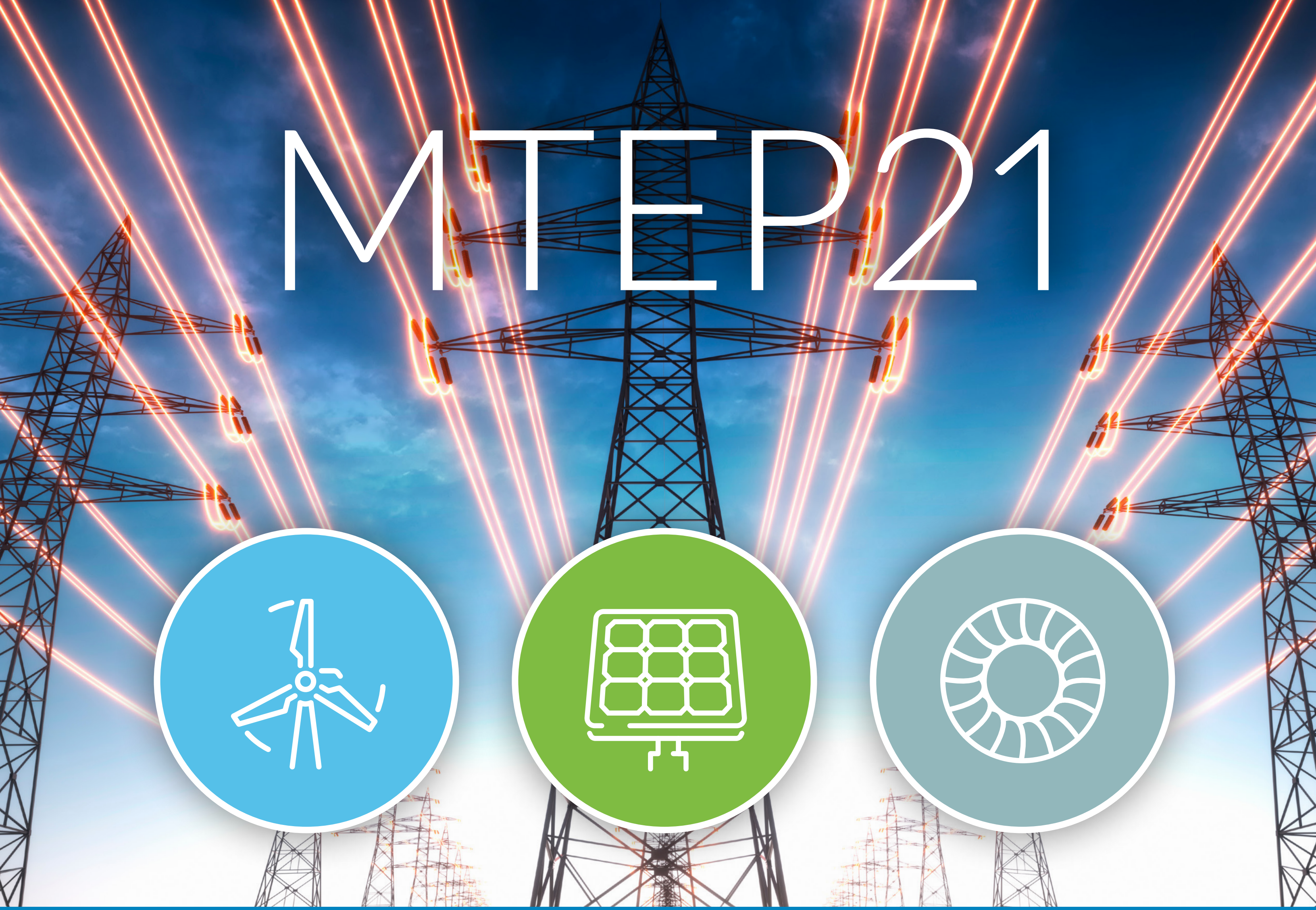
MTEP21



In this MISO Transmission Expansion Plan, MISO staff recommends $3 billion of new transmission enhancement projects for Board of Directors' approval.

Highlights

- 335 new projects for inclusion in Appendix A to address reliability and aging infrastructure
- $24 billion in projects constructed in the MISO region since 2003
- Generator Interconnection queue grew to a record 958 projects totaling 150.3 GW

MISO

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Transmission Expansion for a Changing Industry

Fundamental changes in the electric industry landscape – such as shifts in generation resources, consumer demand for low-carbon resources, and decentralization of generation – require a planning process that can ensure the grid will be able to accommodate these changes in the years to come. Indicators predict as much industry change in the next 5 years as have happened in the past 35 years.

The 2021 MISO Transmission Expansion Plan (MTEP21) evaluates studies and planning initiatives that help MISO address future grid needs. Further, MISO's Long-Range Transmission Planning process, part of MISO's response to the shared Reliability Imperative, provides a holistic, systematic response in ensuring grid infrastructure is in place to realize the plans of member utilities, customer preferences, and state and federal policies.

As a deliverable, MTEP21 defines tangible, incremental improvements to address today's needs and tomorrow's direction as it proposes the approval of 335 new transmission projects, equaling $3 billion in investment. Investments identified address near-term reliability needs and aging infrastructure. Since 2003, $24 billion of MTEP transmission projects have been constructed in the region.

MTEP21 Snapshot

335 new projects representing $3 billion of investment

Proposed MTEP21 Appendix A projects go before the Board of Directors for approval in December 2021.

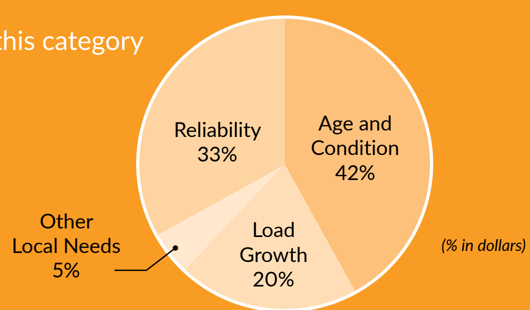
This includes the following project types:

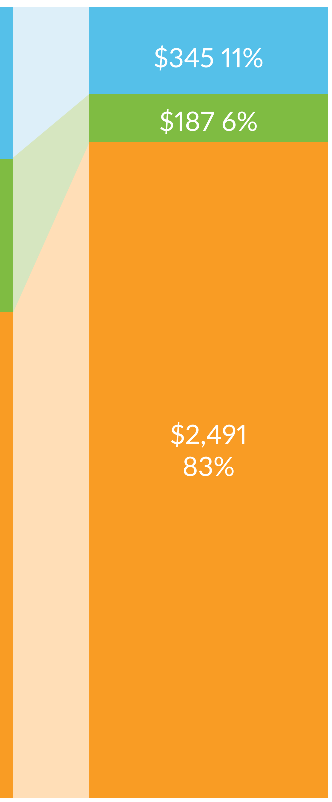
GENERATOR INTERCONNECTION PROJECTS (GIP)
50 projects representing $345 million in investment

BASELINE RELIABILITY PROJECTS (BRP)
30 projects representing $187 million in investment

"OTHER" PROJECTS
255 projects representing $2,491 billion in investment

Drivers of this category





($ in Millions)

Planning Region	GIP	BRP	Other	Total
West	$137	$31	$931	**$1,100**
East	$125	$50	$331	**$506**
Central	$57	$43	$606	**$706**
South	$26	$62	$624	**$712**
Total	**$345**	**$187**	**$2,491**	**$3,023**

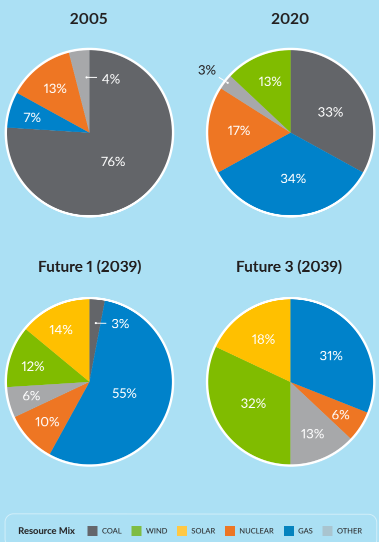
Dramatic Changes in the Fleet Require a Change in Direction

When MISO became a Regional Transmission Organization in 2001, generation was largely provided by coal plants and some gas, and customer demand was the largest source of day-to-day operating variation. Today, coal generation continues to retire; new gas generation in the queue is outpaced by wind and solar generators. And battery storage is gaining an increasing foothold in the region. This change is driven by customers, their member utilities, and state energy and environmental policy. It has challenged the assumptions of legacy planning processes, which were predicated on the idea that serving the hottest day of the year would also mean system and resource sufficiency for all other days of the year. It also supported the idea that a megawatt hour was inextricably bundled with other reliability attributes, such as flexibility, black start and frequency response characteristics.

As legacy units retire, they are replaced by wind and solar – whose best fuel sources are location-dependent. Older units are increasingly prone to outage, and load-modifying resources are an increasing proportion of available resources.

MISO's MTEP process iterates annually to provide a comprehensive grid expansion plan that meets reliability, policy and economic needs. It is in constant evolution and prioritizes transmission needs depending on system-wide needs (top down) and local service territory needs identified by local utilities (bottom up). The process is designed to ensure necessary grid infrastructure is in place to support the reliable operation of the transmission system; support achievement of state and federal energy policy requirements; and enable a competitive electricity market to benefit all customers. MISO's transmission planning processes uses Futures, which are meant to capture a range of possible outcomes over the next 20 years. It does this by incorporating a value-based process that integrates both top-down and bottom-up efforts, and integrates numerous, iterative opportunities for stakeholder feedback.

GENERATOR ENERGY MIX



MISO FORWARD

De-marginalization
Decentralization
Digitalization

NEEDS

- AVAILABILITY
- FLEXIBILITY
- VISIBILITY

See MISO Forward report

MISO RELIABILITY IMPERATIVE

MARKET REDEFINITION

LONG RANGE TRANSMISSION PLANNING

OPERATIONS OF THE FUTURE

MARKET SYSTEM ENHANCEMENT

List is not representative of all efforts

MISO is actively pursuing multiple workstreams to ensure on-going reliability and value creation

See MISO's Reliability Imperative report

Members Active Throughout the MTEP Planning Process

Each cycle, MISO undergoes a rigorous stakeholder process that offers numerous opportunities over 18 months for advice and input from our diverse stakeholder community, which includes utilities, state regulators, and public interest organizations including environmental and consumer groups. Planning Advisory Committee (PAC) meetings are held monthly, and subregional planning meetings are interspersed on this timeline. Utilities submit bottom-up projects, and projects are identified by MISO for consideration through the MTEP process. Finally, in the fall, the System Planning Committee of the MISO Board of Directors recommend a slate of projects in MTEP to the full Board of Directors for consideration and approval in December.

Past MTEP cycles have ensured ongoing reliability and market efficiency as this evolution has occurred, including the execution of a long-range planning analysis spanning 2007-2011 to identify regional solutions needed to integrate a significant amount of wind resources to meet state policy goals. Known as the Multi-Value Projects, this portfolio has continued to generate reliability benefits and greater savings than costs by unlocking economical generation to the footprint.

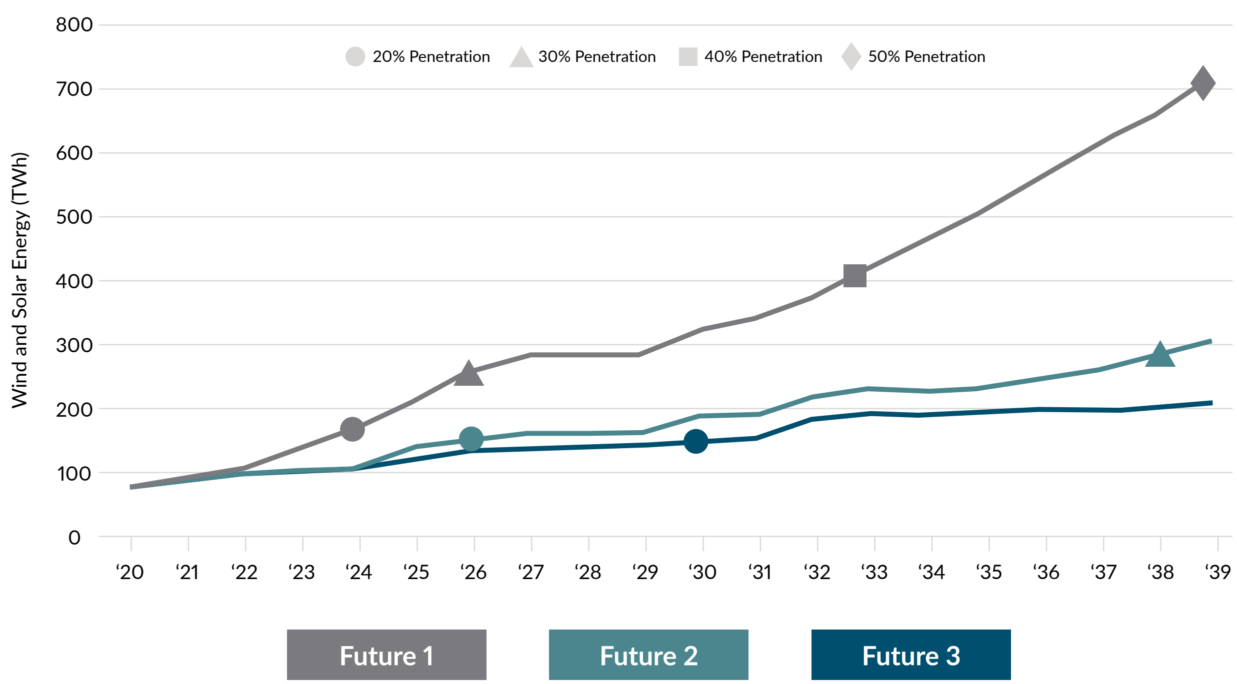
MISO's Planning Futures Show Further Resource Shift

The MISO region is at a point of significant resource and consumption change. Member resource plans, customer preferences and state policies are poised to reshape the industry landscape – and the grid needed to support this shift. The three forward-looking scenarios, or Futures, used in MTEP21 incorporate the increasing pace of fleet evolution that is urgently needed for states and their regulated utilities to meet their energy goals. These scenarios "bookend" plausible outcomes to plan no-regrets additions to the future grid. The Futures, which envision 20 years ahead, inform MTEP21 and the grid planning initiatives within the MTEP report, including Long-Range Transmission Planning and other MISO efforts that ensure continued reliable and economic energy delivery. MISO developed these Futures over the course of 18 months and incorporated numerous rounds of stakeholder feedback, policy assessments and industry trends.

MISO's three planning Futures incorporate varying assumptions about utility and state goals, retirements, Distributed Energy Resources (DER) adoption and electrification, among other factors. All Futures assume changes announced through September 2020 in utility Integrated Resource Plans (or IRPs, resource plans for 10-15 years into the future) are realized.

Further, the Futures model storage usage. The capacity expansion software used in Futures models four-hour duration lithium-ion batteries. In Future 1, 1 GW of storage is assumed; that figure rises to 2 GW in Future 2. Future 3 models 29 GW of storage.

MISO Futures' Wind and Solar Generation



Future 1

Incorporates state and utility goals that are not reflected in enacted legislation at 85 percent of their goal.

Future 2

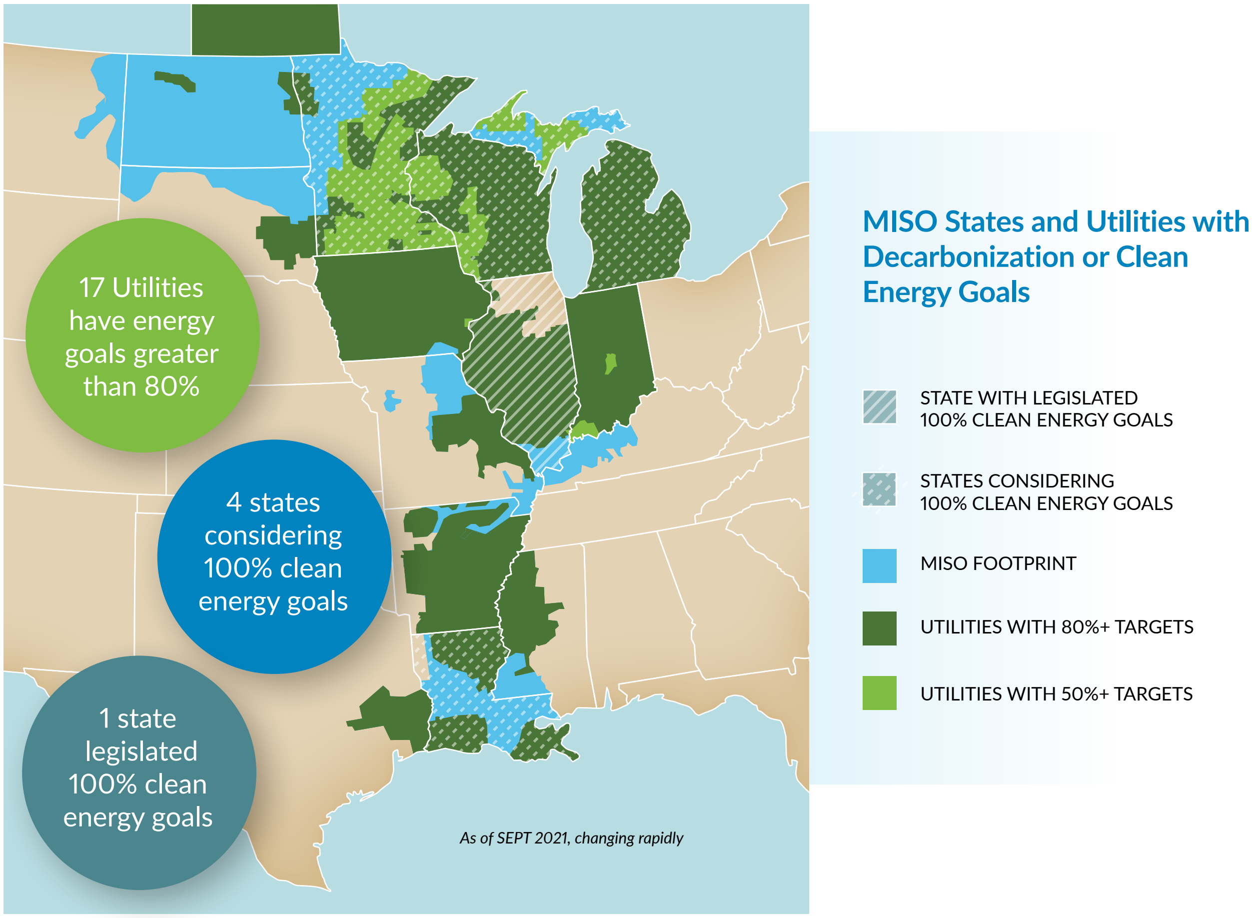
Incorporates announced state and utility goals by their respective timeframes.

Future 3

Incorporates 100 percent of announced state and utility goals within their respective timelines, while also including an 80 percent reduction in carbon dioxide emissions. Future 3 is especially notable for the quantity of resource additions – 330 GW, nearly 2.5 times that of Future 1 and twice that of Future 2.

Future I	Future 2	Future 3
• The footprint develops in line with 100% of utility IRPs and 85% of utility announcements, state mandates, goals, or preferences • Emissions decline as an outcome of utility plans • Load growth consistent with current loads	• Companies/states meet their goals, mandates and announcements • Changing federal and state policies support footprint-wide carbon emissions reduction of 60% by 2040 • Energy increases 30% footprint-wide by 2040 driven by electrification	• Changing federal and state policies support footprint-wide carbon emissions reduction of 80% by 2040 • Increased electrification drives a footprint-wide 50% increase in energy by 2040
	ADDITIONS	
121 GW	160 GW	330 GW
	RETIREMENTS	
77 GW	80 GW	112 GW
	NET PEAK LOAD	
136 GW - July	148 GW - July	164 GW - Jan
	CO_2 EMISSIONS	
↓63% 199 MMT CO_2	↓64% 195 MMT CO_2	↓81% 104 MMT CO_2

MMT CO_2 (million metric tons of carbon dioxide)

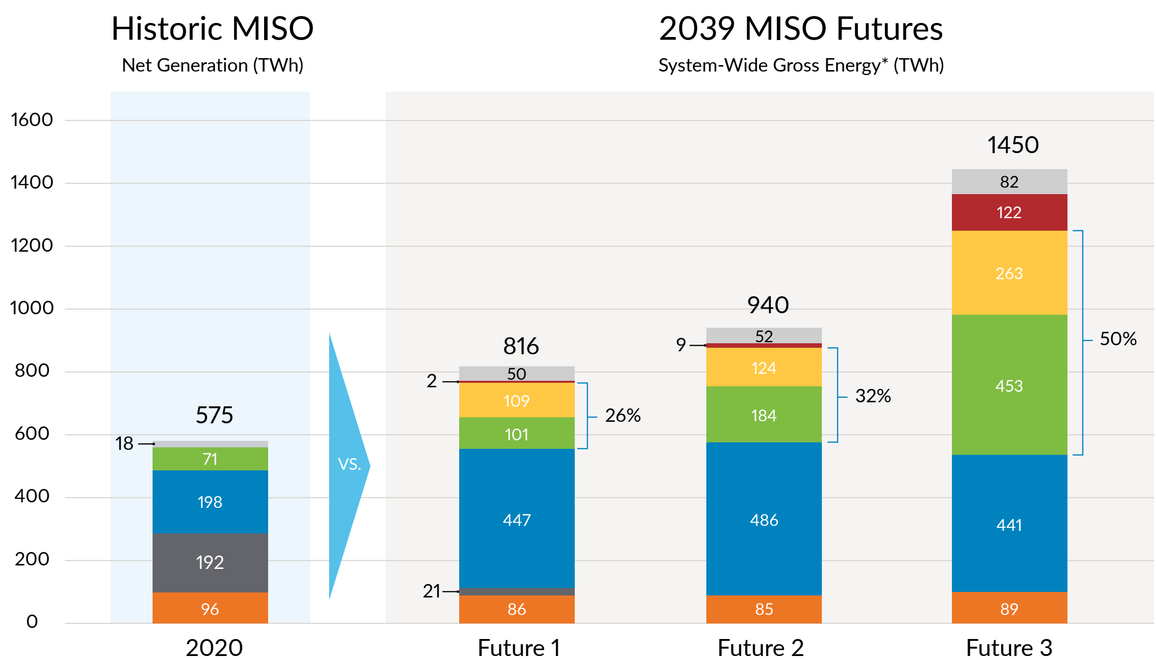


The planning Futures also model different rates of decarbonization. Decarbonization goals are becoming more widespread among states, municipalities, utilities and companies, and those goals are becoming increasingly aggressive, with greater emissions reductions on a shorter timeframe. While the entire footprint does not share these goals, this fleet transition will still have implications regarding what resources are needed regionally to ensure grid reliability. At their apex, goals include reaching 100 percent renewable energy supply or zero net carbon by 2050. Today, carbon emissions in the MISO footprint have reduced 29 percent since 2005. Future 1 and Future 2 both have similar carbon reductions – 65 percent and 64 percent, respectively. Future 3 features reductions of 81 percent. All reductions are from 2005 levels.

Relatedly, the Futures also model load growth, and specifically anticipate electrification of significant portions of the economy. After years of negligible load growth, electrification presents a unique challenge for electric utilities that could potentially transform the electric power system. Electrification —the conversion of equipment to utilize electricity as its energy source — is of special importance as states, municipalities, utilities and companies pursue decarbonization, strategies that depend on a decarbonized electricity system.

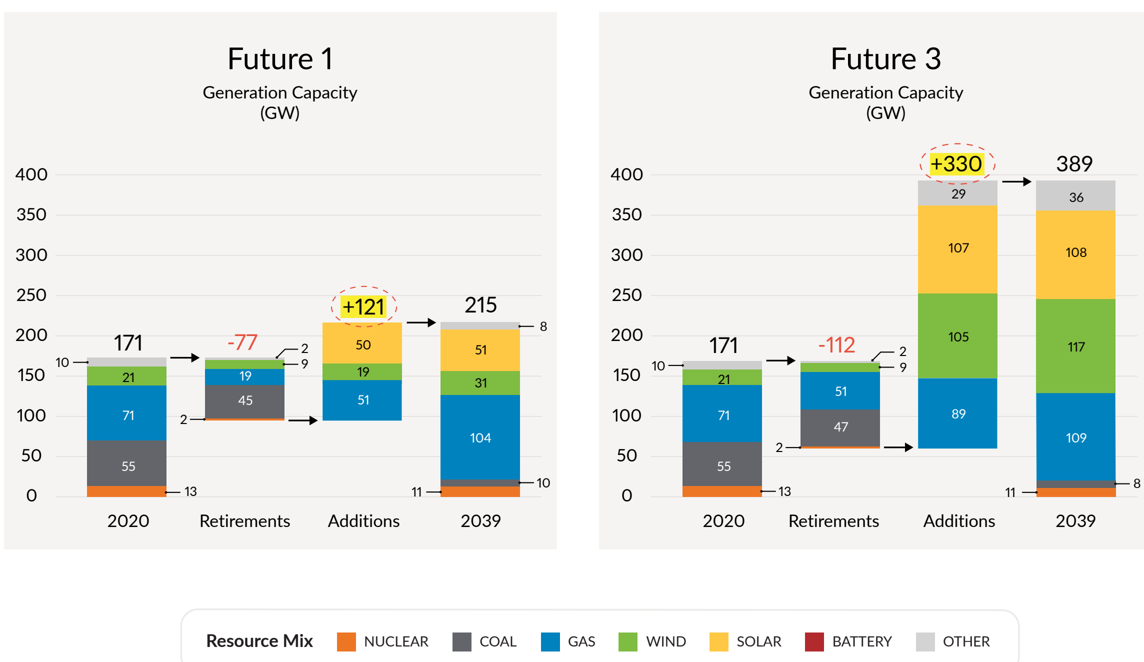
Future 1 assumes that demand and energy growth are driven by existing economic factors, with small increases in electric vehicle adoption, for an annual energy growth rate of 0.5 percent. Future 2 assumes an increase in electrification, with a resulting 1.1 percent annual energy growth rate. Future 3 includes a larger electrification scenario for a 1.7 percent annual energy growth rate.

The Futures incorporate and build upon member plans to reflect the resource transition and changing demand patterns, including dramatic energy increases with electrification...



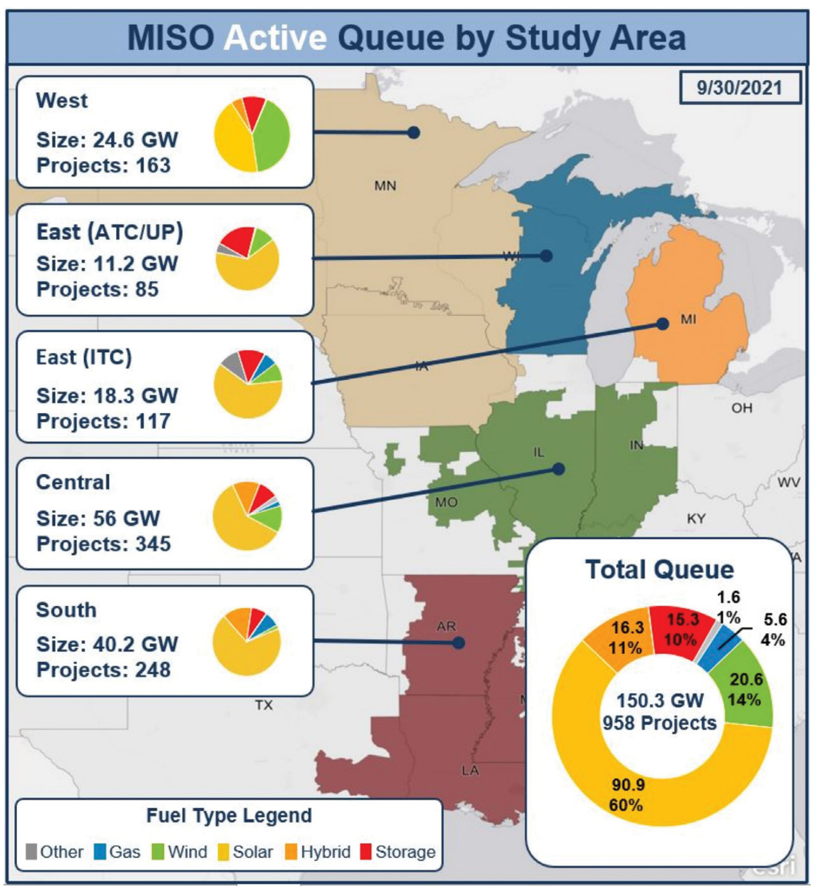
*System-Wide Gross Energy includes increasing amounts of dumped (or curtailed) renewable energy and storage fill;
New Generation does not include dumped energy, storage fill or DERs.

...and substantial capacity requirements and additions



Finally, resource additions are only half the picture. The other half are the number of conventional generators that are retiring, resulting in the overall resource shift in the fleet to intermittent, renewable resources. Age-based retirements of coal units gradually decrease with each Future, with 46 years assumed in Future 1, 36 years in Future 2 and 30 years in Future 3. Gas generation follows a similar pattern of 50, 45 and 35 years at retirement, respectively. Retirements are similar between Future 1 (77 GW) and Future 2 (80 GW). Retirements increase substantially in Future 3 (112 GW).

Change is also occurring on the demand side, both in terms of load growth and how customers interact with the grid. Consumers are increasingly siting solar generation and storage near homes and businesses. Further, customer, utility and state efforts to decarbonize will employ increasing electrification of the economy as an important tool to meeting those goals. All of this will require a very different grid to support these new technologies and uses. To meet these needs, the Futures model different penetrations of DERs. These resources are broken up into three subcategories: Demand Resources (programs in which customers reduce their energy use at times of greatest system need); energy efficiency (using energy more efficiently, for example, through more efficient lighting); and distributed generation (such as customer-sited solar generation). While Demand Resources maintain a consistent addition of 118 GWh of generation across each of the three Futures, both Energy Efficiency and distributed generation increase (from 7.8 GW to 11.7 GW for energy efficiency, and almost 3.5 GW to 6.2 GW, respectively, for Distributed Generation).



In 2021, MISO's interconnection queue process received record generation capacity requests to connect to the transmission system.

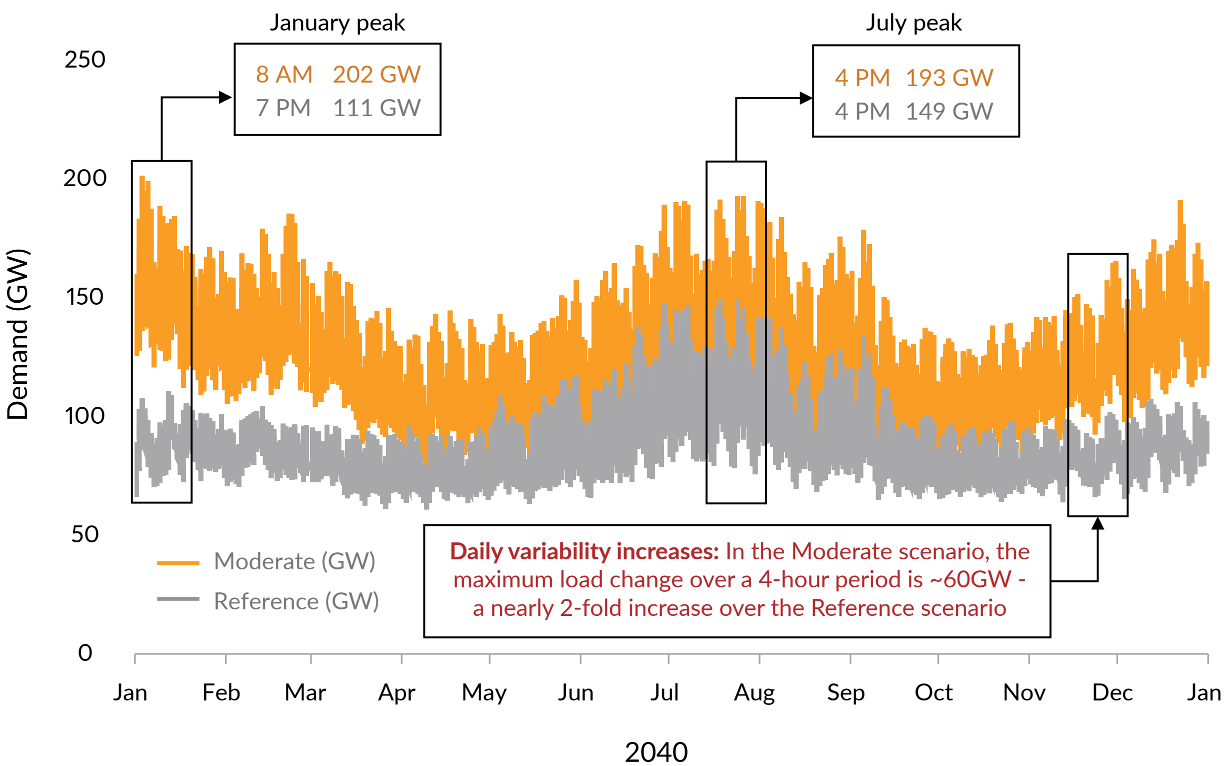
Risks and Mitigations

Recent and ongoing MISO studies offer unique perspectives of what issues different planning futures might require of planning efforts. These studies form a knowledge base and put a lens on possible future risks and how they could be mitigated through transmission expansion planning.

The Renewable Integration Impact Assessment (RIIA), a multi-year study published in 2021, shows that as renewable penetrations increase, so do the variety and magnitude of bulk electric system needs and risks. Up to 30 percent renewable penetration seems manageable with incremental transmission. Managing the system beyond 30 percent of system-wide renewable penetrations will require transformational change in planning, markets and operations.

Additionally, the multi-year Resource Availability and Need (RAN) effort is based on increasing the availability of resources when they are needed, in response to an increasing number of operating emergencies. The ability to

Moderate scenarios of electrification could change MISO to a winter-peaking system, and require greater flexibility and ramp to meet two seasonal peaks in summer and winter



See MISO's Electification Insights study transfer power across the footprint, and across the North-South interface, has been an important factor in mitigating operating emergencies.

The 2021 MISO Electrification Insights study finds that increases in electrification will change load profiles. Electrification requires an increase in ramping services, as the average annual load increases and becomes more variable. It also has the potential to change MISO from a summer-peaking system to one with a winter peak. Research suggests that flexible loads have potential to offset extreme ramps.

MISO's Regional Resource Assessment, scheduled for publication in late 2021, provides visibility into long-range utility resource planning across the region to inform state regulators and utilities as they make their long-term resource plans. As the region evolves, more coordination will be needed between utilities, state regulators and MISO to ensure a reliable system. The Regional Resource Assessment will use MISO's system-wide vantage point to compile resource plans and assumptions to develop zonal models and analysis.

Future Reliability: A Shared Responsibility

As work continues during this resource evolution, it becomes clear that MISO, its members, state regulators and other entities responsible for system reliability all have an obligation to work together to address the challenges posed by a dramatically changing fleet. MISO calls this shared responsibility the Reliability Imperative because the reliability-enhancing work it requires cannot be delayed. This work will also enable utilities and states in the MISO region to invest in the type of infrastructure that is needed to meet energy needs and policy objectives going forward.

Renewable resources account for about 13 percent of today's energy in the MISO footprint. Even at this level, the areas within the region already experience challenges in congestion, trapped generation, pockets of curtailments and negative pricing. The initiatives identified in MISO's response to the Reliability Imperative anticipates future needs in system planning, markets and operations.

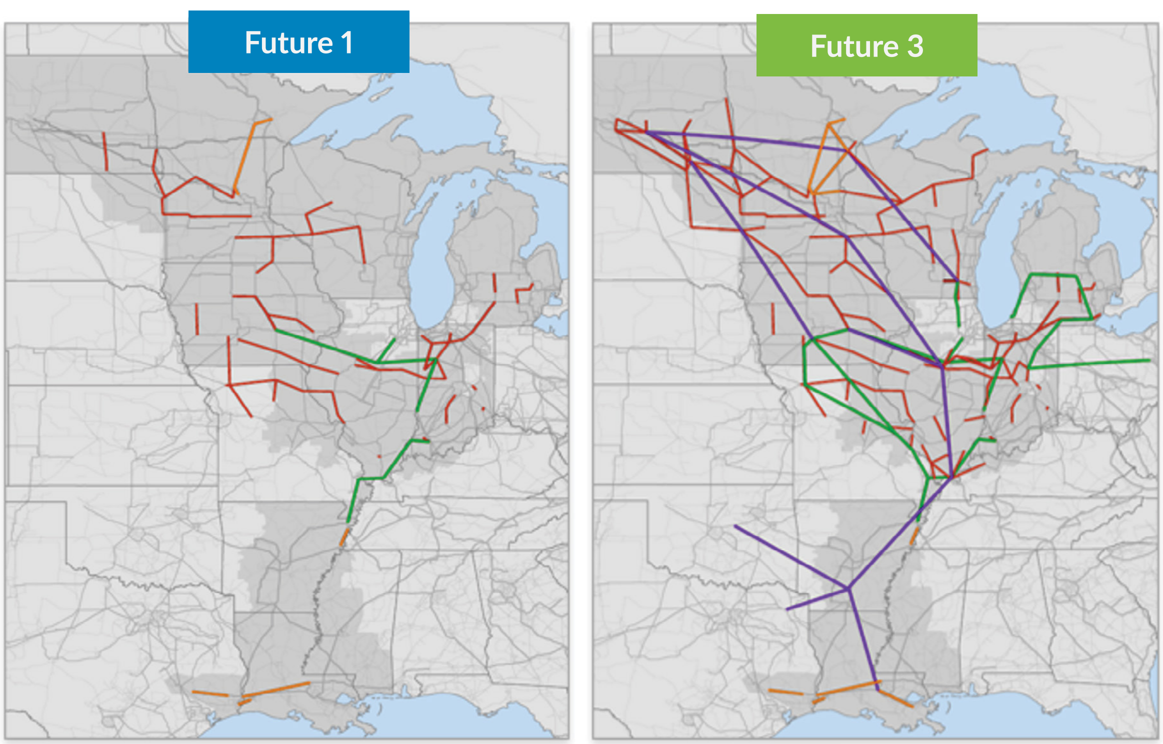
> "MISO calls this shared responsibility the Reliability Imperative because the reliability-enhancing work it requires cannot be delayed."

Long-Range Transmission Planning

Changes in transmission planning, markets and operations are needed to enable the future grid infrastructure to align with the ambitious decarbonization goals in a reliable manner. Transmission facilities take an average of 10 years to go from planning to in-service. Further, areas of MISO are already experiencing periods of more than 40 percent of its energy from wind, creating operating challenges. To ensure the necessary infrastructure is in place, planning processes must proceed — with the input of our diverse stakeholder community — as efficiently as possible.

MISO's transmission planning scenarios reflect significant capacity requirements and additions. Future 1 alone — which reflects member plans as they look to adjust their fleets to achieve clean energy goals — anticipates 121 GW of resource additions to meet those goals. MISO's current

Indicative 'Roadmaps' (as of June 2021)



Indicative 'Cost to Achieve' ($billion)*	Future 1	Future 3
New Generation/Resources	+/- 135	+/- 430
New Transmission Solutions	+/- 30	+/- 100
Total New Investment	**+/- 165**	**+/- 530**

Voltage Level (kV)

- 345
- 500
- 765
- DC Line

* Initial 'indicative' investment cost estimates expressed in 2020 dollars; generation additions thru 2039 are 121 GW in Future 1, 330 GW in Future 3; generation costs from EGEAS modeling; transmission solutions cost from MISO transmission cost estimating tools.

system capacity today is 184 GW. The indicative “cost to achieve” this transformation in Future 1 is estimated at $165 billion in investment. A relatively small portion of that total — $30 billion — would be transmission infrastructure necessary to support this transition.

For decades, grid operators have managed variability and uncertainty in the system. MISO expects this variability and uncertainty to become more profound, making it more challenging to manage supply, load, and reserves.

Unlike annual processes that identify Baseline Reliability Projects, Market Efficiency Projects and generator interconnection network upgrades, MISO periodically identifies regional needs through a regional overlay process. Like other transmission project types, conditions for successful planning include a consensus that transmission is required, a deeper analysis of those issues and solutions, and ensuring allocation of cost is roughly commensurate with benefits received by each area. Long-Range Transmission Planning uses a process that is iterative to ensure the system is planned to be reliable, resilient and efficient in the near term and out to 20 years and beyond. MISO continuously plans, assesses, evaluates and repeats as necessary to ensure a least-regrets plan. In such an approach, MISO seeks to identify transmission that will be used and useful across a variety of scenarios as utility, customer and state plans continue to shift over time.

A strong regional backbone enables the movement of power across the footprint, from where it is generated to where it’s needed most. This further unlocks economic generation across the footprint. The ability to move power around the footprint is also an important benefit during periods of grid stress, such as extreme weather events like the 2021 Arctic storm that crippled Texas.

In this event, extreme low temperatures impeded operation of many generators, especially in the South region. As temperatures plummeted, a number of generators went offline. At that time, it became critical to move power to where it was needed. The MISO system was able to move large amounts of power from north to south across the MISO grid, and import power from the east for use by MISO and its neighboring RTO, Southwest Power Pool (SPP.)
If the trend of severe weather events continue, regional transmission will become even more important for the resiliency of the electric system, providing needed power to homes and businesses as they navigate temperature extremes. Long-Range Transmission Planning projects will promote regional bulk transfer, interzonal support, resource integration and resource retirement.

Long-Range Transmission Planning will facilitate increased regional energy transfer that, in turn, will support and allow for increased interregional energy transfer that results in market efficiencies as well as emergency and reliability support. MISO will identify these projects, along with appropriate cost allocation, through an extensive stakeholder process that includes monthly workshops, periodic discussions at the Planning Advisory Committee, plus additional stakeholder meetings through the Regional Expansion Criteria and Benefits Working Group.

MISO-SPP Joint Transmission Interconnection Queue Study

As both MISO and SPP face large interconnection queues with overwhelming quantities of wind and solar resources, the transmission system is at its capacity on the MISO-SPP seam. Renewable resources and additional transmission at the borders benefit markets as a whole, but network upgrades are too costly for individual interconnection projects to proceed and current cost allocation methodologies do not provide sufficient cost-sharing to facilitate interconnection of new generators. Collaboration between MISO and SPP is important in bringing resources online.

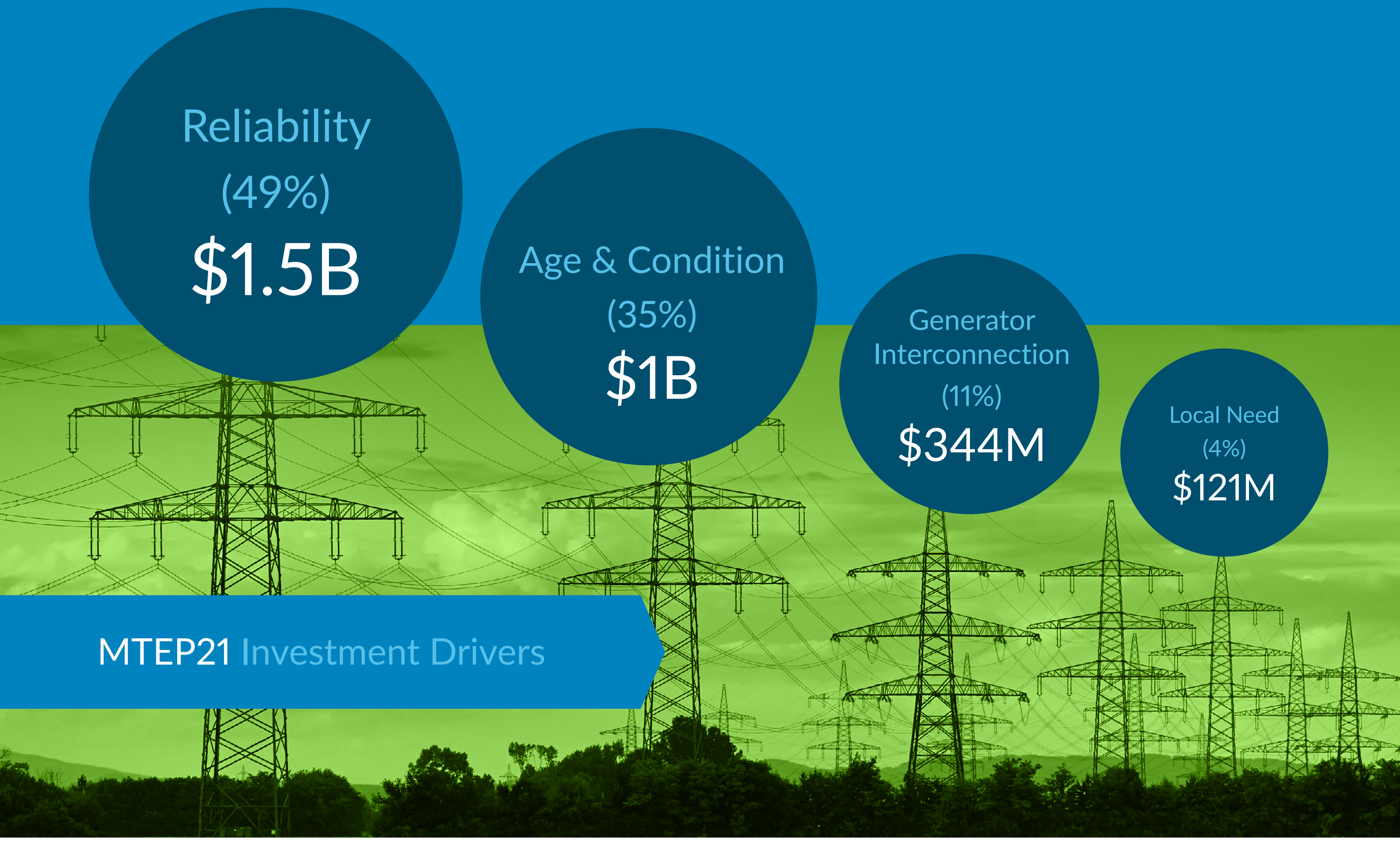
Further, robust interconnection capabilities during severe weather events may avert catastrophe. At one point during the Arctic Event, MISO's RTO neighbor to the east, PJM, exported 13,000 MW into MISO for use in the affected areas. However, ERCOT could only import 800 MW due to its limited interconnections to other regions.

Solutions coming from this effort, and the Long-Range Transmission Planning initiative, will feed into upcoming MTEP cycles.

MISO

SPP Southwest Power Pool

MTEP21 New Projects Overview



MTEP21 Appendix A projects are vetted by MISO through the planning process and are ready for execution.

The 335 new Appendix A projects in MISO's 2021 Transmission Expansion Plan (MTEP21) represents over **$3 billion in transmission infrastructure**

Top 10 proposed MTEP20 projects

(In descending order of cost)

Rank	Project Name	Project Driver	Estimated Cost ($M)
1	Golden Meadow to Clovelly 115 kV: Line Rebuild	Other – Reliability	$86
2	Southern Iowa New 161 kV Line and Breaker Stations	Other – Reliability	$71
3	Northline 230 kV: New Substation	Other – Load Growth	$43
4	Cato – Corktown 120 kV	Other – Reliability	$40
5	J875 Generator Interconnection	Generator Interconnection	$37
6	Lincoln - 43rd Street Terminal 138 kV: Line Rebuild	Other – Age and Condition	$36
7	Southline 138 kV: New Substation	Other – Load Growth	$35
8	Appleton – Benson (AG-AB) 115 kV Line	Other – Reliability	$35
9	Panther – Big Swan Rebuild	Other – Age and Condition	$33
10	Bullock Shale 138 kV - Rebuild	Baseline Reliability	$33

The 10 largest projects represent 15 percent of the total cost and are distributed across the MISO region. These projects support safe, reliable transmission to enable load and generation interconnection, NERC reliability compliance and other local needs.

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MTEP21

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CHAPTER 1: MTEP OVERVIEW

1.1 MISO Overview

Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. Forty-two million people depend on MISO to generate and transmit the right amount of electricity every minute of every day. MISO is committed to delivering electricity reliably, dependably, and efficiently. In addition to managing the power grid within our region, MISO administers the buying and selling of electricity, and partners with members and stakeholders to plan the grid of the future.

Scope of Operations

Generation Capacity

- 184,287 MW (market)
- 200,225 MW (reliability)

Historic Summer Peak Load (set July 20, 2011)

- 127,125 MW (market)
- 130,897 MW (reliability)

Historic Winter Peak Load (set January 6, 2014)

- 109,336 MW (market)
- 114,247 MW (reliability)

Transmission

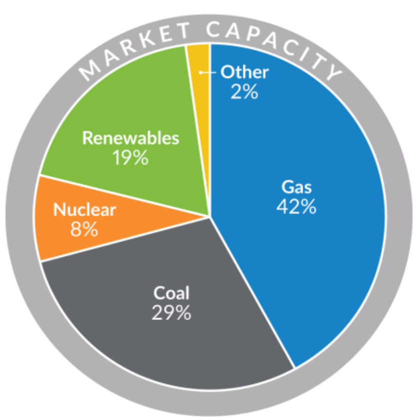
- Approximately 72,000 miles (Reliability Footprint)

Balancing Authorities

- 39 Local Balancing Authorities in MISO

Network Model

- 296,760 SCADA data points
- 6,719 generating units



Corporate data as of August 2021

Registered Wind	27,878 MW
Registered In-Service Wind Generation Capacity	26,806 MW
Registered Solar Generation Capacity	2,004 MW
Registered In-Service Solar Generation Capacity	2,004 MW

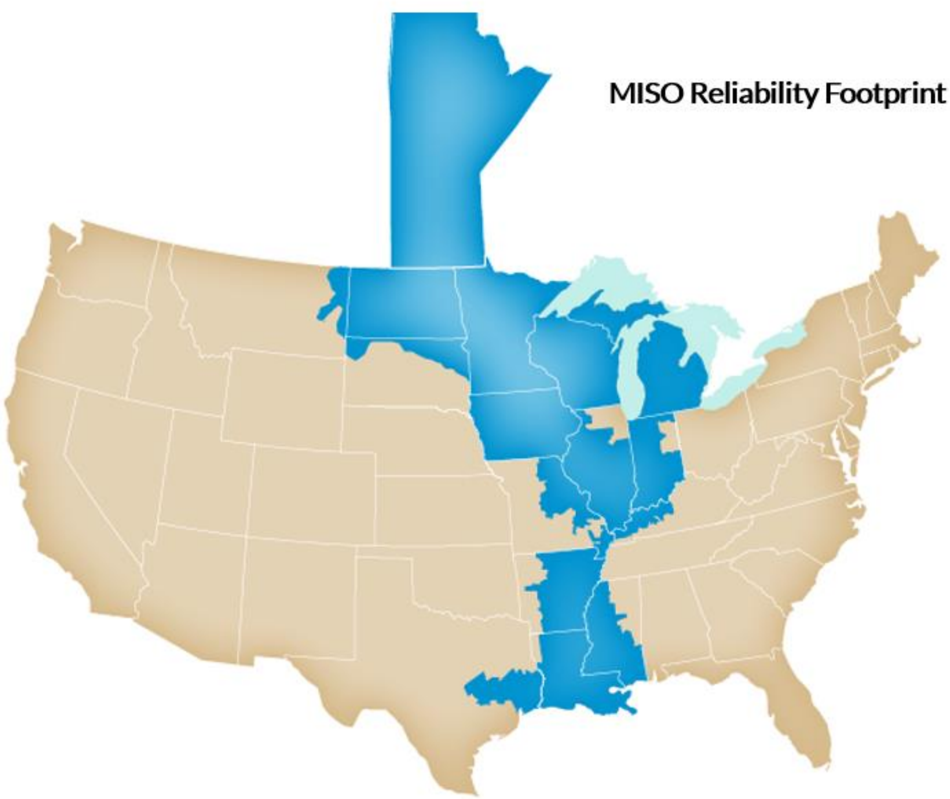
Markets Overview

MISO manages one of the world's largest energy and operating reserve markets using security-constrained economic commitment and dispatch of generation.

