000	37,450,000	37,450,000
2	Depreciation Reserve	-	-	-	-	-	-	-	-	-
3	Removal Expense	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(4,036,174)	(4,574,330)	(5,112,487)	(5,650,643)	(6,188,800)	(6,726,956)	(7,265,113)	(7,803,269)	(8,341,426)
5		33,413,826	32,875,670	32,337,513	31,799,357	31,261,200	30,723,044	30,184,887	29,646,731	29,108,574
6										
7	Average Rate Base	33,682,905	33,144,748	32,606,592	32,068,435	31,530,279	30,992,122	30,453,966	29,915,809	29,377,653
8										
9	Debt Return	703,973	692,725	681,478	670,230	658,983	647,735	636,488	625,240	613,993
10	Equity Return	1,636,989	1,610,835	1,584,680	1,558,526	1,532,372	1,506,217	1,480,063	1,453,908	1,427,754
11	Current Income Tax Requirement	122,061	111,512	100,964	90,415	79,867	69,319	58,770	48,222	37,674
12										
13	Book Depreciation	-	-	-	-	-	-	-	-	-
14	Annual Deferred Tax	538,157	538,157	538,157	538,157	538,157	538,157	538,157	538,157	538,157
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	1,872,500	1,872,500	1,872,500	1,872,500	1,872,500	1,872,500	1,872,500	1,872,500	1,872,500
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	555,309	555,309	555,309	555,309	555,309	555,309	555,309	555,309	555,309
22										
23	Total Revenue Requirements - NSP	3,556,488	3,508,537	3,460,587	3,412,637	3,364,687	3,316,736	3,268,786	3,220,836	3,172,886
24										
25	Discount Rate =									
26										
27	Present Value of Revenue Requirements	2,173,417	2,016,105	1,869,830	1,733,834	1,607,412	1,489,906	1,380,701	1,279,225	1,184,945
28										
29										
30										
31										

Rev Req - ROW

LRTP4 - ROW

Line No.	Rate Analysis	Year 17	Year 18	Year 19	Year 20
1	Plant Investment	37,450,000	37,450,000	37,450,000	37,450,000
2	Depreciation Reserve	-	-	-	-
3	Removal Expense	-	-	-	-
4	Accumulated Deferred Taxes	(8,879,582)	(9,417,739)	(9,955,895)	(10,494,052)
5		28,570,418	28,032,261	27,494,105	26,955,948
6					
7	Average Rate Base	28,839,496	28,301,340	27,763,183	27,225,027
8					
9	Debt Return	602,745	591,498	580,251	569,003
10	Equity Return	1,401,600	1,375,445	1,349,291	1,323,136
11	Current Income Tax Requirement	27,125	16,577	6,028	(4,520)
12					
13	Book Depreciation	-	-	-	-
14	Annual Deferred Tax	538,157	538,157	538,157	538,157
15	ITC Flow Thru	-	-	-	-
16	Tax Depreciation & Removal Expense	1,872,500	1,872,500	1,872,500	1,872,500
17	Tax Depreciation on Easements	-	-	-	-
18	AFUDC Expenditure	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-
20	Avoided Tax Interest	-	-	-	-
21	Property Tax @ 1.4828%	555,309	555,309	555,309	555,309
22					
23	Total Revenue Requirements - NSP	3,124,935	3,076,985	3,029,035	2,981,084
24					
25	Discount Rate =				
26					
27	Present Value of Revenue Requirements	1,097,362	1,016,013	940,467	870,320
28					
29					
30					
31					

Key Inputs

Line No	Capital Structure			
1			**2024**	
2	Capital Structure	Cost	Ratio	WACC
3	Long Term Debt	4.4000%	47.0800%	2.07%
4	Short Term Debt	4.1700%	0.4200%	0.02%
5	Preferred Stock	0.0000%	0.0000%	0.00%
6	Common Equity	9.2500%	52.5000%	4.86%
7	**Required Rate of Return**			6.95%
8	(Rates and Ratios from Settlement in Docket E002/GR-21-630)			
9				
10	**Property Tax Rates**			
11	Property Tax Rate			1.4828%
12	(percentage based on last TCR filing in Docket No. E002M-21-814)			
13				
14	**Income Tax Rates**			
15	Federal Tax Rate			21.00%
16	State Tax Rate			9.80%
17	State Composite Income Tax Rate			28.7420%
18				
19	**Allocators (2024 Estimate)**			
20	MN 12-month CP demand (Electric Demand)			86.63%
21	NSPM 36-month CP demand (Interchange Electric)			83.87%
22	Jurisdictional Allocator			72.66%
23				
24	**Book Depreciation Lives**			
25	Land			0.00
26	Line			61.58
27	Sub			55.61
28				
29	**Net Salvage %**			
30	Land			0.00%
31	Line			-49.33%
32	Sub			-19.60%
33				
34	**Book Depreciation Rates**			
35	Land			0.00%
36	Line			2.4251%
37	Sub			2.1508%