The Energy and Operating Reserves Market includes a Day-Ahead Market, a Real-Time Market, and a Financial Transmission Rights Market. These markets are operated and settled separately.

- $22 billion annual gross market charges (2020)
- 495 Market Participants that serve approximately 42 million people


MISO Market Footprint


MISO Reliability Footprint

MISO Transmission Infrastructure Investment

MISO is a not-for-profit organization; it does not own any generation or transmission facilities. MISO strictly manages the generation and flow of electricity across the high-voltage lines within its territory. Through the collaborative efforts of a diverse group of industry participants, MISO manages approximately 72,000 miles of transmission lines across 15 states and the Canadian Province of Manitoba.

This iteration of the MTEP report, MTEP21, builds and expands on the 17 prior years of projects since 2003 for a total of over $42 billion of investment in the United States (Figure 1.1-1). MISO's proposed new projects for this MTEP cycle are detailed in Section 1.3, Chapter 4, and Appendix A of this report.

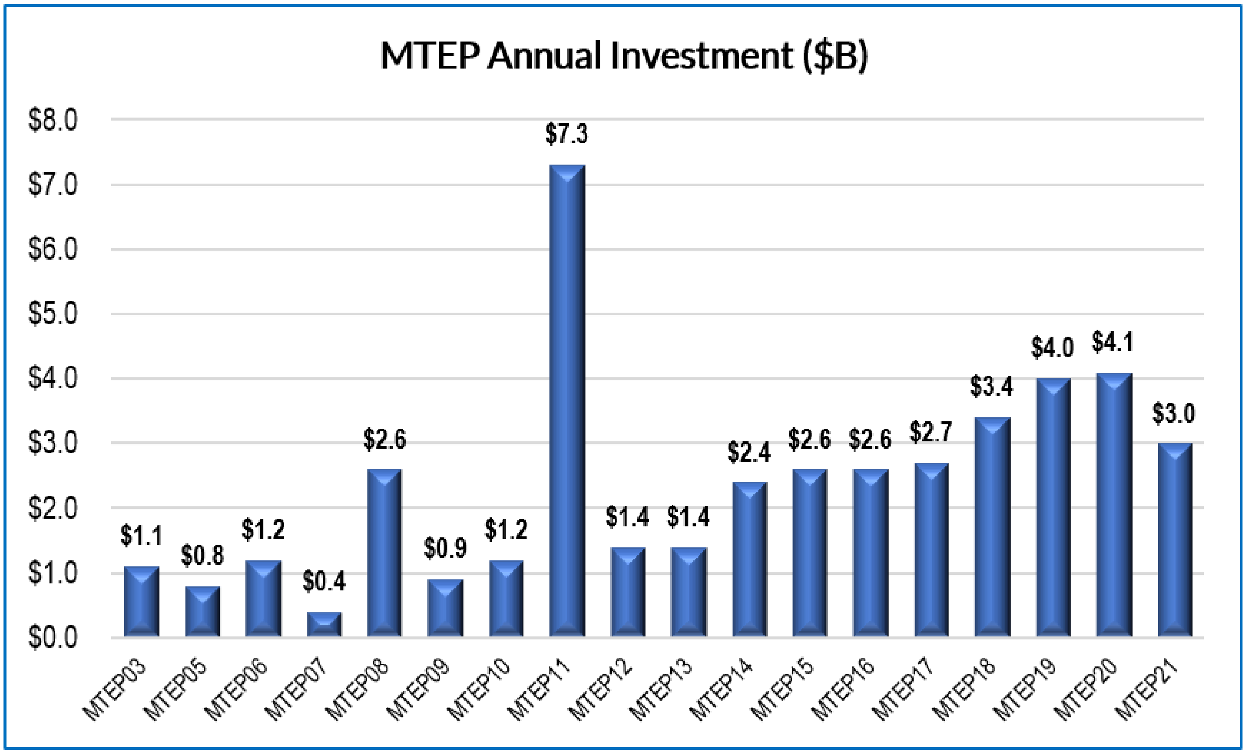


Figure 1.1-1: MTEP annual investment inclusive of MTEP21 proposed projects, data as of 9-20-2021

Highlights in prior MTEP cycles include:

- MTEP06 and MTEP07 were approved in the same calendar year, which accounts for the comparatively small incremental value of projects in MTEP07.
- MTEP11 reflects the approval of the Multi-Value Project portfolio, which accounts for the significantly higher investment totals compared to other MTEPs.
- MTEP14 reflects the inclusion of the new MISO South region projects. A single transmission delivery service project accounts for around 25 percent of the total MTEP14 investment.

Consistent growth in infrastructure investment in the MISO footprint over the last several years reflects the predominance in Transmission Owner-driven upgrades to improve efficiency, reliability, and safety in outdated system designs and replace aging assets to make the system more resilient.

MISO's transmission planning responsibilities include the monitoring of previously approved Appendix A projects. MISO surveys all Transmission Owners and Selected Developers every quarter to determine the progress of each project. These status updates are reported to the MISO Board of Directors and posted quarterly to the MISO Transmission Expansion Plan page at misoenergy.org[1].

MTEP Approved Projects Status

Since MTEP03, $28.2 billion of investment has gone into service and $12.5 billion of approved projects are yet to be fully placed into service (Figure 1.1-2).

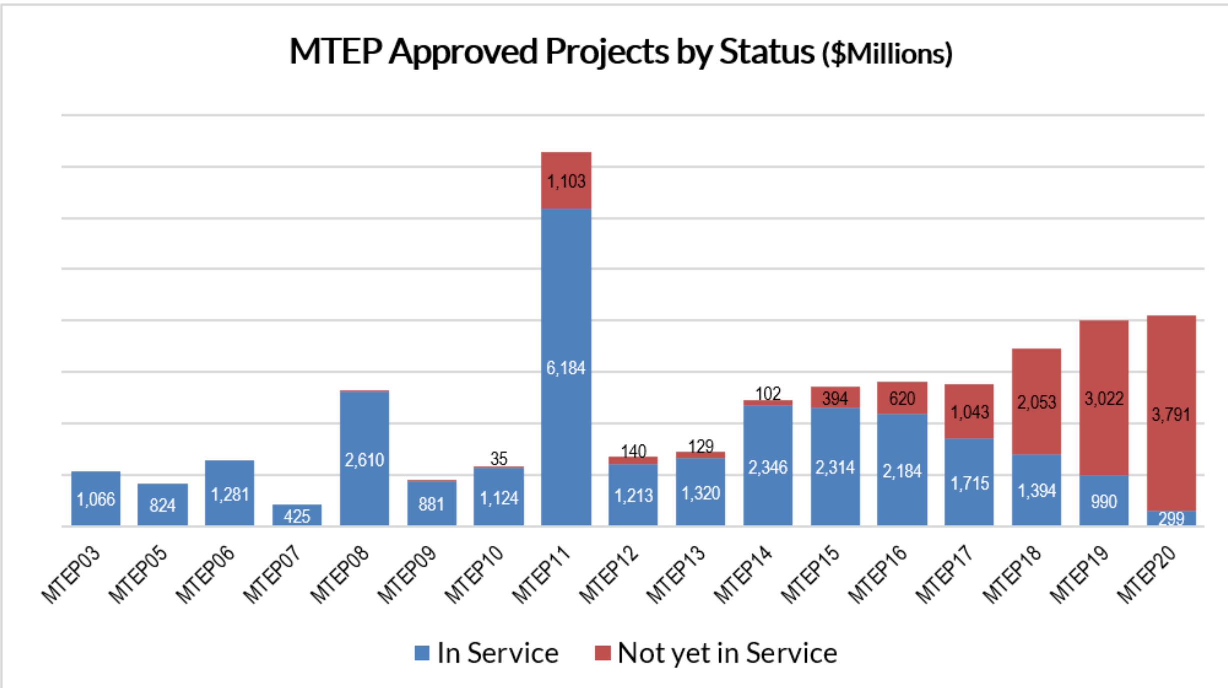


Figure 1.1-2: Appendix A project status as of 9-20-2021 (excluding withdrawn)

Active (Not yet in Service) Appendix A Projects - Future Line Miles

There are approximately 4,325 circuit-miles of planned new or upgraded transmission lines projected in the 10-year planning horizon in Appendix A (Figure 1.1-3).

- 3,137 circuit-miles of upgraded transmission line on existing corridors are planned of which 96% are $\leq$230 kV and 4% are $\geq$345 kV.
- 1,188 circuit-miles of new transmission line on new corridors are planned of which 80% are $\leq$230 kV and 20% are $\geq$ 345 kV.

[1] MISO Transmission Expansion Plan website address: https://www.misoenergy.org/planning/planning/

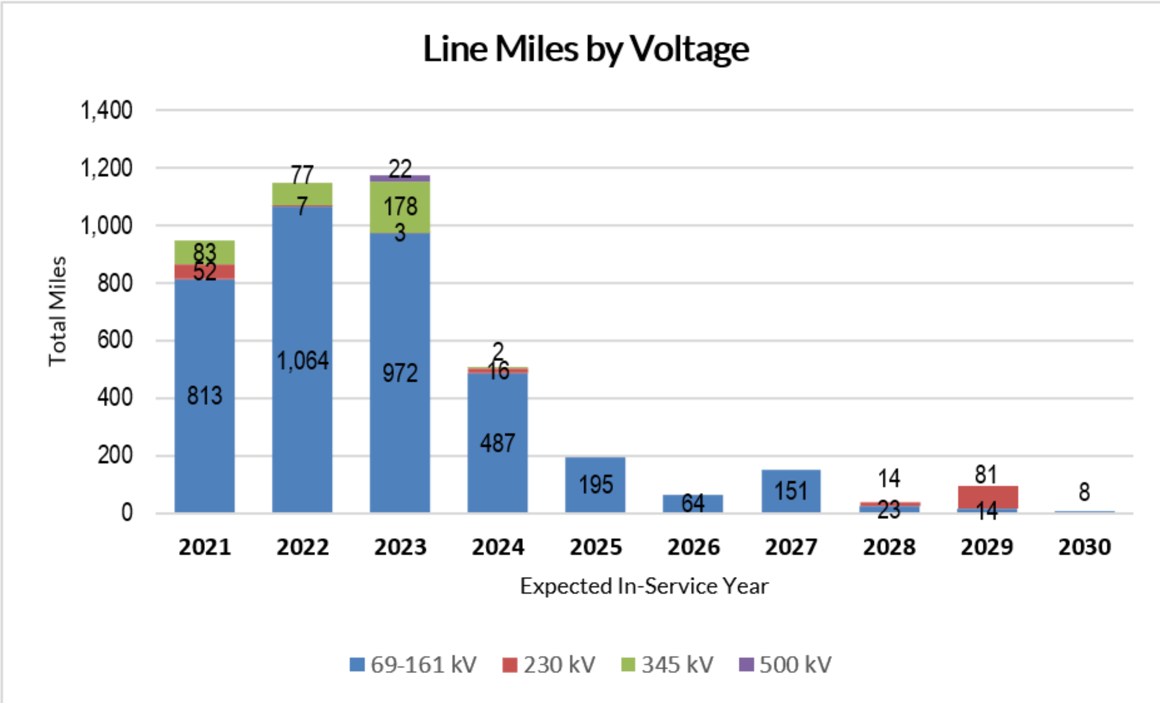


Figure 1.1-3: Active Project circuit line miles by voltage and expected in-service year (as of 7-30-2021).

Existing Line Miles Summary

MISO has approximately 68,000 circuit-miles of transferred functional control transmission lines serving as the backbone of the footprint (Figure 1.1-4) in the United States. Currently, the West region holds 40% of total footprint line miles, the South region holds 24%, the Central region holds 21%, and the East at 14%.

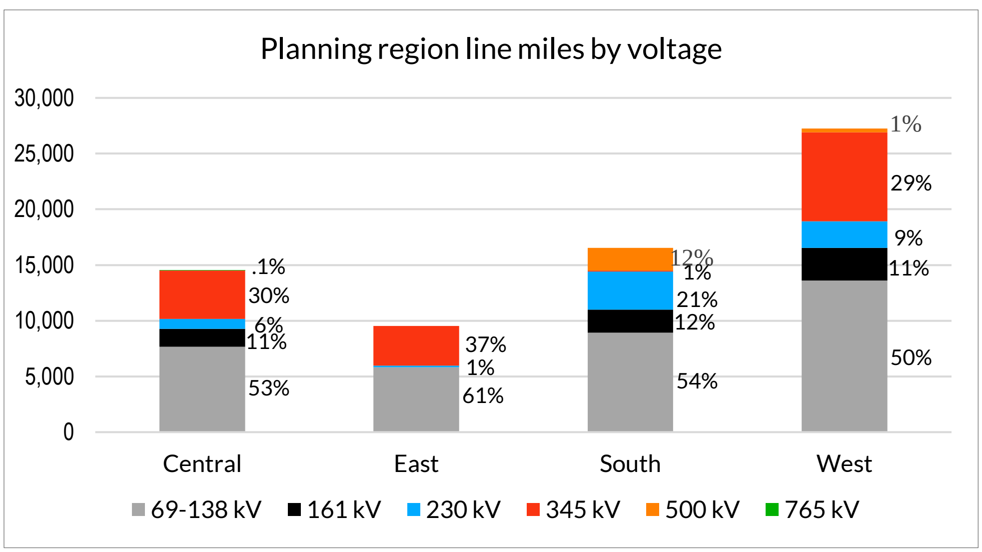


Figure 1.1-4: 2021 in-service transferred circuit miles by voltage class

Transmission Facility Investment

Of the over $40 billion of approved investment that remain active or in-service, $17 billion of that investment, or 43%, has occurred in the last five MTEP cycles. There has been a shift in where those investments are being installed. In the first 12 MTEP cycles, the predominant investment was in new line assets at 56% or$13B cost, with the second largest spend in substation assets at 17%, and line upgrades at 16%. The shift in the last five cycles is represented in Figure 1.1-5 below and reflects current asset investment.

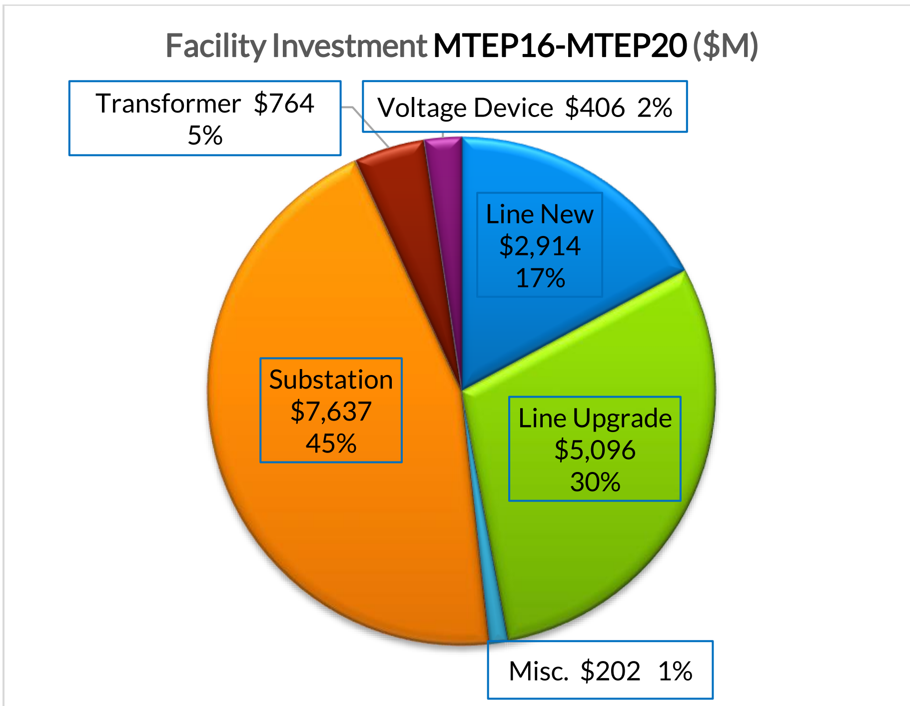


Figure 1.1-5: Appendix A Project data for previously approved five MTEP cycles

Full archived files of previous MTEP Reports can be accessed via the MISO Transmission Expansion Plan page at misoenergy.org.

Planning Guiding Principles

- Develop transmission plans that will ensure a reliable and resilient transmission system that can respond to the operational needs of the MISO region.
- Make the benefits of an economically efficient electricity market available to customers by identifying solutions to transmission issues that are informed by near-term and long-range needs and provide reliable access to 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 of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.
- Analyze system scenarios and make the results available to federal, state, and local energy policy makers and other stakeholders to provide context and to inform choices.
- Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations.

1.2 MISO Transmission Planning Process

A goal of the MTEP report is to satisfy the regulatory requirements as specified in Federal Energy Regulatory Commission Orders and the ISO Agreement. The report provides an annual snapshot with results and recommendations from the continuous planning processes MISO undertakes. MISO's planning process follows established guiding principles to ensure reliability, support policy requirements, and enable a competitive market to benefit all customers (see Figure 1.2-1 planning regions).

MISO will continue to follow federal and state policy as well as monitor fuel prices, plant retirements, and announced member plans for any changing industry trends. The ability not only to meet peak demand, but to move bulk power from resource areas to load centers across the footprint in all hours of the day will be needed to maintain system reliability and improve efficiency with the evolving resource fleet. Regional planning solutions will play an essential role in optimizing the natural and geographic diversity of these resources.

Periodically, the System Planning Committee of the Board of Directors provides input into MISO's Planning Guiding Principles. The most recent review and approval by the Board of Directors occurred in June 2021.

Planning Functions

The planning process includes these functions, which are described in detail in the Transmission Planning Business Practices Manual[2].

- Model Development
- Generator Interconnection Planning
- Transmission Service Planning
- Cyclical regional expansion planning activities
- Interregional coordination with neighboring transmission planning regions
- System Support Resource studies for unit suspension or retirement
- Transmission-to-Transmission Interconnection
- Load Interconnections
- Focus Studies

[2] https://www.misoenergy.org/legal/business-practice-manuals/

MISO addresses current dramatic changes in the projected resource mix in its current strategic vision, which focuses on the key trends of de-marginalization, decentralization, and digitalization.

Furthermore, MISO identified the critical themes to address the associated challenges and opportunities: resource availability, flexibility, and visibility. Understanding these resource characteristics will be key to understanding the characteristics that will directly influence the composition and volume of new interconnection requests.

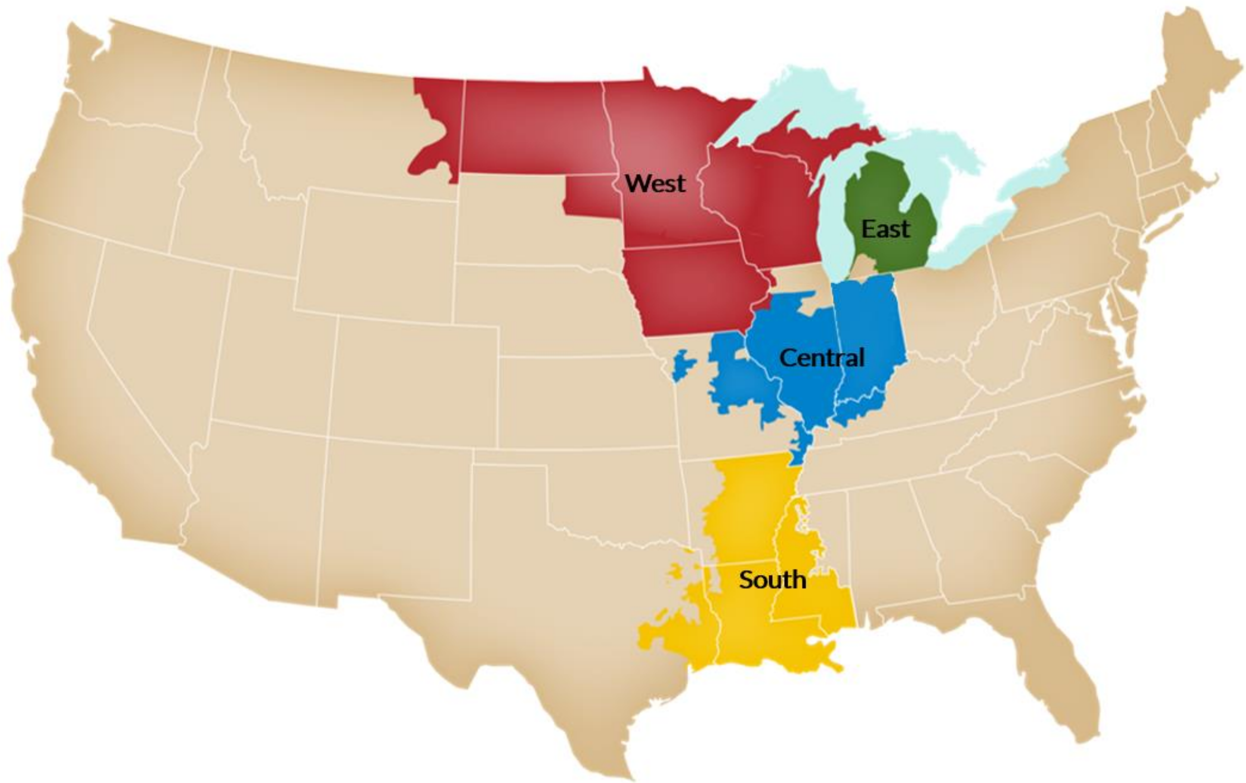


Figure 1.2-1: MISO footprint planning regions

Project Input and Stakeholder Coordination

Each planning cycle commences with regional model development; identification of potential expansions from the local planning processes of the Transmission Owners; identification and selection of transmission needs driven by public policy requirements to be included as transmission issues; and identification by stakeholders or MISO staff of potential expansions that address the transmission issues. Each cycle concludes with recommendations to the MISO Board of recommended solutions to the transmission issues evaluated.

Transmission Owner plans developed through local planning processes are included in the beginning of each regional planning cycle as potential solutions to local transmission issues identified by the Transmission Owners.

MISO's regional planning process makes evaluations — with stakeholder input from the Sub-regional Planning Meetings, the Planning Subcommittee, and the Planning Advisory Committee — throughout the cycle to develop expansion plans to meet the needs of the system. This multi-party collaborative process allows analysis of all projects with regional and inter-regional impact for their combined effects on the Transmission System. Moreover, the design of this collaborative process ensures that the MTEP addresses transmission issues within the applicable planning horizon in an efficient and cost-effective manner, while considering the input of stakeholders.

MISO's planning process ensures local needs are integrated with regional requirements

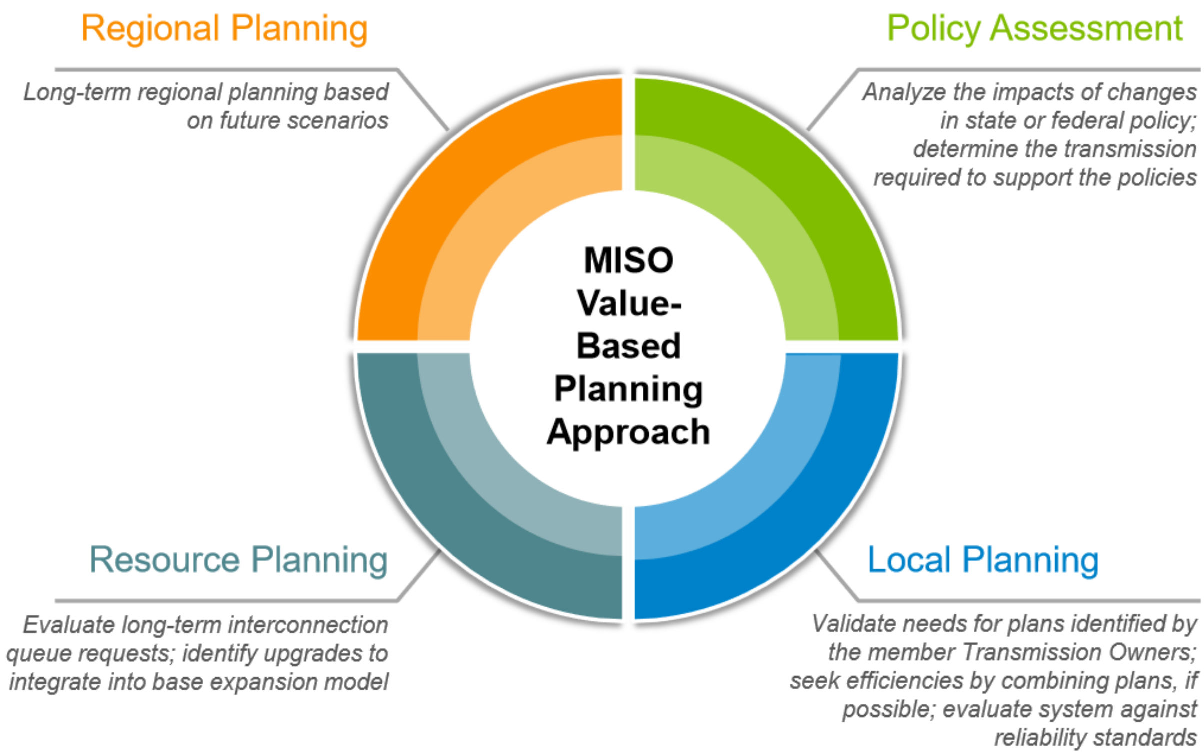


Figure 1.2-2: The MISO Value-Based Planning approach

Key Planning Cycle Milestones

While following the MISO value-based planning approach (Figure 1.2-2), key milestones in the typical MTEP development process include requirements and timelines for data submittal, review, and comment at each of these milestone points as described in the Transmission Planning Business Practices Manual posted on the MISO public website.

- Model development
- Identification of transmission issues
- Testing models against applicable planning criteria
- Development of possible solutions to identified transmission issues
- Selection of preferred solution
- Determination of funding and cost responsibility
- Monitoring progress on solution implementation

Planning Analysis Methods

Planning analyses performed by MISO test the transmission system under a wide variety of conditions using standard industry applications to model steady state power flow, angular and voltage stability, short-circuit, and economic parameters, as determined appropriate by MISO to be compliant with applicable criteria and the Tariff. MISO collaborates with Transmission Owners, other transmission providers, transmission customers, and other stakeholders to develop appropriate planning models that reflect expected system conditions for the planning horizon.

Models are available to stakeholders with security measures as provided for in the Transmission Planning Business Practices Manual. MISO provides opportunity for stakeholders to review and comment on the posted models before commencing planning studies.

Long Range Transmission Planning

Long Range Transmission Planning (LRTP) is an essential element of planning the regional grid to be reliable and efficient over short and long-range planning horizons. LRTP efforts are launched periodically when needed to address significant changes to future conditions that the grid must be prepared to address. LRTP integrates with other shorter term planning processes to provide for the long-range facility development needs (Figure 1.2-3). Each process feeds the others to cover the entire planning horizon. The processes are sequential and the output of one becomes the baseline to the other. Long Range Transmission Planning results in projects that are backbone facilities needed to move bulk power between areas of the region. While they provide for a reliable and efficient grid based on forecast resource developments, they are not intended to resolve all connection issues associated with precise siting of future generation.

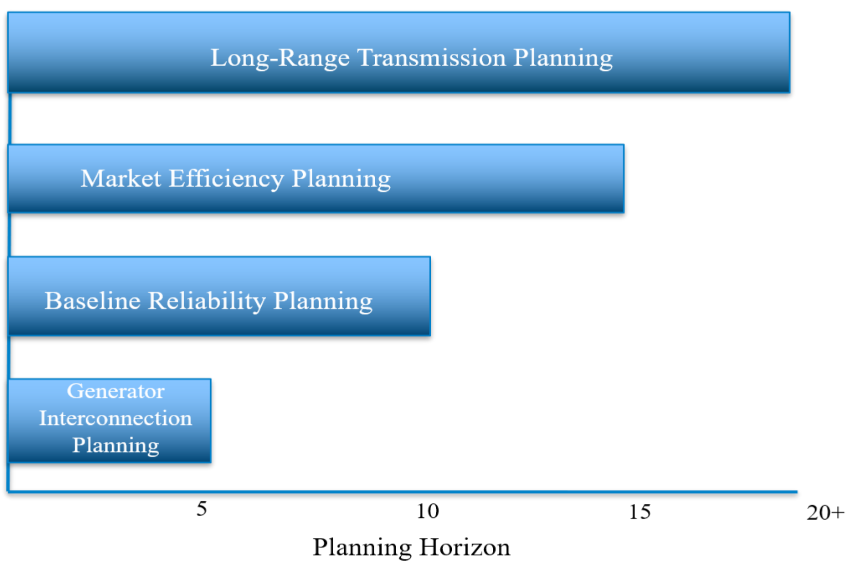


Figure 1.2-3: Long Range Transmission Planning target compared to other planning objectives

MISO staff work to ensure that the future regional transmission system will meet demand levels 'in all hours' under conditions defined by MISO Futures. The current iteration of the LRTP efforts is based on the most recent set of Futures developed with stakeholders. Detailed Futures assumptions are provided in

Appendix E of this MTEP21 Report. In addition, the MISO Futures Report was published in 2021 and available on misoenergy.org after an 18 month collaboration between MISO and its stakeholders.

Long Range Transmission Planning follows MISO's well-established 7 step value-based planning process:

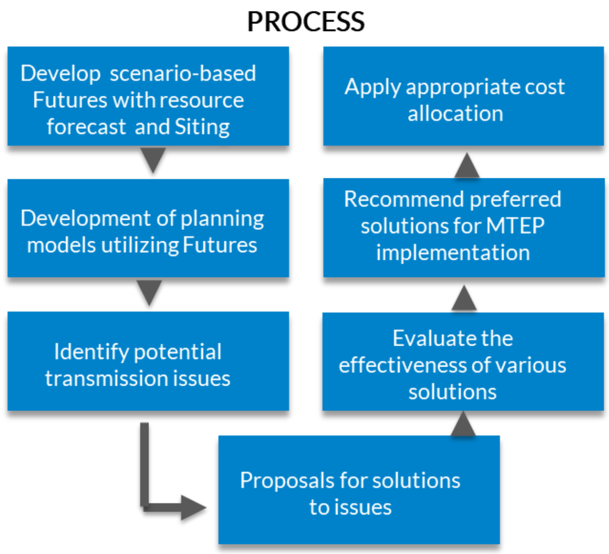


Figure 1.2-4: MISO's 7-step planning process

MISO is working to identify potential grid needs in support of the resource transformation underway and as contemplated under the MISO Futures. This extensive stakeholder process includes monthly workshops, periodic discussions at the Planning Advisory Committee, plus additional stakeholder meetings addressing cost allocation through the Regional Expansion Criteria and Benefits Working Group. Project recommendations resulting from this process will be then presented for Board of Director review and approval over several MTEP cycles as analyses proceed and recommendations are developed.

Details of MISO's Long Range Transmission Planning study progress are summarized in Sections 3.1 and 3.2 of the MTEP21 Report.

Project Approval

MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval after MISO completes an independent review of all proposed projects and addresses any stakeholder feedback received. These projects make up Appendix A of the MTEP report and represent the preferred solutions to the identified transmission needs of the MISO transmission planning process.

Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles.

Details of the project proposal process and transmission projects reviewed this cycle are summarized in Section 1.3 and Chapter 4 of the MTEP21 report.

Interregional Coordination and Planning Studies

On an annual basis MISO works with the neighboring transmission planning regions, Southwest Power Pool (SPP) and PJM Interconnection (PJM), to identify issues on the seams, perform studies, and jointly evaluate transmission solutions that may be more efficient or cost effective than a corresponding regional solution. While MISO has a separate Joint Operating Agreement (JOA) with both SPP and PJM that details specific processes and criteria, the high-level interregional coordination activities are similar on each seam:

1) Exchange modeling data and other system information (typically performed in Q4).
2) Review identified issues on the seam (typically performed in Q1).
3) Evaluate whether to perform an interregional study based on the identified issues.

MISO performs joint coordinated system plan (CSP) studies with SPP and PJM on a regular basis, in accordance with the timelines and frequencies dictated in their respective JOAs. A CSP study may have a targeted scope or a more complex scope requiring a longer study period, and can include reliability, economic and/or public policy issues. All interregional issues and CSP study efforts are coordinated through a public Interregional Planning Stakeholder Advisory Committee (ISPAC) consisting of representatives and interested parties from each RTO community.

In addition to the joint study efforts with SPP and PJM, MISO performs studies as needed with neighboring entities of the Southeastern Regional Transmission Planning (SERTP) group and the Independent Electricity System Operator of Ontario (IESO). While the study process is less formal, MISO and these entities still meet regularly to review interregional issues and possible areas of collaboration.

Details on planning procedures, on-going studies and stakeholder meetings can be found on the Interregional Coordination page of the MISO public website (misoenergy.org).

1.3 MTEP21 Investment Summary

The MTEP21 cycle proposes 335 new Appendix A projects as justified in this MISO Transmission Expansion Plan and represents $3.02 billion in transmission infrastructure investment for the MISO region.

Overview of Tariff-defined Project Types

- **Baseline Reliability Project (BRP) -** Projects are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable national Electric Reliability Organization reliability standards and reliability standards adopted by Regional Reliability Organizations, and applicable within the Transmission Provider Region. Baseline Reliability Project costs are allocated to the local Transmission Pricing Zone(s) and recovered through Attachment O by the Transmission Owner(s) developing the projects.

- **Generator Interconnection Project (GIP) -** Projects are New Transmission Access Projects that are associated with interconnection of new generation or the capacity modification of existing generation. Costs are primarily paid for by the interconnection customers with certain exceptions as specified in Attachment FF. Costs of network upgrades rated at 345 kV and above are eligible for 10 percent cost recovery on a system-wide basis.

- **Market Efficiency Project (MEP) -** Projects meet Attachment FF requirements for reduction in market congestion and are eligible for regional cost allocation. Projects qualify as Market Efficiency Projects based on cost and voltage thresholds and are developed to produce a benefit-to-cost ratio of 1.25 or greater. Costs are distributed to benefiting pricing zones, in accordance with Attachment FF of the Tariff.

- **Targeted Market Efficiency Project (TMEP) -** Projects are designed to alleviate historical market-to-market congestion between MISO and PJM Interconnection, while meeting certain cost and construction requirements. The costs of Targeted Market Efficiency Projects are allocated first between MISO and PJM Interconnection by the ratio of each RTO's Day-Ahead and Excess Congestion Fund congestion, offset by historical market-to-market payments. The MISO share of costs for the project is then allocated to beneficiaries using historical nodal load congestion contribution data.

- **Multi-Value Project (MVP) -** Projects meet Attachment FF requirements to provide regional public policy, economic and/or reliability benefits. Costs are shared with loads and export transactions in proportion to metered MWh consumption or export schedules.

- **Other -** Projects included in MTEP21 which do not qualify as Baseline Reliability Projects, New Transmission Access Projects, Targeted Market Efficiency Projects, Market Efficiency Projects, or Multi-Value Projects.

- **Transmission Delivery Service Project (TDSP) -** Projects are required to satisfy a transmission service request. The costs are generally assigned to the requestor.

- **Market Participant Funded Project (MPFP) -** Projects are defined as Network Upgrades fully funded by one or more market participants but owned and operated by an incumbent Transmission Owner.

Overview of MTEP21 Projects

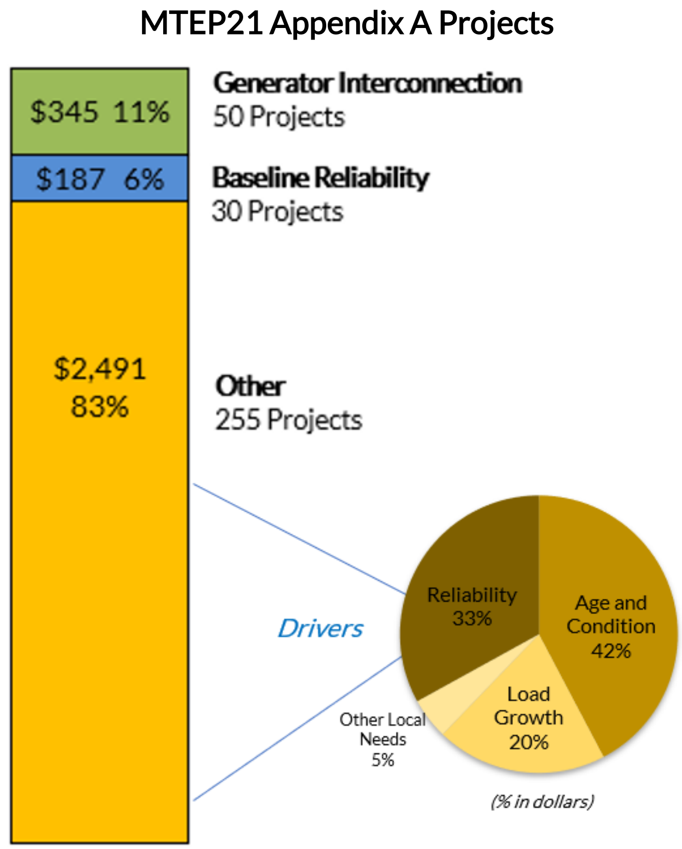


Figure 1.3-1: Appendix A New Project Investment (data as of 9-20-2021)

Of the 335 new Appendix A projects proposed in MTEP21 (Figure 1.3-1), 30 of them are Baseline Reliability; 50 are Generator Interconnection, and 255 are in the Other project category.

The majority of Other projects address localized reliability issues that are due to aging transmission infrastructure or local non-baseline reliability needs that are not dictated by NERC and regional reliability standards.

The new projects recommended for approval in MTEP21 Appendix A are broken down by region and project type (Table 1.3-1 and Figure 1.3-3).

Planning Region	BRP	GIP	Other	Total
Central	$43,100,000	$56,982,056	$605,625,928	$705,707,984
East	$49,965,000	$125,376,518	$330,567,339	$505,908,857
South	$62,330,000	$25,827,464	$623,865,790	$712,023,254
West	$31,177,603	$136,651,940	$931,263,688	$1,099,093,231
Total	**$186,572,603**	**$344,837,978**	**$2,491,322,745**	**$3,022,733,326**

Table 1.3-1: MTEP21 Appendix A new project investment by category and planning region (data as of 9-20-2021)

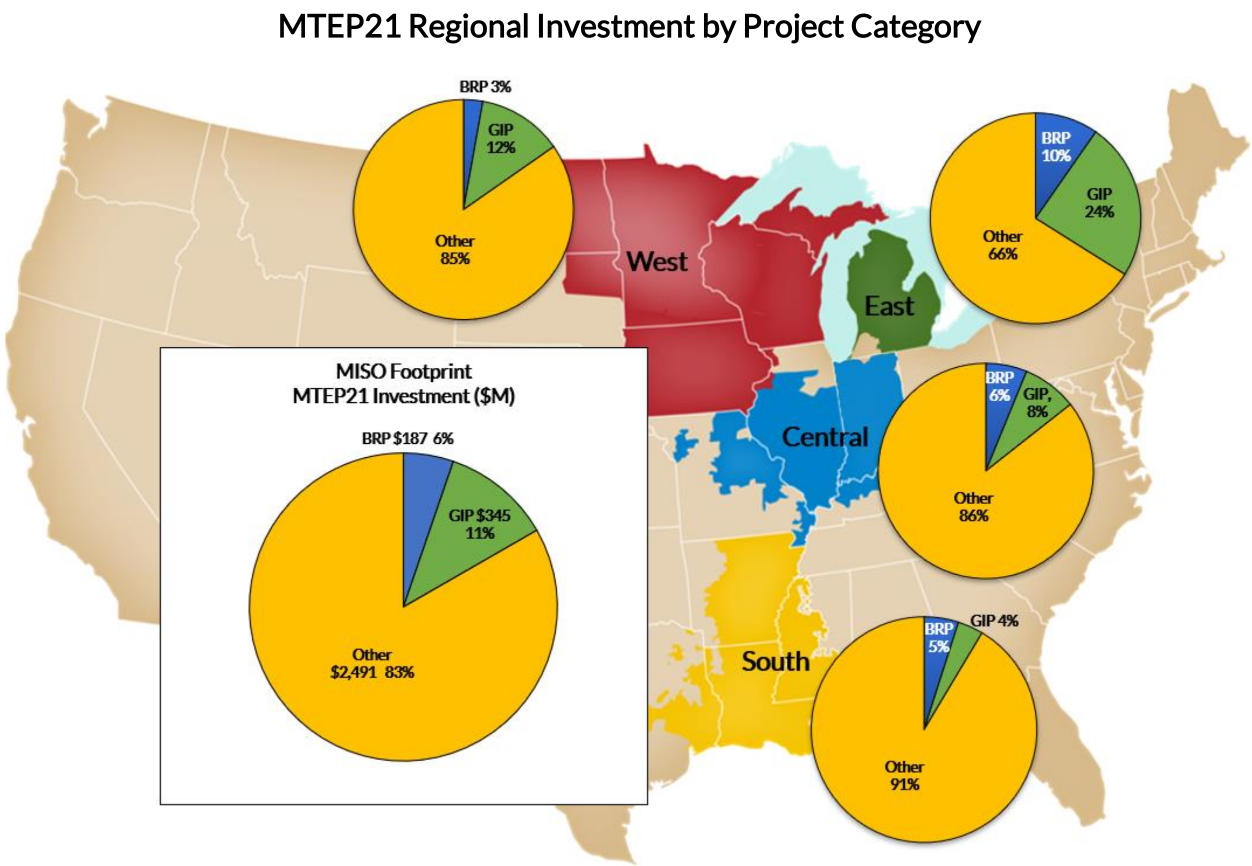


Figure 1.3-3: Regional MTEP21 investment by project category (data as of 9-20-21)

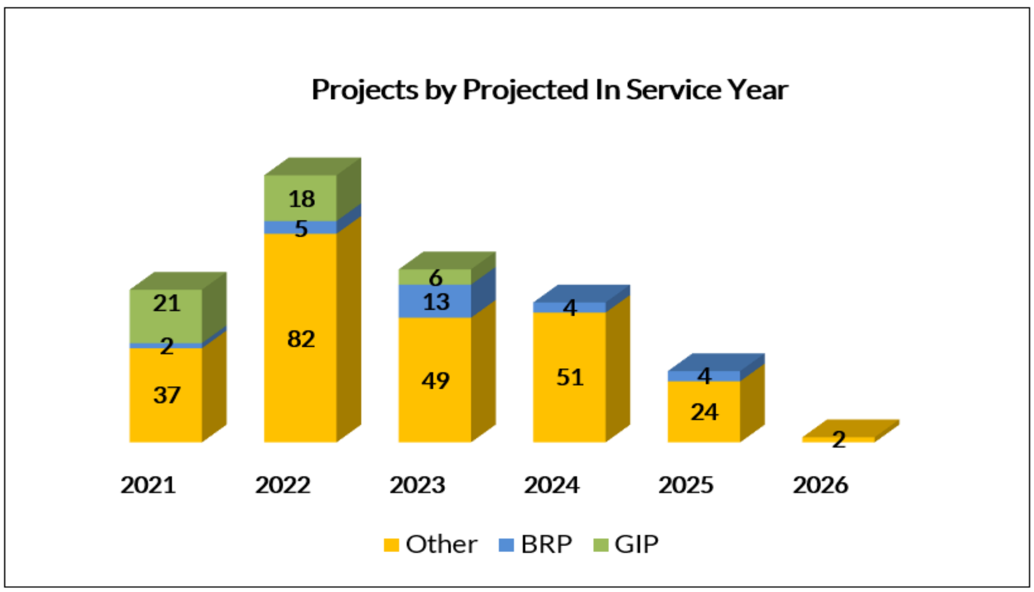


Figure 1.3-4: MTEP21 Projects by In-Service Year (data as of 9-20-21)

Of the 335 projects proposed for MTEP21, 91% percent are projected to go into service in the next three years (Figure 1.3-4).

New Appendix A projects are spread over 15 states, with six states scheduled for more than $200 million in new investment (Figure 1.3-5). These geographic trends vary greatly year to year as local planning dictates blanket asset renewal programs or existing transmission capacity in other parts of the system is consumed and new build becomes necessary.

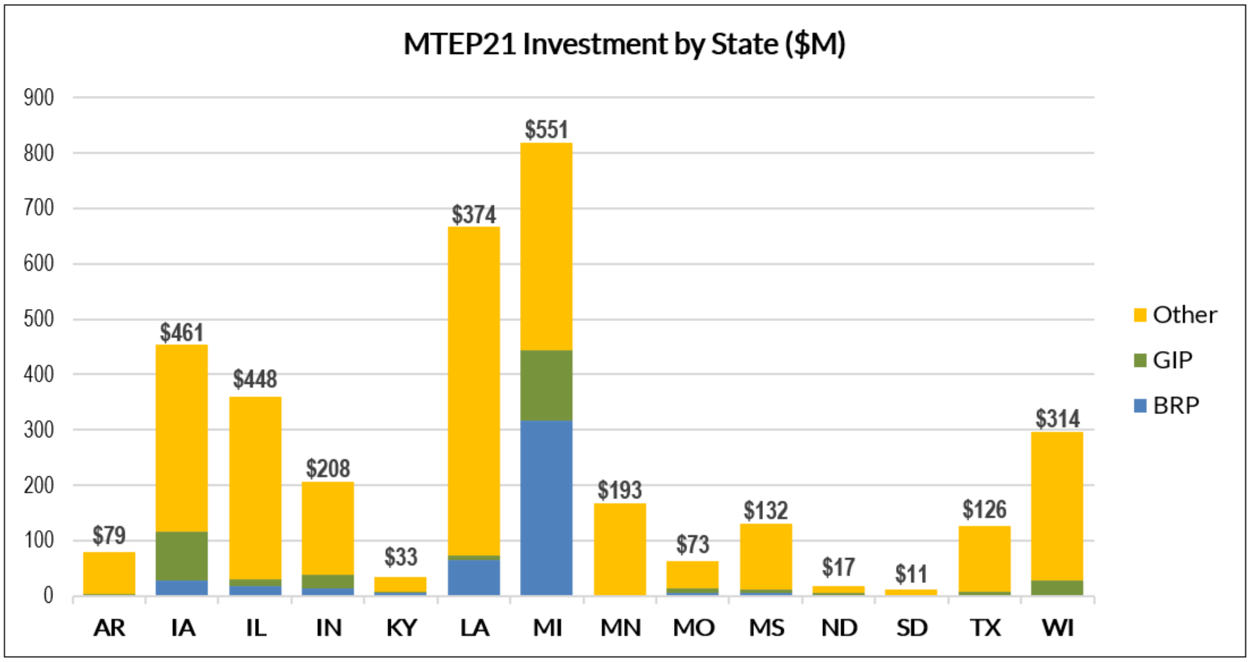


Figure 1.3-5: MTEP21 Appendix A investment categorized by state (data as of 9-20-21)

Facility Type

Each MTEP project is composed of one or more facilities, where each facility represents an individual element of the project. Examples of facilities include substations, transformers, voltage devices, circuit breakers or various types of transmission lines (Figure 1.3-7).

The majority of facility investment in the MTEP21 cycle, 38% percent is dedicated to substation or switching station related construction and maintenance. This includes completely new substations as well as terminal equipment work, circuit breaker additions and replacements, or new transformers. Thirty-six percent is dedicated to line upgrades which includes rebuilds, conversions, and relocations. Fourteen percent of facility costs are dedicated to new lines on new right-of-way across the MISO footprint.

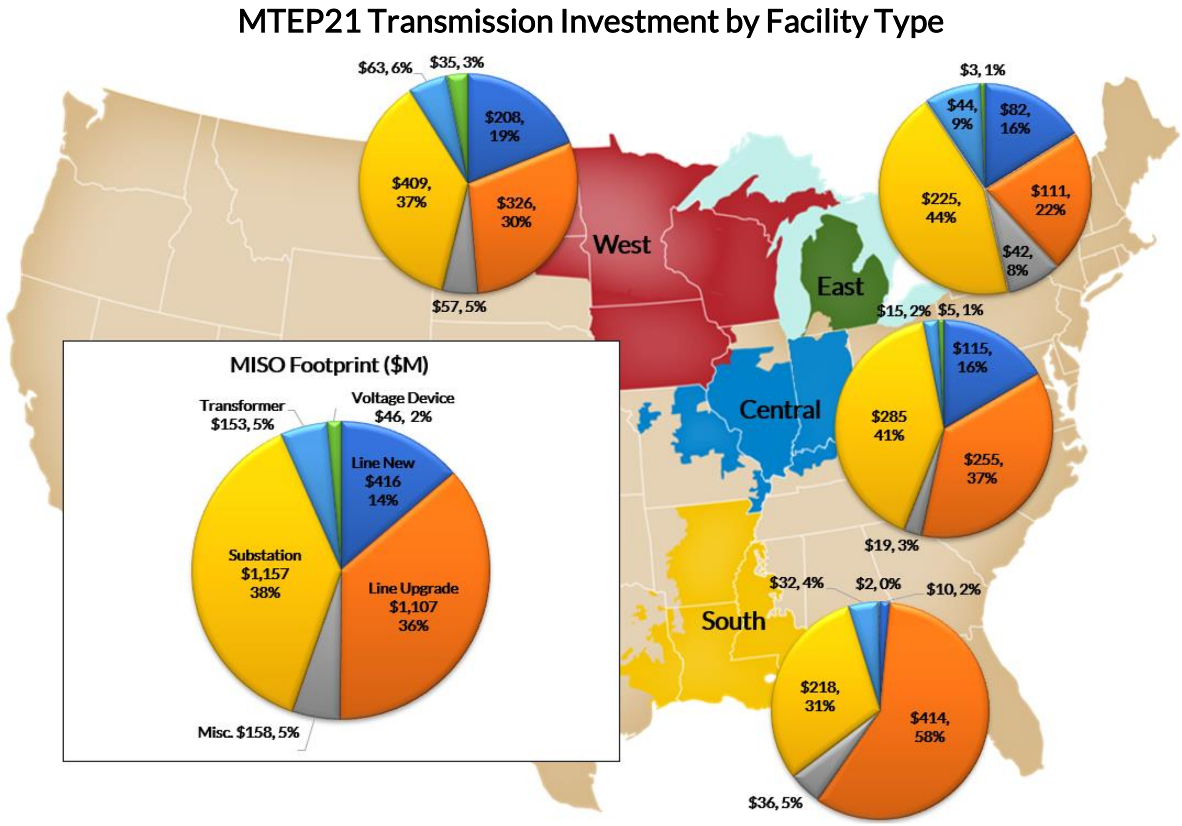


Figure 1.3-7: Facility type for new MTEP21 Appendix A projects by planning region (as of 9-20-2021)

MTEP21 Proposed New and Upgraded Line Miles

MTEP21 Appendix A proposed projects anticipates almost 763 miles of new or upgraded line to go into service through the next five years. Of those, 198 miles are new line mile construction and 565 miles are line upgrades. Ninty-two percent of the total line miles are 161 kV or below. There is one new line mile projected at 230 kV or above for the planning horizon shown in Figure 1.3-8.

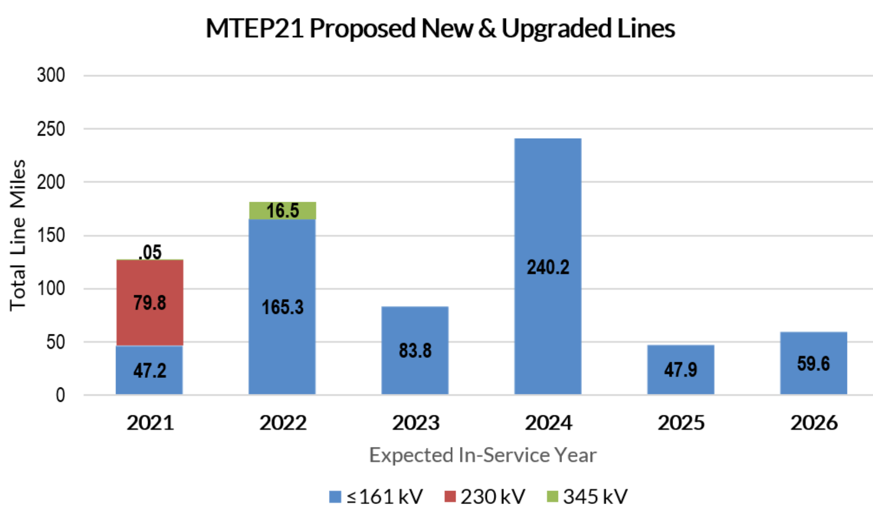


Figure 1.3-8: MTEP21 Appendix A proposed line investment miles by voltage (data as of 9-20-21)

Allocation of Costs

MTEP21 includes a total of 33 new cost-share eligible Generator Interconnection Projects (GIPs) for Appendix A (data as of 7-30-2021). GIP costs are primarily paid for by the interconnecting customer (generator), however, a portion of the costs for certain network upgrades are eligible for regional cost allocation under Attachment FF of the MISO Tariff. Detailed allocations by pricing zone are provided in Appendix A1.

Indicative rates related to past MTEP cost-shared projects are calculated on an annual basis. Please refer to the reports (indicative forecasts of annual charges) posted on the MISO public website[3].

MTEP Appendix B

MTEP Appendix B contains all projects that have been validated by MISO as the preferred solution to address an identified system need based on current information and forecasts, but where it is prudent to defer the final recommendation of a solution to a subsequent MTEP cycle.

This generally occurs when the preferred project does not yet need a commitment based on anticipated lead-time and there is still some uncertainty as to the prudence of selecting this project over an alternative project given potential changes in projected future conditions. MTEP Appendix B is limited to Baseline Reliability Projects and Other Projects and will be reviewed by MISO in subsequent cycles.

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[3] Cost Allocation updates web address: https://www.misoenergy.org/planning/planning/schedule-26-and-26a-indicative-reports/

CHAPTER 2: PORTFOLIO EVOLUTION

MISO manages the life cycle of an extensive and diverse fleet of resources that continues to experience a shift from conventional fossil fuel generation to carbon-free technologies. With the shift away from dispatchable generation closer to load centers to more remote variable energy resources, the transmission system no longer serves the same resources for which it was designed, and transmission upgrades are needed to enable integration of new resources.

To enable reliable and efficient effectuation of the resource portfolio evolution, MISO has to first understand and reflect on the past and identify future trends. This understanding is used to develop the spectrum of possibilities in the creation of MISO Futures. The trends and future reliability and efficiency impacts of resource evolution is the impetus behind what MISO coined the Reliability Imperative, a term that is used to describe the broad range of activities that are underway to anticipate and reliably adapt to the rapid changes that are and will be occurring. The Long Range Transmission Plan (LRTP) is one of the key activities that is part of the Reliability Imperative, and progress on that effort will continue to be reflected in future MTEP reports.

2.1 Historical Trends and Retirements

One aspect of the resource evolution that MISO assists its membership in managing is the retirement of generation facilities to ensure that the broader MISO footprint and markets remain reliable after resources are removed from service. Through the process articulated in Attachment Y of the MISO Tariff, resource owners submit a request to retire generation resources for MISO approval, which triggers an assessment into the impact that the requested resource would cause once it is retired from service. As a result of these analyses, any reliability issues are addressed through transmission reinforcements or other needed mitigation measures; and, if the reliability issue cannot be addressed prior to the planned retirement date, MISO may require the resource to remain in service as a system support resource (SSR) until the upgrade is complete, or mitigation is available. In recent years the need for system support resources has diminished and no generation resources are currently operating under a system support resource agreement.

Resource retirements of coal and gas-fired generation have seen a steady increase in the past several years as renewables have become economically and environmentally more attractive sources of energy. In the last 10 years MISO has experienced retirement of 25.9 GW of which 18.5 GW was coal based (Figure 2.1-1). The age of generating facilities retired in 2021 declined to 46 years compared to 57 years in 2011 displaced largely by the interconnection of renewable resources that are more economically viable. Advancements in technology and interest in renewables are expected to continue the current trend.

A new trend since 2020 is the utilization of the new Generating Facility Replacement process. This new process was approved by FERC in 2019 to allow the owners of an existing generating facility utilizing their existing generator interconnection service to replace the existing generator with a new generating facility at the same injection point without going through the MISO generator interconnection queue. Since 2020, MISO has received 10 generator replacement requests to replace a total of 2,314 MW of existing generation, which otherwise would have been retired through the traditional resource retirement process.

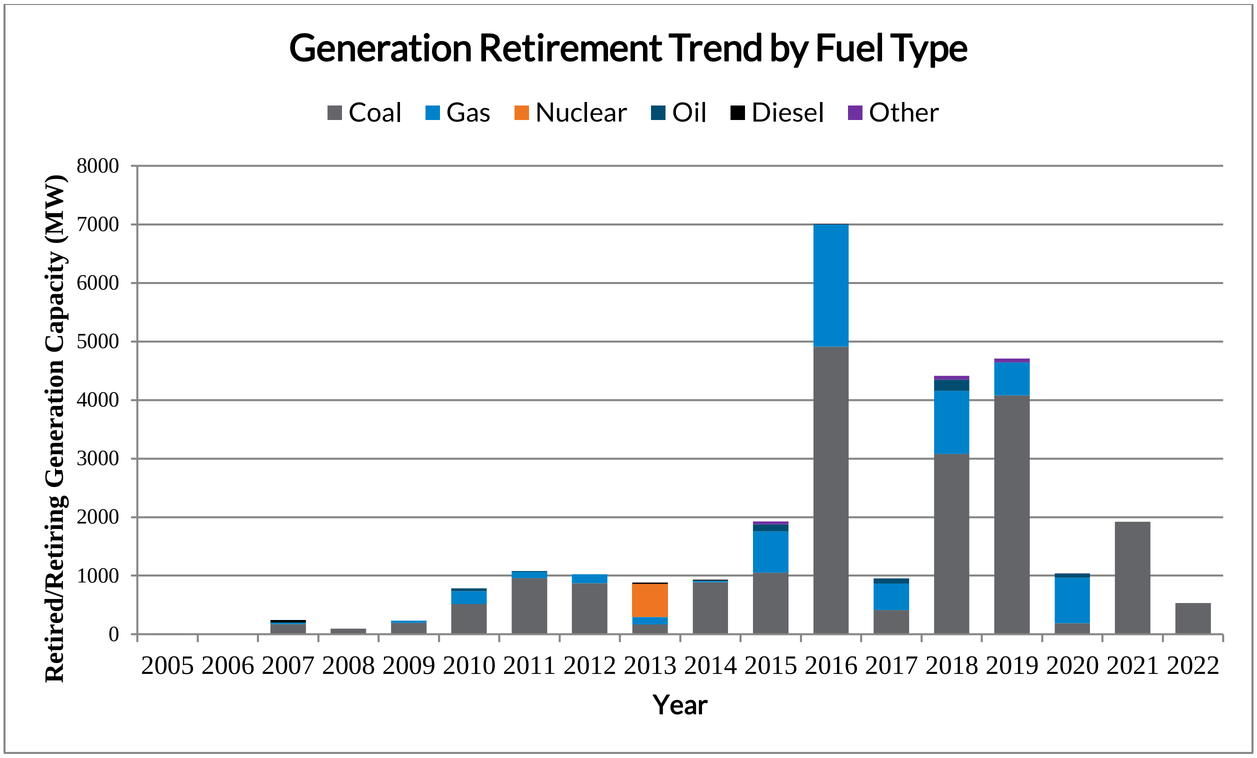


Figure 2.1-1: MW Generation Retirement by Fuel Type

2.2 Current State of the Queue

The MISO Generator Interconnection (GI) queue provides an active and competitive mechanism to enable resource interconnections that will serve future energy and capacity needs. Projects submitted in the annual queue cycle are evaluated by MISO through an iterative study process to determine the reliability impacts and to identify transmission upgrades needed to support resource integration. Project viability is often tied to the costs of network upgrades with the most viable candidates successfully executing a Generator Interconnection Agreement (GIA).

The Generator Interconnection queue has experienced extremely high volume over the last several years as a result of growing interest in renewable technology that has benefitted from declining costs of technology, favorable tax incentives and regulatory treatment. Wind has comprised a large portion of the interconnection queue volume in the last decade while solar resources have emerged more recently in part due to advances in solar technology and escalating regional transmission costs associated with integrating new wind development. As battery storage technology advances and interest continues to grow, MISO has seen an increase in the number of projects comprised of standalone storage or hybrid applications.

In 2021, MISO received 487 individual project requests representing a total of 77.8 GW of requested capacity during the application period that ended in July (Figure 2.2-1) marking a continuing trend of aggressive resource development. Solar installations have continued to trend upward, representing 56% of new entries and new wind development has shown a reversal of a downward trend from the prior year.

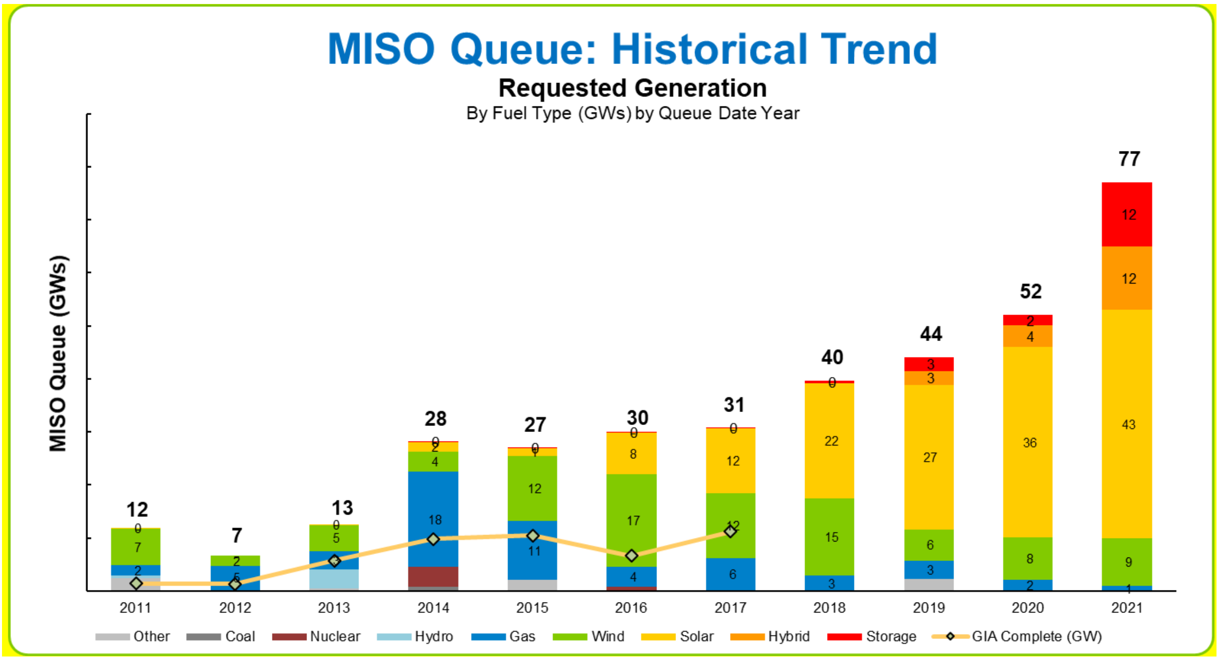


Figure 2.2-1 GI Queue by Fuel Type over the last ten years

As of October 1, the current state of the queue has 958 projects representing 150.3 GW of total capacity. Renewables represent over 80% of the remaining capacity. The figure below is updated monthly on the MISO website under the [GIQ Web Overview] link on the [Generator Interconnection Queue] page. A list of all active projects can also be reviewed on the page. The five study regions in the GI queue currently have 16 active cycles in various stages of the process from the start of the Definitive Planning Phase (DPP) to GIA negotiations.

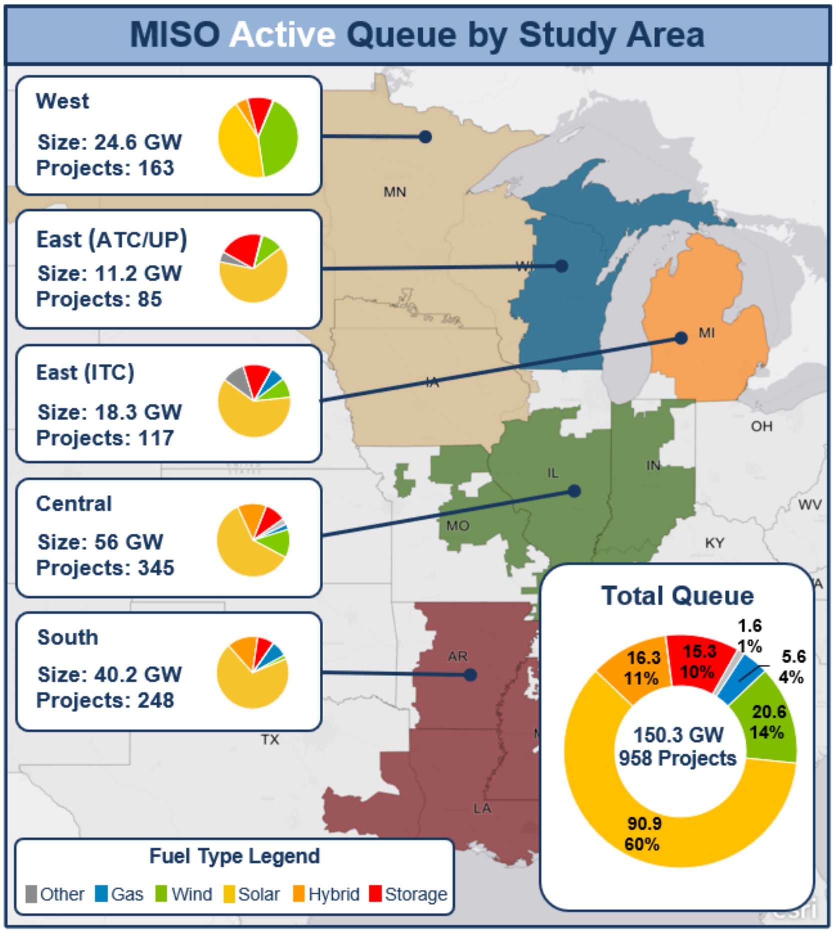


Figure 2.2-2: MISO Active Queue by Fuel Type as of 10-1-2021

2.3 The Cost of New Transmission to Integrate Generation is Changing and Impactful

In the past, the MISO Multi-Value Project (MVP) Portfolio facilitated new renewable resource development that delivered regional benefits by enabling access to lower cost energy. This broad regional approach to transmission planning recognized the benefits of a regional plan that would result in the most cost-effective transmission investment rather than an incremental build-out resulting from the generator interconnection process. Over the last decade, the continued interconnection of new resources has fully utilized the additional capacity provided by the MVPs resulting in the need for more network upgrades to support ongoing interconnection requests.

The continued growth of remotely located renewable resources has resulted in the need for major transmission upgrades with a significant increase in transmission costs incurred for resource interconnections. As the industry transitions away from traditional central station generation to more dispersed and variable energy resources, transmission investment will be needed to facilitate the change and support continued reliability. A comprehensive approach to system planning and resource interconnection recognizes broader benefits of transmission investment while facilitating resource evolution in a timely manner.

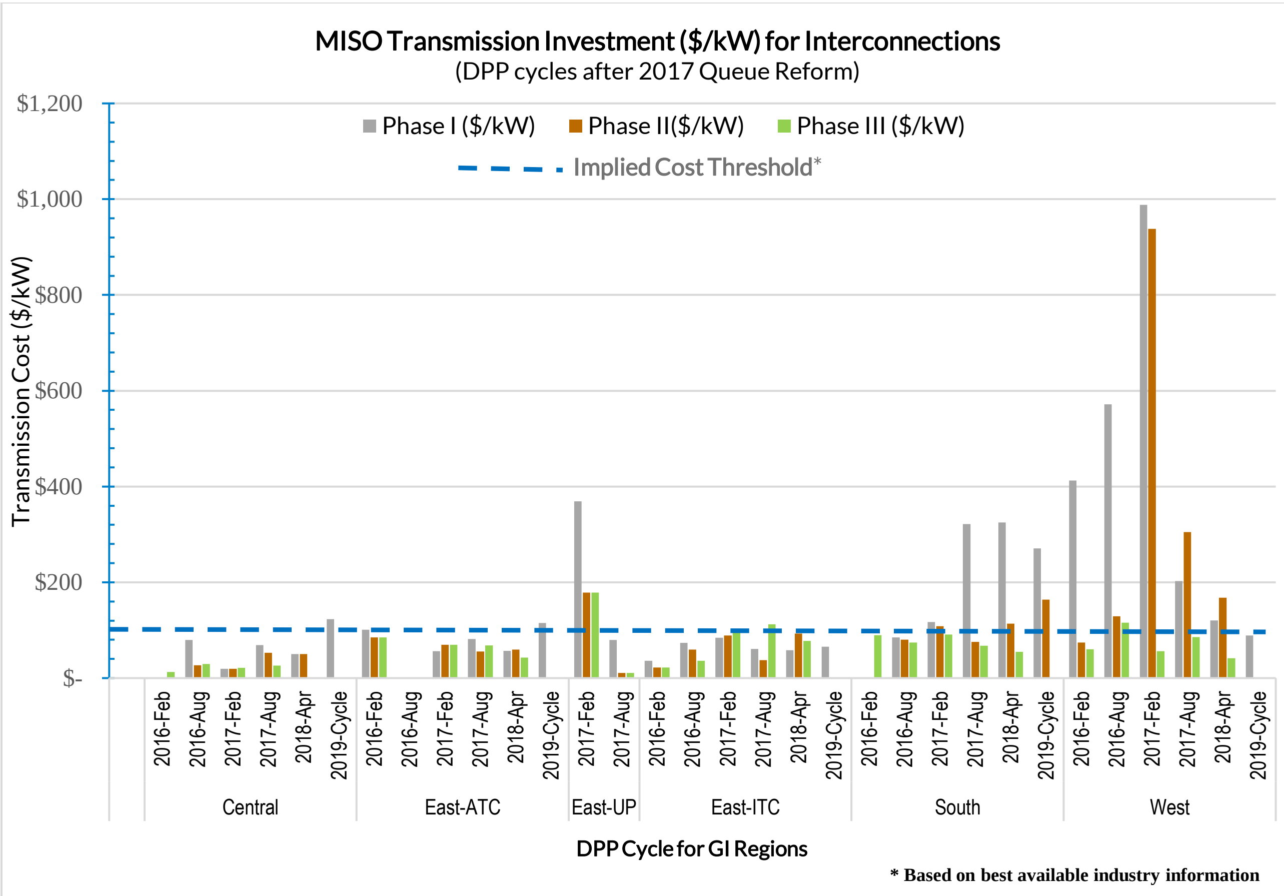


Figure 2.3-1: DPP Cycle Transmission Cost for each Planning Region

2.4 Resource Outlook

The fleet has been steadily changing over the past 10-15 years. Initially this was due to forces such as state Renewable Portfolio Standards, environmental regulations, and fuel competition from historically low natural gas prices. This portfolio evolution continues now to greater levels of renewables and new levels of battery storage based on public interest, support for less reliance on fossil fuels, and historically low costs of renewables. As this change continues, focus on maintaining adequate resources is imperative and becoming increasingly difficult.

The MISO region will have adequate, but tighter, reserve margins for 2022, and continued action will be critical to ensure resource adequacy into the future. For 2022, MISO will have a surplus of resources to meet the regional resource requirement. In most of the MISO region, load-serving entities with oversight by the applicable state or local jurisdiction are responsible for resource adequacy. Though the 2022 peak demand forecast decreased 3.6 GW from last year's survey, the five-year regional demand growth rate remained stable at approximately 0.3% year-over-year. On the supply side, the 2021 OMS-MISO Survey continues to indicate that increasing resource adequacy risk can be avoided by firming up the commitments of additional potential resources.

The potential for significant generation fleet transformation has prompted MISO to evaluate how system needs will change and how MISO might adapt its planning, markets, and operations to maintain reliability with aging and retiring units, higher penetration of intermittent resources, and new load consumption patterns. The MISO membership is rapidly transitioning the resource mix in the footprint.

Resource adequacy planning that focuses on summer peak alone will no longer suffice. Resource adequacy analysis will likely need to reflect patterns across the year to fully capture the magnitude of risks.

Effective dialogue amongst stakeholders will be key to this transformation – identifying needs and working with MISO to develop solutions that work across the footprint. MISO will leverage the forums where discussions are already underway on transmission planning, MISO's resource adequacy construct, and pricing enhancements.

The 2021 OMS-MISO survey indicates that the MISO region will have adequate reserve margins for 2022, however, continued action will be needed to ensure resource adequacy in the extended outlook.

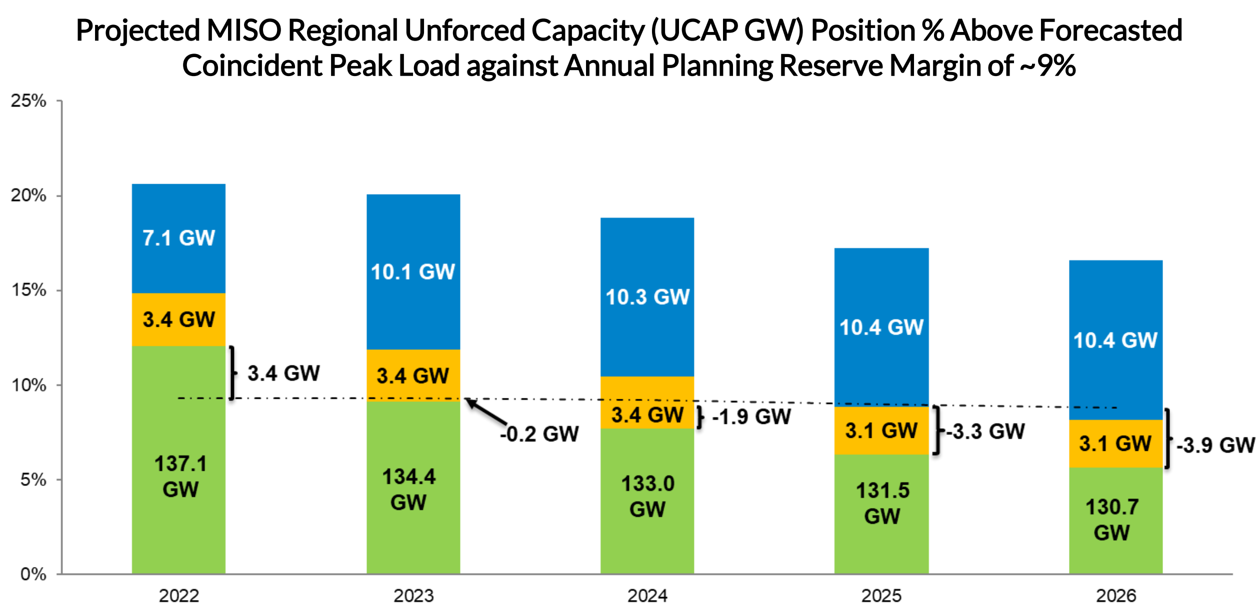


Figure 2.6-2: 2021 OMS-MISO Survey 5-year Results

This year's OMS-MISO survey shows MISO will have 3.4 gigawatts of surplus committed resources beyond the regional requirement. If all potential resources materialize in 2022, there could be as much as 13.9 gigawatts of surplus generation resources.

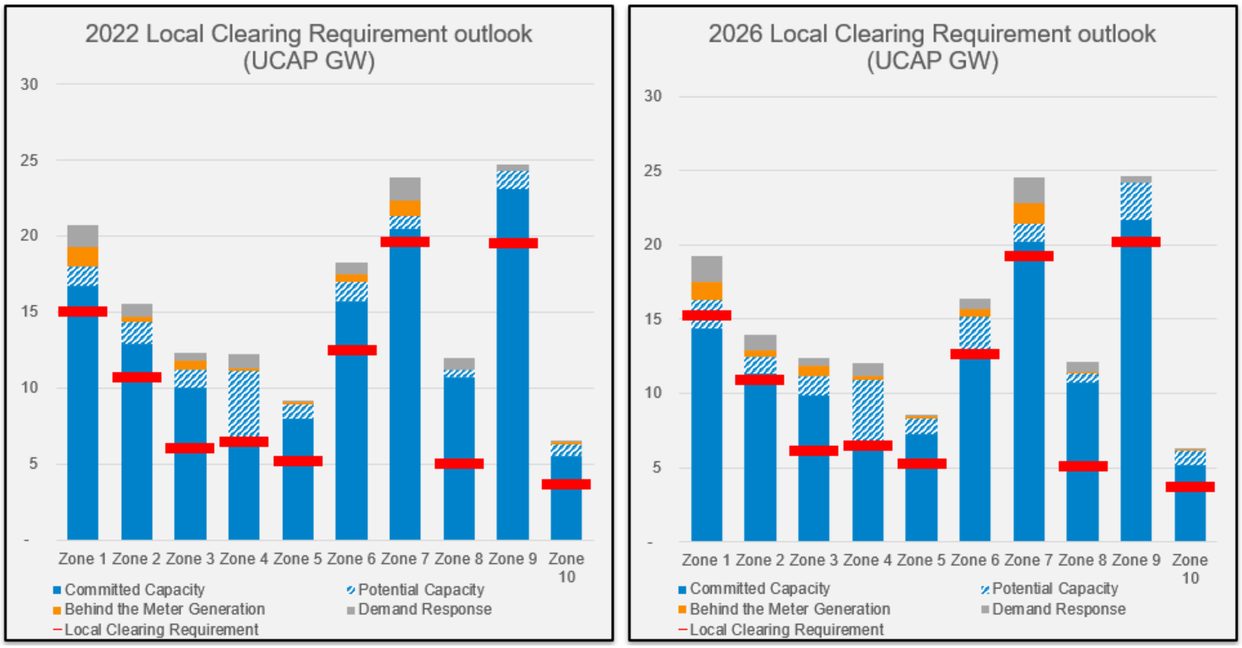


Figure 2.6-3: Potential new generation and retirements, within each zone

Compared to last year, these committed resource reserve margins are lower for both the first year and the full five-year period of the survey, which translates into increased reliance on less certain resources to ensure resource adequacy going forward.

The OMS-MISO Survey shows fleet changes in the next 5-10 years shifting heavily toward renewables. As queue additions are not submitted much beyond 2025, the impacts observed are due more to unit retirement decisions. The increase in battery and hybrid units, non-existent today, but growing significantly in the near future indicates a changing dynamic in the MISO generation fleet. One emphasizing more flexibility and energy-shifting versus traditional fossil-based resources.

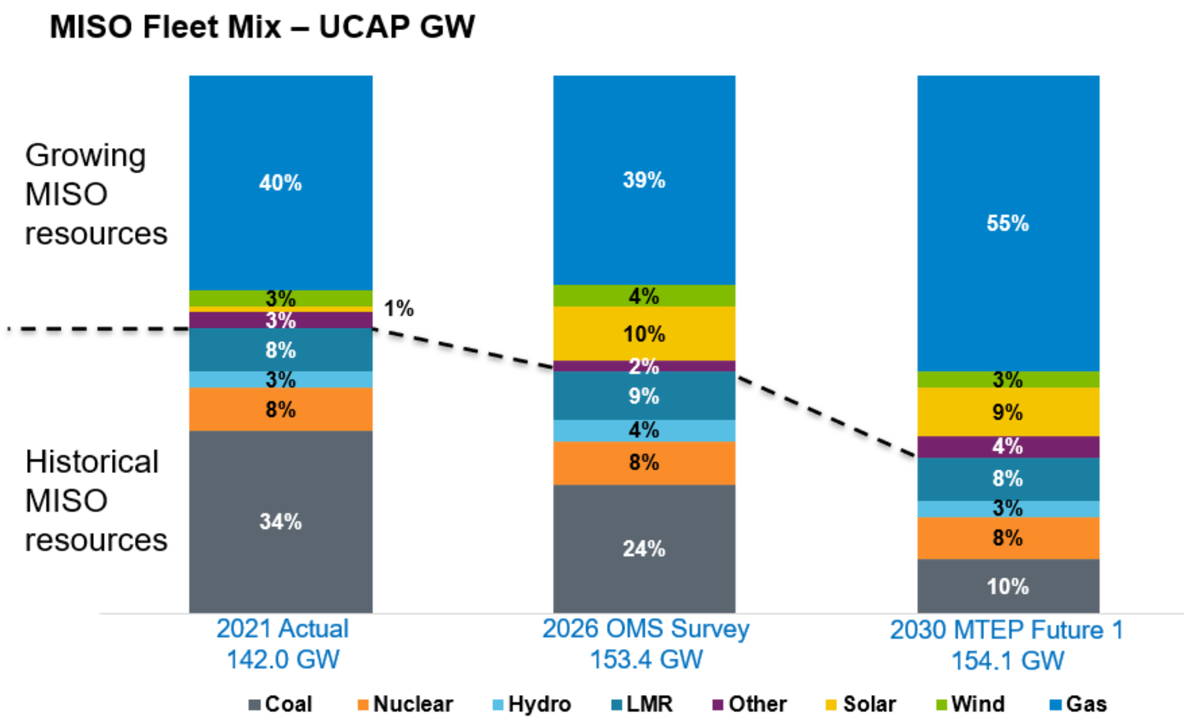


Figure 2.6-4: 2025 and 2030 OMS-MISO Survey Fleet Mix by Nameplate MW

2.5 Planning for the Future

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.

MTEP21 Future Scenarios

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.

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.

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.

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 Appendix E). 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.

The Regional Resource Forecasting (RRF) process uses the assumptions defined within each Future to economically identify the least-cost portfolio of new supply-side and demand-side resources. Data assumptions in the base model are presented in Appendix E along with fuel forecasts, new unit construction costs, emissions constraints, retirement assumptions, renewable energy assumptions and regional demand and energy projections. The resulting resource additions and retirements from the MTEP21 regional resource forecasting process are shown in Figures 2.5-1 through 2.5-3.

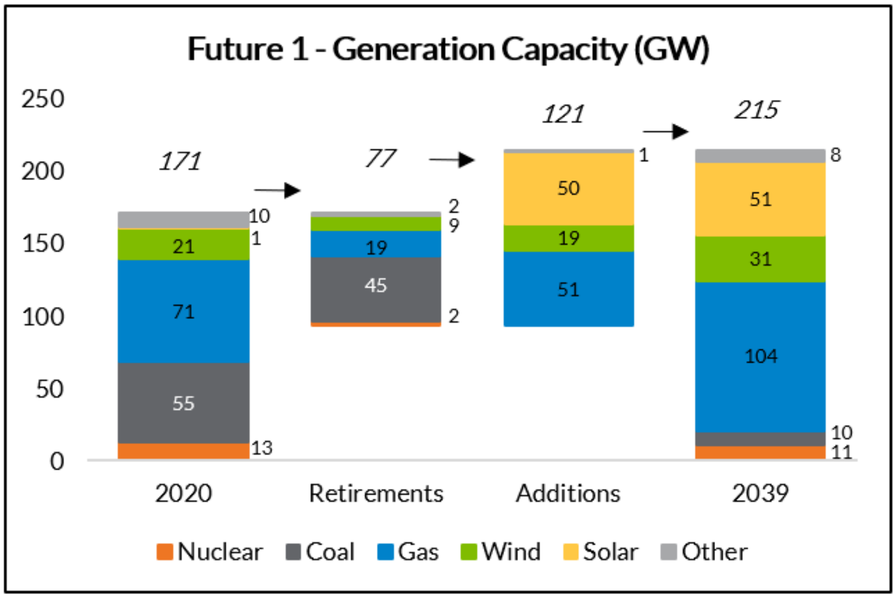


Figure 2.5-1: Future 1 Resource Additions and Retirements

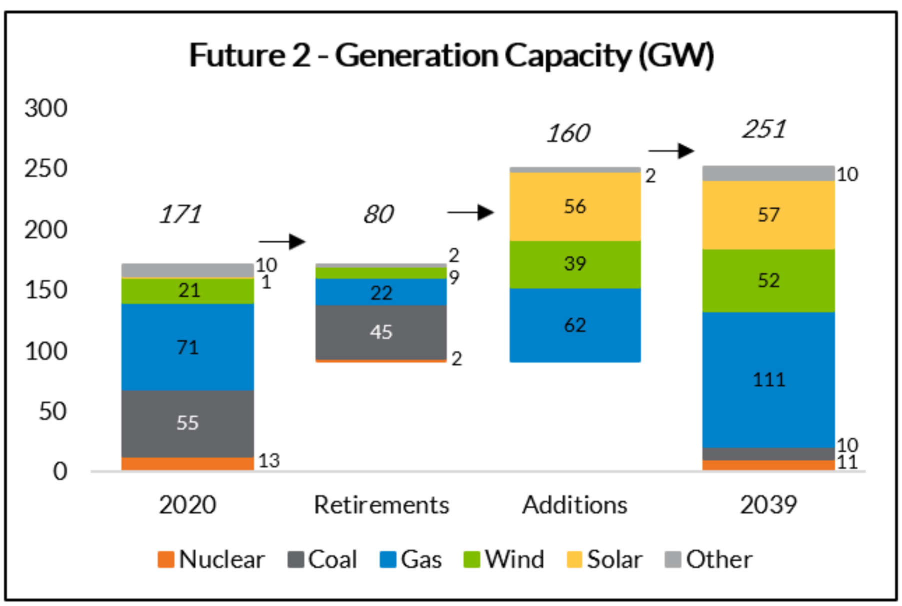


Figure 2.5-2: Future 2 Resource Additions and Retirements

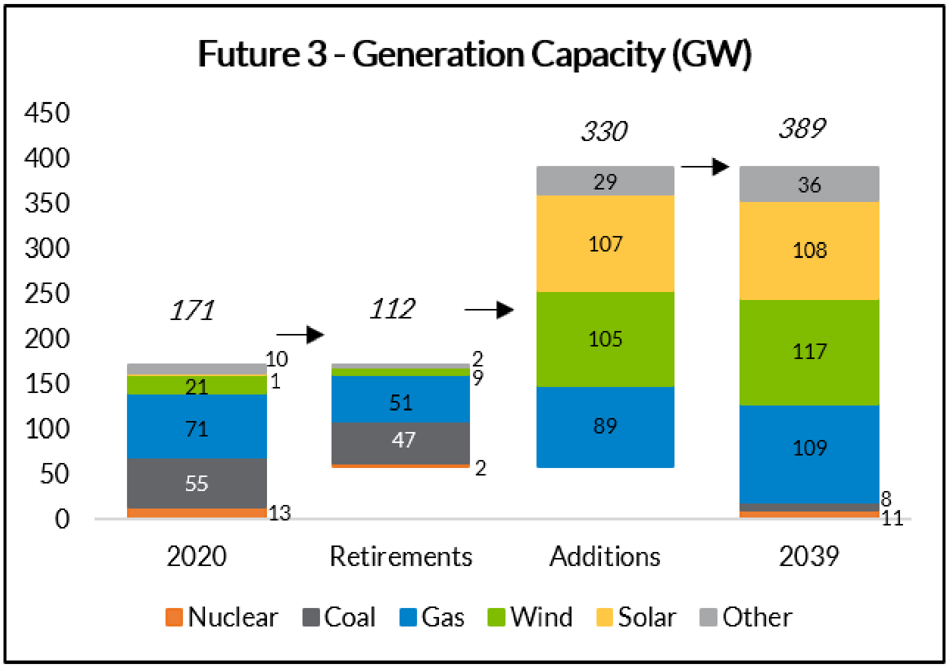


Figure 2.5-3: Future 3 Resource Additions and Retirements

To produce the capacity mix for each Future, the retirements and new resources identified from the regional resource forecasting process must be applied to the existing generation fleet (Figure 2.5-3), which includes new resources from member announcements and plans as well.

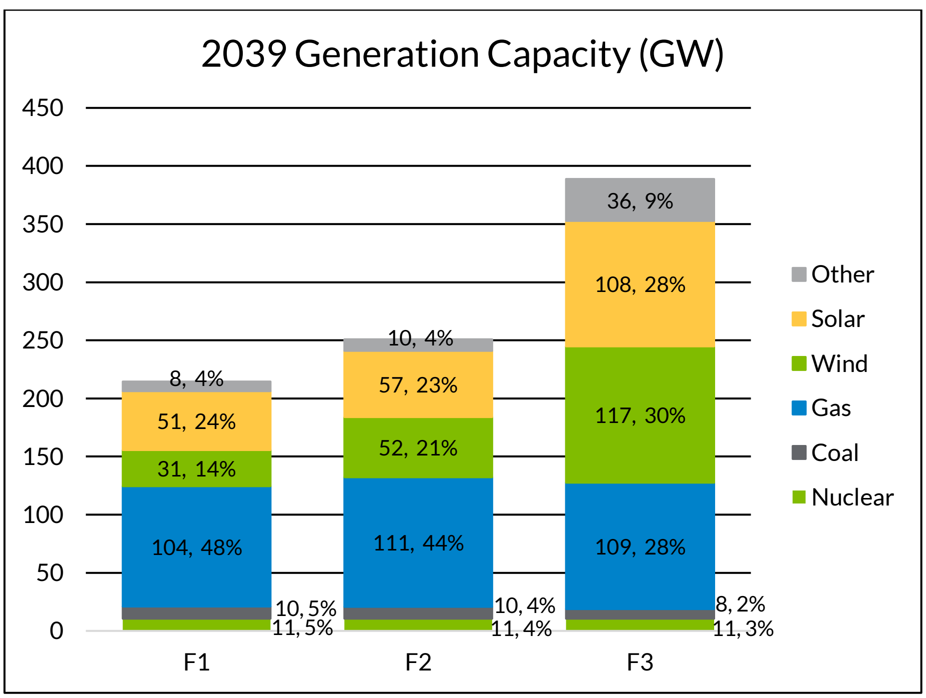


Figure 2.5-4: MTEP21 Futures Nameplate GW Capacity Mix by Resource

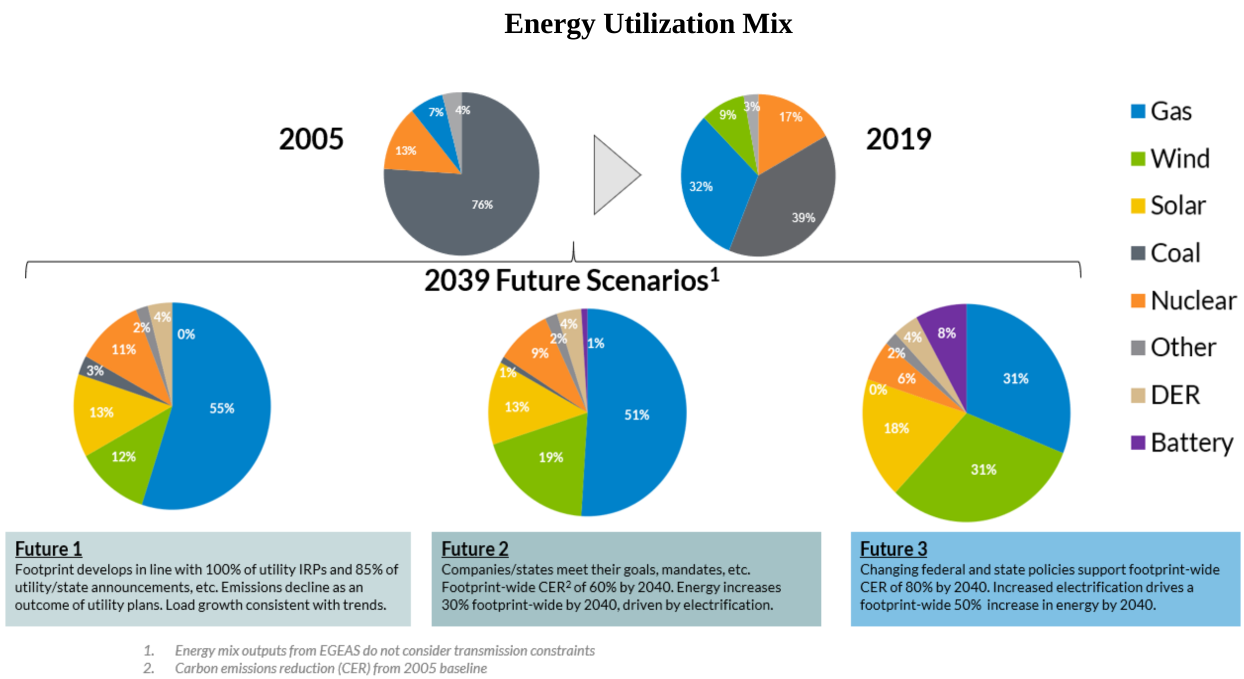
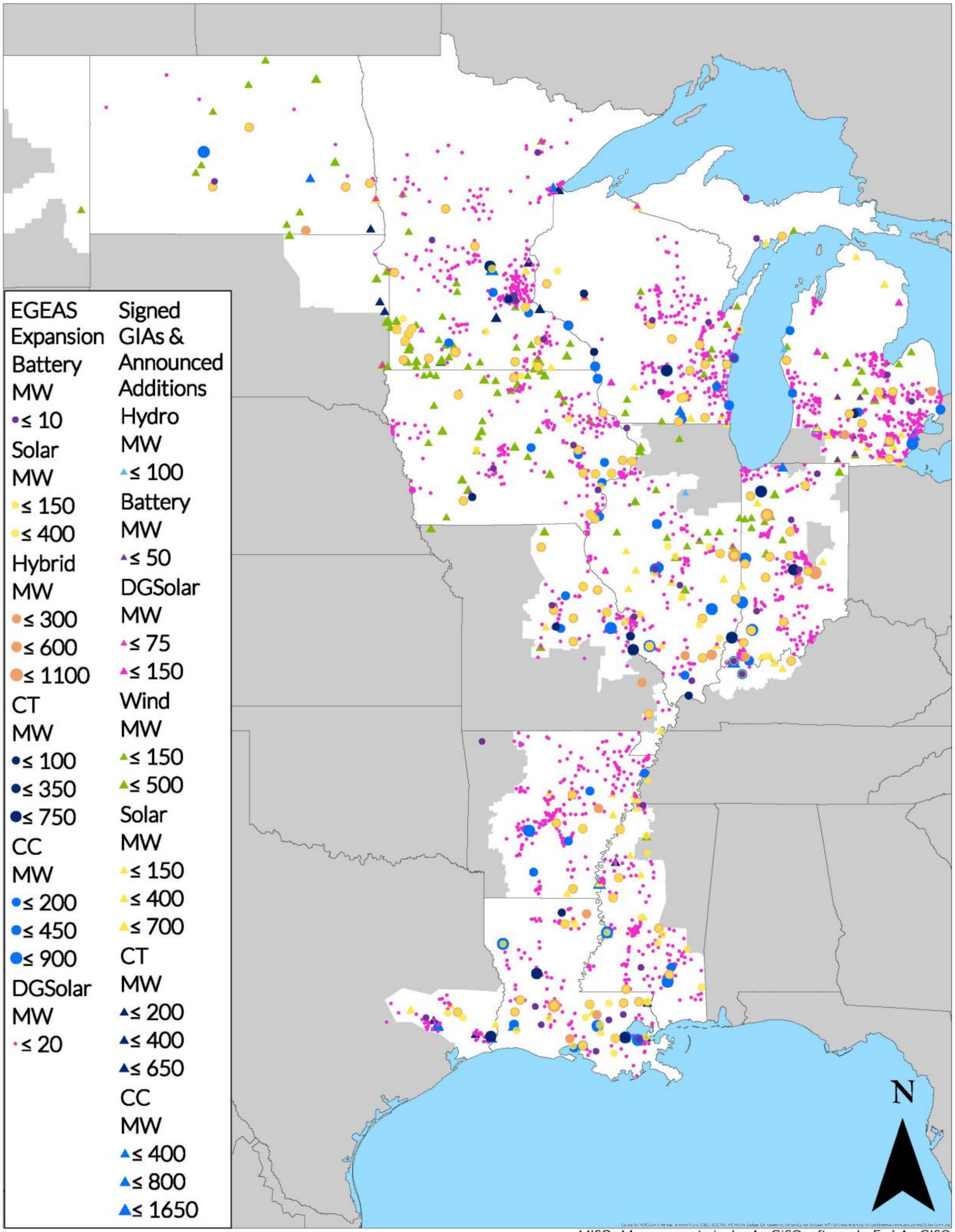


Figure 2.5-5: MTEP21 Futures - MISO 2039 Futures Energy Utilization Mix

The results from the regional resource forecasting (RRF) process identify the type, size, and installation date of new resources. However, they do not specify where these units should be located within the MISO footprint. Therefore, new resources identified in the regional resource forecasting process must be sited within the economic production cost model. The Futures siting process for RRF units and member-planned units is based on stakeholder-agreed-upon rules and criteria detailed in Appendix E (Figures 2.5-6 through 2.5-8).

Future 1: Total Expansion



MISO - Map was created using ArcGIS® software by Esri. ArcGIS®

Figure 2.5-6: MISO Future 1 Non-EGEAS and EGEAS Expansion Siting

Future 2: Total Expansion

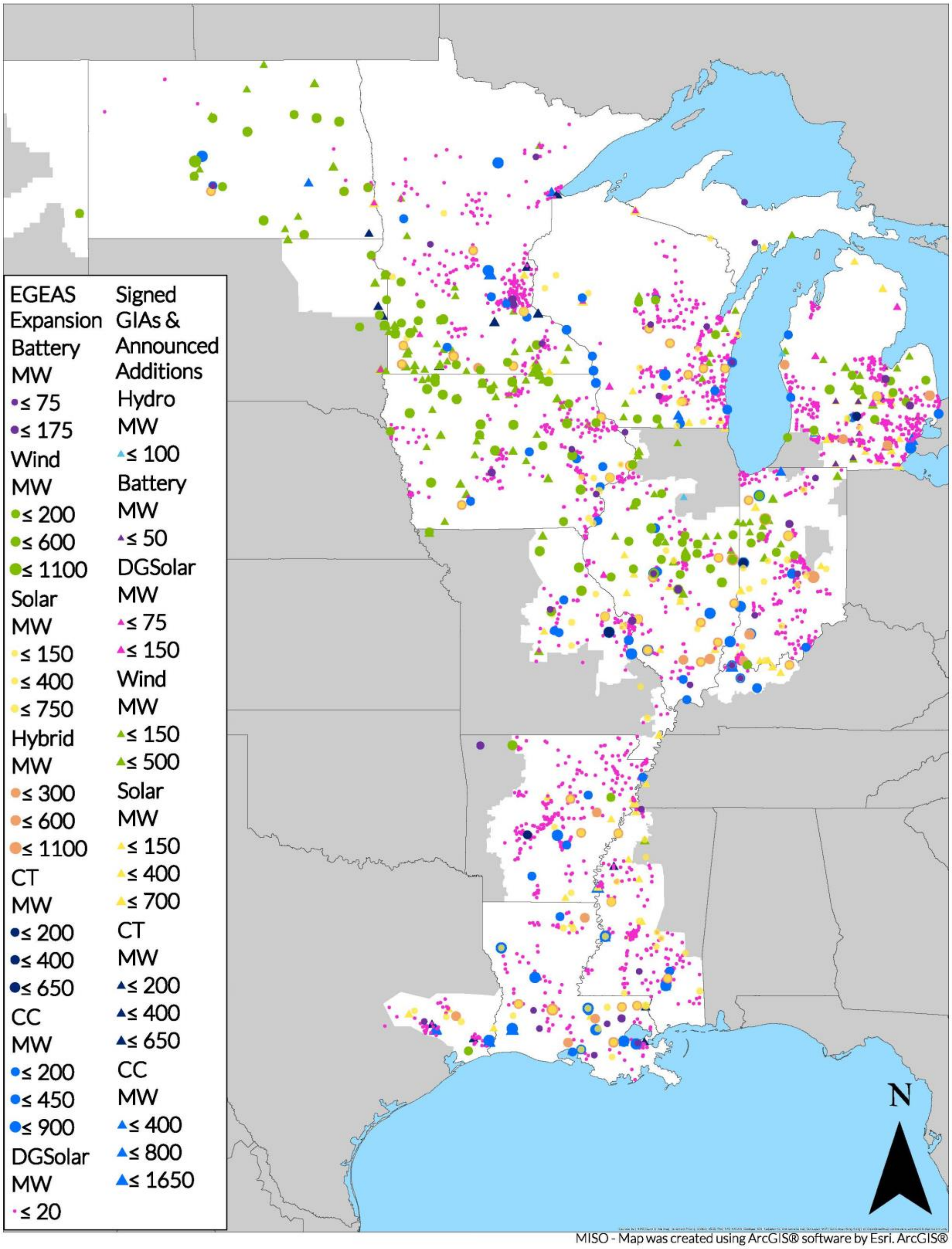


Figure 2.5-7: MISO Future 2 Non-EGEAS and EGEAS Expansion Siting

Future 3: Total Expansion

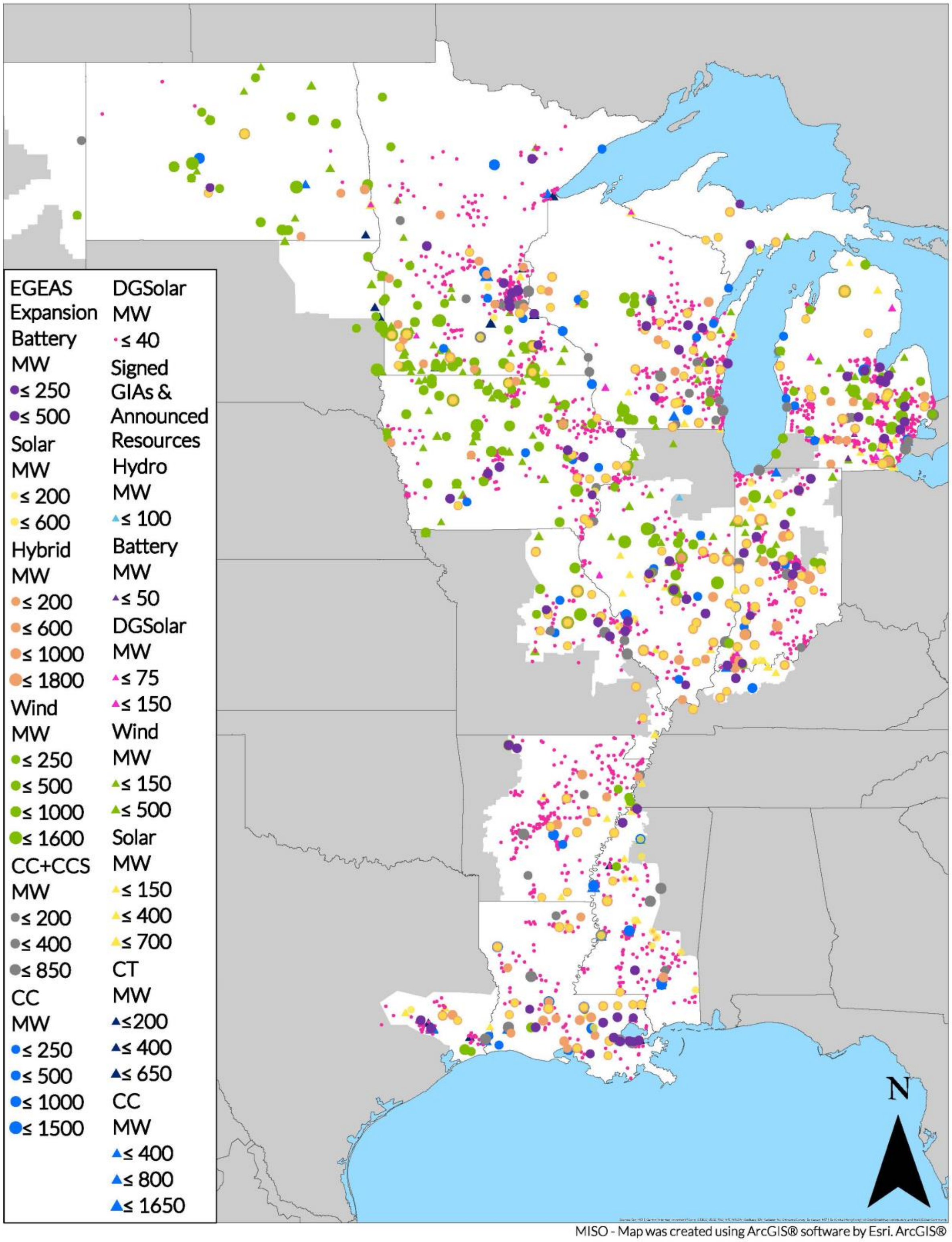


Figure 2.5-8: MISO Future 3 Non-EGEAS and EGEAS Expansion Siting

2.7 Regional Resource Assessment

These new MISO Futures have articulated a wider range of possibilities than in previous MTEP cycles, while further incorporating the plans that MISO's members continue to develop for themselves.

Utilizing the improvements made in the new MISO Futures, a new initiative known as Regional Resource Assessment (RRA) seeks to inform other efforts at MISO and for its members. RRA's informational purpose, as well as its utility- and zonal-level granularity, comprise two key distinctions between this task and the MISO Futures. As advancing utility goals continue to accelerate fleet evolution, MISO lacks visibility into zonal-level implications surrounding market reliance, resource adequacy needs, pricing impacts and reserve/ramp sufficiency. Thus, RRA will inform MISO's Reliability Imperative initiatives (e.g., Market Redefinition), as well as member resource planning and utility commission activities on resource evolution and interactions among company plans.

RRA will build on utility research to develop resource portfolios, which will support enhanced understanding of resource evolution at the utility level, attributes of future zonal resource mixes, and locational impacts and risks. From there the effort will conduct resource adequacy analysis and flexibility needs assessment, reviewing capacity contributions, quantifying performance at sub-hourly timescales, and assessing risk of capacity and flexibility deficits from operational and market perspectives.

CHAPTER 3: REGIONAL AND INTERREGIONAL PLANNING STUDIES

3.1 Long Range Transmission Planning Overview and Process

The Long Range Transmission Planning (LRTP) initiative is MISO's response to the current and future resource evolution that has and continues to affect the bulk electric system. The scale and pace of these changes require prompt attention to develop the most efficient, cost-effective investments that will ensure grid reliability in the future.

MISO's Renewable Integration Impact Assessment (RIIA) demonstrates that as renewable energy penetration increases, so does the variety and magnitude of the bulk electric system need and risks. Managing the system under such conditions, particularly beyond the 30% system-wide renewable level will require transformational change in planning, markets, and operations.

MISO is preparing for an unprecedented pace of change in the resource mix. MISO, members, regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges. MISO calls this shared responsibility the Reliability Imperative, which consists of several linked initiatives: Market Redefinition, Long Range Transmission Planning (LRTP), Operations of the Future, and Market System Enhancements.

The Reliability Imperative focuses on preparing the region for industry transformation as the grid evolves toward increased renewable resources. As a critical part of this effort, Long Range Transmission Planning holistically considers needs of the MISO footprint and identifies solutions that will be needed to maintain system reliability.

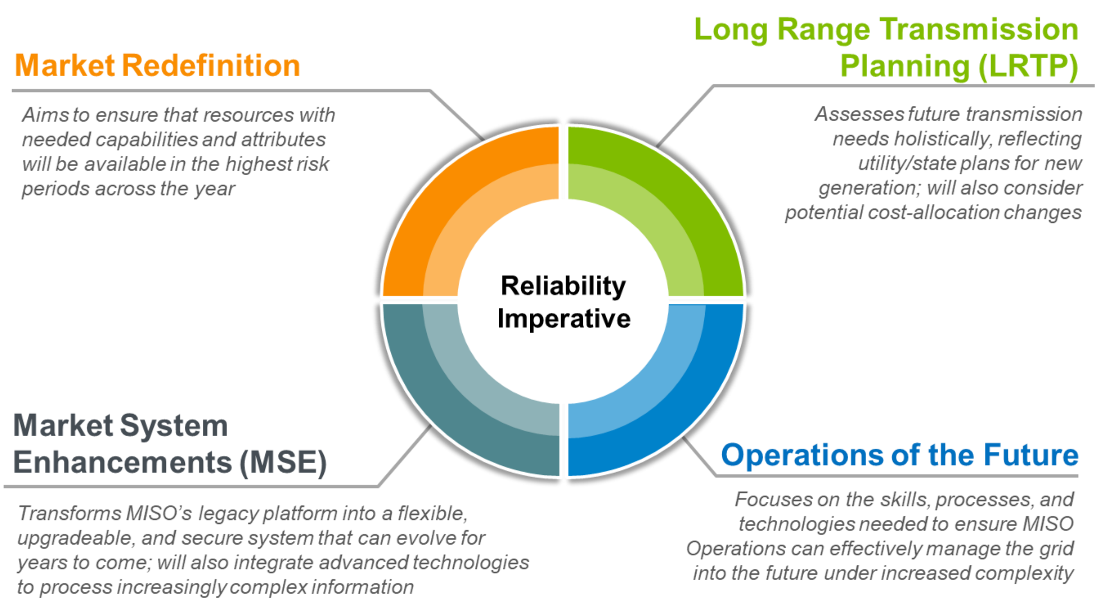


Figure 3.1-1: Reliability Imperative focus areas

In 2020, three future scenarios were finalized to define and bookend regional resource expectations over the next 40 years ([MISO Futures Report]). 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.

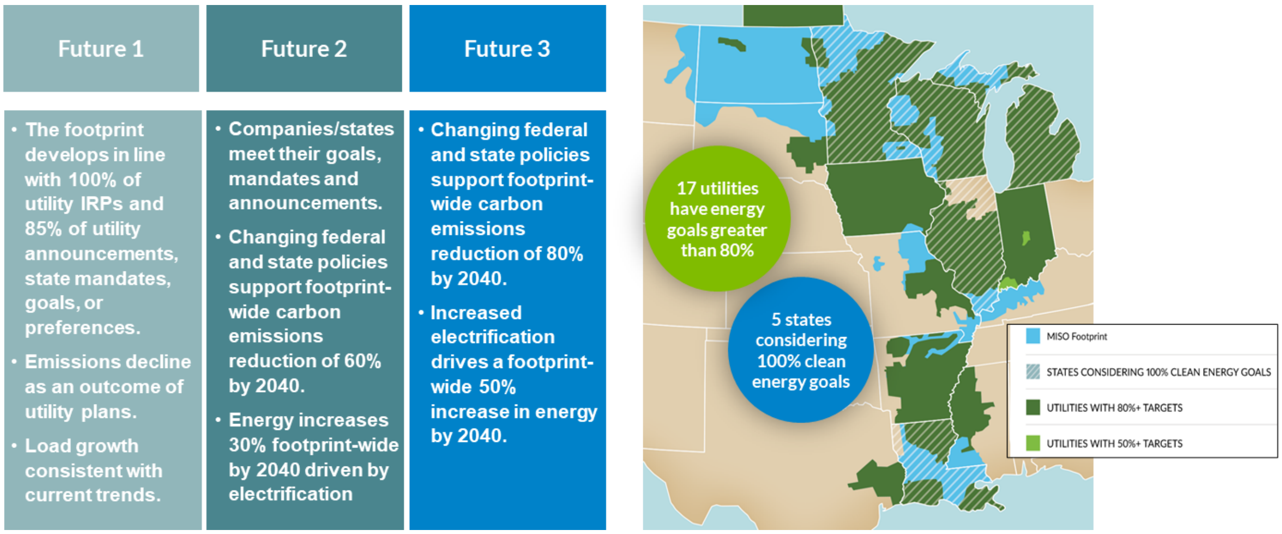
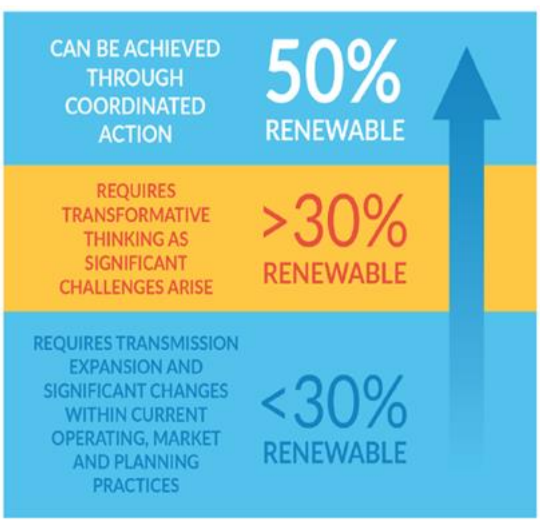


Figure 3.1-2: MISO Futures industry drivers

MISO's Renewable Integration Impact Assessment (RIIA) provided insights into several risks for system reliability as renewable penetration levels increase. The RIIA report highlighted the following:



Risk patterns are shifting, and new risks are emerging due to the increasing penetration of wind and solar in the region.

- Stability Risk requires multiple transmission technologies, operating and market tools to incentivize availability of grid services.
- Shifting periods of grid stress requires flexibility and innovation in transmission planning processes.
- Shifting periods of energy shortage risk requires new unit commitment tools, revised resource adequacy mechanisms.
- Shifting flexibility risk requires market products to incentivize flexible resources.
- Insufficient transmission requires proactive regional transmission planning.

In preparation for addressing these transformational needs, MISO has developed an Indicative Transmission Roadmap of potential transmission expansions throughout the region. The Roadmap provides, among other things, an indication of the potential magnitude of transmission expansions that may be needed to maintain reliable and efficient operations under the expected Futures. This Roadmap was contemplated 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 resilient grid by enabling more transfers of bulk power flows. The Indicative Roadmap is not a plan but provides a basis for considering solutions to Transmission Issues expected. MISO is engaging stakeholders as the planning staff identifies system performance issues under the assumptions projected in the Futures, and as we seek the most cost-effective transmission and non-transmission solutions.

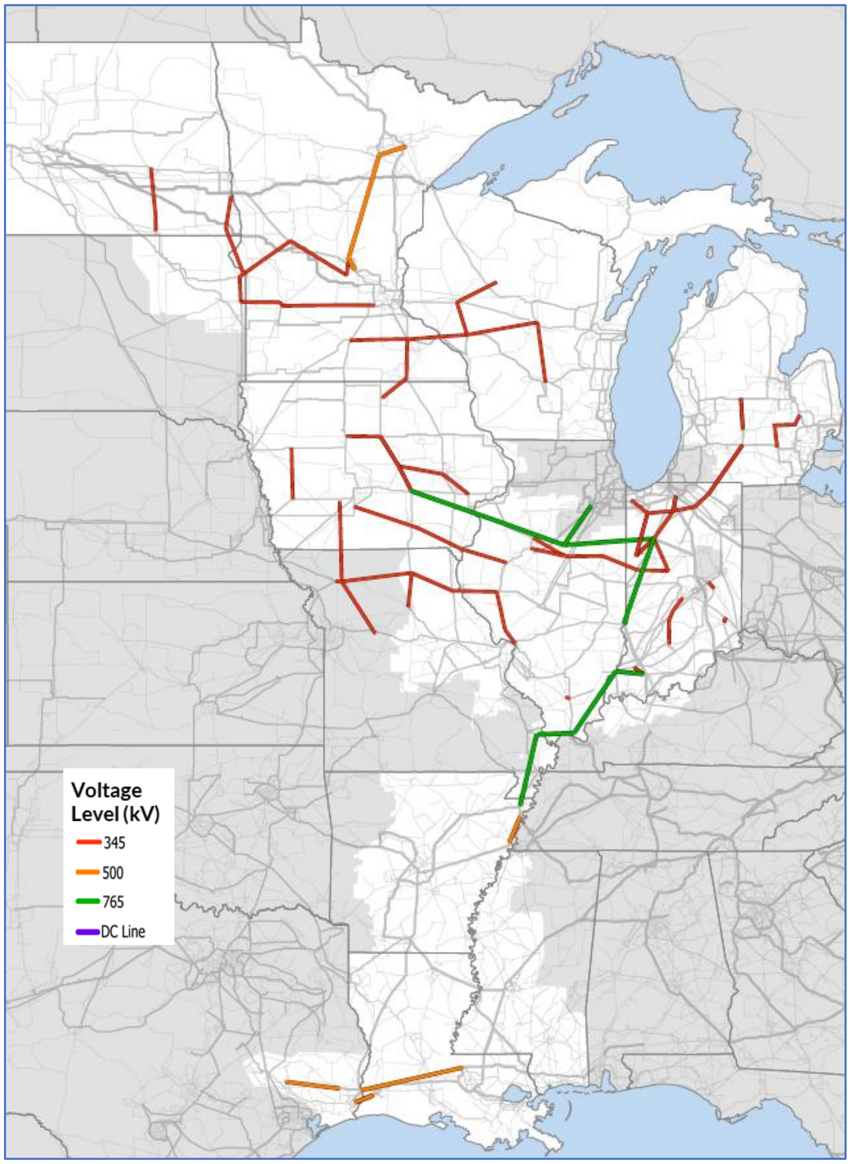


Figure 3.1-3: Future 1 Indicative Roadmap

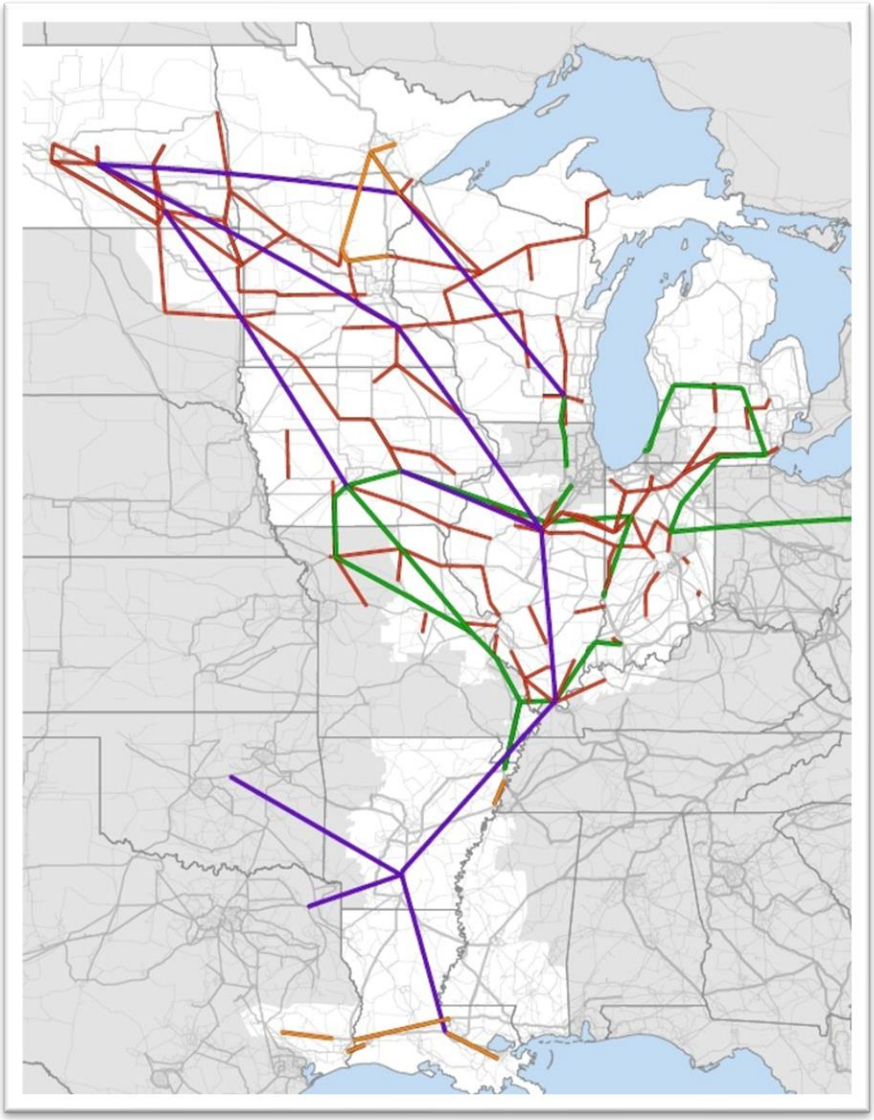


Figure 3.1-4: Futures 1,2, & 3 Indicative Roadmap

The development of the Futures and projection of future transmission needs is consistent with the MISO Value Based Planning approach. Value Based Planning was developed in 2007 as an approach to establish system needs with a planning horizon that takes into consideration the long lead-times to implement major transmission upgrades and the role of long-term planning in providing efficient and reliable grid expansions ahead of immediate needs. This approach provides for grid upgrades that enable better options for resource decisions by resource planners and complements more short term “just-in-time” solution development.

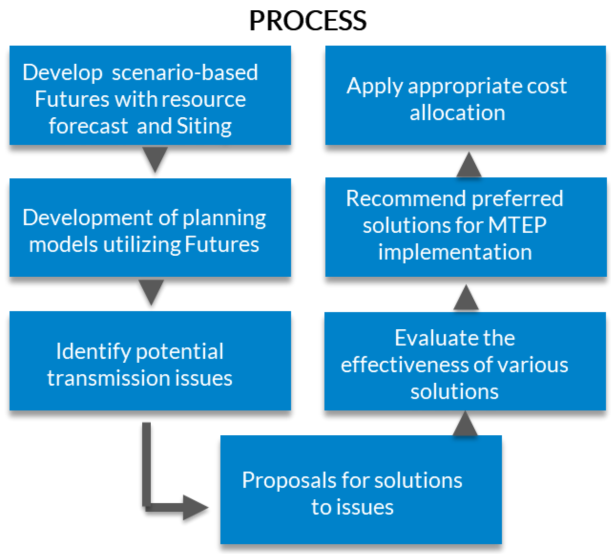


Figure 3.1-5: Seven step Value Based Planning process

The Long Range Transmission Plan will iterate over time as needs and conditions change. This requires a planning process timeline that differs from what stakeholders are more familiar with. Typically, MISO planning studies happen as part of the annual MTEP cycle; they follow the annual reliability process that focuses primarily on local needs and results in recommendations each year as part of the MTEP report. In general, this is a very linear process where each step occurs at about the same time every year.

In contrast, Long Range Transmission Planning is a multi-year effort as needed 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 will seek to recommend projects identified in the LRTP effort over several MTEP cycles as work progresses.

MISO believes it is important to move quickly, while ensuring a least regrets plan. Meeting both objectives is critical to enable our member plans, and to 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. Long Range Transmission Planning 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.

3.2 Long Range Transmission Planning Studies - 2021

In 2021, the MISO Long Range Transmission Planning efforts are focused on the future transmission investments needed to address the MTEP Future 1 resource evolution (Figure 3.2.1). MTEP Future 1 represents transformational changes to the future generation fleet driven by projected increases in renewable integration, resource retirements, and adoption of new technologies.

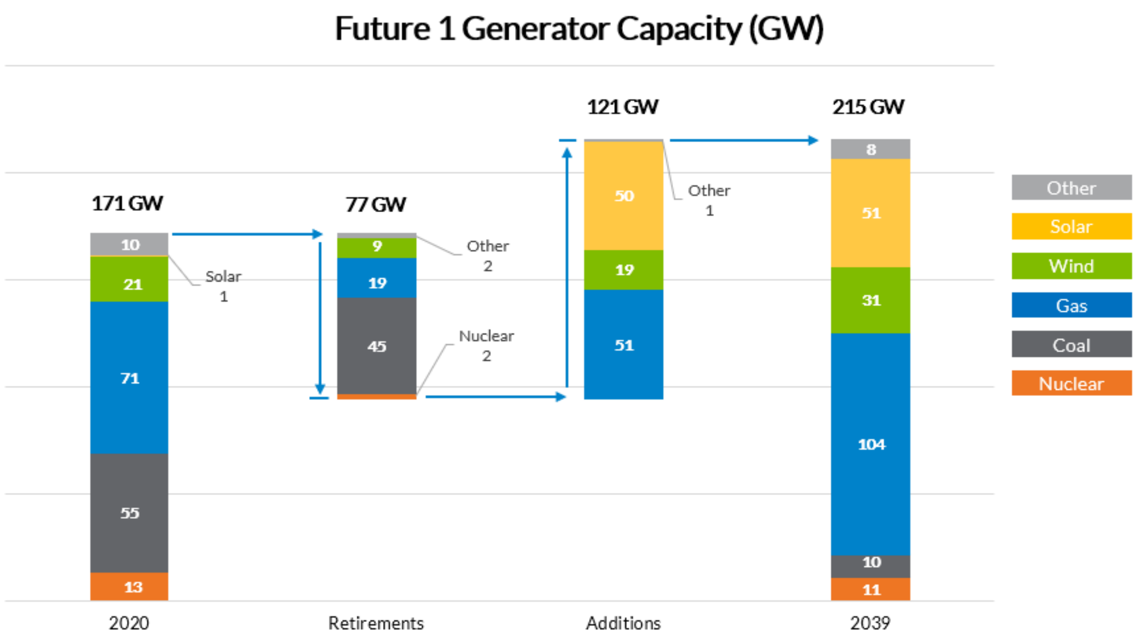


Figure 3.2.1: Comprehensive resource evolution developed in Future 1

To develop the Long Range Transmission Plan, MISO engaged Stakeholder participation through several monthly workshops where schedule, progress, and results were reviewed (LRTP Webpage).

Base System Modeling for the MTEP21 LRTP Effort

The initial round of LRTP analysis is focused on Future 1 and the 10- and 20-year horizon and provides an initial scope of work to be completed in the MTEP21 cycle. It will be used to develop a business case for any initial recommendations that are expected to ensue from it. Future 2 and 3 models were created to support robustness and a least regrets business case. As MISO moves into the next phase of LRTP post-MTEP21, the horizon will expand upon Future 1 efforts to also include Futures 2 and 3 specific needs in the 10- and 20-year time frame. An initial set of Future 1 projects are targeted for the MISO Board of Directors in March 2022 while Future 1 continued efforts will go beyond MTEP21 and into the next phase(s) of LRTP.

Base Model Assumption Set

Futures

The MISO MTEP21 Futures Analysis was used to develop models for the MTEP21 effort of LRTP. The Futures encompass several factors that were developed and refined through rigorous review in a collaborative MISO stakeholder process during the 2019-2020 timeframe. These factors led to the final version of the MTEP21 Futures in three data sets referred to as Future 1, Future 2 and Future 3. This section will not go through the various Futures details as they can be found via numerous 2018 through 2020 Futures Workshops documents (Stakeholder Engagement - Futures Workshops page available on the MISO website). The Futures are summarized below:

Variables / Futures	Future 1	Future 2	Future 3
EGEAS Ready Gross Load^ Energy Demand	Low-Base EV growth 0.63% CAGR growth rate 0.59% CAGR growth rate	30% energy growth 1.23% CAGR growth rate 1.09% CAGR growth rate	50% energy growth 1.91% CAGR growth rate 1.94% CAGR growth rate
Potential Load Modifiers^^ *(Technical Potential by 2040)* DR EE DG	Technical Potential Offered 5.2 GW 13.3 GW 14.7 GW	Technical Potential Offered 5.9 GW 14.5 GW 14.7 GW	Technical Potential Offered 5.9 GW 14.5 GW 21.8 GW
Carbon Reduction* *(2005 baseline)* MISO Footprint currently at 22%**	40%	60%	80%
Min. Wind & Solar Penetration	No minimum	No minimum	50%
Utility Announced Plans	85% goals met 100% IRPs met	100% goals met 100% IRPs met	100% goals met 100% IRPs met
Retirement Age-Based Criteria Coal Natural Gas-CC Natural Gas-Other	46 years 50 years 46 years	36 years 45 years 36 years	30 years 35 years 30 years

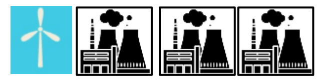
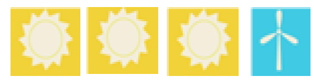
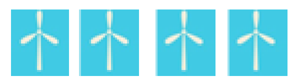
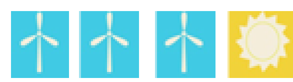
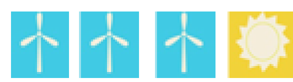
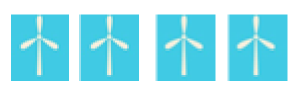
* Entire footprint in aggregate
** 2005-2017; MISO calculation from EIA Form 860 data
^ Compound annual growth rate (CAGR); does not include impact from DERs, DSM, or Wind/Solar
^^ Distributed Energy Resources (DER); Demand Response (DR); Energy Efficiency (EE); Distributed Generation (DG): Capacity technical potential offered into EGEAS as resources; final amounts selected to be determined by EGEAS simulations.

Reliability

The LRTP reliability base models were developed using MTEP20 reliability power flow models that were the latest available at the time MTEP21 reliability modeling process was completed at the end of Q1 2021. Topology changes were incorporated as needed to reflect transmission updates from the MTEP20 planning cycle. Applicable load and generation profiles from the Futures were applied to the reliability power flow models to create the LRTP base models representing a range of generation and load scenarios. These power flow models provide the basis for all steady state and dynamic analysis and were and will be used to construct sensitivity cases with the relevant adjustments in dispatch and load.

The base reliability models include year-10 and year-20 set of models (2030 and 2040) which encompass Summer Peak, Spring/Fall Light Load, Fall/Spring Shoulder Load, and Winter Peak conditions. Load levels for each of those model periods apply the Futures load forecast in a manner consistent with the regular MTEP process. Composition and siting of generation resources is derived from the Futures data with wind the dominant provider in the north and solar primarily in the south. The characteristics of the wind and solar resources require modeling of daytime and nighttime generation dispatch patterns in the study scenarios. A wide variety of resource dispatch scenarios are considered that are representative of conditions that the grid is expected to be subjected to in the high renewable penetration Futures projected. Sample dispatch scenarios are tabulated below.

Reliability Base Models:

Base Model	Variation	Reasoning for inclusion	Wind/Solar Dispatch
Summer Peak	Day	-Typical system summer peak load -Low wind scenario -Represents MISO west import -S-N flows	Current MTEP planning assumptions based on Capacity Credit for wind and solar 
	Night	-Typical system peak load level at night -No solar generation -Low wind -N-S Flows	Current MTEP planning assumptions based on Capacity Credit for wind and solar 
Spring/Fall Light load	Day	-Explore voltage and dynamic stability concerns	High solar output during low load conditions 
	Night	-Explore voltage and dynamic stability with minimal thermal units available for reactive support -N-S flows	High wind output during low load conditions 
Fall/Spring shoulder load	Day	-Explore thermal, voltage and stability concerns with minimal thermal units available for reactive support	High renewable output during approximate shoulder load conditions 
Winter Peak	Day	-Typical system winter peak load -Represents high wind in North Observe different geographical loading pattern (Minnesota/Manitoba flow)	Typical wind with high Minnesota to Manitoba flow 
	Night	-Typical system winter peak load at night -N-S flow	Typical wind with high Minnesota to Manitoba flow 

Economic

Economic (PROMOD) models and associated load/generation profiles were developed in a similar fashion as MISO annually builds MTEP economic models. For MTEP21, those models are based on the MISO Futures with the MTEP20 base transmission topology. While MISO typically constructs annual 5, 10, and 15 year out economic models based on the latest Futures, the LRTP studies also include a 20-year model consistent with MISO's economic modeling process. Economic models were created representing each of the four years without the Futures generation or transmission improvements and a set of economic models with Futures generation and proposed LRTP transmission projects. Evaluation of economic benefits compares the production cost savings associated with the Futures resource expansion and transmission reinforcements needed to reliably support it, versus the production costs without generation that cannot be reliably supported.

Study Overview

The LRTP reliability studies include steady state and stability analysis under a range of system conditions reflected in assumptions about the future generation and load composition in the 5, 10, and 20 year time horizons. The resource composition, resource siting, and load characteristics developed in the MTEP Future 1 scenario is incorporated into the LRTP study models, to capture various system conditions.

Transmission system analysis is an iterative process spanning the development of models, running analysis, and identifying issues, and testing potential solutions.

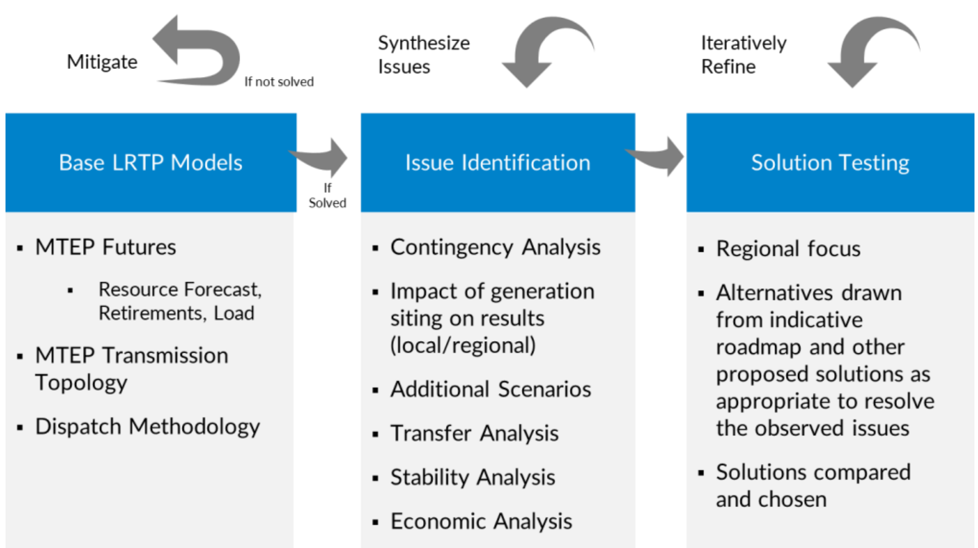


Figure 3.2.2: Reliability assessment iterative phases

Power flow analysis was performed on each of the study cases to assess steady state system performance under base case and contingency events in accordance with NERC TPL-001 Standard and NERC Regional Entity standards. Planning events that include Category P0-P7 contingencies defined by NERC TPL-001 Standard are simulated to identify thermal and voltage violations that require mitigation. Economic analysis will be used to identify transmission needs for energy integration levels and the value associated with enablement of renewable resources through the evaluation of the benefits. Economic analysis will be used as part of the business case development and as applicable for cost allocation.

Initial Analysis Findings

In the MTEP21 work plan, most of the work has been devoted to the development of models and methodology for analysis which is a collaborative effort with stakeholders. The extensive changes in the resource portfolio over the study horizon has proven to be a challenging process that has involved iterative review and update cycles. MISO created the initial reliability and economic models and posted them for stakeholder feedback, and work continues to test indicative solutions and other ideas from stakeholders. At the time of drafting of this report, results from the initial 10-year and 20-year Future 1 reliability analysis are emerging and identifying issues in the northern portion of the MISO footprint consistent with many of the findings from the RIIA analysis. Thermal and voltage violations are observed throughout the northern subregion for scenarios with high renewable output and shoulder load conditions. High southerly flows are observed across the Iowa EHV system, and heavy west-to-east flow causes thermal loading on both EHV and HV facilities. Along the North Dakota/Minnesota border, thermal and voltage violations are prevalent. East to West transfers cause thermal and voltage issues in Michigan while fewer issues are seen in the Central Region at this point in the study work.

Reliability study work will continue and will explore the various transfers and sensitivities needed to ensure a robust plan. Solution ideas from the LRTP indicative roadmap will be tested along with alternative projects provided through the stakeholder review process that can resolve the issues observed across the full range of scenarios and recommended for MTEP approval once the project has been selected as the most cost-effective solution.

The following map images (Figures 3.2.3 through 3.2.6)-are examples of analysis shared with MISO Stakeholders during June and July Workshops showing contingency violations and low voltage areas: (darker red denotes heavier overloads, darker blue denotes more severe low voltage).

Future 1, Year 10 N-1* Thermal and Voltage Issues

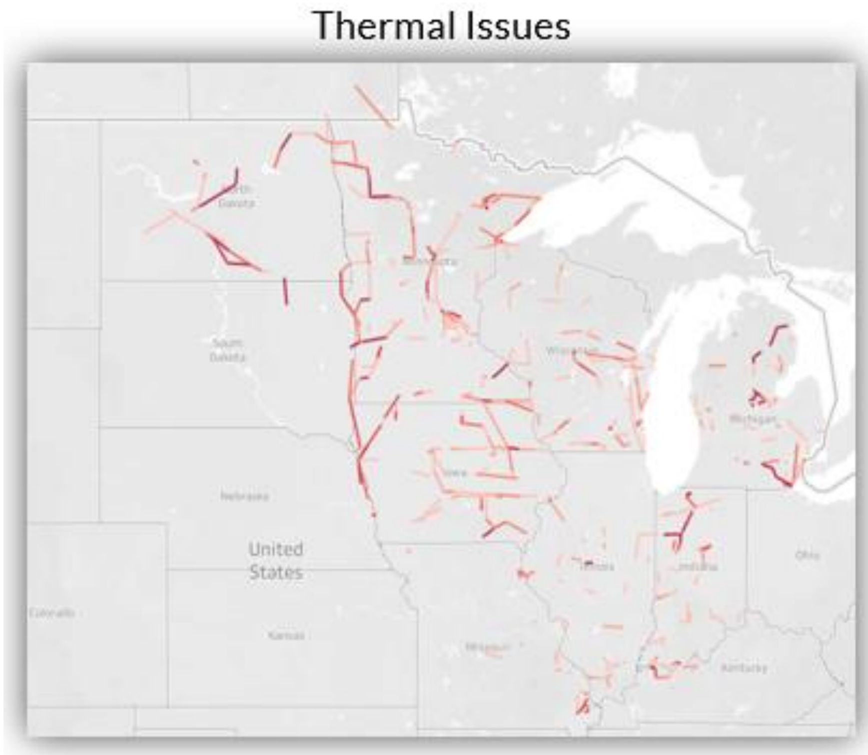


Figure 3.2.3: Cumulative thermal issues across all models

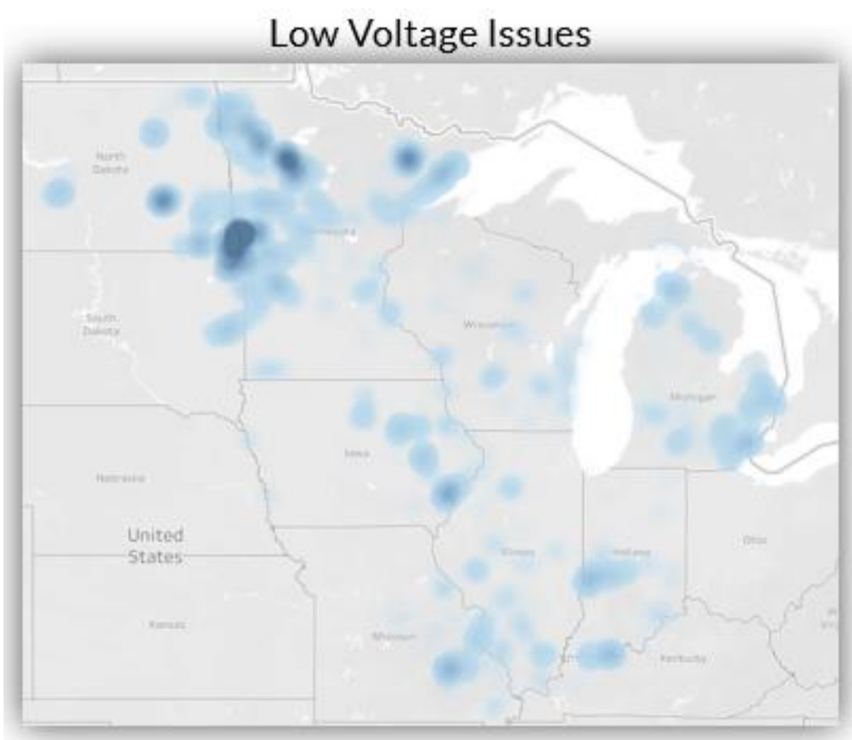


Figure 3.2.4: Cumulative voltage issues (by count) across all models

Future 1 – Year 20 N-1* Thermal and Voltage Issues

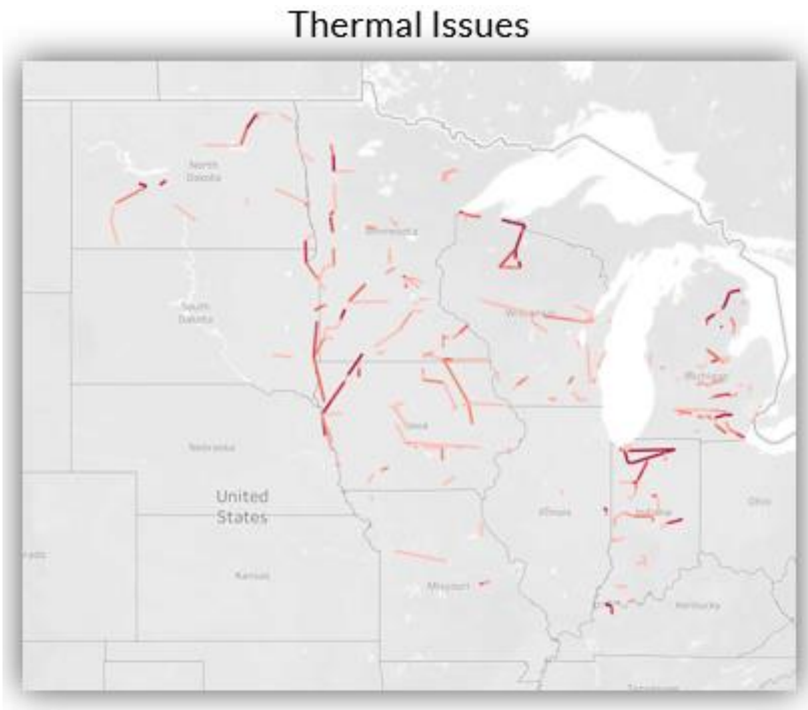


Figure 3.2.5: Cumulative thermal issues across all models

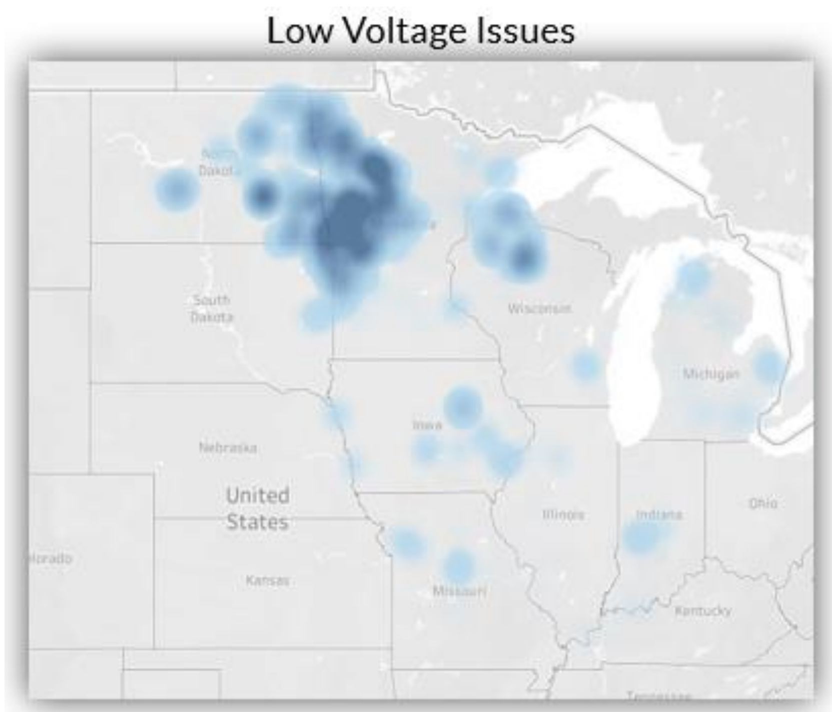


Figure 3.2.6: Cumulative voltage issues (by count) across all models

* N-1 refers to NERC P1, P2, P4, P5, and P7 contingency categories.

Cost Allocation

Cost allocation for LRTP projects is a challenging topic that remains to be resolved. Current mechanisms may not sufficiently reflect the full range of benefits from such large-scale regional projects. While the proposed transmission projects are expected to yield economic benefits that can be captured using many of the existing metrics, the value of the reliability benefits is difficult to quantify. The method for cost allocation of baseline reliability projects is focused on the local benefits and too narrow for LRTP application. Market efficiency projects have a limited scope of benefits around incremental efficiencies in production costs from singular projects. MVP cost allocation considers broader benefits of a system wide portfolio and regional postage stamp does not align well with the identification of LRTP projects over multiple development cycles.

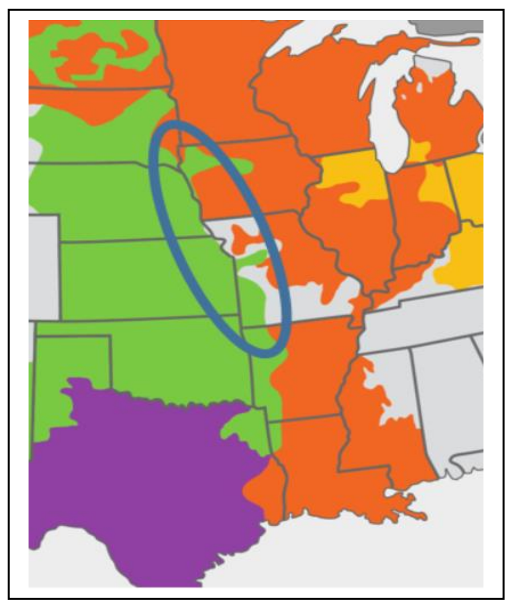
LRTP projects address a broader objective that enables a transformative industry outcome rather than a specific goal, and the method of cost allocation must recognize the extent of economic and reliability benefits. As technical work progresses on the Future 1 project candidates, cost allocation discussions will need to consider how existing cost allocation methods could be enhanced in the context of the current footprint as well as new ideas that can more fully capture value of the LRTP investments.

3.3 Interregional Studies

MISO-SPP Joint Targeted Interconnection Queue Study

Study Background and Purpose

In the recent Interconnection Studies in MISO and SPP, it was observed that the transmission system on the MISO-SPP seam is at its capacity and the next iteration of network upgrades are too costly for interconnection customers to proceed. While the addition of renewable resources and transmission along the seam benefit the market, current mechanisms do not provide sufficient cost sharing to facilitate new generator interconnection. Process, criteria, and schedule differences between the RTO's contribute to study delays and introduce questions on study results. To explore these issues MISO and SPP are collaborating on the MISO-SPP Joint Targeted Interconnection Queue (JTIQ) Study.



SPP-MISO JTIQ Study Goals:

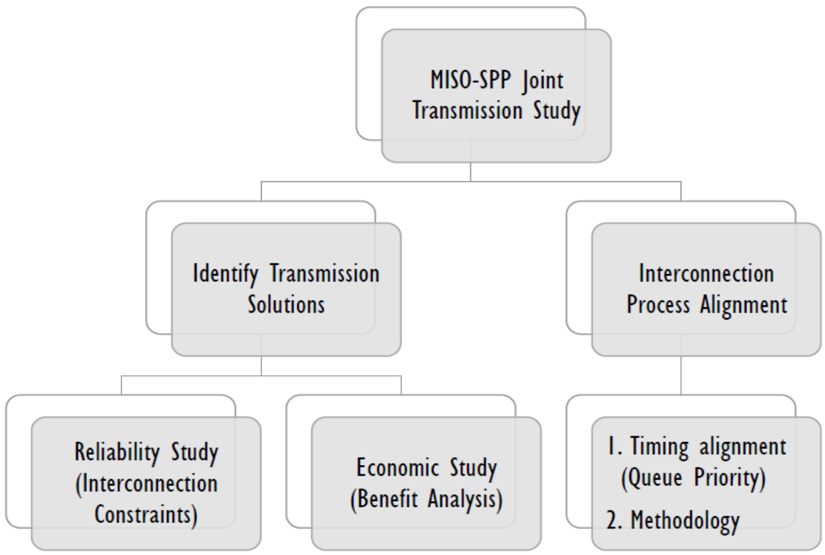
- Identify more comprehensive, cost effective and efficient upgrades than would otherwise be identified in the current interconnection queue process where upgrades are identified in the time sequence by one or the other RTO.

- Identify solutions that meet the needs of interconnection customers and provide benefits to load in both SPP and MISO near the seam.

- Identify opportunities to improve coordination between processes and affected parties both in this instance and on an ongoing basis.

Study Framework

This study has two parallel objectives: (1) Identify transmission solutions to interconnect generation in both queues along our common seam and (2) align Interconnection processes between SPP and MISO to reduce restudies/delays and post Generator Interconnection Agreement (GIA) uncertainties for Interconnection Customers.



Study Scope

The study scope document is posted on the MISO website under [Interregional Meetings](), and the specific scoping document is hyperlinked here: [JTIQ Scope of Work.]()

Initial Results

Fifty-two constraints were identified to be mitigated through transmission projects as part of this study. Twenty-six constraints are in the SPP footprint, twenty-one constraints are in MISO and five are tie-lines between MISO and SPP.

Solutions

MISO and SPP proposed mitigation plans and invited stakeholders to propose alternate mitigation plans. Sixty-two Mitigation Solutions (including preliminary and stakeholder submitted plans) were tested in the reliability models. Project #62 is a portfolio and is considered the best solution to the reliability constraints. Economic benefits were calculated for all mitigation plans. (Table 3.3-1)

Round	JTIQ Project ID	Project name	Cost $ (M)	Location
1	1	Stranger Creek - Eastown	143	SPP
1	2	Turney - Nashua	160	SPP
1	3	Astoria - Broadland	204	MISO
1	4	Big Stone South - Alexandria	192	MISO
1	5	Big Stone South - Hazel Creek	140	MISO
1	6	Jamestown - Ellendale	160	MISO
1	7	Twinbrooks - Watertown	64	MISO
1	8	Raun - Ft. Calhoun - Council Bluffs - Fairport	721	MISO/SPP
1	9	Nashua - Hawthorn - Sibley 345	111	SPP
1	10	Sherco -Benton Co. - Monticello 345 (Option 1DC) Remove Benton - Mont 230	70	MISO
1	11	Benton Co. - Monticello 345 (Option 1SC) Remove Benton - Mont230 kV line	70.4	MISO
1	12	Monticello - Benton Co. - Quarry 345 (Option 2DC)	230.4	MISO
1	13	Benton Co. - Quarry 345 (Option 2SC1)	160	MISO
1	14	Benton Co. - Monticello 345 (Option 2SC2)	70.4	MISO
1	15	Orient -Dekalb-Zachary-Maywood -Herleman - Mdoes, Dekalb - Fairport 345	871.5	MISO/SPP
1	16	Orient- Dekalb - Zachary, Dekalb - Fairport 345	555.5	MISO/SPP
1	17	Orient - Dekalb - Fairport 345	225.7	MISO/SPP
1	18	Sioux City and Fallow Ave -Overland Trail 345 kV	362	SPP
1	19	Ellendale - Fergus Falls 345 kV	459	MISO
1	20	Hazel Creek - Helena	375	MISO
1	21	Alexandria - Monticello	324	MISO
1	22	Monticello - Parkers	121	MISO
1	23	Hawthorne - Sibley	32	SPP
1	24	BigStone - Hazel - Helena (Project 5 and 20)	515	MISO
1	25	Bigstone - Alex - Monticello (Project 4 and 21)	516	MISO
1	26	Ell - FF, Parkers - Mont - Alex - BigS - Hazel - Helena (Project 19, 22, 24, 25)	1611	MISO
1	27	Ell - FF, Parkers - Mont - Alex - BigS - Hazel - Helena, Hawthorne - Sibley (Project 19, 22, 24, 25, 23)	1643	MISO/SPP
1	28	BigS - Alex, Nashua-Hawthorne- Sibley, Monti - Parkers (Project 4, 9,22)	424	MISO/SPP
1	29	BigS - Alex, Nashua-Hawthorne- Sibley, Alex- Monti, Monti - Parkers (Project 4, 9, 21, 22)	728	MISO/SPP
2	30	Tap Sherco - Coon Creek existing line into Monticello	6	MISO
2	31	Atchinson Co - Rock Creek 345	54	SPP
2	32	StrangerCreek - Midland 230	24	SPP
2	33	BigStone - Hazel - Bluelake 345	633	MISO
2	34	Jamestown - Ellendale 345	253	MISO
2	35	Bison - Hankinson - BigStone 345	476	MISO
2	36	Big Stone - Quarry - Monticello - Parkers 345	651	MISO
2	36A	BigStone - Quarry -Monticello	530	MISO
2	37	Project 9+33+34+35+36	2055	MISO

Round	JTIQ Project ID	Project name	Cost $ (M)	Location
2	38	Brookings Co. - Lakefield 345	331	MISO
2	39	Split Rock - Sioux Falls 2nd Ckt 230	13	MISO
2	40P	40+41+42 OPPD combo	33.94	SPP
2	40	1209_1231	3.3	
2	41	1209_1252	1	
2	42	Cooper_StJoe	29.64	
2	43	Crowned Ridge 2 - Watertown 230kV	33.5	
2	44	Eau Clair Transformer	4.356	
2	45	Iatan - Metropolitan	97.74	
2	46	Nashua-Hawthorn	58.18	
2	47	Stranger-87th-Craig	99	
2	48	Rebuild Maryille - Midway 161, St. Joe - Avenue City 161, & Midway - Avenue city 161	43.3	
2	49	Rebuild RNRidge - Nashua 161	6	
2	50	Rebuild SplitRock-White 345kV	68.9	
2	51	Raun-Council Bluffs 345	156.5	
2	52	Raun - S3451 345	106	
2	53	Rebuild Raun - Tekemah, Tekemah - S1226	213	
2	54	New Branch Raun - S3452 345kV	152.3	
2	55	Portfolio (9+34+36A+38+43+47)	1357.5	
2	56	SPP2020ITP TPL and Raun - S3452	33.94	SPP
2	57	9+35+36A+38+43+45+47+53+54+58	2134.05	
2	58	Kelly Constraint Project	90.5	SPP
2	59	9+34+36A+38+43+45+47+53+54+58	1911.04	MISO-SPP
2	60	9+34+35+36A+38+43+45+47+53+54+58	2387.05	
2	61	Ellendale - Hankinson 345	311	
2	62	9+35+36A+38+43+45+47+53+54+58+ 61 (57+61)	2445.04	

Table 3.3-1: JTIQ project preliminary mitigation plans

Reliability Study Results

JTIQ Project 62 is able to mitigate most of the targeted constraints and all of MISO region constraints.

Targeted Constraints	JTIQ Project ID																												
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
345409 5OVERTON 1 161 345411 5OVERTON 2 161 Z	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
532772 STRANGR7 345 532775 87TH 7 345 1	X	X	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	X	X	X	X	X	X	X	X	X	X	X	X
532775 87TH 7 345 542977 CRAIG 7 345 1	X	X	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	X	X	X	X	X	X	X	X	X	X	X	X
532913 KELLY 5 161 997595 KELL TX-1 115 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
532913 KELLY 5 161 997597 KELL TX-1 115 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
541199 ST JOE 7 345 542980 NASHUA 7 345 1	X	X	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	X	X	X	X	X	X	X	X	X	X	X	X
541201 SIBLEY 7 345 542972 HAWTH 7 345 1	X	√	X	X	X	X	X	X	√	-	-	-	-	-	-	-	-	X	X	X	X	X	√	X	X	X	√	√	√
541201 SIBLEY 7 345 997456 SIBLEY11 161 11	X	√	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	√	X	X	X	X	√	X	X	X	√	√	√
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541202 SIBLEY 5 161 541250 SIBLEYPL 161 1	X	√	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	X	X	X	X	X	√	X	X	X	√	√	√
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541202 SIBLEY 5 161 997458 SIBLEY11 161 11	X	√	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	√	X	X	X	X	√	X	X	X	√	√	√
542972 HAWTH 7 345 542980 NASHUA 7 345 1	X	X	X	X	X	X	X	X	√	-	-	-	-	-	-	-	-	X	X	X	X	X	X	X	X	X	X	√	√
542972 HAWTH 7 345 997433 HAWTHORN22 161 22	-	-	-	-	-	-	-	-	√	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
542972 HAWTH 7 345 997434 HAWTHORN20 161 20	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
542980 NASHUA 7 345 997426 NASHUA11 161 11	-	-	-	-	-	-	-	-	√	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
542980 NASHUA 7 345 997428 NASHUA11 161 11	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
543028 NASHUA-5 161 997426 NASHUA11 161 11	-	-	-	-	-	-	-	-	√	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
543028 NASHUA-5 161 997428 NASHUA11 161 11	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
543665 HAWTHN5 161 997433 HAWTHORN22 161 22	-	-	-	-	-	-	-	-	√	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
543665 HAWTHN5 161 997434 HAWTHORN20 161 20	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
601005 ELM CRK3 345 601010 MNTCELO3 345 1	X	X	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	X	X	X	X	√	X	X	X	√	√	√	√
601005 ELM CRK3 345 601022 PARKERS3 345 1	X	X	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	X	X	X	X	√	X	X	X	√	√	√	√
601006 SPLT RK3 345 652537 WHITE 3 345 1	X	X	X	√	X	X	X	X	X	-	-	-	-	-	-	-	-	X	X	X	X	X	X	√	√	√	√	√	√
601006 SPLT RK3 345 997369 SPLT 11 115 11	X	X	X	√	X	√	X	X	X	-	-	-	-	-	-	-	-	√	√	X	X	X	X	√	√	√	√	√	√
601010 MNTCELO3 345 601011 SHERCO 3 345 1	X	X	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	X	X	X	X	√	X	X	X	√	√	√	√
601015 BLUE LK3 345 997364 7000550 115 9	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
601028 EAU CL 3 345 997344 EAU CL 3_1 161 9	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
601028 EAU CL 3 345 997346 EAU CL 3_1 161 9	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
602004 SPLT RK4 230 652523 SIOUXFL4 230 1	X	X	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	X	X	X	X	X	X	X	X	X	X	√	√
602008 MINVALT4 230 652550 GRANITF4 230 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
603016 SPLT RK7 115 997329 SPLT RK4 115 7	X	X	X	√	√	√	X	X	X	X	X	X	X	X	X	X	X	√	√	√	X	X	X	√	√	√	√	√	√
603016 SPLT RK7 115 997369 SPLT 11 115 11	X	X	X	√	√	√	X	X	X	X	X	X	X	X	X	X	X	√	√	√	X	X	X	√	√	√	√	√	√
603062 BLUE LK7 115 997364 7000550 115 9	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
615529 GRE-PANTHER4 230 658276 HUC-MCLEOD 4 230	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
620314 BIGSTON4 230 620325 BROWNSV4 230 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
620314 BIGSTON4 230 655465 BLAIR-ER4 230 1	X	X	X	√	√	X	√	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	√	√	√	√	√	√
620325 BROWNSV4 230 620328 NEW EFFNGTN4 230 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
620327 HANKSON4 230 620328 NEW EFFNGTN4 230 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
620327 HANKSON4 230 620829 WAHPETON XF4 230 1	X	X	X	√	√	√	X	X	X	X	X	X	X	X	X	X	X	X	√	X	X	X	X	√	√	√	√	√	√
620329 WAHPETN4 230 620829 WAHPETON XF4 230 Z	X	X	X	√	√	√	√	X	X	X	X	X	X	X	X	X	X	X	√	X	X	X	X	√	√	√	√	√	√
620329 WAHPETN4 230 658109 FERGSFL4 230 1	X	X	√	√	√	√	√	X	X	X	X	X	X	X	√	√	X	X	√	√	X	X	X	√	√	√	√	√	√
620362 OAKES 4 230 661098 ELLENDL345 4 230 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
635701 SYCAMORE 5 161 635703 DELAWARE5 161 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
646209 S1209 5 161 646252 S1252 5 161 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
652512 GROTON 7 115 652568 GROTONSOUTH7 115 Z	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
652550 GRANITF4 230 655465 BLAIR-ER4 230 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
652550 GRANITF4 230 658259 WMU-WILLMAR4 230 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
652552 SIOUXCY2 230 652565 SIOUXCY4 230 Z	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
652555 MORRIS 7 115 658102 GRANTCO7 115 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
652626 UTICAJC7 115 660026 NAPA JCT7 115 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
660006 YKNTJCT7 115 660026 NAPA JCT7 115 1	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 3.3-2: Reliability study mitigation success against the constraints (Round 1)

Key	
√	Resolved
X	Unresolved
-	Not tested in Round 1

Targeted Constraints	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61	62
	JTIQ Project ID																													
345409 5OVERTON 1 161 345411 5OVERTON 2 161 Z	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
532772 STRANGR7 345 532775 87TH 7 345 1	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
532775 87TH 7 345 542977 CRAIG 7 345 1	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
532913 KELLY 5 161 997595 KELL TX-1 115 1	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	√	√	√	x	√
532913 KELLY 5 161 997597 KELL TX-1 115 1	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	√	√	√	x	√
541199 ST JOE 7 345 542980 NASHUA 7 345 1	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
541201 SIBLEY 7 345 542972 HAWTH 7 345 1	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
541201 SIBLEY 7 345 997456 SIBLEY11 161 11	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	√	x	√
541201 SIBLEY 7 345 997458 SIBLEY11 161 11	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
541202 SIBLEY 5 161 541250 SIBLEYPL 161 1	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
541202 SIBLEY 5 161 997456 SIBLEY11 161 11	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	√	x	√
541202 SIBLEY 5 161 997458 SIBLEY11 161 11	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
542972 HAWTH 7 345 542980 NASHUA 7 345 1	x	x	x	x	√	x	x	x	x	x	x	x	x	√	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
542972 HAWTH 7 345 997433 HAWTHORN22 161 22	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
542972 HAWTH 7 345 997434 HAWTHORN20 161 20	x	x	x	x	x	x	x	x	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	√	x	√	√	x	√
542980 NASHUA 7 345 997426 NASHUA11 161 11	x	x	x	x	√	x	x	x	x	x	x	x	√	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
542980 NASHUA 7 345 997428 NASHUA11 161 11	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
543028 NASHUA-5 161 997426 NASHUA11 161 11	x	x	x	x	√	x	x	x	x	x	x	x	√	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
543028 NASHUA-5 161 997428 NASHUA11 161 11	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
543665 HAWTHN5 161 997433 HAWTHORN22 161 22	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
543665 HAWTHN5 161 997434 HAWTHORN20 161 20	x	x	x	x	x	x	x	x	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	√	x	√	√	x	√
601005 ELM CRK3 345 601010 MNTCELO3 345 1	x	x	x	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
601005 ELM CRK3 345 601022 PARKERS3 345 1	x	x	x	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
601006 SPLT RK3 345 652537 WHITE 3 345 1	√	x	√	√	√	√	x	x	x	x	x	x	x	x	x	x	x	√	x	x	x	x	√	x	√	x	√	√	x	√
601006 SPLT RK3 345 997369 SPLT 11 115 11	√	√	√	√	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
601010 MNTCELO3 345 601011 SHERCO 3 345 1	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
601015 BLUE LK3 345 997364 7000550 115 9	√	x	√	√	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
601028 EAU CL 3 345 997344 EAU CL 3_1 161 9	x	x	x	x	x	x	x	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
601028 EAU CL 3 345 997346 EAU CL 3_1 161 9	x	x	x	x	x	x	x	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
602004 SPLT RK4 230 652523 SIOUXFL4 230 1	x	x	x	x	x	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
602008 MINVALT4 230 652550 GRANITF4 230 1	√	x	x	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
603016 SPLT RK7 115 997329 SPLT RK4 115 7	√	√	√	√	√	√	√	x	x	x	√	√	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	√	√
603016 SPLT RK7 115 997369 SPLT 11 115 11	√	√	√	√	√	√	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	√	√
603062 BLUE LK7 115 997364 7000550 115 9	√	x	x	√	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
615529 GRE-PANTHER4 230 658276 HUC-MCLEOD 4 230 1	√	√	√	√	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	√	√
620314 BIGSTON4 230 620325 BROWNSV4 230 1	x	x	√	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
620314 BIGSTON4 230 655465 BLAIR-ER4 230 1	√	x	√	√	√	x	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
620325 BROWNSV4 230 620328 NEW EFFNGTN4 230 1	√	x	√	√	√	√	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
620327 HANKSON4 230 620328 NEW EFFNGTN4 230 1	√	x	√	√	√	√	x	x	x	x	√	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
620327 HANKSON4 230 620829 WAHPETON XF4 230 1	√	x	x	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
620329 WAHPETN4 230 620829 WAHPETON XF4 230 Z	√	√	x	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
620329 WAHPETN4 230 658109 FERGSFL4 230 1	√	√	x	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
620362 OAKES 4 230 661098 ELLENDL345 4 230 1	x	√	x	x	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	x	x	√	√	√	√
635701 SYCAMORE 5 161 635703 DELAWARE5 161 1	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
646209 S1209 5 161 646252 S1252 5 161 1	x	x	x	x	x	x	x	x	√	x	x	x	x	x	x	x	x	x	√	x	√	√	x	√	√	x	√	√	x	√
652512 GROTON 7 115 652568 GROTONSOUTH7 115 Z	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
652550 GRANITF4 230 655465 BLAIR-ER4 230 1	√	x	x	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
652550 GRANITF4 230 658259 WMU-WILLMAR4 230 1	x	x	x	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
652552 SIOUXCY2 230 652565 SIOUXCY4 230 Z	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
652555 MORRIS 7 115 658102 GRANTCO7 115 1	√	√	√	√	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√
652626 UTICAJC7 115 660026 NAPA JCT7 115 1	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
660006 YKNTJCT7 115 660026 NAPA JCT7 115 1	x	x	x	x	√	√	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	√	x	√	x	√	√	x	√

Table 3.3-3: Reliability study mitigation success against the constraints (Round 2)

Economic Benefits

	MISO		SPP				
Project ID	F1 B/C Ratios	F1 PV Benefit (M$-Real)	F1 20Y APC Benefit (M$)	F2 20Y APC Benefit (M$)	F1 20Y B/C	F2 20Y B/C	MISO & SPP Combined B/C Ratio
1	-0.03	-4.04	10.31	-8.40	0.05	-0.04	-0.09
2	0	0.58	15.56	33.12	0.07	0.15	0.21
3	0.37	81.87	45.99	76.91	0.17	0.28	0.78
4	-16.93	-3562.04	21.77	33.72	0.08	0.13	-18.38
5	1.18	180.72	19.47	6.08	0.10	0.03	1.33
6	2.38	417.29	10.10	43.01	0.05	0.20	2.88
7	2.81	197.14	-33.57	6.92	-0.39	0.08	3.19

	MISO		SPP				
Project ID	F1 B/C Ratios	F1 PV Benefit (M$-Real)	F1 20Y APC Benefit (M$)	F2 20Y APC Benefit (M$)	F1 20Y B/C	F2 20Y B/C	MISO & SPP Combined B/C Ratio
8	0.01	7.78	67.12	303.32	0.07	0.31	0.43
9	-0.05	-6.61	10.09	33.04	0.07	0.22	0.24
10	0.97	74.49	2.08	-2.76	0.02	-0.03	1.02
11	-0.52	-39.79	7.29	7.43	0.08	0.08	-0.46
12	0.16	39.58	-0.06	7.58	0.00	0.02	0.20
13	0.09	15.13	-0.95	7.16	0.00	0.03	0.14
14	1.38	106.42	7.29	7.43	0.08	0.08	1.62
15	0.21	196.96	-53.90	-22.65	-0.05	-0.02	0.20
16	0.15	93.27	53.97	179.80	0.07	0.24	0.49
17	0	-0.27	86.50	106.33	0.28	0.35	0.47
18	0.07	25.83	14.93	23.06	0.03	0.05	0.14
19	0.03	16.63	63.42	79.33	0.10	0.13	0.21
20	0.1	39.16	14.84	-3.73	0.03	-0.01	0.09
21	-1.84	-654.58	17.80	8.65	0.04	0.02	-1.99
22	0.47	61.89	-1.37	-2.04	-0.01	-0.01	0.49
23	-0.22	-7.85	18.58	28.23	0.43	0.65	0.64
24	0.51	286.54	25.32	76.21	0.04	0.11	0.70
25	-9.4	-5315.53	1.83	-2.17	0.00	0.00	-10.31
26	-2.02	-3571.02	29.81	56.61	0.01	0.03	-2.18
27	-1.99	-3573.49	31.41	53.82	0.01	0.02	-2.14
28	1.98	917.90	34.32	22.14	0.06	0.04	2.08
29	0.98	785.00	4.40	-35.66	0.00	-0.04	1.02
30	0.92	101.28	6.04	18.81	0.75	2.32	1.20
31	-0.05	-5.91	-0.56	-8.44	-0.01	-0.12	-0.14
32	0	0.16	17.23	-23.83	0.53	-0.74	-0.24
33	0.45	310.21	-19.96	-79.63	-0.02	-0.09	0.36
34	1.48	411.07	18.45	61.68	0.05	0.18	1.87
35	0.1	54.01	83.32	158.93	0.13	0.25	0.45
36	0.01	6.98	-7.06	-65.52	-0.01	-0.07	-0.10
36A	-0.26	-150.18	19.37	-70.16	0.03	-0.10	-0.42
37	-0.29	-652.16	9.08	-16.13	0.00	-0.01	-0.33

	MISO		SPP				
Project ID	F1 B/C Ratios	F1 PV Benefit (M$-Real)	F1 20Y APC Benefit (M$)	F2 20Y APC Benefit (M$)	F1 20Y B/C	F2 20Y B/C	MISO & SPP Combined B/C Ratio
38	0.16	57.68	6.57	9.36	0.01	0.02	0.20
39	-112	-1590.05	-35.70	-28.45	-2.04	-1.62	-124.50
40	-0.03	-0.11	-7.60	18.45	-1.71	4.14	5.56
41	0.95	1.04	-0.03	-0.02	-0.02	-0.02	1.02
42	-0.03	-0.97	4.78	-7.33	0.12	-0.18	-0.28
43	2.47	90.54	11.48	28.22	0.25	0.62	3.54
44	-0.75	-3.56	15.49	-25.55	2.64	-4.35	-6.68
45	0.06	6.65	35.36	120.49	0.27	0.91	1.30
46	-0.14	-8.62	5.53	58.34	0.07	0.74	0.85
47	-0.01	-1.11	36.18	128.59	0.27	0.96	1.29
48	-0.17	-8.06	7.13	2.62	0.12	0.04	-0.13
49	-0.28	-1.85	-3.59	-6.70	-0.44	-0.83	-1.42
50	0.04	2.73	-10.77	-7.63	-0.12	-0.08	-0.07
51	0.06	11.14	40.39	183.46	0.19	0.87	1.24
52	0.1	11.04	28.09	168.66	0.20	1.18	1.70
53	0.05	10.73	17.02	57.15	0.06	0.20	0.32
54	0.14	24.17	31.46	82.24	0.15	0.40	0.70
55	-0.02	-33.5	46.51	53.92	0.03	0.03	0.02
56	-14.3	-532.48	-6.12	-0.75	-0.13	-0.02	-15.71
57	-0.12	-265.44	112.15	262.13	0.04	0.10	0.00
58	-0.05	-5.02	4.25	15.53	0.03	0.13	0.12
61	0.69	236.59	22.63	13.00	0.05	0.03	0.80
62	0.24	652.5	48.47	149.45	0.01	0.05	0.33

Table 3.3-4: Economic benefits of the twenty-nine mitigation plans

Next Steps

Cost Allocation Methodology

MISO and SPP held two joint stakeholder meetings on July 07 and August 13, 2021 to discuss cost allocation for JTIQ mitigation projects. The next joint stakeholder meeting to further discuss cost allocation is on October 8, 2021. Cost Allocation methodology is yet to be determined.

Report

The final study report will be published by November 2021.

MISO-SPP Coordinated System Planning

In Q1 of 2021, MISO and SPP held an Interregional Planning Stakeholder Advisory Committee meeting to help determine whether to perform a Coordinated System Plan (CSP) study in 2021. After careful consideration and stakeholder discussion, MISO and SPP mutually determined not to initiate a CSP study based on the following rationale:

- Avoid overlapping efforts with the MISO-SPP JTIQ study (as described above)
- Work on process improvements for future studies, primarily focusing on improved cost estimation coordination
- Staff to begin exploring a Targeted Market Efficiency Project study concept based on the recommendations and guidance of the OMS-RSC Seams Liaison Committee

MISO-PJM Coordinated System Planning

In Q1 of 2021, MISO and PJM held an Interregional Planning Stakeholder Advisory Committee meeting to help determine whether to perform a Coordinated System Plan (CSP) study in 2021. After careful consideration and stakeholder discussion, MISO and PJM mutually determined not to initiate a CSP study based on the following rationale:

- No interregional congestion drivers were identified for consideration as a part of an Interregional Market Efficiency Project study
- A Targeted Market Efficiency Project study will not be conducted in 2021 as RTOs continue to assess the impact of planned upgrades and congestion persistence with additional data
- No appropriate reliability constraints or public policy drivers were identified or planned at this time

CHAPTER 4: RELIABILITY STUDIES

CHAPTER 4: RELIABILITY STUDIES

4.1 Reliability Assessment and Compliance

MISO, in collaboration with its transmission-owning members and stakeholders, performs annual reliability assessments to identify transmission infrastructure upgrades needed to ensure the continued system reliability in compliance with applicable local and regional reliability standards. The reliability assessment process for MTEP21 (shown in Figure 4.1-1) began with a roll-up of issues and potential solutions from the local planning processes of the Transmission Owners (TOs), followed by an independent reliability assessment conducted by MISO to evaluate and integrate the TO local planning information into the development of the overall MISO Transmission Expansion Plan.

MISO closely coordinates the annual reliability assessment with other planning efforts to ensure the transmission expansion plan is identified in an efficient and cost-effective fashion. A variety of factors are considered as part of MISO's transmission expansion plan development, including but not limited to, urgency of needs, cost effectiveness of solutions, system performance of solution alternatives to address identified transmission issues, and other considerations such as lead time to develop a project, right-of-way (ROW) or substation impacts, expandability, operational flexibility, etc.

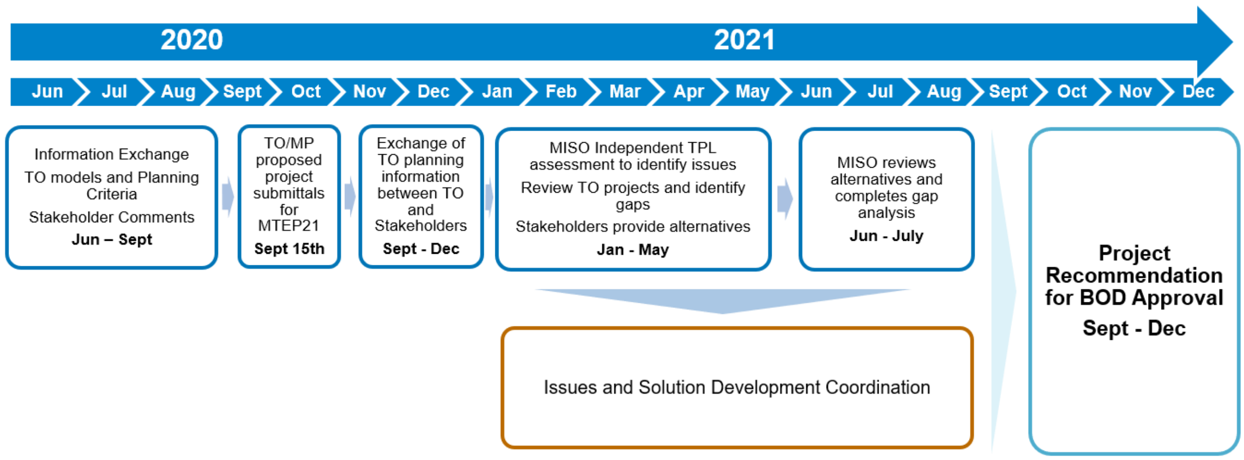

Figure 4.1-1: MTEP21 reliability assessment process

In conjunction with the MTEP planning process, an inclusive, transparent stakeholder process is utilized to facilitate open discussions and allow stakeholders to provide early and meaningful inputs into the development of transmission solutions in each planning cycle. The results of MISO's independent reliability assessments, along with proposed solution alternatives, are presented to stakeholders through a series of public Sub-regional Planning Meetings (SPM), and additional Technical Study Task Force (TSTF) meetings as needed, for each of the four MISO planning sub-regions: Central, East, South, and West.

After MISO completes its independent review of all proposed projects and associated alternatives and addresses stakeholder feedback received through SPM discussions, MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval. These projects make up Appendix A of the MTEP report and represent the preferred solutions to the identified transmission needs of the MISO reliability assessments. Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles.

The complete results of MTEP21 reliability assessments are detailed in Appendices D3-D10 of the MTEP21 report, which are available on the MISO ShareFile site at https://misoenergy.sharefile.com/, subject to Critical Energy Infrastructure Information (CEII) and non-disclosure agreements. These results serve as compliance evidence for a variety of NERC planning standards listed on the MISO public website at https://www.misoenergy.org/planning/transmission-planning/reliability-planning.

MTEP21 project recommendations

As the result of the MTEP21 reliability assessments, 30 baseline reliability projects totaling $187 million are included in the MTEP21 proposed Appendix A, accounting for 6% of total transmission infrastructure investment in MTEP21. Sixteen Expedited Project Review requests were received and evaluated. The vast majority of the recommended projects are driven by reliability (either baseline or local reliability), load growth, and age and condition, and are expected to be in service within three years. Project justification details of the recommended Appendix A projects are summarized in the following subsections for each of the four MISO planning sub-regions.

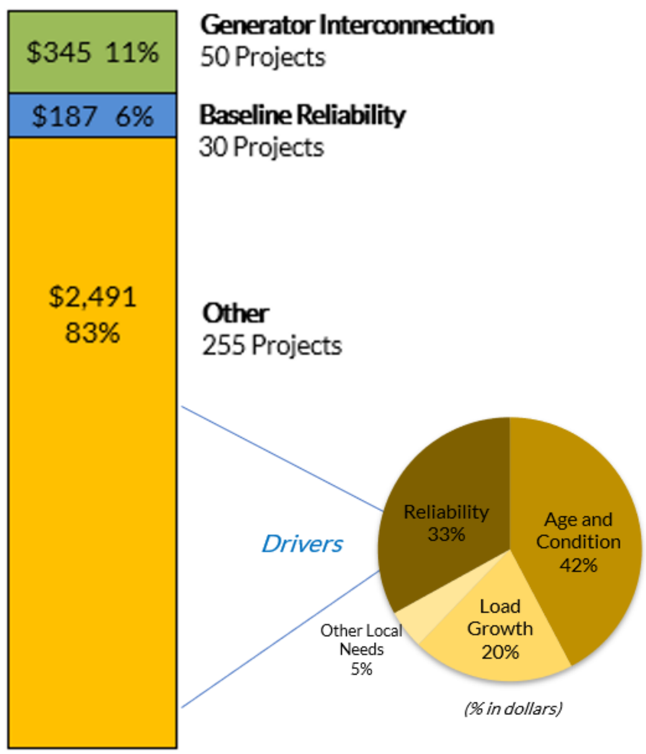

Figure 4.1-2: Project count and cost by project types for MTEP21 cycle, data as of 9-20-2021.

In the following pages, the region's MTEP21 projects are categorized into three categories, Baseline Reliability, Other, and Generator Interconnection. The definition of each of these categories are detailed below:

Baseline Reliability Projects

According to Attachment FF of the MISO Tariff, "Baseline Reliability Projects are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable national Electric Reliability Organization (ERO) reliability standards and reliability standards adopted by Regional Reliability Organizations and applicable within the Transmission Provider Region."

Other Projects

The "Other" projects category are projects that do not meet the criteria to be considered as Baseline Reliability Projects (BRP), New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. Other projects may include projects to satisfy Transmission Owner and/or state and local planning criteria other than NERC or regional reliability standards, interconnection of new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plant, improve operational performance or address other operational issues, address service reliability issues with end-use consumers, improve aesthetics including but not limited to undergrounding overhead transmission facilities, address localized economic issues, and address other miscellaneous localized needs. The tables of project information are broken down by four general categories of project drivers; Local Reliability, Age and Condition, Load Growth, and Other Local Need, but note that these four drivers are not defined in the MISO Tariff.

Generator Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generator Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation."

These projects include both Direct Assignment Facilities, which are defined in Module A of the Tariff and represent facilities necessary to physically interconnect the Generation Resource to the Transmission System when necessary, as well as Network Upgrades required to facilitate reliable delivery of the output of the Generation Resource to ultimate Load.

The Generator Interconnection Projects (GIPs) noted in the following sections of this Chapter have been evaluated through the Generator Interconnection queue and the associated Generator Interconnection Agreements have been signed.

4.2 Project Justifications – Central Region

Central Region Overview

The MISO Central planning region consists of seventeen Transmission-Owning members spanning four states: Missouri, Illinois, Indiana, and Kentucky. These Transmission Owners are:

American Electric Power Service Corporation (AEP)
Ameren (AMIL/AMMO)
Big Rivers Electric Corp. (BREC)
City of Columbia, Mo. (CWLD)
City of Springfield, Ill. (CWLP)
Duke Energy Corp. (DEI)
GridLiance Heartland LLC (GLH)
Henderson Municipal Power & Light (HMPL)
Hoosier Energy REC Inc. (HE)
Indianapolis Power & Light (IPL)
Northern Indiana Public Service Co. (NIPSCO)
Pioneer Transmission (PT)
Prairie Power Inc. (PPI)
Republic Transmission (RTx)
Southern Indiana Gas & Electric (SIGE)
Southern Illinois Power Cooperative (SIPC)
Wabash Valley Power Association Inc. (WVPA)

The Bulk Power System (BPS) within these states consists of an extensive 345 kV, 230 kV, 161 kV, and 138 kV networked transmission system. The 345 kV network spans Missouri, Illinois, and Indiana, both north to south and east to west. The 230 kV network spans through Indiana, both north to south and east to west. The 161 kV network spans north to south and east to west in Missouri, Illinois, and Kentucky, and the 138 kV networks span both north and south, and east to west in Illinois, Indiana, and Kentucky. All of Ameren, BREC, CWLD, CWLP, GLH, HMPL, and SIPC belong entirely in the SERC Region. All of DEI, HE, IPL, NIPSCO, PT, RTx and SIGE belong entirely in the ReliabilityFirst Region. Wabash Valley is split between both ReliabilityFirst and SERC Regions.

Major load pockets in the MISO Central planning region are St. Louis, MO; Peoria, IL; Springfield, IL; Evansville, IN; and Indianapolis, IN (shown in Figure 4.2-1).

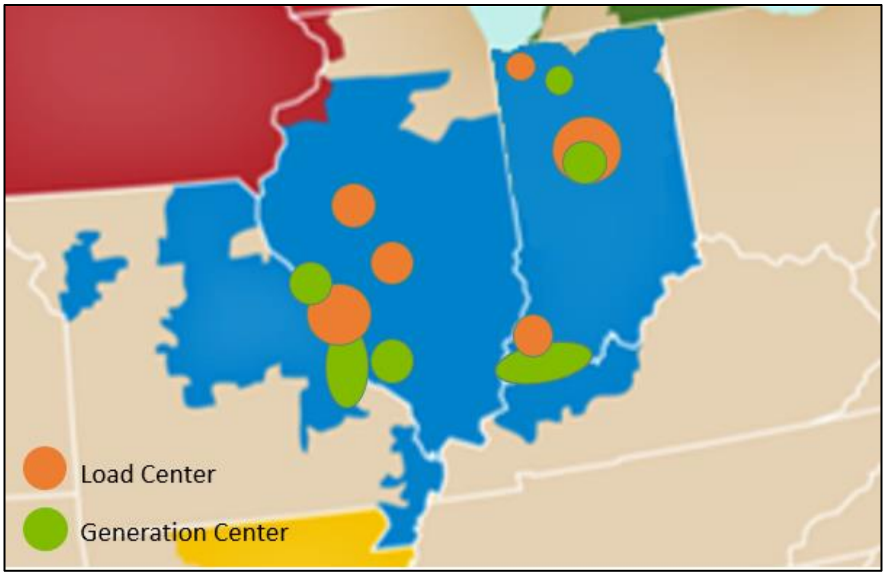

Figure 4.2-1: Generation and load centers in the Central planning region

For MTEP21, MISO Transmission Planning is recommending 96 projects from the Central region for inclusion in Appendix A at an estimated cost of $695 million. Of these, 10 are Baseline Reliability Projects and nine are Generator Interconnection Projects. The remaining 77 projects are classified as Other projects because they do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects.

Of the 96 projects, that are being recommended to be included in MTEP21, 12 have an estimated cost of less than $1 million, 31 have an estimated cost between $1 million and $5 million, and the remaining 53 projects are estimated to cost greater than $5 million (indicated in Figure 4.2-2).

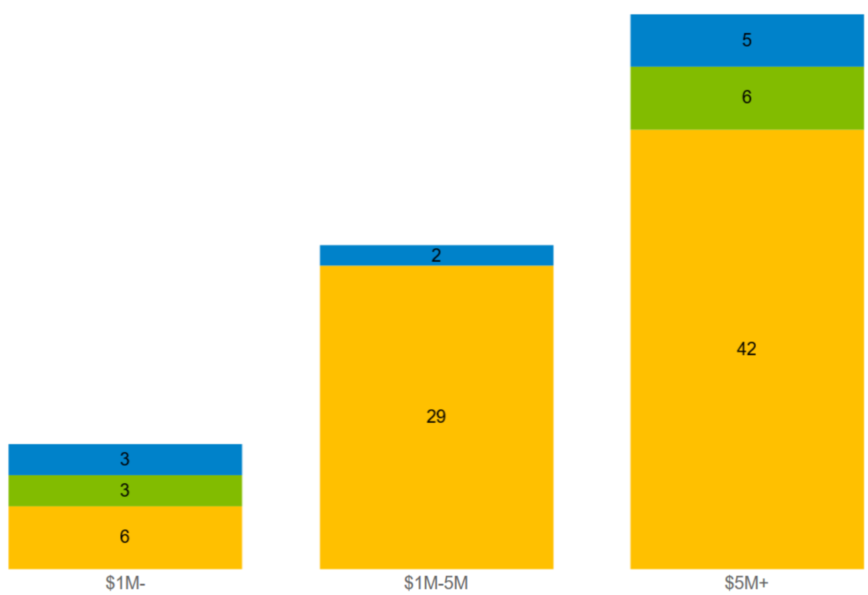

Figure 4.2-2: Project counts by cost category of MISO Central region MTEP21 projects (data as of 9-17-2021)

The majority of the projects in the MISO Central planning region are expected to go in service in the next three years (shown in Figure 4.2-3).

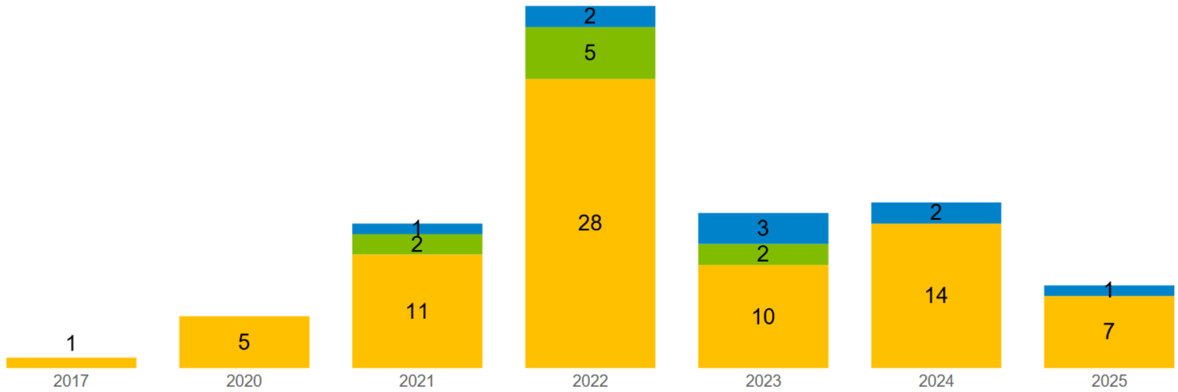

Figure 4.2-3: Central region MTEP21 projects by in-service date (data as of 9-17-2021)

In accordance with Attachment FF of the tariff, in the event a Transmission Owner determines that system conditions warrant the urgent development of system enhancements an expedited review of the impacts of the project can be requested. MISO shall use a streamlined approval process for reviewing and approving projects proposed by the Transmission Owner(s) and decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO unless a longer review period is mutually agreed upon. During the MTEP21 cycle, MISO received the following projects through the Expedited Project Review (EPR) process:

1. Project ID 19852 New [AMMO] Sikeston 161 kV substation
2. Project ID 19746 Rebuild [GLH] Joppa—[GLH] Shawnee 161 kV line No. 2
3. Project ID 21045 Relocate [AMIL] ADM North—[AMIL] Mt. Zion 138 kV line
4. Project ID 21165 New [BREC] Maxon 69 kV load addition
5. Project ID 21325 Rebuild Rossville-Vermilion 138 kV line (1305)
6. Project ID 21585 Rebuild Decatur East Main St-Route 51 Decatur 138 kV line (1416)

Also, in accordance with Attachment FF Section VIII.A.3, the following project was identified as an Immediate Need Reliability Project and is excluded from the competitive developer selection process:

- None

The ten highest cost projects in the MISO Central Region represent $158 million (23%) of the $695 million total recommended projects for the whole MISO region in MTEP21. The locations of these projects are shown in Figure 4.2-4 and the investment is spread across the Central planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

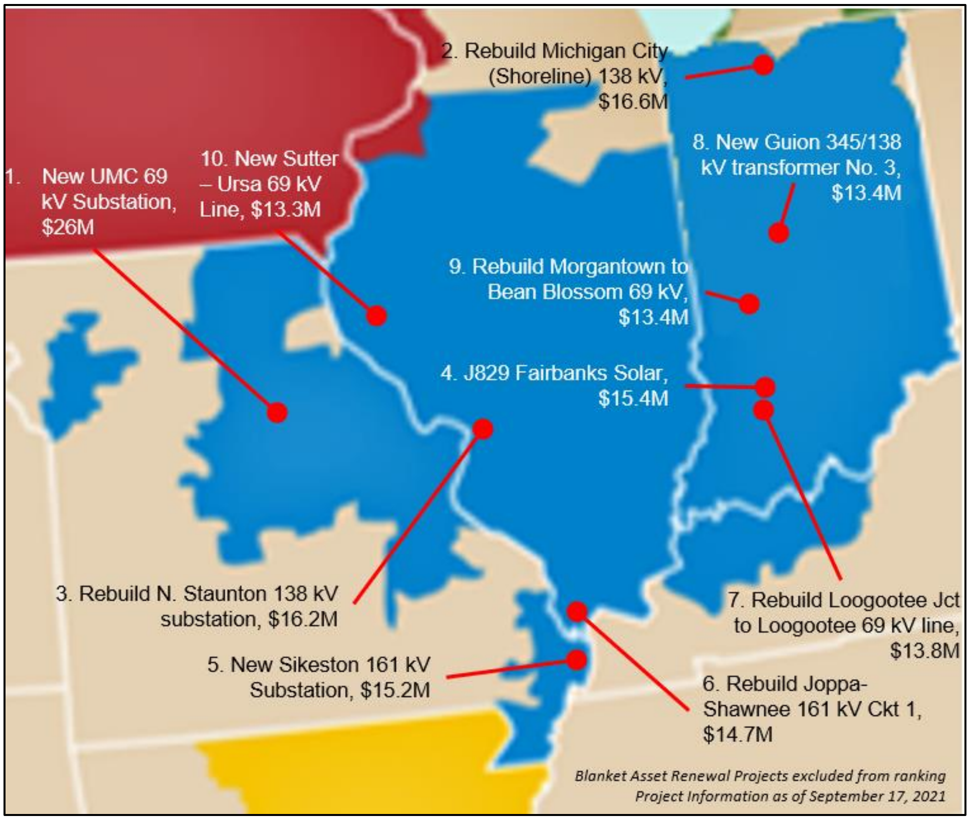

Figure 4.2-4: Central region top ten projects by cost (data as of 9-17-2021)

4.2.1 American Electric Power Service Corporation (AEP)

American Electric Power Service Corporation includes the AEP Transmission business unit which is responsible for the planning and operation of the AEP Transmission system, including assets owned by its affiliates in MISO.

American Electric Power Service Corporation did not submit any new projects for MTEP21. MISO has not identified any issues in AEP area.

4.2.2 Ameren Illinois

Ameren Illinois (AMIL) is a regulated electric and gas delivery company based in Collinsville, Ill. Its parent company is Ameren Corp., located in St. Louis, Mo. AMIL serves 1.2 million electric customers and 816,000 natural gas customers in central and southern Illinois. Its transmission system includes approximately 4,500 miles of transmission lines; 46,000 miles of distribution lines; 18,200 miles of natural gas pipe-line transmission and distribution mains; and 12 underground natural gas storage fields. AMIL's total generation is about 12,000 MW, more than half of which comes from Dynegy-owned coal units of 5,698 MW and Prairie State Energy-owned coal units of 1,600 MW.

Ameren Illinois proposed 28 projects at an estimated cost of $166 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the Ameren area, 28 of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $166 million. Of these projects, 3 are Baseline Reliability projects, 22 are Other projects, and 3 are Generator Interconnection projects with signed Generator Interconnection Agreements. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

Project 18889 - Rebuild [AMIL] Hickok—[AMIL] North LaSalle 138 kV line

Project Description

The rebuild of the [AMIL] Hickok—[AMIL] North LaSalle 138 kV line (1659) will address an overload on the same line during a P6-1-1 contingency event. The total estimated cost of this project is $TBD million dollars. The expected in-service date for this project is December 1, 2023.

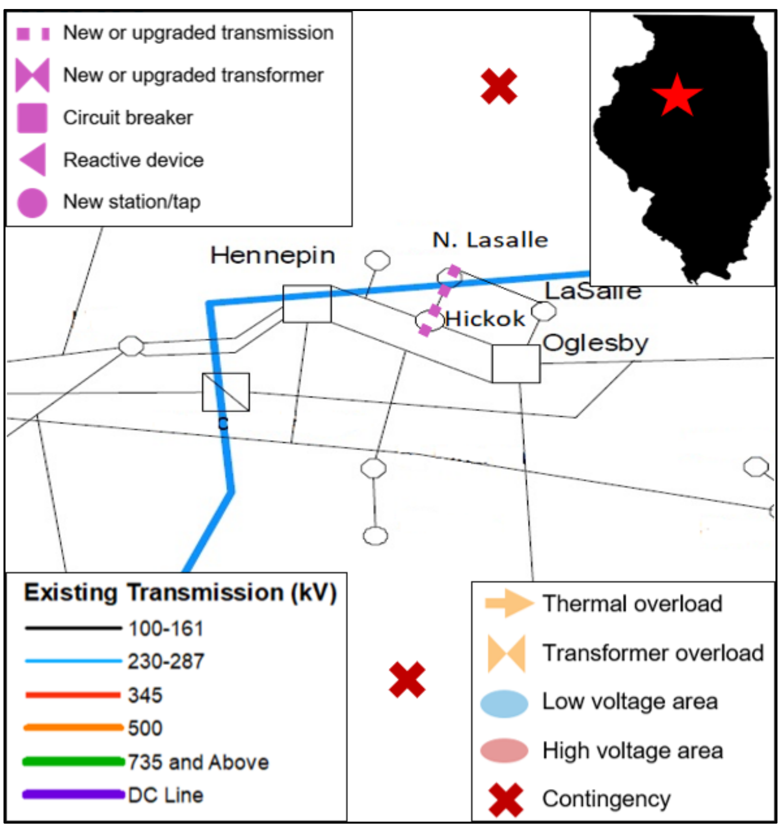

Figure 4.2.2-1: P18889 Geographic transmission map of project area

Project Need

Low voltages at the [AMIL] Hallock 138 kV substation by year 2022 for a NERC-defined category P6-1-1 contingency event. Adding a second [AMIL] Woodhall—[AMIL] Hallock 138 kV line No. 2 will allow for the [AMIL] Hallock 138 kV substation to remain energized during this P6-1-1 event (Table 4.2.2-1).

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
Base case	[AMIL] Hickok—[AMIL] North LaSalle 138 kV line	202	40	40
P6-1-1	[AMIL] Hickok—[AMIL] North LaSalle 138 kV line	478	103	40

Table 4.2.2-1: P18889 Thermal loading drivers

Alternatives Considered
Generation redispatch or load shed is not feasible for voltage violations due to P6 contingency events if there is no applicable short-time emergency rating. No other alternatives were considered. These line terminal upgrades are the best and cheapest option to address this reliability issue.

Immediate Need Reliability Project
In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 19956 - Rebuild [AMIL] Tanner—[AMIL] Jasper 138 kV line

Project Description

The project will rebuild twenty-three miles of the [AMIL] Tanner—[AMIL] Jasper 138 kV line to 2000 Amperes. This line rebuild will mitigate an overload for a P6-1-1 contingency event. The total estimated cost of this project is still being determined. The expected in-service date for this project is June 1, 2024.

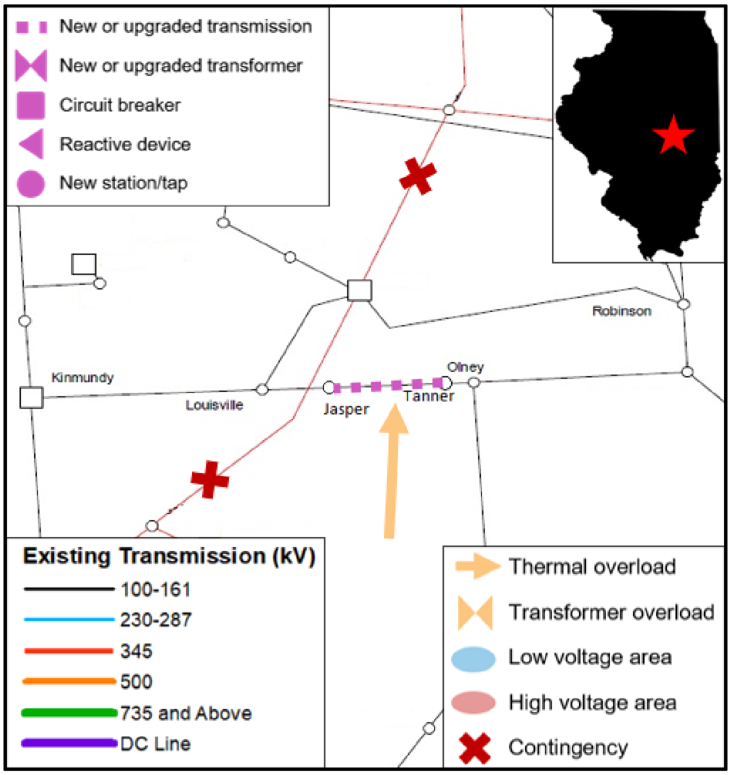

Figure 4.2.2-2: P19956 Geographic transmission map of project area

Project Need

Several BES lines in Decatur Illinois become heavily loaded in year 2026 for a NERC defined category P6-1-1 contingency event. Rebuilding this new line will relieve the overloaded [AMIL] Tanner—[AMIL] Jasper 138 kV line in Central Illinois for the coincident P6-1-1 events (Table 4.2.2-2).

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
n-0	[AMIL] Tanner—[AMIL] Jasper 138 kV line	143/423	76	76
P6-1-1	[AMIL] Tanner—[AMIL] Jasper 138 kV line	143/423	176	60

Table 4.2.2-2: P19956 Thermal loading drivers

Alternatives Considered

No other alternatives were considered. These line terminal upgrades are the best and cheapest option to address this reliability issue.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 20184 - New [AMIL] REOS 138 kV Substation

Project Description

The project will build a new [AMIL] REOS 138 kV Substation. This new substation will mitigate both thermal and low voltages in Central Illinois for a P6-1-1 contingency event. The total estimated cost of this project is still being determined. The expected in-service date for this project is December 1, 2024.

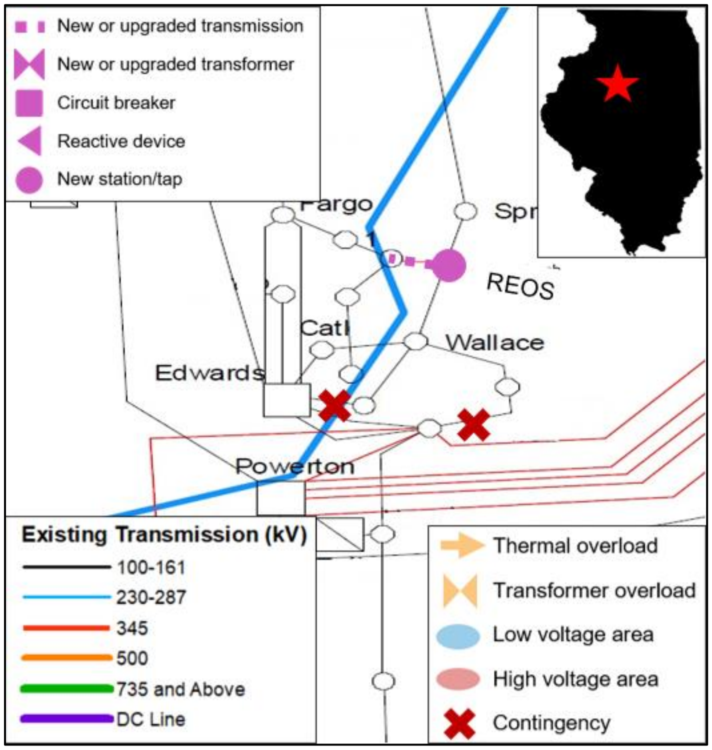

Figure 4.2.2-3: P20184 Geographic transmission map of project area

Project Need

There is an overload on the [AMIL] Edwards—[AMIL] CAT 138 kV line in year 2026 summer light load conditions for a NERC defined category P6-1-1 contingency event. Building this new substation will redirect flows from the overloaded facility (Table 4.2.2-3).

Cont. Type	Limiting Element	SE Rating (MVA)	Pre-project (post-cont.) Loading (%)	Post-project (post-cont.) Loading (%)
n-0	[AMIL] Edwards—[AMIL] CAT 138 kV line	220	33	34
P6-1-1	[AMIL] Edwards—[AMIL] CAT 138 kV line	304	103	83
n-0	[AMIL] CAT—[AMIL] RS Wallace 138 kV line	233	24	25
P6-1-1	[AMIL] CAT—[AMIL] RS Wallace 138 kV line	304	90	73

Table 4.2.2-3: P20184 Thermal loading drivers

Alternatives Considered

Reconductoring the [AMIL] Edwards—[AMIL] Cat 138 kV line was a viable alternative submitted by Ameren. Ameren asked MISO to determine which project was the better project to move forward with. MISO and Ameren collaborated and selected P20184 as the better project.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
21045	Relocate ADM North-Mt. Zion 138 kV line (1616)	Relocate 0.6 miles of existing 138 kV ADM North-Mt. Zion Route 121-1616 to single circuit, single shaft steel poles. The entire section has distribution underbuild.	December 1, 2021	3.5

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
16989	New Mattoon W 345 kV substation	Install new 6 position ultimate ring bus at Mattoon West Substation.	December 1, 2023	8.5
16990	New Kline 138 kV substation	Install new 6 position ultimate ring bus at Kline Substation (formerly known as Wanda).	June 1, 2022	7.2
17864	Upgrade Cahokia 345/138 kV substation	Replace OCB H27 on the C-GRAT-3 position and OCB H35 on the C-RUSL-2 position with symmetrically rated SF6 55 kA circuit breakers.	December 1, 2022	4.2
17979	Rebuild North Staunton 138 kV substation	Rebuild the North Staunton 138 kV substation to a ring bus configuration.	November 30, 2022	16.2
18074	Replace Jacksonville Industrial Park 138 kV Breakers	Jacksonville Industrial Park Breaker replacement. Replace 138 kV breaker JCKI-138KV BT 1-2 BKR 1302 at Jacksonville Industrial Park Substation.	December 1, 2023	1.2
19345	New Valmeyer 138 kV Substation (TP-1422)	Construct Valmeyer 138 kV Substation Ring Bus and add a second 138/34.5 kV Transformer.	June 1, 2024	5.9
19826	Upgrade Dupo Ferry 138 kV Substation	Replace overstressed breakers.	December 1, 2025	TBD
19988	New Roxford 345/138 kV Transformer Addition	Add second 345/138 kV transformer.	December 1, 2023	10.2
20187	Upgrade Chesterville 138 kV Substation	Add two (2) line breakers.	December 1, 2025	1.7
20188	Upgrade Gibson City S 138 kV Substation	Add five (5) position ring bus.	December 1, 2025	7.0
20191	Upgrade Marion N 138 kV substation	Add ring bus.	December 1, 2024	8.0
20285	Reconfigure Herrin East 138 kV substation to ring bus	Install initial 4-position ring bus at the existing Herrin East substation location.	December 1, 2022	7.5
20365	New Normal East 138/69 kV transformer	Install new 112 MVA, 138/69 kV Transformer.	June 1, 2022	2.0
20425	Upgrade Holland-Kickapoo 138 kV	Remove CT limit as part of Kickapoo substation rebuild.	December 1, 2022	0.5
21325	Rebuild Rossville-Vermilion 138 kV line (1305)	Rebuild the Rossville-Vermilion-1305 138 kV circuit with 2000 A summer emergency capability conductor. Also, install OPGW.	June 1, 2022	12.8
21585	Rebuild Decatur East Main St-Route 51 Decatur 138 kV line (1416)	Rebuild the Decatur East Main St-Decatur Route 51 138 kV line. Scope of work includes: Replacement of existing	December 1, 2022	4.2

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		OPGW with new OPGW, all to be installed in upper static position. Replacement remaining (31) wood pole structures; (28) will be replaced with single wood pole structures and 3 will be replaced with steel monopole structures. Reconductor with 2000A conductor.		
20465	New Commodore 230 kV Interim Configuration	Interim configuration.	October 5, 2021	TBD

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
13546*	New County Highway 20 138 kV breaker station	Construct a 3-position (ultimate 4-position) ring bus at the existing County Highway 20 Substation location in the N. Decatur-Clinton Rt. 54-1313 138 kV line. Ring bus to be rated for a minimum of 2000A continuous current carrying capability.	December 1, 2020	-

*Project 13546 was previously approved in MTEP18. However, Ameren submitted data in the MTEP21 cycle that impacts topology and therefore, this project is included here for transparency. There is no incremental cost from MTEP18.

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20193	Replace Breakers Program - MTEP21	Breaker Upgrades Requested by Maintenance.	December 1, 2024	13.5
20194	Replace Relays Program - MTEP21	Electromechanical Relay Upgrades Requested by System Protection.	December 1, 2024	10.4
20195	Replace Pole and Insulator Program - MTEP21	Pole and Insulator replacements requested by Maintenance.	December 1, 2024	15.0

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
9843	New Normal East 138/34.5 kV Transformer	Add 2nd 138/34 kV transformer to Normal East.	May 1, 2017	1.5
19085	New Shelbyville S. 138 kV Ring Bus for PPI ISHI Load Addition	Rebuild the Shelbyville S. 138 kV bus to a 6 position ultimate ring bus. This will allow a new interconnection with PPI to serve their ISHI load.	June 1, 2022	10.0

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19025	New J815 Hickory Point Solar Generator Interconnection (Yvonne 138 kV switching Station) 250 MW	Install new Yvonne 138 kV switching Station (J815 Hickory Point Solar Generator Interconnection) on the Austin-Taylorville S.-1545 line.	November 1, 2022	5.7
19026	New J912 Christian County Solar Generator Interconnection (Pana 138 kV switching station)	New J912 Christian County Solar Generator Interconnection at Pana 138 kV switching station.	November 1, 2023	0.9
20985	New Snyder 345 kV Substation (J1180 Solar)	Build a 3 position, 4 ultimate ring bus on the Casey West-Sullivan line approximately 4.7 miles from Sullivan substation for J1180 75 MW solar farm.	June 1, 2023	10.0

4.2.3 Ameren Missouri

Ameren Missouri (AMMO) is a regulated electric and gas delivery company based in St. Louis, Mo. AMMO provides power to serve 1.2 million electric and 130,000 natural gas customers in central and eastern Missouri. Its service area covers 64 counties and more than 500 communities, including the greater St. Louis area. More than half of the AMMO generation comes from Ameren-owned coal and nuclear generation at more than 6,800 MW. Ameren also owns a good percentage of renewables and hydroelectric generation plants across central and eastern Missouri.

Ameren Missouri proposed 8 projects at an estimated cost of $48 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the Ameren Illinois area, all 8 projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $48 million. Of these projects, 2 are Baseline Reliability projects, 4 are Other projects, and 2 are Generator Interconnection projects with signed Generator Interconnection Agreements. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

Project 19969 - New [AMMO] Belleau 138 kV Capacitor Bank

Project Description

The project will build a new [AMMO] Belleau 138 kV Capacitor Bank. This new capacitor will mitigate low voltages in and around O'Fallon Missouri for a P6-1-1 contingency event. This project is also needed to aid in transient recovery in the same O'Fallon Missouri area. A separate dynamic stability analysis will need to be performed to confirm the stability issues. The total estimated cost of this project is still being determined. The expected in-service date for this project is June 1, 2027.

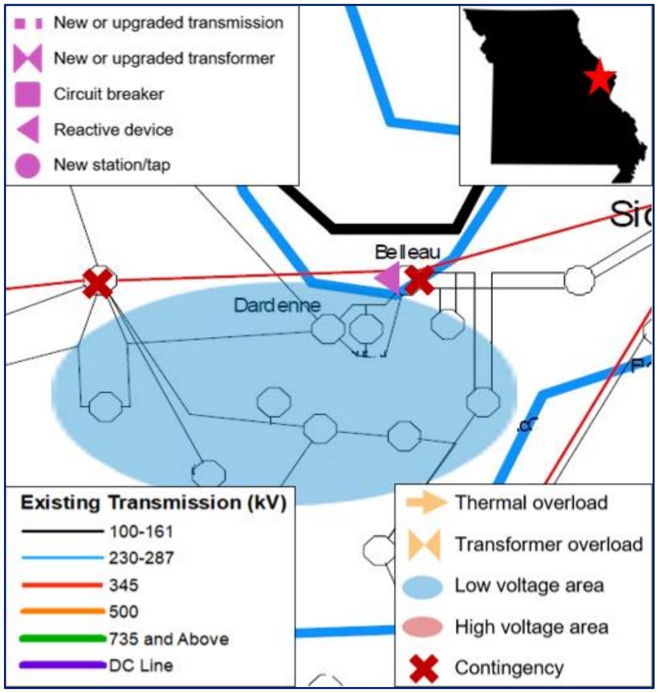

Figure 4.2.3-1: P19969 Geographic transmission map of project area

Project Need

Several BES 138 kV buses in O'Fallon Missouri observe low voltages below an acceptable operating level in year 2023 for a NERC defined category P6-1-1 contingency event. Building this new capacitor bank will prop up the voltage levels in O'Fallon Missouri for the coincident P6-1-1 events. (Table 4.2.3-1).

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
n-0	[AECI] Enon 161 kV bus	0.95	1.00	0.94
n-0	[AECI] O'Fallon 161 kV bus	0.95	1.00	0.94
n-0	[AECI] Lake Street 161 kV bus	0.95	0.99	0.94
n-0	[AMMO] Pointe Prairie 161 kV bus	0.95	1.00	0.94
P6-1-1	[AECI] Enon 161 kV bus	0.95	1.00	0.98
P6-1-1	[AECI] O'Fallon 161 kV bus	0.95	1.00	0.98
P6-1-1	[AECI] Lake Street 161 kV bus	0.95	0.99	0.98
P6-1-1	[AMMO] Pointe Prairie 161 kV bus	0.95	1.00	0.99

Table 4.2.3-1: P19969 Thermal loading drivers

Alternatives Considered

Generation redispatch or load shed is not feasible for thermal violations due to P6 contingency events if there is no applicable short-time emergency rating. No other alternatives were considered. This line reconductoring project is the best and cheapest option to address this reliability issue.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 20156 - New [AMMO] Galena 138 kV Capacitor Bank

Project Description

The project will build a new [AMMO] Galena 138 kV Capacitor Bank. This new capacitor will mitigate low voltages in and around O'Fallon Missouri for a P6-1-1 contingency event. The total estimated cost of this project is still being determined. The expected in-service date for this project is December 1, 2022.

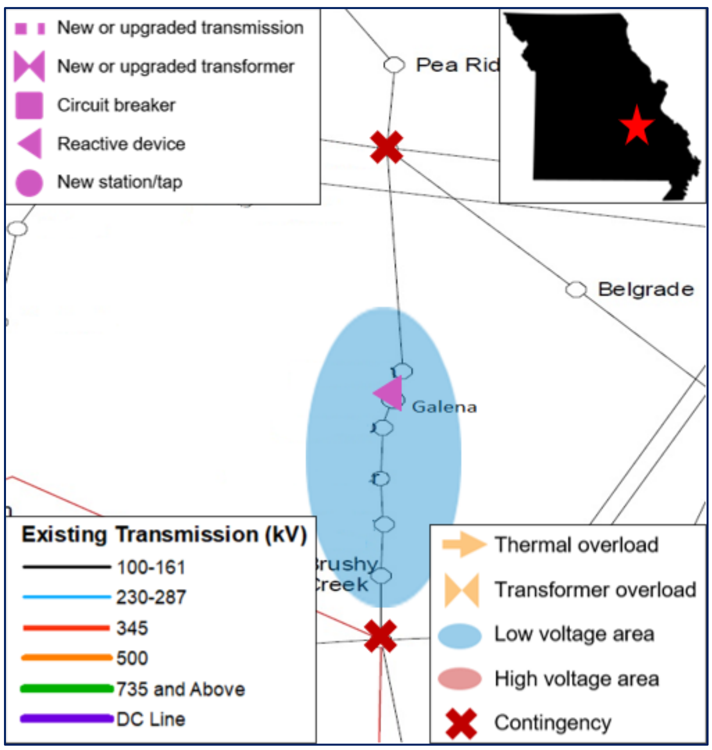

Figure 4.2.3-2: P20156 Geographic transmission map of project area

Project Need

There are a number of 138 kV buses that exceed their low voltage limit of 0.94 p.u. in year 2026 summer peak conditions for NERC defined P6-2-2 contingency events. Adding the new [AMMO] Galena 138 kV Capacitor Bank (28 Mvar) of new capacitance will help raise the low voltages back up during the 2026 summer peak season (Table 4.2.3-2).

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
n-0	[AMMO] Galena 161 kV bus	0.93	1.00	0.94
n-0	[AMMO Buick Mine 161 kV bus	0.93	1.00	0.94
n-0	[AMMO] Cominco 161 kV bus	0.93	1.00	0.94
n-0	[AMMO Buick Smelter 161 kV bus	0.93	1.00	0.94
P6-2-2	[AMMO] Galena 161 kV bus	0.93	0.90	0.94
P6-2-2	[AMMO Buick Mine 161 kV bus	0.93	0.90	0.94
P6-2-2	[AMMO] Cominco 161 kV bus	0.93	0.90	0.94
P6-2-2	[AMMO Buick Smelter 161 kV bus	0.93	0.90	0.94

Table 4.2.3-2: P20156 Thermal loading drivers

Alternatives Considered
Generation redispatch or load shed is not feasible for thermal violations due to P6 contingency events if there is no applicable short-time emergency rating. No other alternatives considered; this line reconductoring project is the best and cheapest option to address this reliability issue.

Immediate Need Reliability Project
In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
9830	Upgrade Meramec-Joachim 138 kV line 2	Reconductor to 1600 A summer emergency capability	June 1, 2022	0.49
19827	Upgrade Sioux 138 kV Substation	Replace overstressed breaker	June 1, 2022	0.7

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20193	Replace Breakers Program - MTEP21	Breaker Upgrades Requested by Maintenance	December 1, 2024	13.5
20194	Replace Relays Program - MTEP21	Electromechanical Relay Upgrades Requested by System Protection	December 1, 2024	10.4
20195	Replace Pole and Insulator Program - MTEP21	Pole and Insulator replacements requested by Maintenance	December 1, 2024	15.0

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
18063	New Mt. Pleasant 345 kV substation	At the request of Mt. Pleasant Municipal Utilities (MPMU), Ameren Missouri to construct three breaker, 345 kV substation west of Mt. Pleasant, Iowa, along Ameren Missouri's Maywood-Sub T Transmission Line. Ameren Transmission Company of Illinois (ATXI) to install	December 31, 2023	TBD

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
		345/69 kV step-down transformer and construct 69 kV networked loop to interconnect MPMU's distribution substations. MPMU to fund 69 kV facilities.		

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
21125	New Burns 345 kV Substation (J1145 Solar)	Construct 3 position ring bus on Montgomery-McCredie 345 kV line for 250 MW Show Me State Solar project J1145	October 1, 2022	10.1
19968	New Zachary-Maywood 345 kV Ring Bus for (J1025)	Zachary-Maywood 345 kV New Ring Bus for J1025 Generator Interconnection (Station name is Fabius)	June 1, 2022	9.8

4.2.4 Big Rivers Electric Corporation (BREC)

Big Rivers Electric Corporation (BREC) is a member-owned, not-for-profit, generation and transmission cooperative (G&T) with headquarters in Henderson, KY. Big Rivers provides wholesale electric power and services to three distribution cooperative members across twenty-two counties in western Kentucky.

Big Rivers Electric Corporation (BREC) proposed six projects at an estimated cost of $18.4 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the BREC area, all of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $18.4 million. Of these projects, two are Baseline Reliability Projects, two are Other projects, and two are Generator Interconnection Projects with signed Generator Interconnection Agreements. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

Project 3439 New [BREC] Ensor 161/69 kV substation

Project Description
The project will construct a new [BREC] Ensor 161 kV substation with a new [BREC] Ensor 161/69 kV transformer (56 MVA). Also, this project includes a new [BREC] Ensor 69 kV capacitor (30 Mvar). The new [BREC] Ensor 161/69 kV substation and capacitor will mitigate low voltages for the loss of a NERC defined P1-2 contingency event and mitigate thermal overloads for the loss of a NERC defined P1-3 contingency event. The total estimated cost of this project is approximately $5.8 million dollars. The expected in-service date for this project is December 31, 2024.

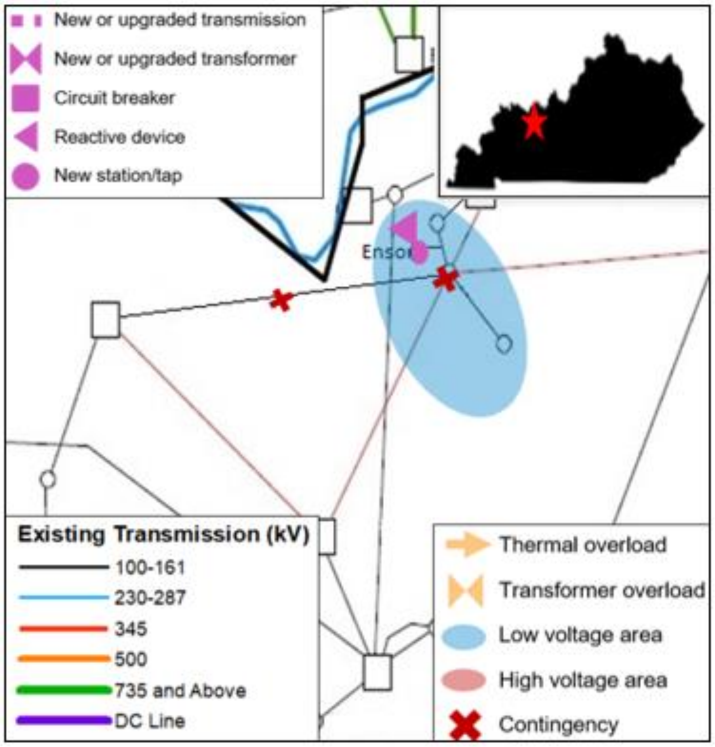

Figure 4.2.4-1: P3439 Geographic transmission map of project area

Project Need

There are four 69 kV and two 161 kV buses that exceed their low voltage limits of 0.92 p.u. in year 2026 summer peak conditions for a NERC defined category P1-2 contingency event. Adding this new [BREC] Ensor 161/69 kV substation along with new [BREC] Ensor 69 kV capacitor (30 Mvar) will help raise the low voltages back up to an acceptable operating level in 2026 summer peak season.

MISO observed the [BREC] Thurston 69 kV bus experiences low voltage issues. This bus is outside of the functional control of the MISO Transmission System; however, usage of the [BREC] Coleman SPS addresses the low voltage issues at this non-MISO facility.

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
n-0	[BREC] Local 69 kV Buses	0.92	0.93	0.93
n-0	[BREC] Newman 161 kV	0.92	0.98	0.99
n-0	[BREC] Daviess County 161 kV	0.92	0.99	1.00
P1-2	[BREC] Local 69 kV Buses	0.92	0.90	0.92
P1-2	[BREC] Newman 161 kV	0.92	0.89	0.93
P1-2	[BREC] Daviess County 161 kV	0.92	0.90	0.94

Table 4.2.4-1: P3439 Thermal loading drivers

The [BREC] Daviess County 161/69 kV transformer is overloaded in year 2026 for a NERC defined category P1-3 contingency event. The new [BREC] Ensor 161/69 kV substation along with new [BREC] Ensor 69 kV capacitor (30 Mvar) will reduce the line loadings during this NERC defined category P1-3 contingency event.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
n-0	[BREC] Daviess County 161/69 kV transformer	100	54	41
P1-3	[BREC] Daviess County 161/69 kV transformer	100	111	82

Table 4.2.4-2: P3439 Thermal loading drivers

Alternatives Considered

No other alternatives considered; this line reconductoring project is the best and cheapest option to address this reliability issue.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 21387 - New [BREC] Hancock County Capacitor Bank Addition

Project Description

The project will add a new [BREC] Hancock County 69 kV capacitor bank (35 Mvar) at the existing Hancock County 69 kV substation. This new [BREC] Hancock County 69 kV capacitor addition will mitigate base case and low voltages for the loss of a NERC defined category P1-2 contingency event. The total estimated cost of this project is approximately $500,000. The expected in-service date for this project is October 1, 2022.

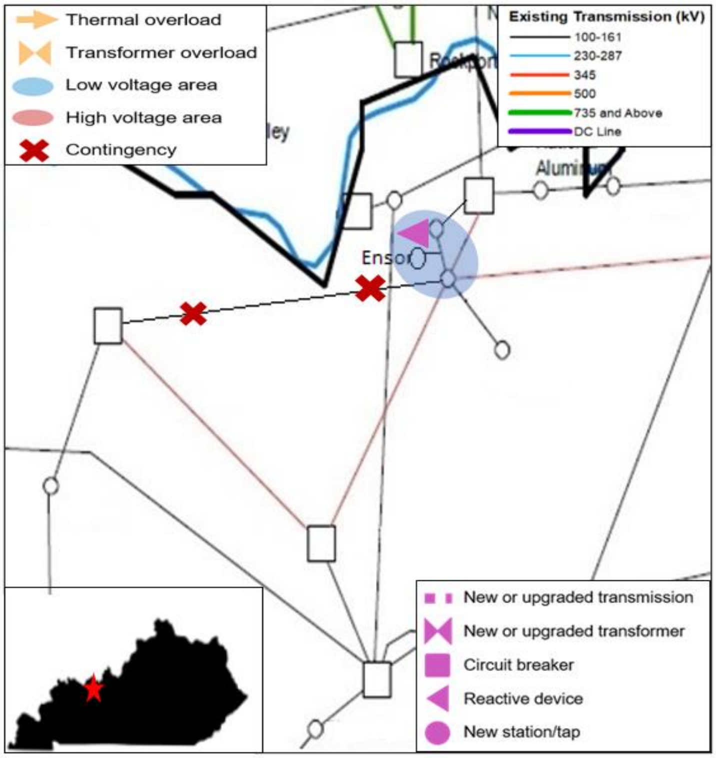

Figure 4.2.4-2: P 21387 Geographic transmission map of project area

Project Need

There are two (2) 161 kV buses (one BES and one radial non-BES) that exceed their low voltage limit of 0.92 p.u. in year 2023 summer peak conditions for NERC defined category P1-2 contingency events. new [BREC] Hancock County 69 kV capacitor bank (35 Mvar) will help raise the low voltages at the [BREC] Davis 161 kV bus and the [BREC] Newman 161 kV bus back up during the 2023 summer peak season. The [BREC] Newman 161 kV bus is a non-BES radial bus.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
n-0	[BREC] Davis 161 kV Bus	0.92	0.98	0.98
n-0	[BREC] Newman 161 kV Bus	0.92	0.99	0.99
P1-2	[BREC] Davis 161 kV Bus	0.92	0.90	0.94
P1-2	[BREC] Newman 161 kV Bus	0.92	0.89	0.93

Table 4.2.4-3: P21387 Thermal loading drivers

Alternatives Considered

No other alternatives considered; this capacitor bank addition project is the best and cheapest option to address this reliability issue.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19006	New Hartford 69 kV Tie line	69 kV normally open tie from KU Hartford to a BREC tap near Beda	November 3, 2020	0.00

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
21165	New Maxon Load Addition	Phase I - Expand existing 69 kV substation to serve 30 MW industrial load. Phase II - Customer will increase load to 60 MW and a 161 kV radial will be constructed as an overbuild of the existing 69 kV circuit feeding the load in Phase 1.	September 1, 2021	11.4

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
18605	New Hardinsburg 161 kV Substation (J753) for solar Interconnection	Hardinsburg 161 kV Substation (J753) for 100 MW solar Interconnection	July 1, 2023	0.20
18606	New Meade 161 kV Substation (J762) for solar Interconnection	Meade County 161 kV Substation modification for (J762) solar Interconnection	July 1, 2023	0.50

4.2.5 City of Columbia, MO (CWLD)

City of Columbia, MO, (CWLD) is a customer-owned utility company located in Columbia, MO. CWLD provides power to serve its nearly 50,000 residents of the City of Columbia with a peak electric load exceeding 250 MW. Its service area covers the city limits of Columbia. Its transmission system consists of 100 miles of both overhead and underground 161 kV and 69 kV network transmission system. The majority of Columbia's electricity comes from electric producers outside of Columbia.

City of Columbia, MO, (CWLD) proposed one project at an estimated cost of $26 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the CWLD area, this Other project is recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $26 million. The project's expected in-service date and estimated cost is provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19805	New UMC 69 kV Substation	Build a new UMC substation and add a new 69/13.8 kV transformer, build a 69 kV ring bus switch station, and connect two 69 kV lines to UMC ring bus. Ring bus will have four 69 kV breakers protecting two incoming 69 kV transmission lines and will be connected to two parallel output 69 kV lines feeding two 69/13.8 kV transformers through their own 69 kV breakers.	September 1, 2025	26.0

4.2.6 City of Springfield, IL (CWLP)

City of Springfield, IL, (CWLP) is the municipal electric and water utility for Springfield, IL. CWLP's generation capacity is provided by various fuel mix of generators with a total nameplate capacity of 723 MW. The CWLP electric system's transmission network consists of lines and associated substations operating at voltages of 138 kV and 69 kV. Its 138 kV portion of the transmission network currently includes approximately 63 circuit miles of overhead lines forming a complete loop around the system's service area. The 138 kV transmission lines presently serve nine of the system's substations or switching stations, plus the village of Chatham, IL.

City of Springfield, IL, (CWLP) did not submit any new projects for MTEP21. MISO has not identified any issues in CWLP area.

4.2.7 Duke Energy Corporation (DEI)

Duke Energy Corporation (DEI) is a regulated electric and gas delivery company with operations based in Cincinnati, OH. DEI provides power to serve 840,000 electric customers in Indiana across its 23,000 square miles service area. The DEI generation comes from its own coal and gas generation units totaling more than 6,600 MW. DEI also owns a good percentage of renewables and hydroelectric generation plants across Indiana.

Duke Energy Corporation (DEI) proposed 26 projects at an estimated cost of $268 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the DEI area, 23 of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $163 million. Of these projects, three projects are a Baseline Reliability Projects, eighteen are Other projects and two projects are Generator Interconnection projects with signed Generator Interconnection Agreements. Most of the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

Project 20230 - [DEI] Purdue NW Tap—[DEI] Purdue—[DEI] Cincinnati St. 138 kV line

Project Description

The project will Rebuild [DEI] Purdue NW Tap—[DEI] Purdue 138 kV line sections of the [DEI] Purdue NW Tap—[DEI] Cincinnati St.138 kV line (13820). The line rebuild will mitigate an overload on the same line for NERC defined category P2-4 contingency events. The total estimated cost of this project is approximately $9.5 million dollars. The expected in-service date for this project is December 31, 2023.

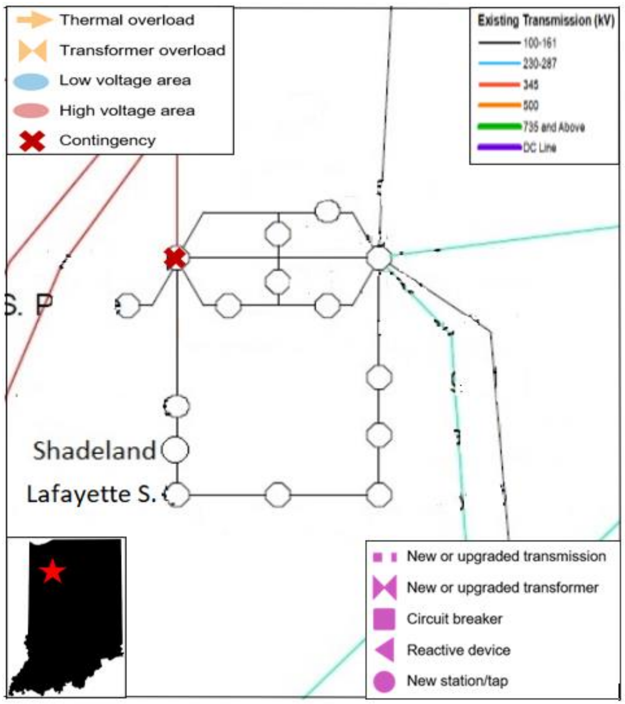

Figure 4.2.7-1: P20230 Geographic transmission map of project area

Project Need

The [DEI] Purdue NW Tap—[DEI] Purdue 138 kV line becomes overloaded to 111% percent in year 2023 summer peak for a NERC defined category P2-4 contingency event. Rebuilding this line will relieve the overload by increasing the summer emergency rating from 178 MVA to 243 MVA.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
n-0	[DEI] Purdue NW Jct Tap 2 - [DEI] West Lafayette Airport	178	57	57
n-0	[DEI] Purdue - [DEI] West Lafayette Airport	178	49	49
P2-4	[DEI] Purdue NW Jct Tap 2- [DEI] West Lafayette Airport	243	111	73
P2-4	[DEI] Purdue - [DEI] West Lafayette Airport	243	103	67

Table 4.2.7-1: P20230 Thermal loading drivers

Alternatives Considered

No other alternatives considered; this line reconductoring project is the best and cheapest option to address this reliability issue.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 20247 - Rebuild [DEI] Lafayette South—[DEI] Shadeland 138 kV line

Project Description

The project will rebuild [DEI] Lafayette South—[DEI] Shadeland 138 kV line. This line rebuild will mitigate an overload on the same line for both NERC defined P6-1-1 and a NERC defined P7 contingency events; the NERC defined category P6-1-1 event is equivalent to the NERC defined category P7 event. The total estimated cost of this project is approximately $6 million dollars. The expected in-service date for this project is June 1, 2023.

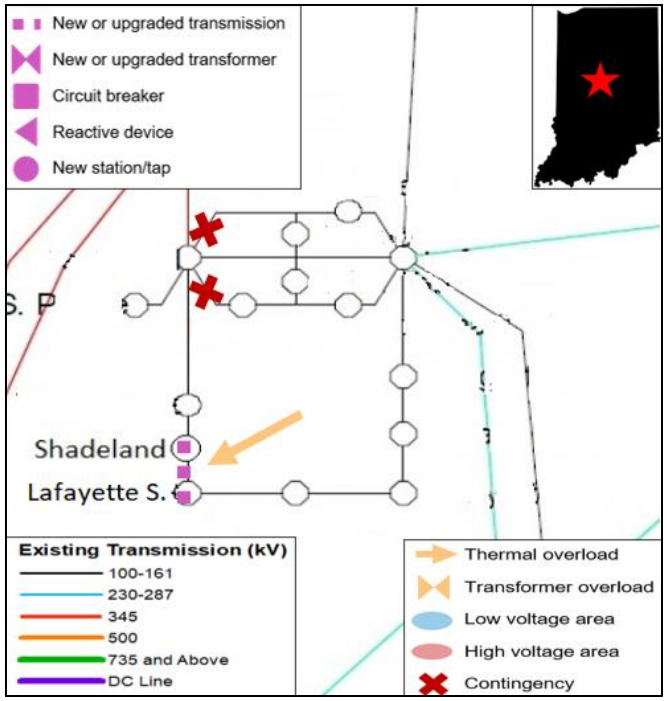

Figure 4.2.7-2: P20247 Geographic transmission map of project area

Project Need

The [DEI] Lafayette South—[DEI] Shadeland 138 kV line becomes loaded up 99% in year 2026 summer peak for both NERC defined category P6-1-1 and P7 contingency events. Rebuilding this line will increase the summer emergency rating from 178 MVA to 291 MVA.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
n-0	[DEI] Lafayette South—[DEI] Shadeland 138 kV line	178	41	26
P6-1-1	[DEI] Lafayette South—[DEI] Shadeland 138 kV line	291	99	61
P7	[DEI] Lafayette South—[DEI] Shadeland 138 kV line	291	99	61

Table 4.2.7-2: P20247 Thermal loading drivers

Alternatives Considered

Generation redispatch or load shed is not feasible for thermal violations due to P6 contingency events if there is no applicable short-time emergency rating. No other alternatives considered; this line reconductoring project is the best and cheapest option to address this reliability issue.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 20248 - New [DEI] Dresser 345 kV Redundant Circuit Breaker

Project Description

New [DEI] Dresser 345 kV Redundant circuit breaker addition between Breaker-1 and Breaker-2 with fully redundant protection scheme per future TPL-001-5 P5 contingency definition. The Dresser 345/138 kV transformer is overloaded in year 2026 summer peak for a NERC defined category P4 contingency event. This new redundant circuit breaker will eliminate the P4 contingency event; thus, the overload on Dresser 345/138 kV transformer for the P4 contingency event will be mitigated. The total estimated cost of this project is approximately $8 million dollars. The expected in-service date is June 1, 2023.

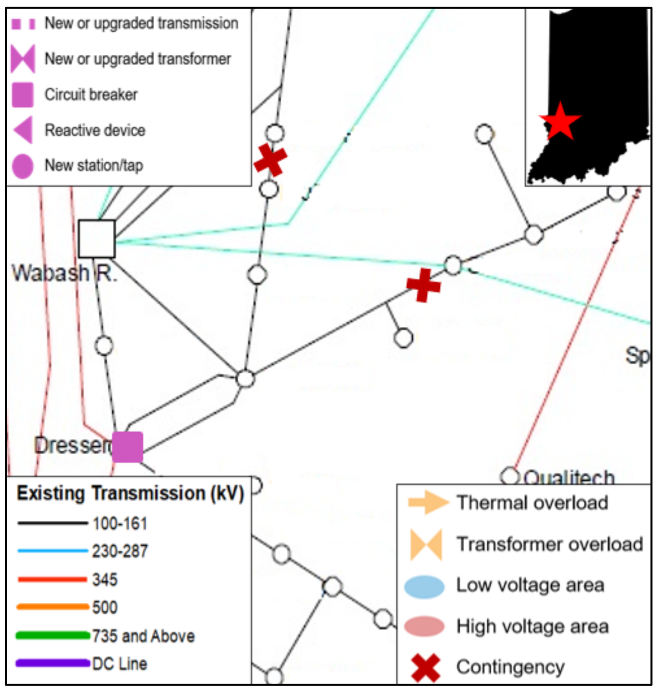

Figure 4.2.7-3: P20248 Geographic transmission map of project area

Project Need

The [DEI] Dresser 345/138 kV transformer is overloaded in year 2026 summer peak 102% for a NERC defined category P4 contingency event. Adding the new [DEI] Dresser 345 kV redundant circuit breaker will eliminate the P4 contingency event; thus, will mitigate this thermal overload by eliminating the NERC defined P4 contingency event.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
n-0	[DEI] Dresser 345/138 kV transformer	581	44	44
P4-3	[DEI] Dresser 345/138 kV transformer	581	102	61

Table 4.2.7-3: P20248 Thermal loading drivers

Alternatives Considered

No other alternatives considered; this line reconductoring project is the best and cheapest option to address this reliability issue.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20174	New Sullivan 69 kV capacitor	Sullivan 69kV - 19.8 Mvar capacitor	June 1, 2023	.5
20197	Reconfigure Wabash 138 kV substation	Upgrade 69 kV station equipment and convert 138 kV straight bus to ring bus	December 31, 2022	12.57
20198	Reconfigure Hortonville 345 kV substation	Replace line relays: 34504, 34527, 6917, 69142, 69155. Install equipment to convert 345 kV bus to ring bus config.	December 31, 2022	1.87
20199	Reconfigure Tipton West 230 kV substation	Reconfigure 230 kV bus to ring configuration	December 31, 2022	1.86
20200	Replace Noblesville Generating Station 138/69 kV equipment	Replace 138/69/2.4 kV Bk9; misc. upgrades to 138kV relays and wave traps, etc.	December 31, 2022	4.33
20205	Reconfigure Greenwood Clark Township 69 kV substation	Expand ring bus and add 69165 line terminal at Clark Township; build short line to HE Willard Green	December 31, 2022	4.06
20206	Rebuild Huntington 138 kV to Meridian Rd junction 69 kV	6923 Part 2 rebuild with 954acsr; replace switches at Erie Stone junction	December 31, 2022	4.0
20207	Rebuild Loogootee junction to Loogootee 69kV line	Rebuild transmission line 69194 from Loogootee junction (pole No. 816-2001 through No. 816-2152). Approx. 10.2 miles. Approx. 152 poles. Replace Loogootee junction No. 1, No. 2, and No. 3 switches. Replace H.E. Bramble No. 1 and No. 2 switches.	December 31, 2022	13.76
20208	Rebuild Morgantown to Bean Blossom 69 kV line	Rebuild transmission line 6949 from Morgantown substation (pole No.#825-3122) to Bean Blossom substation (pole No.825-3270) using light duty steel poles, 477 ACSR	December 31, 2022	13.35
20225	Rebuild McKay Rd Junction. to H.E. Lewis Creek Junction. 69 kV line	Rebuild transmission line 6975 from McKay Rd Junction (pole No. 807-3096) to H.E. Lewis Creek Junction (pole No. 807-3168) using light duty steel poles, 477 ACSR conductor and OPGW. - 5.9 miles ; Replace two switches at McKay Rd Junction 2000A	December 31, 2022	7.24
20226	Reconfigure Deedsville 345 kV substation	Reconfigure 345kV to ring bus. Replace various 345kV and 69kV transmission equipment including relays and OCBs	December 31, 2022	7.71

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20227	Reconfigure Middlefork 69 kV substation	Replace misc. 69kV OCBs and relays; replace 6910-01 line switch with 2000A; establish 69 kV ring bus	December 31, 2022	8.71
20228	Reconfigure Prescott 345 kV substation	Replace misc. 69 kV OCBs and relays; establish 345 kV ring bus	December 31, 2022	7.54
20250	DEI Bolivar to NIPS Templeton 69kV line	WVPA to construct new N.O. reserve 69kV line to existing NIPS Templeton sub from DEI Bolivar	April 1, 2022	7.0

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20181	Replace Five Points 138 kV Circuit Breakers	Replace (5) 138 kV oil circuit breakers with SF6 gas circuit breakers - 13803, 13804, 13809, 13813, and 138 kV Bus tie breaker; 13803,04,13 were identified in 2020 as over-duty in the DEI short circuit analysis	December 31, 2022	5.0
20190	Rebuild Monroe City Junction - Petersburg Junction 69 kV line	6960 Pt 3 Rebuild Monroe City Junction Petersburg Junction w/ 477 ACSR - 6.25 miles. Reconductor 2.4 miles of circuit 13825 (structures No. 844-1162 to No. 844-1190/No. 844-3100) and 1.2 miles of circuit 13838 where they are double-circuited with 6960. Replace Monroe City Junction No. 1 and No. 2 switches and rename to 69-1 and 69-2. Rebuild the line at the Petersburg Junction (poles No. 821-1322 through 821-1327).	December 31, 2022	10.01
20645	New Greenfield Hastings Park 138 kV ring bus	Greenfield Hastings Park - establish a 3-breaker, 138 kV, ring bus.	December 31, 2021	4.24

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20196	New Rosston 69/12 kV substation	New sub to be fed from the 69182 circuit and will replace existing Whitestown 69/12 kV sub in the 6983 circuit.	June 1, 2022	1.34

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20245	J805 Gwynneville Solar	J805 Gwynneville Solar	February 15, 2022	7.54
20246	J829 Fairbanks Solar	J829 Fairbanks Solar	August 19, 2022	15.0

4.2.8 GridLiance Heartland LLC (GLH)

GridLiance Heartland LLC (GLH) is an electric utility that owns and operates transmission assets in Illinois and Kentucky. The assets include 50 miles of 161 kV transmission lines and a 161 kV switching station. The transmission assets are interconnected to the Joppa Generating Station in Illinois.

GridLiance Heartland LLC (GLH) proposed four projects at an estimated cost of $49 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the GLH area, all four of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $49 million. Of these projects, zero projects are Baseline Reliability Projects, four are Other projects, and zero projects are Generator Interconnection Projects with a signed Generator Interconnection Agreement. The projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19746	Rebuild Joppa-Shawnee 161 kV Ckt 2 (EPR)	Rebuild the GridLiance Heartland portion of Joppa-Shawnee 161 kV Ckt 2	March 1, 2022	11
20001	Rebuild Joppa-Shawnee 161 kV Ckt 3	Rebuild the GridLiance Heartland portion of Joppa-Shawnee 161 kV Ckt 3	June 1, 2023	11.7
20004	Rebuild Joppa-Shawnee 161 kV Ckt 4	Rebuild the GridLiance Heartland portion of Joppa-Shawnee 161 kV Ckt 4	June 1, 2023	11.7
20005	Rebuild Joppa-Shawnee 161 kV Ckt 1	Rebuild the GridLiance Heartland portion of Joppa-Shawnee 161 kV Ckt 1	June 1, 2023	14.7

4.2.9 Henderson Municipal Power & Light (HMPL)

Henderson Municipal Power & Light (HMPL) is a municipally owned generation, transmission, and distribution electric utility providing services to the City of Henderson, KY. Henderson owns a transmission network consisting of 56 miles of 161 kV and 69 kV facilities. HMPL is regulated by the City of Henderson, KY Utility Commission.

Henderson Municipal Power & Light did not submit any new projects for MTEP21. MISO has not identified any issues in HMPL area.

4.2.10 Hoosier Energy REC, Inc. (HE)

Hoosier Energy REC Inc. (HE) is a generation and transmission electric cooperative providing wholesale power and services to 18 electric cooperative members in central and southern Indiana and southeastern Illinois. HE's generation includes coal, natural gas and renewable energy resources and delivers power through a nearly 1,700-mile transmission network consisting of 345 kV, 161 kV, 138 kV, 69 kV, and 34.5 kV voltage levels.

Hoosier Energy REC, Inc. did not submit any new projects for MTEP21. MISO has not identified any issues in HE area.

4.2.11 Indianapolis Power & Light Company (IPL)

Indianapolis Power & Light Company (IPL) is an investor-owned utility. IPL provides retail electric service to approximately 500,000 customers in Indianapolis, IN, and the surrounding communities. The IPL transmission system consists of approximately 458 circuit miles of lines at 345 kV, 408 circuit miles of 138 kV transmission and associated substations. IPL owns and operates four generating stations with a total generating capacity of 3,555 MW.

Indianapolis Power & Light Company (IPL) proposed two projects at an estimated cost of $16.5 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the IPL area, these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $16.5 million. Of these projects, zero are Baseline Reliability Projects, two are Other projects, and there were no Generator Interconnection projects with signed Generator Interconnection Agreements. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20134	New Stout 345 kV Breaker	Add one 345 kV breaker to form a ring bus at the Stout South substation.	December 31, 2022	3.15
20137	New Guion 345/138 kV transformer No. 3	One (1) new third 500 MVA auto transformer is scheduled to be installed at Guion substation. This project is needed to increase import capability and plan for the possible unavailability of long lead time equipment. The project includes three (3) new 345 kV breakers, two (2) replacement 345 kV breakers, two (2) 138 kV breakers, and terminal equipment including disconnect switches, relays, etc.	December 31, 2023	13.38

4.2.12 Northern Indiana Public Service Company (NIPSCO)

Northern Indiana Public Service Company (NIPSCO) is a vertically-integrated gas and electric company providing electric generation, transmission, and distribution services as well as natural gas distribution service across the northern third of Indiana. NIPSCO is headquartered in Merrillville, IN and is a subsidiary of NiSource Inc. (NiSource). The NIPSCO transmission system consists of 21 circuit miles of 765 kV lines, 453 circuit miles of 345 kV lines, and 810 circuit miles of 138 kV lines.

Northern Indiana Public Service Company (NIPSCO) proposed one project at an estimated cost of $16.6 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the NIPSCO area, this one project has been recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $16.6 million. Of these projects, zero are Baseline Reliability Projects, one is Other project, and there were no Generator Interconnection projects with signed Generator Interconnection Agreements. The project's expected in-service date and estimated cost is provided as of September 17, 2021.

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20605	Rebuild Michigan City (Shoreline) 138 kV Substation	Rebuild Michigan City 138 kV substation	December 31, 2022	16.6

4.2.13 Pioneer Transmission, LLC

Pioneer is a joint venture between Duke Energy and American Electric Power formed to build, own and operate the Reynolds to Greentown 765 kV transmission line.

Pioneer Transmission, LLC did not submit any new projects for MTEP21. MISO has not identified any issues in the Pioneer Transmission area.

4.2.14 Prairie Power, Inc. (PPI)

Prairie Power, Inc. (PPI) is a member-owned, not-for-profit electric generation and transmission cooperative. PPI produces and supplies wholesale electricity to ten electric distribution cooperatives in central Illinois. PPI's distribution cooperatives provide retail electric service to approximately 78,000 members within its local service territories. PPI owns and operates approximately 590 miles of transmission lines at 138 kV, 69 kV and 34.5 kV voltage levels. PPI generates 141 MW of oil and gas-fired peaking units and 79 distribution and transmission substations to serve its members.

PPI proposed 16 projects at an estimated cost of $98 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the PPI area, these 16 projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $98 million. Of these projects, zero are Baseline Reliability Projects, 15 are Other projects, and there is one Generator Interconnection Project with signed a Generator Interconnection Agreement. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19847	New Golden 138/69 kV Substation	New 138/69 kV substation near La Prairie, IL	December 31, 2024	7.4
19848	New Camden—Rushville 69 kV line	New 12.0-mile Camden to Rushville 69 kV line in Adams Electric Cooperative	December 31, 2024	7.6
19849	New Rushville—Sugar Grove 69 kV line	New 13.2-mile Rushville to Sugar Grove 69 kV line in Adams Electric Cooperative	December 31, 2024	8.4
19850	New Sugar Grove—Mt. Sterling 69 kV line	New 8.7-mile Sugar Grove to Mt. Sterling 69 kV line in Adams Electric Cooperative	December 31, 2024	5.5
19851	New Mt. Sterling—Kellerville 69 kV line	New 17.7-mile Mt. Sterling to Kellerville 69 kV line in Adams Electric Cooperative	December 31, 2024	11.3
19932	New Disco to Lomax 69 kV Line	New 15.0-mile Disco to Lomax 69 kV line in Western Illinois Electric Cooperative	December 31, 2024	9.8
19933	New Disco—Powellton 69 kV Line	New 12.5-mile Disco to Powellton 69 kV line in Western Illinois Electric Cooperative	December 31, 2024	8.0
19934	New Elvaston 69 kV Breakers	Add breakers on the Elvaston to Powellton line and the Elvaston to Sutter line	December 31, 2024	0.35
19935	New Sutter—Ursa 69 kV Line	New 20.8-mile Sutter to Ursa 69 kV line between Western Illinois Electric Cooperative and Adams Electric Cooperative	December 5, 2025	13.3
19937	New Bluffs 69 kV Breaker substation	New Bluffs 69 kV Breaker Station located near Bluffs, IL in Illinois Electric Cooperative	December 31, 2022	2.8
19940	Replace Grand Island 138/69 kV Transformer	Replace 56 MVA Delta-Wye 138/69 kV transformer with 84 MVA Wye-Wye 138/69 kV transformer	December 31, 2024	1.5
19949	New ISHI Shelbyville 69 kV Loop	New 6.4-mile ISHI Distribution to Johnston to Crest to Airport 69 kV line in Shelby Electric Cooperative	December 31, 2025	4.0

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19938	Rebuild Grand Island—Poplar City 69 kV Line	Rebuild 1.2-mile Grand Island—Poplar City 69 kV line in Menard Electric Cooperative	December 31, 2021	0.6
19939	Rebuild Grand Island—Topeka 69 kV line	Rebuild 5.3-mile Grand Island—Topeka 69 kV line in Menard Electric Cooperative	December 31, 2021	2.4
19951	Rebuild Pisgah Tap—Berlin 69 kV line	Rebuild 14.6-mile Pisgah Tap—Berlin 69 kV line between Illinois Electric Cooperative and Menard Electric Cooperative	December 31, 2023	7.8

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20607	New Illinois Winds Pittsfield 69 kV Generator Interconnection	New Illinois Wind Panther Creek 44.5 MW Wind Farm connecting to the PPI Pittsfield 69 kV bus.	January 31, 2023	3.0

4.2.15 Republic Transmission, LLC (RTx)

Republic Transmission, LLC (Republic Transmission) is an electric transmission utility company, with the mission to ensure reliable and cost-effective electric transmission in the Central region of the MISO transmission system. Republic Transmission is a subsidiary of LS Power, a power generation, transmission, and investment group.

Republic Transmission owns and operates a 345 kV transmission line connecting the Vectren Duff substation to the Big Rivers 345 kV high voltage electrical system ultimately terminating at the Big Rivers Coleman Substation.

Republic Transmission did not submit any new projects for MTEP21. MISO has not identified any issues in the area.

4.2.16 Southern Indiana Gas & Electric Company (SIGE)

Vectren Energy Delivery (doing business as Southern Indiana Gas and Electric (SIGE)) is a subsidiary of CenterPoint Energy, headquartered in Houston, Texas. Vectren provides electricity to 144,000 customers in southwestern Indiana. Vectren owns and operates 63.8 miles of 345 kV transmission lines, 375.4 miles of 138 kV transmission lines, 562.9 miles of 69 kV transmission lines. Vectren (SIGE) serves a peak load of approximately 1.1 GW and owns and operates 1 GW of coal generation, 150 MW of natural gas generation, 4 MW solar generation, and 1 MW of battery storage.

Southern Indiana Gas & Electric Company (SIGE) did not submit any new projects for MTEP21. MISO has not identified any issues in this area.

4.2.17 Southern Illinois Power Cooperative (SIPC)

Southern Illinois Power Cooperative (SIPC) is a generation and transmission cooperative providing wholesale electric power to seven-member distribution cooperatives and two wholesale customers in southern Illinois. Its member cooperatives provide electricity to more than 100,000 end-use customers. SIPC generates around 600 MW from coal fired and natural-gas fired generation plants and owns more than 900 miles of 161 kV, 138 kV and 69 kV transmission lines.

Southern Illinois Power Cooperative did not submit any new projects for MTEP21. MISO has not identified any issues in the SIPC area.

4.2.18 Wabash Valley Power Association, Inc. (WVPA)

Wabash Valley Power Association, Inc. (WVPA) is a generation and transmission cooperative providing wholesale electric power to 23-member distribution cooperatives in Illinois, Indiana, and Missouri. Its member cooperatives provide electricity to more than 321,000 end-use customers. WVPA generates 33% of its energy from coal and 11% from natural gas fired generation plants; WVPA owns 744 miles of transmission lines ranging from 345 kV to 34.5 kV along with 94 substations.

WVPA proposed eight projects at an estimated cost of $19 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the WVPA area, these eight Other-type projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $19 million. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20065	Replace New Bourbon 69 kV Breakers	Replace 69 kV breakers B24, B25, B26, B39, & B40 at New Bourbon Sub. Also purchase a spare breakers Install GPS clocks and wire to the microprocessor relays.	March 30, 2021	1.2
20069	New Salem Bulk DFR Installation	Install a new SEL data concentrator, Install GPS clocks and wire the GPS clocks to the microprocessor relays, Remove the relay 67 directional overcurrent tripping.	December 31, 2020	0.1
20070	Upgrade Trail of Tears 69 kV Breakers	Replace the four oil filled 69 kV breakers at Trail of Tears to fix identified constraints for CT availability for the new bus differentials	December 31, 2021	2.8
20072	Rebuild Seminary to Park 69 kV Line	Upgrade 3 mi. 3/0 ACSR to 477 ACSR of 69 kV Line T17 from Seminary B43 to Park tap switch 117. Add 48 fiber OPGW to entire 3 mile line.	June 1, 2021	2.0
20079	Rebuild Butler 69/12 kV Substation	Rebuild Butler sub with new 5/6.25 MVA 3ph transformer, relocate regulators, replace all switches	December 31, 2021	1.8

20112	Rebuild Fair Oaks 138/69 kV Substation	Install new 138/69/12 switchable 22.4 MVA transformer. Install a new 69 kV line terminal with auto throwover scheme equipment for a new loop line to Colfax. Expand the fence and install new 69 kV rigid bus.	April 30, 2021	4.7
20113	Update Colfax South 69 kV Substation	Install a new 69 kV line terminal with an auto sectionalizing scheme equipment for a new loop line to Fair Oaks.	December 31, 2021	1.5
20114	New Fair Oaks to Colfax South 69 kV line	New 138 kV (Operated at 69 kV) 477 ACSR conductor looping Colfax to Fair Oaks for reliability in Jasper and Newton Counties.	December 31, 2021	5.3

4.3 Project Justifications – East Region

East Region Overview

The MISO East Planning Region consists of six Transmission-Owning members within Michigan. These Transmission Owners are:

- ITC Transmission (ITCT)
- Michigan Electric Transmission Co. (METC)
- Wolverine Power Supply Cooperative Inc. (WPSC)
- Michigan Public Power Agency (MPPA)
- Michigan South Central Power Agency (MSCPA)
- Lansing Board of Water & Light (LBWL)

The region contains 9,830 circuit miles of transmission lines ranging from 120 kV to 345 kV. It also contains 1216 circuit miles of 69 kV sub-transmission system. The MISO East Region is interconnected with non-MISO systems: Hydro One Networks Inc. and American Electric Power to the east.

The 2023 Summer Peak planning model indicates the region contains more than 30.3 GW of generation. Installed generation capacity in the region consists mostly of coal, gas, and wind. Figure 4.3-1 shows the major load centers and generation pockets within the East Region. The load centers are typically found around larger cities in the region, i.e., Detroit, Lansing, and Grand Rapids. According to the 2023 Summer Peak planning model, the region's load exceeds 20.56 GW.

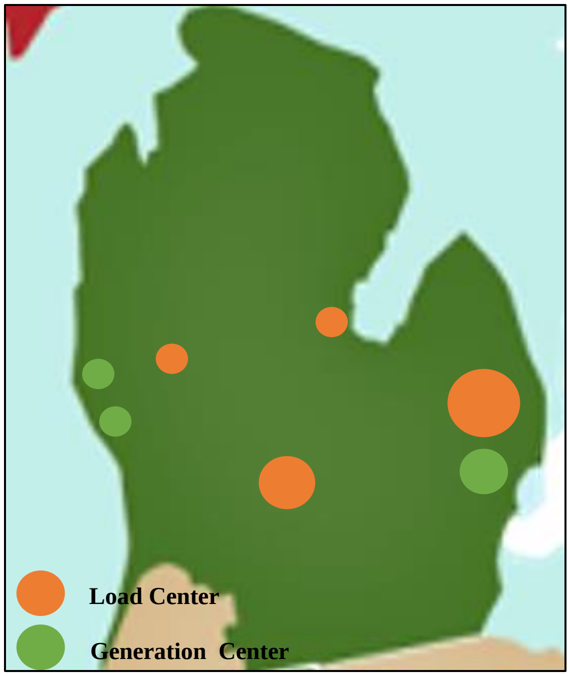

Figure 4.3-1: Generation and load centers in the East planning region

For MTEP21, MISO Transmission Planning is recommending 65 projects from the East region for inclusion in Appendix A at an estimated cost of $517 million. Of these, 8 are Baseline Reliability Projects and 17 are Generator Interconnection Projects. The remaining 40 projects are classified as Other projects because they do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects.

Of the 65 projects, that are being recommended to be included in MTEP21, 11 have an estimated cost of less than $1 million, 27 have an estimated cost between $1 million and $5 million, and the remaining 27 projects are estimated to cost greater than $5 million (shown in Figure 4.3-2).

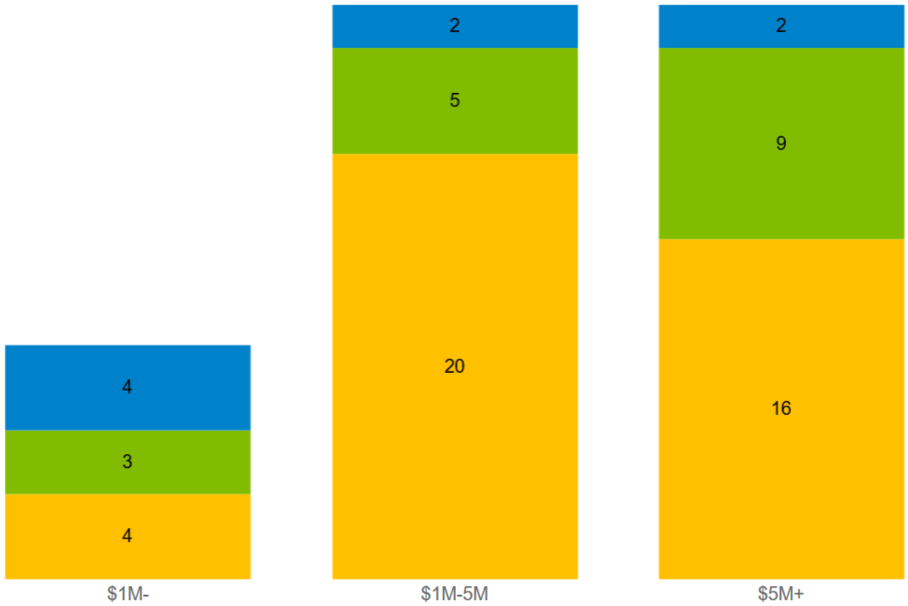

Figure 4.3-2: Project cost category by project type for MTEP21 East projects (as of 9-17-2021)

The projects in the MISO East planning region are expected to go into service in the next five years as shown in Figure 4.3-3. There are 9 GIP projects that are being approved in MTEP21 with in-service dates in 2021.

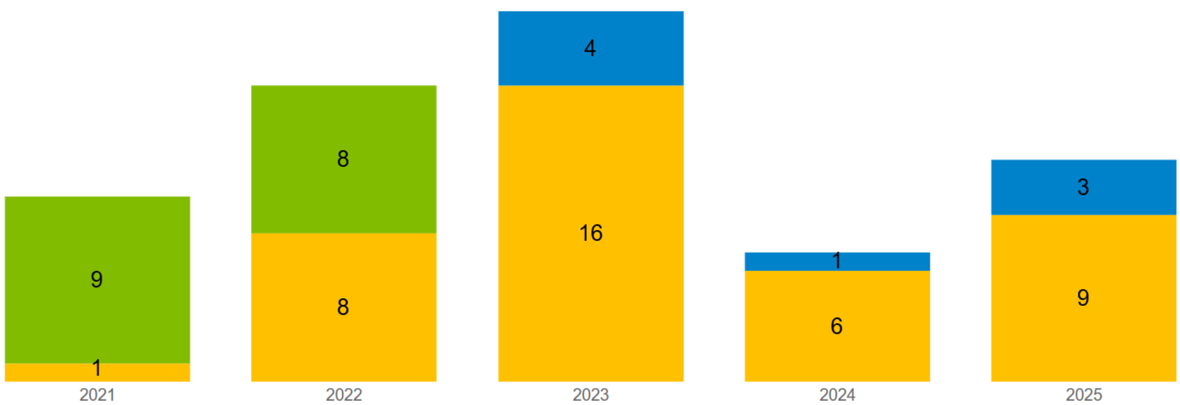

Figure 4.3-3:Project in-service date by project type for MTEP21 East projects (as of 9-17-2021)

In accordance with Attachment FF of the MISO tariff, if a Transmission Owner determines system conditions warrant the urgent development of system enhancements, MISO will perform an expedited review of the impacts of the project. MISO shall use a streamlined approval process for reviewing and approving such projects proposed by the Transmission Owner(s) so that decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO, unless a longer review period is mutually agreed upon. During the MTEP21 cycle, MISO received the following projects through the Expedited Project Review (EPR) process:

1. Project ID 20711, Stamping Plant 138kV Station Decommission
2. Project ID 21105, Apollo Interconnection
3. Project ID 21170, Lenox-Stephens-Henry Ford MH-Shrine

Also, in accordance with Attachment FF Section VIII.A.3, the following project was identified as an Immediate Need Reliability Project and is excluded from the competitive developer selection process:

- None

The ten highest cost MISO East projects represent $251 million (48%) of the $517 million total recommended projects for the region in MTEP21. The locations of these projects are shown in Figure 4.3-4 with the investment spread across the East Planning region. Projects that are blanket expenditures (such as relays, physical security, etc.) are excluded from this list.

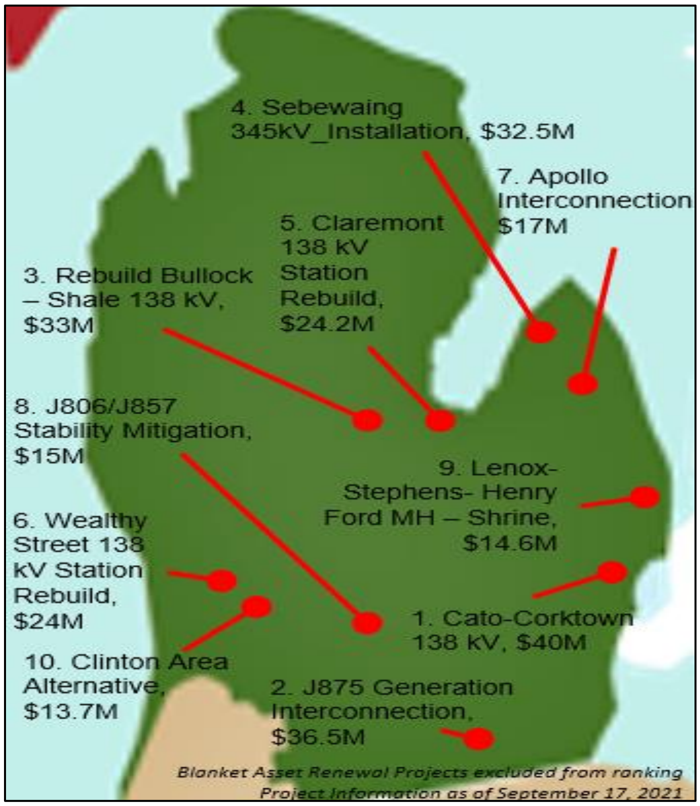

Figure 4.3-4: East region top ten projects, by cost (data as of 9-17-2021)

4.3.1 ITC Transmission (ITCT)

ITCT proposed 36 projects at an estimated cost of $270 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of ITCT area, 25 of these projects are recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $232 million. Of these projects, 1 is a Baseline Reliability Project, 18 are Other projects and 6 are Generator Interconnection projects with signed Generator Interconnection Agreements. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

ITCT proposed 12 Baseline Reliability Projects targeting Appendix A in MTEP21. MISO's independent reliability analysis recommends one Baseline Reliability Project to be included in MTEP21 Appendix A.

MISO identified open issues in the ITCT area as listed in Appendix D3 (CEII) and will be coordinating with ITCT to develop a solution in MTEP22.

Project 21206 – Coventry to Hager 120 kV Projects

Project Description

The project will rebuild approximately 1 mile from Duvall tap to Hager, disconnect and reconnect conductors, remediate sag from Coventry to the Nitro cut-in to a target rating of 269 MVA SE, and install breakers at Duvall, Coventry and Hager 120 kV stations. The project's estimated cost is approximately $11 million dollars, and the expected in-service date is December 31, 2023.

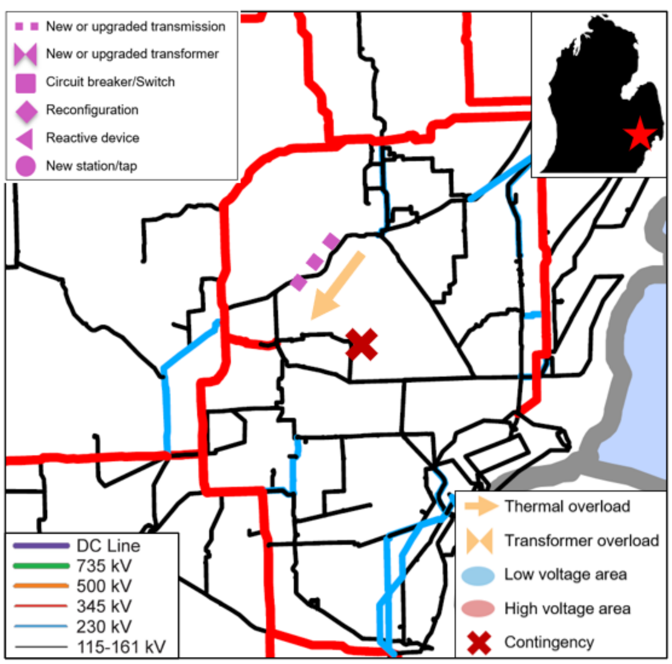

Figure 4.3.2-1: P21206 Geographic transmission map of project area

Project Need

The Sunset – Hager 120 kV line is projected to overload for P6 contingencies.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Sunset – Hager 120 kV Ckt 1	291	112	74

Table 4.3.2-1: P21206 Thermal loading drivers

Alternatives Considered

Project #21206 is a proposed alternative to MTEP20 Appendix A Project # 15959 (Hager – Sunset 120 kV Rebuild).

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20167	Cato – Corktown 120 kV	Build approximately 0.85 miles of 120kV 1600mm² underground cable from Cato to Corktown and expand the Cato and Corktown stations to accommodate a third line termination.	December 31, 2024	40.0
19992	ITCT Pole Top Switch Additions/Replacement Program 2022	Install, or replace as appropriate, pole-top switches at tap points of circuits to provide the operational flexibility to sectionalize parts of the line to isolate faults or perform maintenance work without shut down of entire circuit.	December 31, 2022	1.0
20107	Atlanta-Karn-Thetford Split & Station Reconfiguration (ITCT)	Install a 120 kV, 3000 Amp, 40 kA section breaker and expand 138 kV into a ring bus configuration. Add two 138 kV breakers to configure the 138 kV into a ring bus. Add 0.75 miles of 1431 ACSR to complete the Atlanta – Thetford circuit. New equipment should be rated for 3000 Amps or higher.	December 31, 2024	5.4
19185	Red Run & Bismarck Line Breakers	Install two 230 kV Line breakers, one at Red Run position “HW” and one at Bismarck position “HC" on the Red Run – Bismarck line.	December 31, 2023	2.7
21626	Red Run & Bismarck Line Breakers	Install a new control building large enough to contain all the ITCT relaying and controls. The new control building will include a dedicated ITCT AC and DC systems large enough to power all ITCT’s assets at the substation.	December 31, 2022	1.6

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
18237	2023 ITCT Asset Replacement Program	Replace aging and outdated equipment at a pace that will ensure each type of equipment is replaced near its projected end of life.	December 31, 2023	34.2

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20132	Pontiac 303 Transformer Replacement	Replace the Pontiac #303 345/120 kV transformer with a 750 MVA Summer Emergency rated transformer.	December 31, 2025	4.8
20133	Hines 201 Transformer Replacement	Replace the Hines #201 230/120 kV transformer. The anticipated replacement is the ITCT-standard 230/120kV 560 MVA transformer.	December 31, 2025	4.8
20138	Milan 303 Transformer Replacement	Replace the Milan #303 345/120 kV transformer with a 750 MVA (3608 Amps) Summer Emergency rated transformer.	December 31, 2023	4.8
20140	Pontiac 301 Transformer Replacement	Replace the Pontiac #301 345/120 kV transformer. The anticipated replacement is the ITCT-standard 345/120 kV 560 MVA transformer.	December 31, 2023	4.8
21047	Waterman 120kV Reactor HX Replacement	Replace Waterman 120 kV series reactor HX with a new series reactor.	December 31, 2023	0.9

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20036	Sebewaing 345 kV Installation	Construct New Sebewaing station as a 345 – 120 kV station with three 345 kV 40 kA breakers and one 120 kV 40 kA breaker. Install a 345/120 kV transformer. Install 4.5 miles of 954 ACSR in new right of way to connect Sebewaing to New ITC 120 kV Station at position HQ. Extend the Bauer - Grassmere 345 kV line by adding 0.2 miles of 954 ACSR to loop in New ITC Station 345 kV for transmission service.	June 1, 2024	32.5
20044	ITCT Customer Interconnections - Year 2024	Customer interconnection requests and retirements less than $1 million with in service date in year 2024.	December 31, 2024	2.0
21105	Apollo Interconnection	Construct a new in-and-out station consisting of a single tie breaker and three straight buses with room for future tie breaker. Install one 120 kV tie breaker, two 120 kV line breakers, bus work, and associated disconnects. Connect two customer owned transformers to the new station.	May 28, 2023	17.1
21170	Lenox-Stephens- Henry Ford MH - Shrine	Henry Ford Macomb Hospital is a DTE interconnection request. ITCT will construct Shrine as a straight bus station with two-line breakers and a section breaker. ITCT will extend the Lenox-Stephens 120 kV line by adding about 1 mile of 954 DCT to loop in the new station. Fiber will be run from Bismarck 120 kV station requiring fiber patches at Bismarck, Jewell, and Sigma 120 kV station. Interconnection will require relaying upgrades at Lenox and Stephens.	June 1, 2023	14.6

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20325	Custer-Monroe Line Relocation	Relocate approximately 1.8 miles of 120 kV circuit at the request of the city of Monroe.	December 31, 2022	8.8
20845	Apache-Seneca 120kV Relocation	Relocate 9 structures of the Apache-Seneca 120 kV circuit along Rochester Road in the city of Troy.	December 31, 2023	2.0
21026	Montcalm Equipment Removal and Bypass	Permanently bypass the Montcalm station and remove all ITCT assets.	December 31, 2022	1.6

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19266	J799 Interconnection	Construct the J799 Interconnection 120 kV station as a three-breaker ring bus station. The Milan - Pioneer 120 kV line will be extended to loop in the J799 Interconnection station for transmission service. Changes will require relaying upgrades at Milan 120 kV.	March 31, 2022	7.5
19508	Bauer - Pontiac 345kV Sag Remediation & Station Equipment Upgrade (J701, J794, J796, J832)	Sag remediation requires replacing sixteen (16) 345 kV double circuit structures. The terminal equipment upgrade requires replacing four disconnect switches at Pontiac 345 kV.	December 31, 2021	8.21
19509	Thetford - Jewell Sag Remediation and Reconductor (J701, J794, J796,J832)	Reconductor approximately 0.1 miles of the Thetford – Jewell 345 kV circuit with a conductor rated to at least that of 2-945 ACSR. Remediate the sag on the Thetford - Jewell 345 kV circuit to achieve a minimum Summer Emergency circuit rating of 1556 MVA.	December 31, 2021	5.7
19405	J833 Interconnection	Construct J833 Interconnection station as a breaker and half station with three 40 kA breakers in a ring bus configuration. Extend the Milan - Pioneer 120 kV line 0.1 miles to loop in J833.	May 29, 2021	10.3
19585	Placid - Pontiac 345kV Sag Remediation (J701,J793,J794,J796,J832)	The scope of this network upgrade involves sag remediation on the Placid - Pontiac 345 kV circuit. The sag remediation requires replacing nine 345 kV double circuit structures.	December 31, 2021	2.9
19586	Pontiac - Wixom 345kV Sag Remediation & Station Equipment Upgrade (J701,J793,J794,J796,J832)	The scope of this network upgrade involves sag remediation on the Pontiac - Wixom 345 kV circuit, as well as upgrading terminal equipment at Pontiac 345 kV & Wixom 345 kV.	December 31, 2021	2.5

4.3.2 Michigan Electric Transmission Co. (METC)

METC proposed 57 projects at an estimated cost of $505 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of METC area, 37 of these projects are recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $270 million. Of these projects, seven are Baseline Reliability Projects, 19 are Other projects, and 11 are Generator Interconnection projects with signed Generator Interconnection Agreements. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

MISO identified open issues in the METC area as listed in Appendix D3 (CEII) and will be coordinating with METC to develop a solution in MTEP22.

Project 20018 – Rebuild Bullock – Shale 138 kV Line

Project Description

The project will rebuild the Bullock - Shale 138 kV line. The project's estimated cost is approximately $33 million dollars, and the expected in-service date is June 1, 2025.

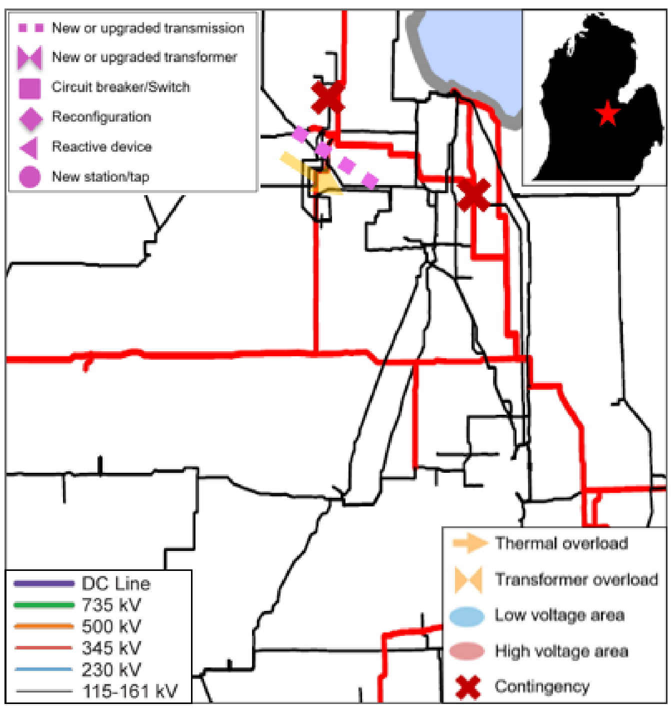

Figure 4.3.2-1: P20018 Geographic transmission map of project area

Project Need

The Bullock to Shale 138 kV line is projected to be overloaded for categories P1, P2, P3, P6, and P7. The overloaded equipment identified on this circuit is the overhead conductor and terminal station equipment at Bullock. Rebuilding this line alleviates all thermal violations.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Gleaner Jct – Bullock West 138 kV Ckt 1	332	119.3	70.2
P6	Gleaner Jct – Hackett Jct 138 kV Ckt 1	332	122.3	68.0
P6	Hackett Jct – Laundra Jct 138 kV Ckt 1	332	125.7	66.0
P6	Laundra Jct – Shale 138 kV Ckt 1	332	126.2	64.8

Table 4.3.2-1: P20018 Thermal loading drivers

Alternatives Considered

No alternatives were considered for this project.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 19970 – Rebuild Alma – Vestaburg 138 kV Line

Project Description

The project will rebuild 0.43 miles of the Alma - Vestaburg 138kV circuit using 954 ACSR on double circuit structures. The project's estimated cost is $2.8 million dollars, and the expected in-service date is December 31, 2024.

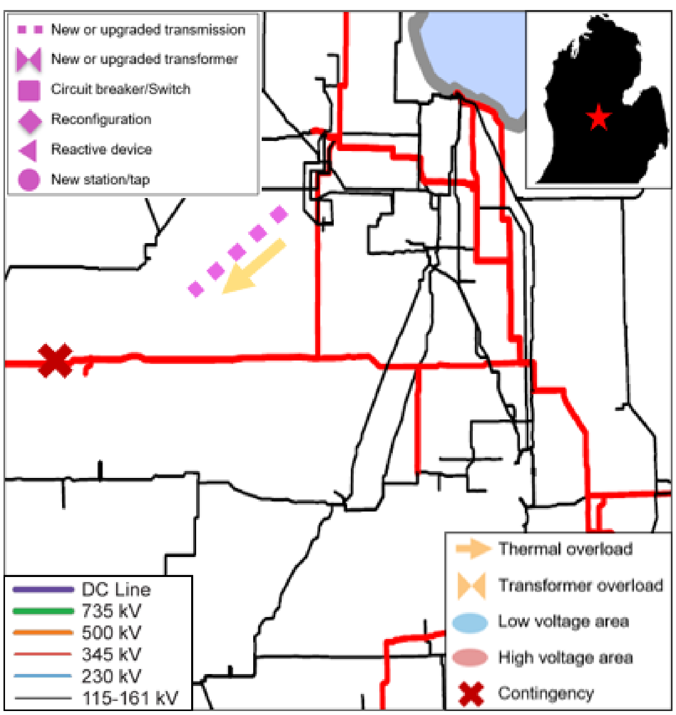

Figure 4.3.2-2: P19970 Geographic transmission map of project area

Project Need
The Alma - Vestaburg 138kV line is projected to be overloaded for P1-P7 contingency scenarios during Ludington Pumping and light load conditions. The identified overloaded equipment on this circuit is the conductor and terminal equipment at Alma. Rebuilding this line alleviates all thermal violations.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P7	Alma – Vestaburg 138 kV Ckt 1	287	104.9	80.6

Table 4.3.2-2: P19970 Thermal loading drivers

Alternatives Considered
No alternatives were considered for this project.

Immediate Need Reliability Project
In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 20054 - Warren 138 kV 377 Equipment Upgrades

Project Description

The project will upgrade terminal station equipment at Warren Station, including a 138 kV breaker. The project's estimated cost is $1.05 million dollars, and the expected in-service date is December 31, 2023.

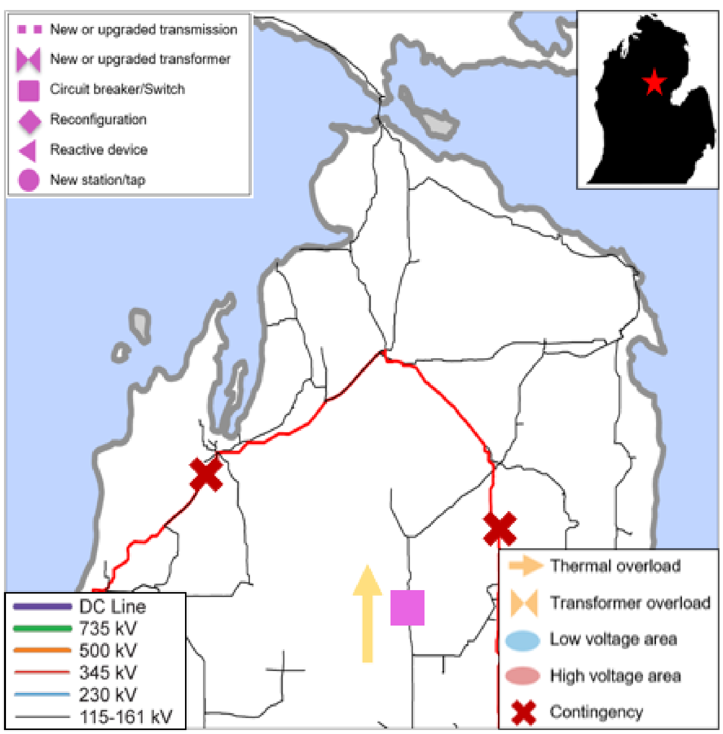

Figure 4.3.2-3: P20054 Geographic transmission map of project area

Project Need

The Warren – Clare Jct. 138 kV line is projected to be overloaded for category P1, P2, P3, and P6 contingencies. This project alleviates all thermal violations.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Clare Jct – Warren 138 kV Ckt 1	332	137.13	66.2

Table 4.3.2-3: P20054 Thermal loading drivers

Alternatives Considered

No alternatives were considered for this project.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 20053 – Warren 138 kV 188 Bus Upgrade

Project Description

The project will upgrade terminal station equipment at Warren Station. The project's estimated cost is approximately $160,000, and the expected in-service date is December 31, 2023.

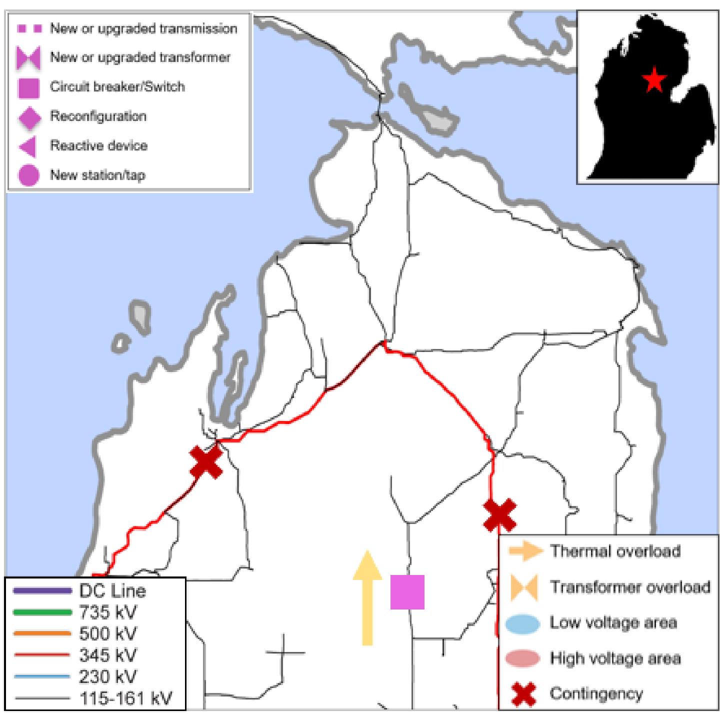

Figure 4.3.2-4: P20053 Geographic transmission map of project area

Project Need

The Warren – Salt River 138 kV line is projected to be overloaded for category P2, P3, P6, and P7 contingencies. The overloaded equipment identified on this circuit is the overhead conductor. This project alleviates all thermal violations.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Warren – Salt River 138 kV Ckt 1	332	131.42	72.1

Table 4.3.2-4: P20053 Thermal loading drivers

Alternatives Considered

No alternatives were considered for this project.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 20049 – Rebuild and Sag Remediate Gallagher - Twining 138kV Line

Project Description

The project will raise the sag limit on the Gallagher and Withey Lake Jct., as well as rebuild the Withey Lake Jct. - Twinning 138kV line. The project's estimated cost is $970,000 and the expected in-service date is June 1, 2025.

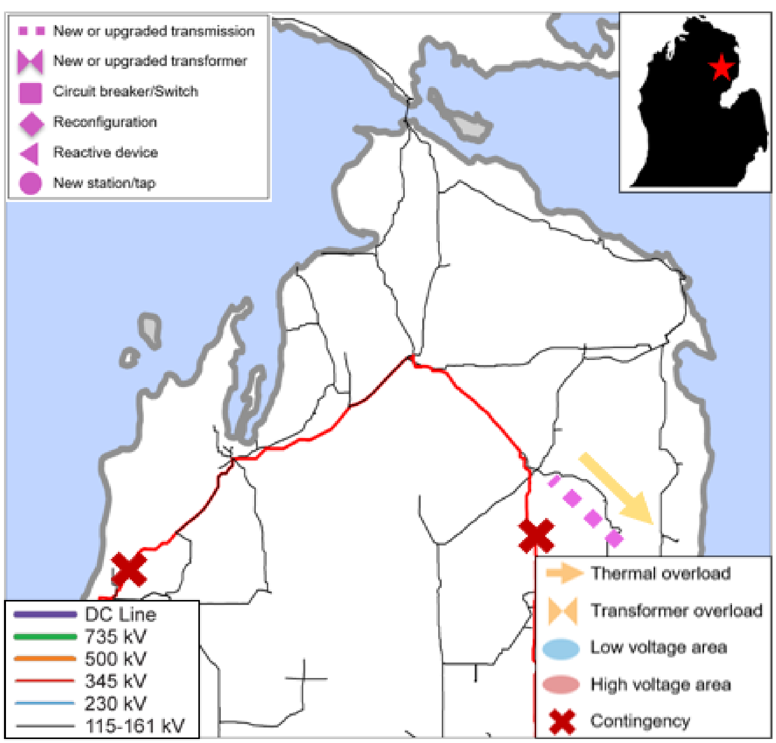

Figure 4.3.2-5: P20049 Geographic transmission map of project area

Project Need

The Gallagher to Twining 138 kV line is projected to be overloaded for category P6 contingencies. This project alleviates all thermal violations.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Withy Lake – Gallagher 138 kV Ckt 1	127	98.41	82.2
P6	Withy Lake – Twining 138 kV Ckt 1	131	103.38	78.1

Table 4.3.2-5: P20049 Thermal loading drivers

Alternatives Considered

No alternatives were considered for this project.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 20033 –Sag Remediate Weadock – Carter Jct 138 kV Line

Project Description

The project will raise the sag limit on the Carter - Weadock 138 kV Line. The project's estimated cost is $880,000 and the expected in-service date is June 1, 2025.

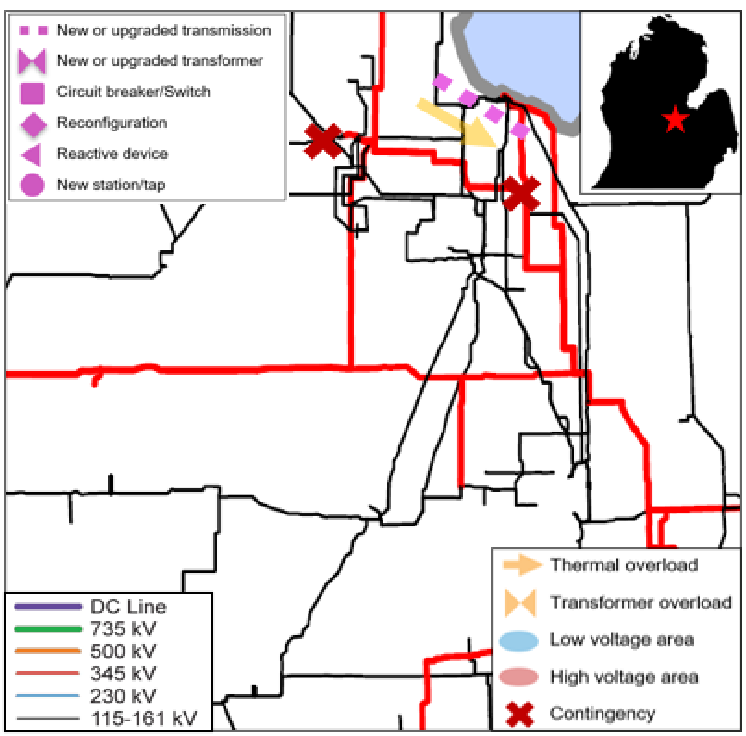

Figure 4.3.2-6: P20033 Geographic transmission map of project area

Project Need

The Carter to Weadock 138 kV line is projected to be overloaded for category P6 contingencies. This project alleviates all thermal violations.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Carter Jct - Hotchkiss 138 kV Ckt 1	171	109.43	74.2
P6	Hotchkiss – Weadock 138 kV Ckt 1	171	103.36	72.5

Table 4.3.2-6: P20033 Thermal loading drivers

Alternatives Considered

No alternatives were considered for this project.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 20120 –Wackerly 138 kV Station Equipment

Project Description

The project will replace station equipment in the Wackerly Substation. The project's estimated cost is $140,000 and the expected in-service date is December 31, 2023.

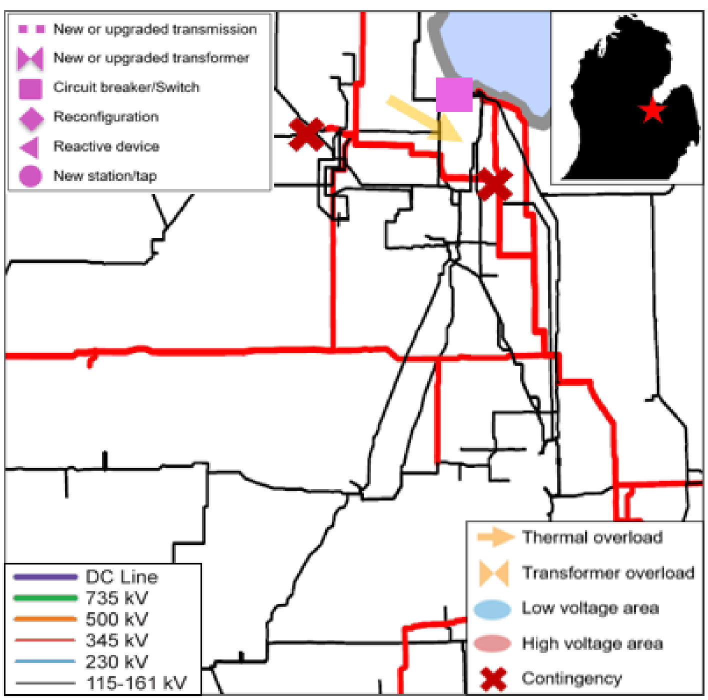

Figure 4.3.2-7: P20120 Geographic transmission map of project area

Project Need
Equipment at the Wackerly section breaker is projected to be overloaded for category P1, P2, P3, P6 and P7 contingencies. This project alleviates all thermal violations.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Wackerly1 – Wackerly2 138 kV Ckt Z1	285	122.54	57.1

Table 4.3.2-7: P20120 Thermal loading drivers

Alternatives Considered
No alternatives were considered for this project.

Immediate Need Reliability Project
In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
18404	Nelson Rd - Install 22H9 Breaker	Install a breaker at position 22H9 along with associated disconnect switches to complete row 22 at Nelson Road.	June 1, 2022	1.5
19991	METC Pole Top Switch Additions/Replacement Program 2022	Install or replace an existing 138 kV, 2-way, full-load-break pole top switch at various tap points.	December 31, 2022	2.0
20108	Atlanta-Karn-Thetford Split & Station Reconfiguration (METC)	Split the three-ended Atlanta-Karn-Thetford 138 kV line into Atlanta – Karn 138 kV and Atlanta – Thetford 138 kV.	December 31, 2024	0.3
21208*	Clinton Station Cut-in	Cut into the Island Rd – Delhi 138 kV line at the Clinton Junction with a new double tap structure and install pole top switches at the Packard and Eaton Rapids taps. Wolverine to utilize existing 795 ACSS conductor on the east side of the structures for the Clinton Rd – Delhi 138 kV circuit and reconductor the line on the west side of the structures utilizing 795 ACSS conductor to complete the Island Rd - Clinton 138 kV circuit.	June 1, 2025	3.3

*MTEP21 P21208 proposed as alternative to MTEP21 Target A P20158 and P21245.

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
18239	2023 METC Asset Replacement Program	Replace aging and outdated equipment at a pace that will ensure each type of equipment is replaced near its projected end of life.	December 31, 2023	36

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20144	Argenta 2 Transformer Replacement	Replace the Argenta #2 345/138 kV transformer. The anticipated replacement is the METC-standard 345/140 kV 500 MVA transformer.	December 31, 2025	5.4
20145	Tallmadge 2 Transformer Replacement	Replace the Tallmadge #2 345/138 kV transformer. The anticipated replacement is the METC-standard 345/140 kV 500 MVA transformer.	December 31, 2025	6.1
20146	Tittabawassee 1 Transformer Replacement	Replace the Tittabawassee #1 345/138 kV transformer.	December 31, 2023	6.2
20147	Vergennes 2 Transformer Replacement	Replace the Vergennes #2 345/138 kV transformer. The anticipated replacement is the METC-standard 345/140kV 500 MVA transformer.	December 31, 2023	7.1
20162	Claremont 138 kV Station Rebuild	The proposed solution is to rebuild Claremont 138 kV station with a new control house at a new site just to the southwest of the existing site utilizing new equipment in a five-row, breaker-and-a-half scheme configuration.	December 31, 2025	24.2
20164	Wealthy Street 138 kV Station Rebuild	Rebuild Wealthy Street 138 kV station with a new control house at a new site just to the southwest of the existing site utilizing new equipment in a four-row, breaker-and-a-half scheme configuration. The new 138 kV station to be built will be called New Station. This new 138 kV station would reduce equipment failures, unplanned outages, and repair costs. In addition, it would enable routine maintenance to be performed in a safe and efficient manner.	December 31, 2023	24.0
21046	Livingston 345kV Reactor 34F Replacement	Replace Livingston 345kV Shunt Reactor #34F with a new reactor.	December 31, 2023	2.5

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20047	METC Customer Interconnections - Year 2024	Customer interconnection requests and retirements less than $1 million with in service dates in the year 2024.	December 31, 2024	2.0

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20118	Higgins 138 kV Station Expansion	Reconfigure the Higgins 138 kV station to accommodate the CE request for METC to provide separate and independent exits in the ring bus for 2 new 138/46 kV transformer banks. METC will expand the existing ring bus and install one 138 kV breaker and associated disconnects.	April 1, 2023	4.5

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20826	Arenac CE Interconnection	Arenac Substation is proposed to connect to the Twining 138kV substation. CE to convey Twining 138 kV equipment to METC. METC to provide a new 138kV line between Twining and CE's new Arenac Substation. Fiber will be installed for relay communication.	January 1, 2023	21.8
21025	Foundry Bypass	Disconnect the Stable - Foundry 138 kV line at Calhoun. Disconnect the Foundry - Rice Creek line at structure 074B28. Connect the two lines to make the Stable - Rice Creek line. Install one-way switch at structure 074B28 for Calhoun.	September 1, 2022	1.7
21305	North Belding - Control House Replacement	Install new Control House at North Belding 138 kV station. Migrate relaying and vacate old control houses. Install SSVTs and Battery system.	June 1, 2024	1.9
20711	Stamping Plant 138kV Station Decommission	Terminate the 138 kV lines and bypass the Stamping Plant 138 kV station at structure #068C134. Tie Gaines – Stamping Plant to Stamping Plant – Beals Road to create Gaines – Beals Road 138 kV line. Decommission the Stamping Plant Station and remove all equipment.	June 1, 2021	1.3

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
17965	J806 Generator Interconnection	Build a new 138 kV, 3-breaker ring switching station cut in from the METC Rice Creek - Vrooman 138 kV circuit.	March 31, 2022	12.2
19365	J806/J857 Stability Mitigation	METC will extend the Marshall – Blackstone 138 kV line to loop in J857 Interconnection station. Install two breakers at Stable (the J857 interconnection station) to accommodate the change.	September 1, 2022	15
19385	J806/J857 Thermal Mitigation	METC will remediate the sag limit on the J806 POI – Denso Jackson 138 kV line segment and rebuild approximately 2 miles of the J806 POI – Vrooman 138 kV line segment. Replace existing 336 ACSR with 1431 ACSR.	December 31, 2022	6.3
19425	Gleaner - Hackett - Laundra Sag Remediation	Raise the sag limits on the Gleaner - Hackett and Hackett - Laundra line segments of the Bullock - Saginaw River 138 kV line.	December 31, 2021	0.8
19445	Stable - J857 Generator Interconnection	Construct the Stable 138 kV station as a ring bus station with three 40 kA breakers. Loop in the Verona - Foundry 138 kV line for transmission service.	September 1, 2022	10.9

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19465	ParrRd-J875-RaisnJ Sag Remediation	Remediate the sag on the Parr Road - J875 Interconnection station and the J875 - Raisin Tap line segment.	December 31, 2021	0.4
19506	Riggsville-Livingston 138kV & Mcgulpin-Riggsville 138kV Dual-Pilot Relay Upgrade (J832)	Install dual pilot relaying on the Riggsville-Livingston 138 kV & Mcgulpin-Riggsville lines. The installation of dual pilot relaying on these lines requires installing new relaying and wave traps at Mcgulpin, Riggsville and Livingston, as well as removing breaker bypass switches at Riggsville.	December 13, 2022	1.5
19546	J875 Generator Interconnection	Build a new 138 kV, 3-breaker ring switching station cut in from the METC Parr Road - Whiting 138 kV circuit.	November 18, 2022	36.5
19606	Thetford Station Eq Upgrade, Reconductor, and Sag (J701,J794,J796,J832)	Sag remediate and reconductor the Thetford - Jewell 345 kV circuit, as well as upgrade station equipment at Thetford 345 kV. The sag remediation requires replacing one (1) 345 kV double circuit structure. The reconductor requires replacing approximately 325 feet of 2156 ACSR type conductor with 2-954 ACSR type conductor. The terminal equipment upgrade requires upgrading buswork and a line entrance at Thetford.	December 31, 2021	0.8
19625	Bauer - Pontiac 345kV Sag Remediation (J701,J794,J796,J832)	The scope of this network upgrade involves sag remediation on the Bauer - Pontiac 345kV circuit. The sag remediation requires replacing four (4) 345kV double circuit structures.	December 31, 2021	1.9
19985	Murphy38kV_J1194NU_Install Row12	Construct Row 12 and install two 63 kA breakers at Murphy 138 kV.	November 1, 2021	2.0

4.3.4 Wolverine Power Supply Cooperative Inc. (WPSC)

Wolverine Power Supply Cooperative Inc. proposed three projects in the Other Projects type category at an estimated cost of $14.8 million, targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the Wolverine Power Supply Cooperative Inc. area, these three projects are recommended by MISO to be included in MTEP21 Appendix A. Wolverine Power Supply Cooperative Inc. did not propose any Base Line Reliability projects for MTEP21. The projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
21205*	Clinton Area Alternative	Wolverine proposes to utilize Wolverine's existing Clinton station and double circuit line as an alternative to METC's MTEP Project #20158 [Delhi - Island Rd 138 kV Station Cut-in (Clinton Jct)]. In order to address other future drivers, Wolverine also proposes to convert its Bradley to Clinton line from 69 kV to 138 kV that is additional to METC's protection needs.	December 31, 2025	13.7

*MTEP21 P21205 proposed as alternative to MTEP21 Target A P20158 and P21245.

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20885	Cimmaron Interconnection	Install tap pole and 2 switches on White Cloud to Hesperia line section to allow Consumers to interconnect service for new Cimmaron substation.	December 31, 2022	0.6

4.3.5 Michigan Public Power Agency (MPPA)

Michigan Public Power Agency did not submit any new projects for MTEP21. MISO has not identified any open issues in MPPA area.

4.3.6 Lansing Board of Water and Light (LBWL)

Lansing Board of Water and Light did not submit any new projects for MTEP21. MISO has not identified any open issues in LBWL area.

4.3.7 Michigan South Central Power Agency (MSCPA)

Michigan South Central Power Agency did not submit any new projects for MTEP21. MISO has not identified any open issues in MSCPA area.

4.4 Project Justifications – South Region

South Region Overview

The MISO South Planning Region consists of eleven Transmission-Owning members spanning four states, Arkansas, Louisiana, Mississippi, and parts of Texas. These Transmission Owners are:

Arkansas Electric Cooperative Corporation (AECC)
City of Alexandria (AXLA)
CLECO Power LLC (CLEC)
Cooperative Energy (SMEPA)
East Texas Electric Cooperative (ETEC)
Entergy Arkansas LLC (EAL)
Entergy Louisiana LLC (ELL)
Entergy Mississippi LLC (EML)
Entergy New Orleans LLC (ENO)
Entergy Texas Incorporated (ETI)
Lafayette Utilities Systems (LAFA)

The region contains approximately 16,500 circuit miles of transmission lines ranging from 115 kV to 500 kV. There is also a significant 69 kV sub-transmission network interspersed across the footprint.

In the 2023 Summer Peak planning model, the region contains more than 38.1 GW of generation. The MISO South generation profile consists of mostly combine cycle, nuclear, gas, and coal fuel types, serving major load centers such as Little Rock, New Orleans, etc. Approximately 53 percent (20.2 GW) of the South region's generation capacity is made up of Combine Cycle (CC) units. Major generation centers are in central Arkansas, lower Louisiana, and western Mississippi (Figure 4.4-1).

Major load centers are typically found around larger cities in the region such as Little Rock, Jonesboro, and Pine Bluff in Arkansas; Monroe, Alexandria, Lake Charles, Lafayette, New Orleans, and Baton Rouge in Louisiana; Jackson, Hattiesburg, Natchez, Vicksburg, and Greenville in Mississippi. Texas major load centers in the Western load pocket include Bryan and the Woodlands area. The major load center in the WOTAB load pocket portion of Texas is in South Beaumont and the Port Arthur Area (Figure 4.4-1). According to the 2023 Summer Peak planning model, the regional load is over 36.1 GW.

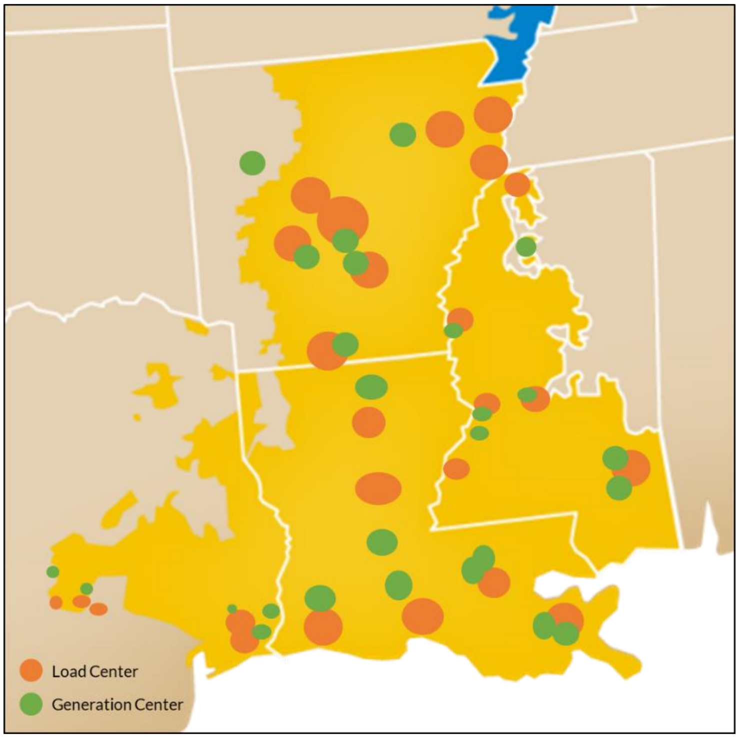

Figure 4.4-1: Generation and load centers in the South planning region

For MTEP21, MISO Transmission Planning is recommending 42 projects from the South region for inclusion in Appendix A at an estimated cost of $712 million. Of these, seven are Baseline Reliability Projects, and eight are Generator Interconnection Projects. The remaining 27 projects are classified as Other projects because they do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects.

Of the 42 projects, that are being recommended to be included in MTEP21, six have an estimated cost of less than $1 million, nine have an estimated cost between $1 million and $5 million, and the remaining 27 projects have an estimated cost greater than $5 million (Figure 4.4-2).

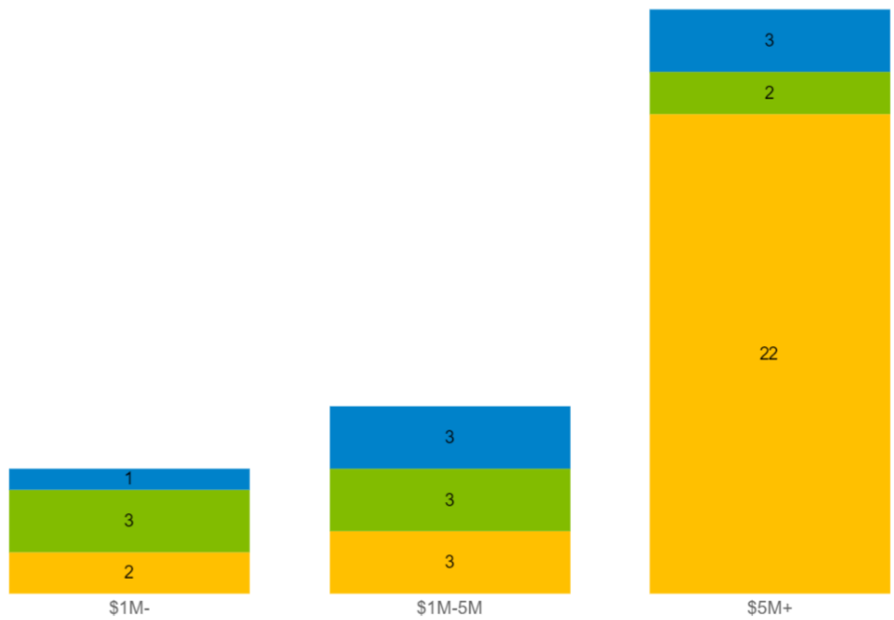

Figure 4.4-2: Cost category by project types (project data as of 9-17-2021)

The majority of the projects in the MISO South planning region are expected to go in service in the next three years (figure 4.4-3).

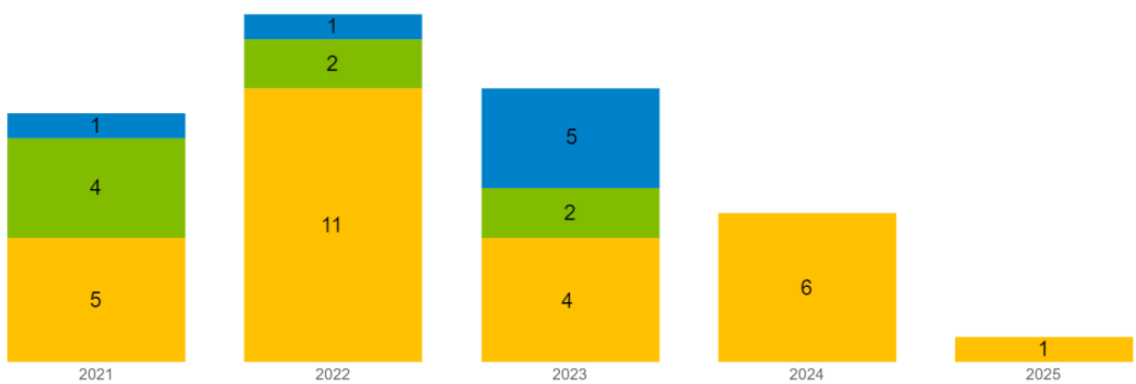

Figure 4.4- 3: Project in-service date by project type (project data as of 9-17-2021)

In accordance with Attachment FF of the tariff, in the event a Transmission Owner determines that system conditions warrant the urgent development of system enhancements an expedited review of the impacts of the project can be requested. MISO shall use a streamlined approval process for reviewing and approving projects proposed by the Transmission Owner(s) and decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO unless a longer review period is mutually agreed upon. During the MTEP21 cycle, MISO received three projects in the South planning region through the Expedited Project Review (EPR) process:

1. Project ID 18228, Golden Meadow to Clovelly 115 kV: Rebuild line

2. Project ID 21085, Sugar House 230 kV: New Station
3. Project ID 21525, Sullivan 230 kV: New Station, Southport to Sullivan 230 kV Line upgrade

Also, in accordance with Attachment FF Section VIII.A.3, the following project was identified as an Immediate Need Reliability Project and is excluded from the competitive developer selection process:

- None

The ten most expensive projects account for $312.7 million (44%) of the $712 million total recommended projects for the South in MTEP21. The locations of the ten most expensive projects are shown in Figure 4.4-4 and it is seen that they are spread across the southern part of the South planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

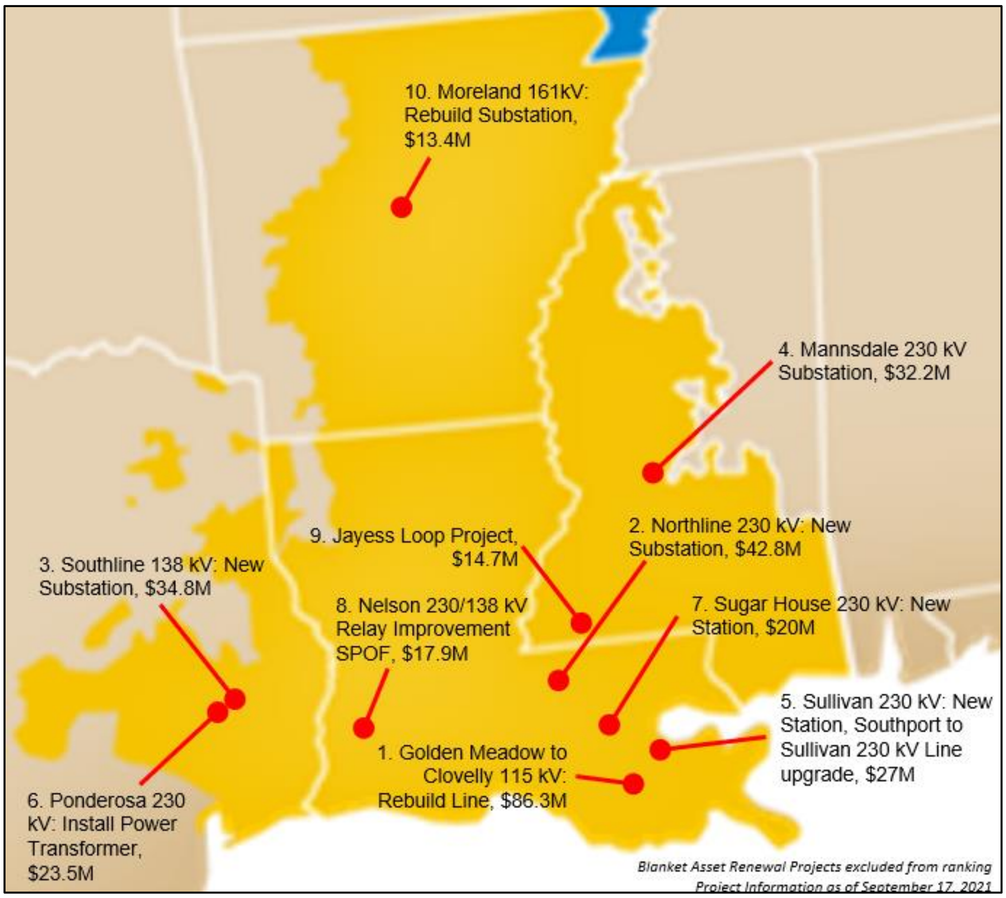

Figure 4.4-4: South region top ten projects by cost (data as of 9-17-2021)

4.4.1 Arkansas Electric Cooperative Corporation (AECC)

Arkansas Electric Cooperative Corporation proposed two projects at an estimated cost of $7.0 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the AECC area, both projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $7.0 million. Both projects are categorized as an Other type projects. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20161	Tap EAL Monticello East - Reed: Construct Selma South 115/69 kV substation	Tap Entergy's Monticello to Reed 115 kV transmission and construct the Selma South 115/69 kV, 60/80/100 MVA transmission substation.	January 1, 2024	6.0
20265	Glendale Capacitor Bank	Install 9.6 MVAR capacitor bank at Glendale.	January 1, 2024	1.0

4.4.2 City of Alexandria (AXLA)

City of Alexandria did not submit any new projects for MTEP21. MISO has not identified any open issues in the City of Alexandria area.

4.4.3 CLECO Power LLC (CLEC)

CLECO Power LLC proposed three projects at an estimated cost of $18.6 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the CLECO Power LLC area, the three projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $18.6 million. Of these projects, two are Baseline Reliability Projects, and one is an Other project. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

Project 13874 – Flagon Substation

Project Description

This project builds a new 230 kV substation Tapped into the Donahue to Sherwood 230 kV line and uses the distribution in the area to move 16 MW from Beaver Creek substation. The project's estimated cost is $8.1 million and expected in-service date is June 1, 2022.

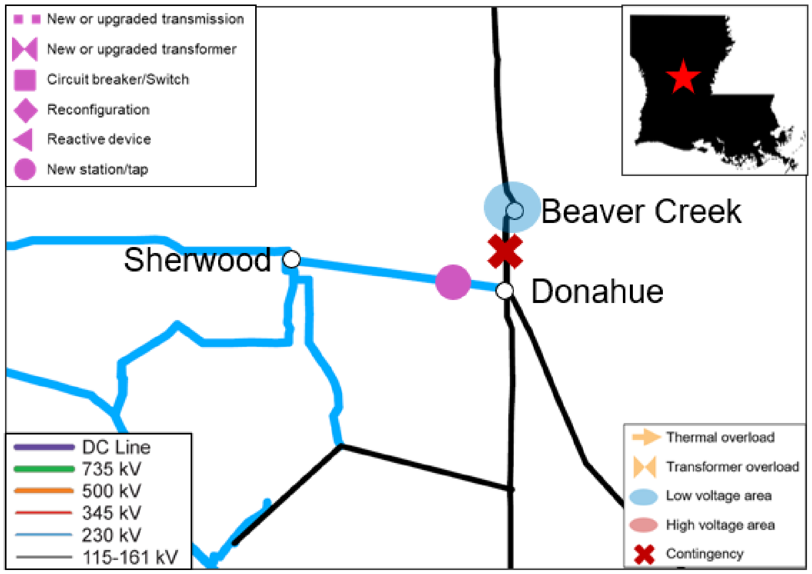

Figure 4.4.3-1: P13874 Geographic transmission map of project area

Project Need

NERC defined P7 contingencies on Donahue-Beaver Creek 138 kV line 1 and Donahue-Beaver Creek 138 kV line 2 create low voltage, shown in Table 4.4.3-1, at the Beaver Creek 138 kV substation in Summer Peak models. Building the Flagon substation will allow more distribution flexibility in the area and reduce the load at Beaver Creek by 16 MW. This will eliminate the low voltage caused by the P7 contingencies.

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P7	Beaver Creek 138 kV	.90	.88	1.02

Table 4.4.3-1: P13874 Voltage performance drivers

Alternatives Considered

No other alternatives considered.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 21169 –Bayou Sale Cap Move

Project Description

This project moves the existing 19.2 MVAR cap bank at the Bayou Sale 138 kV substation to the Pelican 138 kV substation. The project's estimated cost is $700,000 and expected in-service date is June 1, 2023.

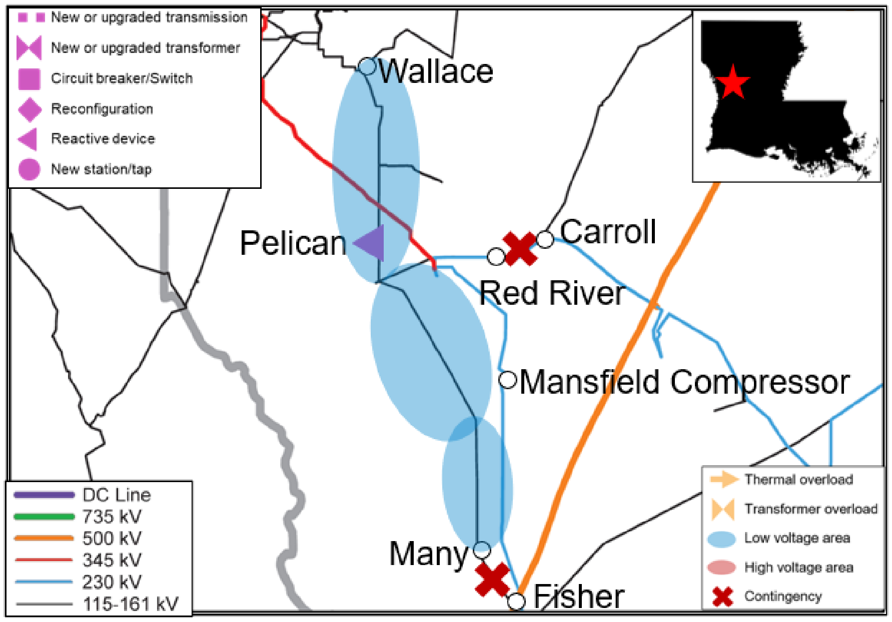

Figure 4.4.3-3: P21169 Geographic transmission map of project area

Project Need

NERC defined P6 contingences on the Carroll-Red River 138 kV line and on the Many-Fisher 138 kV line causes low voltage issues and potential overloads on the South Shreveport-Wallace Lake 138 kV line as shown in Table 4.4.3-3.

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	South Shreveport-Wallace Lake 138 kV	.90	.87	.98

Table 4.4.3-3: P21169 Voltage performance drivers

Alternatives Considered

No other alternatives considered.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
21207	Slidell Airport Line Move	Slidell airport expansion requires the relocation of the North Slidell-Tailsheek 230 kV line and the North Slidell-Cane Bayou 230 kV line.	December 1, 2023	9.8

4.4.4 Cooperative Energy (SMEPA)

Cooperative Energy proposed three projects at an estimated cost of $32.02 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the Cooperative Energy area, all of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $32.02 million. Of these projects, zero are Baseline Reliability Projects, two are Other projects, and one is a Generator Interconnection project with a signed Generator Interconnection Agreement. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
15848	Jayess Loop Project	Rebuild L523 (Norfield SS to Little Creek) with sufficient ACSR conductor. Tap L549 (Jayess SS to Jayess) with a 115kV GOAB, tap L523 with a 115kV GOAB and build a new 115kV transmission line from Jayess GOAB to Little Creek GOAB. Build a new 115kV breaker switching station at Jayess and build a new 115kV breaker switching station at Norfield.	May 1, 2024	14.66^
15850	Olive Oil Loop Project	Rebuild L546 (Pisgah GOAB to Magee Road SS) with sufficient ACSR conductor. Rebuild L547 (Arlington GOAB to Arlington) with sufficient ACSR conductor. Tap L547 with a 115kV GOAB, tap L576 (Magee Road SS to Olive Oil) with a 115kV GOAB and build a new 115kV transmission line from Arlington GOAB to Olive Oil GOAB. Build a new 115kV breaker switching station at Arlington.	December 1, 2024	12.11^^

^$3.3M funded by Entergy MS.

^^$1.7M funded by Entergy MS.

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20305	MS Solar 4 Switching Station	Construct a new 161kV breaker switching station that taps the Moselle – Columbia 161kV line	October 1, 2022	5.25

4.4.5 East Texas Electric Cooperative (ETEC)

East Texas Electric Cooperative proposed two projects at an estimated cost of $6.2 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the ETEC area, their two projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $6.2 million. These projects are both classified as Other projects. The projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19853	Fork Creek 138kV Station Upgrade	Upgrade of existing substation with addition of 138kV line breakers for through-bus operation.	December 31, 2022	0.9
19954	Newton 138 kV Station	Convert existing radial substation to looped substation and install 138/69 kV transformer.	April 1, 2023	5.3

4.4.6 Entergy Arkansas LLC (EAL)

Entergy Arkansas proposed five projects at an estimated cost of $71.67 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the EAL area, all five of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $71.67 million. Of these projects, four are Other projects, and one is a Generator Interconnection Project with a signed Generator Interconnection Agreement. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19907	Moreland 161kV: Rebuild Substation	Wreck out the existing 20 MVA substation Transformer and associated bus and breakers and install a new substation consisting of 2-new 40 MVA substation transformers on the existing property to include two 161-13.8 KV, 40 MVA LTC transformers. Build 13.8kV low-side operating bus and transfer buses as per Entergy Substation Specifications including a 2000A bus tie breaker and bay connecting the two transformer buses. Install two 2000A main breaker bays and eight feeder breaker bays.	December 30, 2022	13.4
19908	Cave City 161kV: Add 2nd Transformer	Add a 40 MVA 161/34.5kV LTC transformer in the existing substation. Install three 1200 Amp feeder breakers and a 1200 Amp bus tie breaker.	June 1, 2023	8.0
19909	2021 EAL Asset Renewal Program	This project includes the EAL asset renewal projects that will be performed in 2021.	December 30, 2021	27.2
19910	2022 EAL Asset Renewal Program	This project is for the EAL Asset Renewal Program that will be executed in 2022.	December 30, 2022	19.3

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
21447	Happy 115kV: New Switching Station (J1373)	Happy 115kV (J1373) is a new ring bus switching station tapped on the Searcy Price - Griffithville line section. Entergy Arkansas will install line taps into and out of the Happy 115kV switching station as well as line protection and breaker control relay upgrades, new RTU installation, and wave trap removal at the remote end Brinkley East and Searcy Price 115kV substations. Approximately 4.7 miles of underground fiber will be installed between Happy and Griffithville 115kV substation.	March 15, 2023	3.7

4.4.7 Entergy Louisiana LLC (ELL)

Entergy Louisiana proposed thirteen projects at an estimated cost of $319.9 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the ELL area, all thirteen of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $319.9 million. Of these projects, two are Baseline Reliability Projects, seven are Other projects, and four are Generator Interconnection projects with signed Generator Interconnection Agreements. The projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

Project 15605 Frisco-Tezcuco 230kV: Upgrade Circuit 1 and 2

Project Description

Increase the rating of the Tezcuco to Frisco 230 circuit #1 and #2 to a minimum of 1925A (765 MVA). The project's estimated cost is $2.2 million and expected in-service date is December 1, 2021.

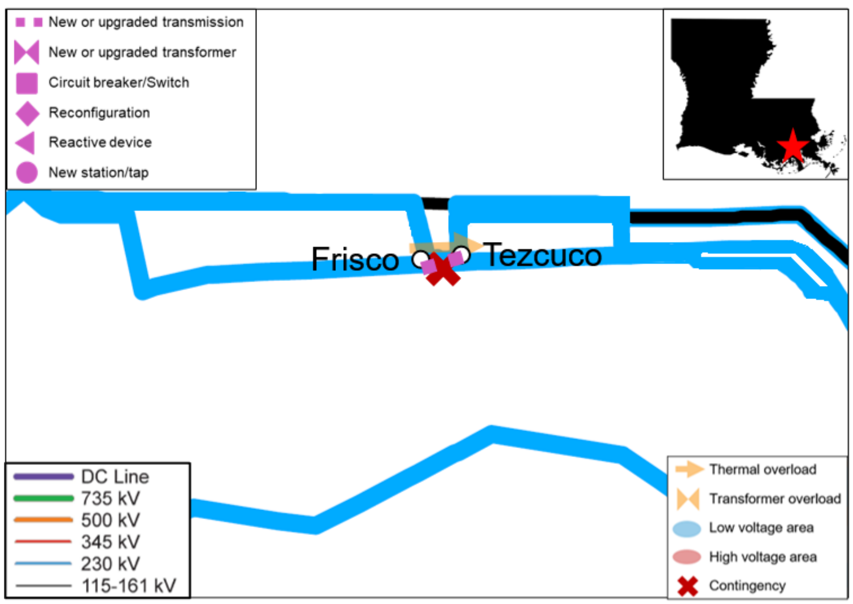

Figure 4.4.7-1: P15605 Geographic transmission map of project area

Project Need

MISO identified thermal overloads on the Tezcuco to Frisco circuit #1 and #2 during generator interconnection and deliverability analysis (Table 4.4.7-1).

- Tezcuco to Frisco 230kV circuit #1 following the loss of Tezcuco to Frisco 230kV circuit #2
- Tezcuco to Frisco 230kV circuit #2 following the loss of Tezcuco to Frisco 230kV circuit #1

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P12	Tezcuco to Frisco 230kV circuit #1	641	N/A	N/A
P12	Tezcuco to Frisco 230kV circuit #2	641	N/A	N/A

Table 4.4.7-1: P15605 Thermal loading drivers

Alternatives Considered
No other alternatives considered.

Immediate Need Reliability Project
In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 19987 Nelson 230/138 kV Relay Improvement SPOF

Project Description

Dual Battery installations or monitoring sufficient to FERC 754 guidelines at Nelson 230 kV and 138 kV stations. Install and verify high speed dual primary protection on the GSU for all power plants interconnected at Nelson 230 kV and 138 kV substations.

The project's estimated cost is $17.9 million and expected in-service date is December 1, 2023.

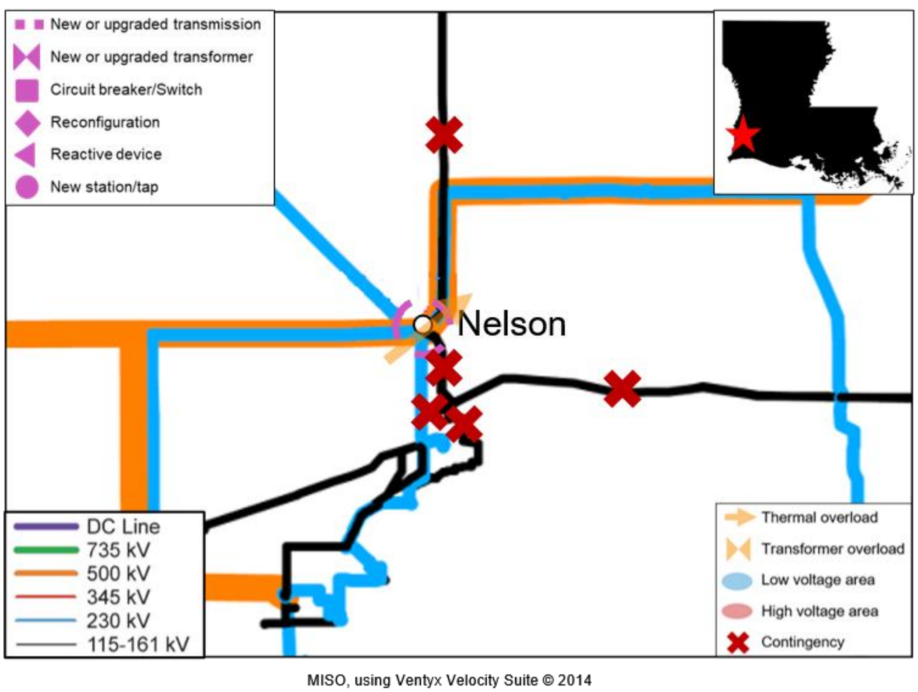

Figure 4.4.7-1: P19987 Geographic transmission map of project area

Project Need

NERC TPL-001-4 violations observed for a P5 contingency at Nelson including thermal overloads on the Carlyss 230-138 kV Autotransformer and the Sphere to Mossville 69 kV line (Table 4.4.7-1).

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P5	Carlyss 230/115 kV Transformer	300	110.5	N/A
P5	Sphere to Mossville 69 kV Line	72	107.7	N/A

Table 4.4.7-1: P19987 Thermal loading drivers

Alternatives Considered
No other alternatives considered.

Immediate Need Reliability Project
In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
18228	Golden Meadow to Clovelly 115 kV: Rebuild line	Rebuild the ~7 mile Golden Meadow to Clovelly 115 kV line to 230 kV specifications.	February 28, 2022	86.3
19957	Lake Arthur 69 kV Switch Upgrade	Replace switch 732 at Lake Arthur with a motorized load break switch that has whips and bottles. Move the Normally Open point from switch 8873 to switch 732 so that Lake Arthur 69 kV station is fed out of Lawtag 69 kV station.	June 1, 2022	0.7
20058	Baxter Wilson - Perryville 500 kV terminal equipment upgrade	Upgrade the following terminal equipment at Baxter Wilson SES SWYD (Perryville Line Bay) to a minimum through-path rating of 1940 MVA: J2217, J2219, Line Trap, SEL321.	December 15, 2022	0.35^

^Entergy LA's cost of joint project between Entergy-LA and Entergy-EML

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20039	2021 ELL Asset Renewal Program	This project is for the ELL Asset Renewal Program that will be executed in 2021	December 31, 2021	96.5
20040	2022 ELL Asset Renewal Program	This project is for the ELL Asset Renewal Program that will be executed in 2022	December 31, 2022	42.1

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20045	Northline 230 kV: New Substation	Northline 230 kV distribution substation will cut in between the existing Addis and Cohen 230 kV stations.	June 1, 2024	42.8
21085	Sugar House 230 kV: New Station	Entergy is proposing to construct a new 230 kV substation (Sugar House 230 kV Substation) which will serve an industrial	December 31, 2022	20.1

		customer's 50 MW of new load in Port Allen, LA. The new lines into the Sugar House substation will be cut in and out (~.7 miles total) of the existing Formosa to Placid 230 kV line. The Sugar House 230 kV station will be constructed as a 3 breaker ring bus. Relocation of a portion of the existing 138 kV line that shares right of way with the 230 kV line will also be part of this project.		

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20306	Adams Creek Relay upgrades (J830,J868,J908)	Relay upgrades at Adams Creek/Bogalusa 500 kV.	December 15, 2021	0.42
20307	Par 115 kV Station(J1184)	Construct a 115 kV substation named Par between the existing Franklinton and Holton 115 kV substations.	March 2, 2021	4.05
20585	J1142 Generator Interconnection at Vacherie 230 kV	Facilities required for the interconnection of J1142 at the existing Vacherie 230 kV substation.	March 29, 2021	4.3
20628	J1158 Generator Interconnection at Vacherie 230 kV	Facilities required for the interconnection of J1158 at the existing Vacherie 230 kV substation.	December 1, 2022	0.04

4.4.8 Entergy Mississippi LLC (EML)

Entergy Mississippi proposed seven projects at an estimated cost of $100.06 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the EML area, all of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $100.06 million. Of these projects, two are Baseline Reliability Projects, four are Other projects, and one is a Generator Interconnection project with a signed Generator Interconnection Agreement. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

Project 20057 - Franklin 115kV: Relay Improvement SPOF

Project Description

This project will install dual primary protection with independent CT and PT winding inputs on the Franklin 115kV bus. Dual battery installations or monitoring sufficient to meet FERC 754 guidelines. The project's estimated cost is $1.7 million and expected in-service date is June 1, 2023.

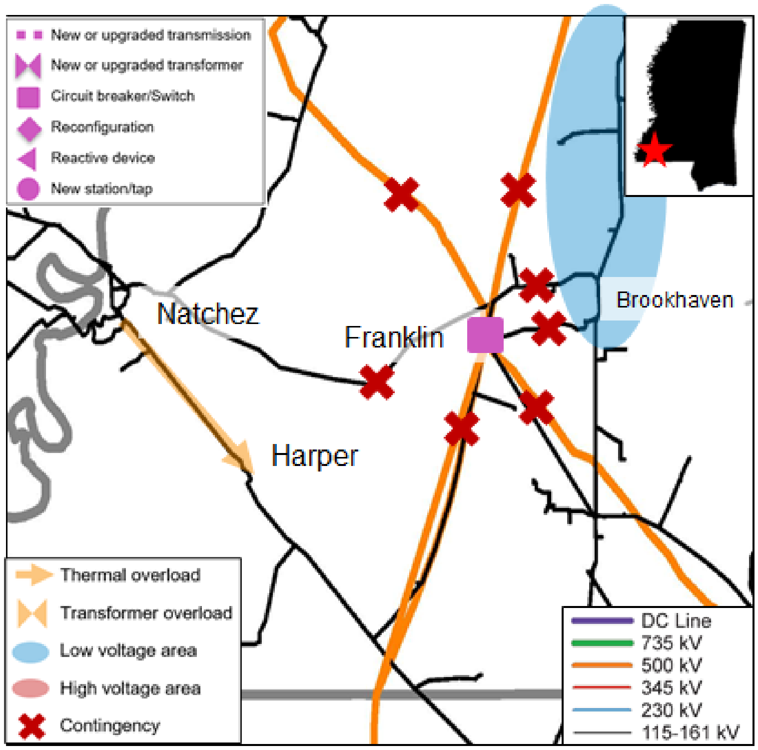

Figure 4.4.8-1: P20057 Geographic transmission map of project area

Project Need

This project is needed due to NERC TPL-001-4 violations observed for a P5 contingency at Franklin 115kV. Failure of the 115kV bus differential relay to clear a fault causes the loss of the Franklin 115kV and 500kV buses. This results in widespread thermal and voltage issues in Southwest Mississippi. (Tables 4.4.8-1 and 4.4.8-2)

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P5	Natchez 115kV – SE Natchez 115kV Ckt 1	108	124.6	N/A
P5	SE Natchez 115kV – Crosby 115kV Ckt 1	108	117.5	N/A
P5	Crosby 115kV – Harper 115kV Ckt 1	120	103	N/A

Table 4.4.8-1: P20057 Thermal loading drivers

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P5	Brookhaven 115kV	.92	.843	N/A
P5	Wesson 115kV	.92	.836	N/A
P5	James Road 115kV	.92	.836	N/A
P5	Hazelhurst 115kV	.92	.839	N/A

P5	Copiah 115kV	.92	.839	N/A
P5	Gallman 115kV	.92	.844	N/A
P5	Crystal Springs 115kV	.92	.859	N/A
P5	Terry 115kV	.92	.907	N/A

Table 4.4.8-2: P20057 Voltage performance drivers

Alternatives Considered

No other alternatives considered.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 20055 – McAdams 230kV: Relay Improvement SPOF

Project Description

This project addresses Relay Single Point at McAdams 230kV substation by adding or replacing bus differential protection on the 230kV buses, adding or replacing bus potential transfer panel, replacing two OCBs, breaker control panel and CCVTs.

The project's estimated cost is $4.6 million and expected in-service date is June 1, 2023.

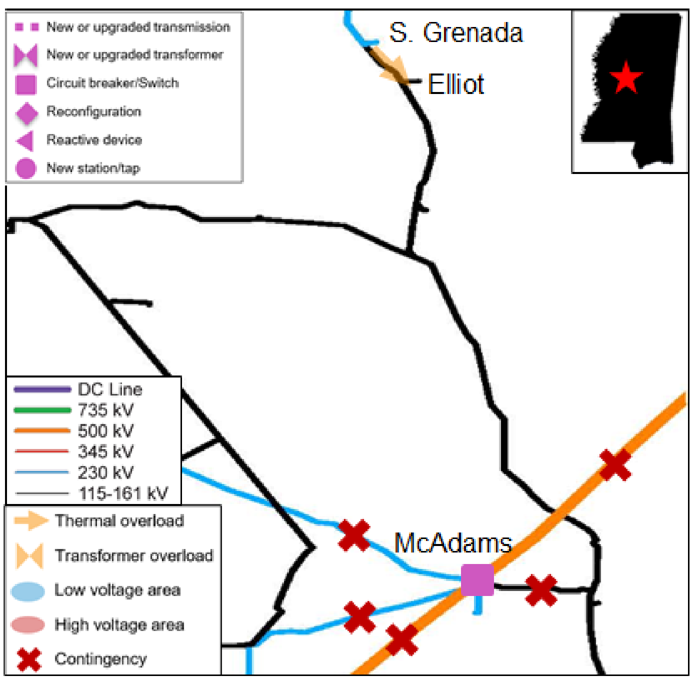

Figure 4.4.8-2: P20055 Geographic transmission map of project area

Project Need

The P5 loss of the McAdams 230kV bus due to a failed bus differential relay causes thermal overloads on the S. Grenada to Elliot 115kV line.

There is also the potential for ~2000 MW of generation trip to occur for a 3PH fault on the McAdams 230 kV bus with non-redundant relay failure (TPL-001-4 category 2 stability extreme event). This project improves relay protection deficiencies at the McAdams 230 kV substation (Table 4.4.8-3).

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P5	Elliot – South Grenada 115kV Ckt 1	108	113	N/A

Table 4.4.8-3: P20055 Thermal loading drivers

Alternatives Considered
No other alternatives considered.

Immediate Need Reliability Project
In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20058	Baxter Wilson – Perryville 500kV Termina Equipment Upgrade	Upgrade the following terminal equipment at Baxter Wilson SES SWYD (Perryville Line Bay) to a minimum through-path rating of 1940 MVA: J2217, J2219, Line Trap, SEL321.	December 15, 2022	1.11^

^EML's cost of joint project between Entergy-LA and Entergy-EML

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20060	2021 EML Asset Renewal Program	This project includes the EML asset renewal projects that will be performed in 2021.	December 31, 2021	29.07
20061	2022 EML Asset Renewal Program	This project includes the EML asset renewal projects that will be performed in 2022.	December 31, 2022	30.48

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
13995	Mannsdale 230kV Substation	Build new Mannsdale 230kV substation in operating and transfer configuration. Include appropriate high-side fault protection. Install two (2) – 40 MVA, 230 kV-13.8kV, LTC, transformers including high-side circuit switchers to operate at 12.47kV. Install two (2) – 2,000 amp, 13.8kV, main breakers. Install eight (8) 1200 amp, 12.47 kV, breaker bays and equip with six (6) breakers; three (3) breakers to be served by T-1, and three (3) to be served by T-2. Install control house and all necessary relaying equipment.	June 1, 2025	32.20

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20308	Franklin Relays Upgrade (J830, J868, J908)	Relay upgrade at Franklin 500kV.	December 15, 2021	0.90

4.4.9 Entergy New Orleans LLC (ENO)

Entergy New Orleans (ENO) proposed three projects at an estimated cost of $47.2 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the ENO area, all of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $47.2 million. Of these projects, one is a Baseline Reliability Project and two are Other projects. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

Project 21525 Sullivan 230 kV: New Station, Southport to Sullivan 230 kV Line upgrade

Project Description

Construct new 230 kV station to be cut into the Southport to Joliet 230 kV line. Upgrade the Southport to Sullivan 230 kV line. The project's estimated cost is $27.1 million and expected in-service date is June 1, 2023. The cost of the project is split between Entergy Louisiana ($2.9 million) and Entergy New Orleans ($24.2 million).

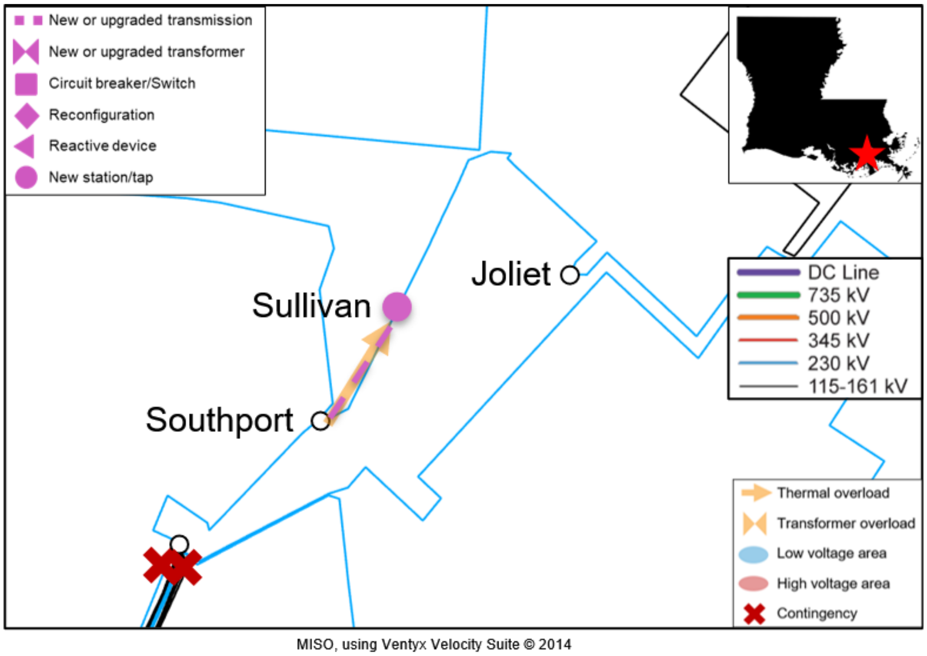

Figure 4.4.9-1: P21525 Geographic transmission map of project area

Project Need

The Sullivan station will be dedicated to serve New Orleans Sewerage and Water Board load. The Southport to Sullivan 230 kV upgrade is driven by NERC TPL-001-4 Reliability Standards and Entergy's Planning Guidelines. In 2023 summer the P2.3 Internal Breaker Fault of a Ninemile breaker will cause overloads on the Southport to Sullivan 230kV line.

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P23	Southport to Sullivan 230kV	641	109	78

Table 4.4.9-1: P21525 Thermal loading drivers

Alternatives Considered

No other alternatives considered.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20122	2021 ENOL Asset Renewal Program	This project is for the ENOL Asset Renewal Program that will be executed in 2021	December 31, 2021	5.9
20124	2022 ENOL Asset Renewal Program	This project is for the ENOL Asset Renewal Program that will be executed in 2022	December 31, 2022	4.5

4.4.10 Entergy Texas, Inc. (ETI)

Entergy Texas Incorporated proposed five projects at an estimated cost of $120.05 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the ETI area, these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $120.05 million. Of these projects, four are Other projects and one is a Generator Interconnection project with a signed Generator Interconnection Agreement. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20042	2021 ETI Asset Renewal Program	This project is for the ETI Asset Renewal Program that will be executed in 2021.	December 31, 2021	$22.1M
20043	2022 ETI Asset Renewal Program	This project is for the ETI Asset Renewal Program that will be executed in 2022.	December 31, 2022	$32.5M

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20067	Southline 138 kV: New Substation	Southline 138 kV substation is a distribution station that will be cut into the Cleveland to Jayhawker 138 kV line.	December 1, 2023	$34.8M
20073	Ponderosa 230 kV: Install Power Transformer	Install power transformer at the Ponderosa 230 kV substation, there are no power transformers currently install at Ponderosa.	June 1, 2024	$23.5M

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20405	J1030 Station Interconnection Project	This project is to construct the interconnection station for the solar project J1030 on the Poco to Menard 138 kV line.	January 1, 2023	7.15

4.4.11 Lafayette Utilities System (LAFA)

Lafayette Utilities System, LAFA did not submit any new projects for MTEP21. MISO has not identified any open issues in the LAFA area.

4.5 Project Justifications – West Region

West Region Overview

The MISO West Planning Region consists of 20 Transmission-Owning members spanning eight states in the upper Midwest. It includes Iowa, Minnesota, Wisconsin, and parts of North Dakota, South Dakota, Montana, Michigan, and Illinois. These Transmission Owners are:

American Transmission Company (ATC)
Cedar Falls Utilities (CFU)
Central Minnesota Municipal Power Agency (CMMPA)
City of Ames, IA (COA)
Dairyland Power Cooperative (DPC)
Great River Energy (GRE)
ITC Midwest (ITCM)
MidAmerican Energy Company (MEC)
Minnesota Municipal Power Agency (MMPA)
Minnesota Power (MP)
Missouri River Energy Services (MRES)
Montana-Dakota Utilities Co. (MDU)
Muscatine Power and Water (MPW)
Northwestern Wisconsin Electric (NWEC)
Otter Tail Power Company (OTP)
Rochester Public Utilities (RPU)
Southern Minnesota Municipal Power Agency (SMMPA)
Wilmar Municipal Utilities (WMU)
WPPI Energy (WPPI)
Xcel Energy (Northern States Power, XEL/NSP)

The West planning region contains approximately 27,300 miles of transmission ranging from 57 kV to 500 kV. In the 2023 Summer Peak planning model, the region contains more than 67.2 GW of generation. Installed generation capacity in the region consists mostly of coal, gas and wind. Approximately 33.4 percent (22.5 GW) of the West region's generation capacity is made up of wind units. Major generation centers are located in central North Dakota; the Twin Cities in Minnesota; and the Quad Cities in Iowa and Illinois, with wind generation located in the eastern Dakotas and western Iowa and Minnesota (Figure 4.5-1).

Major load centers are typically found around larger cities in the region: Minneapolis/Saint Paul, Milwaukee, and Des Moines. According to the 2023 Summer Peak planning model, the regional load exceeds 42.2 GW. Power generally flows from generation-rich areas in the western portion of the region through Minnesota, Iowa, and Wisconsin, toward large load centers in the east. This is especially prevalent in times of high wind output.

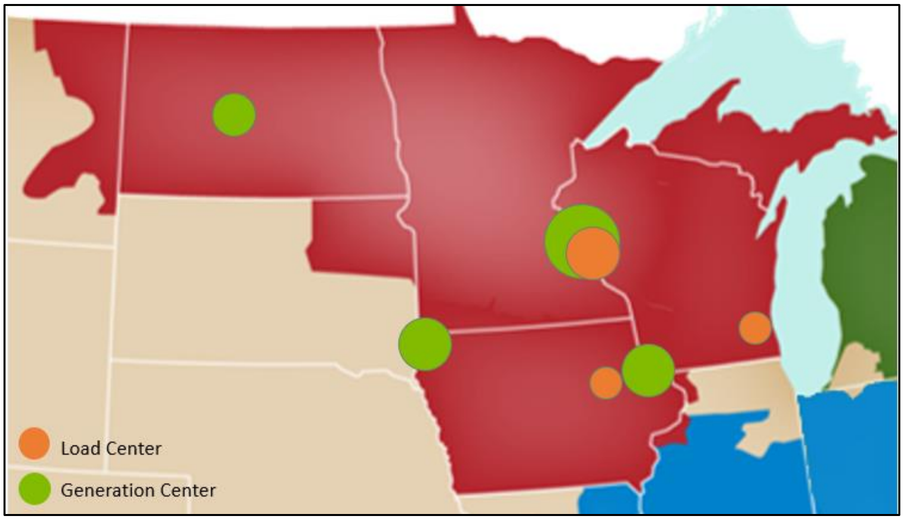

Figure 4.5-1: Generation and load centers in the West Planning Region

For MTEP21, MISO Transmission Planning is recommending 133 projects from the West region for inclusion in Appendix A at an estimated cost of $1.10 billion. Of these, five are Baseline Reliability Projects, 16 are Generator Interconnection Projects and the remaining 112 projects are classified as Other because they do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects.

Of the 133 projects, that are being recommended to be included in MTEP21, 27 have an estimated cost of less than $1 million, 51 have an estimated cost between $1 million and $5 million, and the remaining 55 projects are estimated to cost greater than $5 million (Figure 4.2-2).

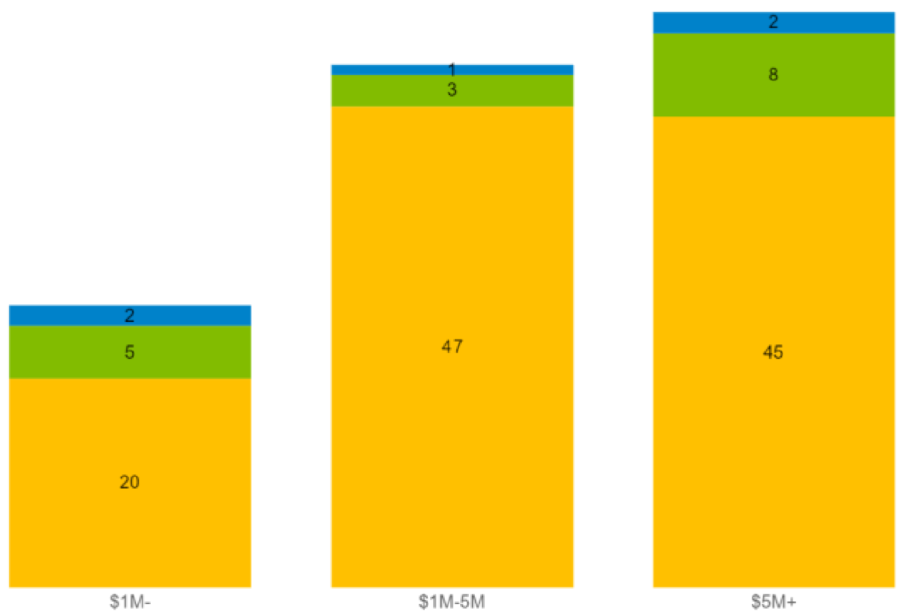

Figure 4.5-2: Project cost category by project type (data as of September 17, 2021)

The majority of the projects in the MISO West planning region are expected to go in service in the next three years (Figure 4.5-3). There were a handful of projects that are being approved in 2021 that either already went into service in 2020 or are expecting to go into service in 2021. Some of those were transmission network upgrades (GIP) correlated with generation projects that were justified by a separate Generator Interconnection process. Others fit into a bucket of timing or constructability considerations. Examples of these are the retirement of catastrophic failure devices, load additions which required short time frames to come online, or those that take advantage of outages already scheduled and planned the upgrade accordingly to meet the compliance.

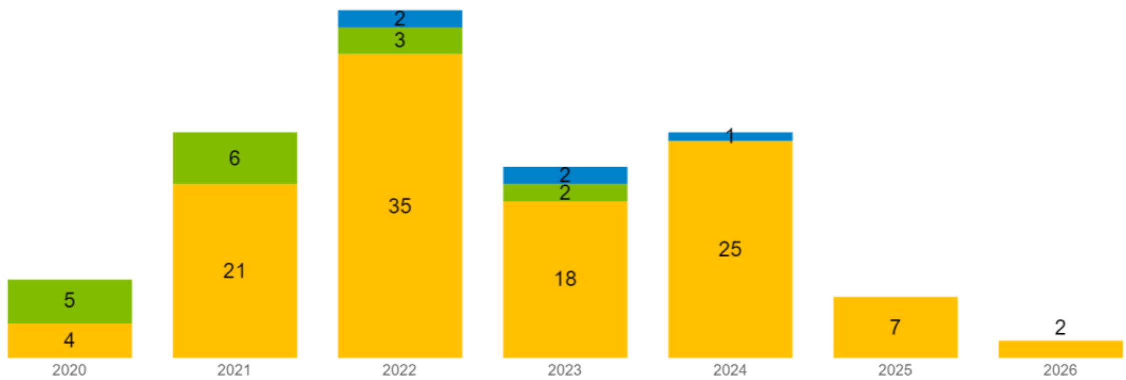

Figure 4.5-3: Project in-service date by project type (data as of September 17, 2021)

In accordance with Attachment FF of the tariff, in the event that a Transmission Owner determines that system conditions warrant the urgent development of system enhancements that would be jeopardized unless MISO performs an expedited review of the impacts of the project, MISO shall use a streamlined approval process for reviewing and approving projects proposed by the Transmission Owner(s) so that decisions will be provided to the Transmission Owner within 30 Days of the project's submittal to MISO unless a longer review period is mutually agreed upon. During the MTEP21 cycle, MISO received the following projects through the Expedited Project Review (EPR) process:

1. Project ID 21429, ITCM Tiffin Crossroads Substation Interconnection
2. Project ID 21625, ITCM Keokuk Geode 69 kV Substation Interconnection
3. Project ID 21545, MEC Diamond Trail to Hills 345 kV Line Structure Replacements
4. Project ID 20608 Worthington Substation

Also, in accordance with Attachment FF Section VIII.A.3, the following project was identified as an Immediate Need Reliability Project and is excluded from the competitive developer selection process:

- None

The ten most expensive projects represent $326.7 million of the $1.03 billion total recommended projects for the West in MTEP21. The locations of these projects can be seen in Figure 4.5-4 and the investment is spread across the West Planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

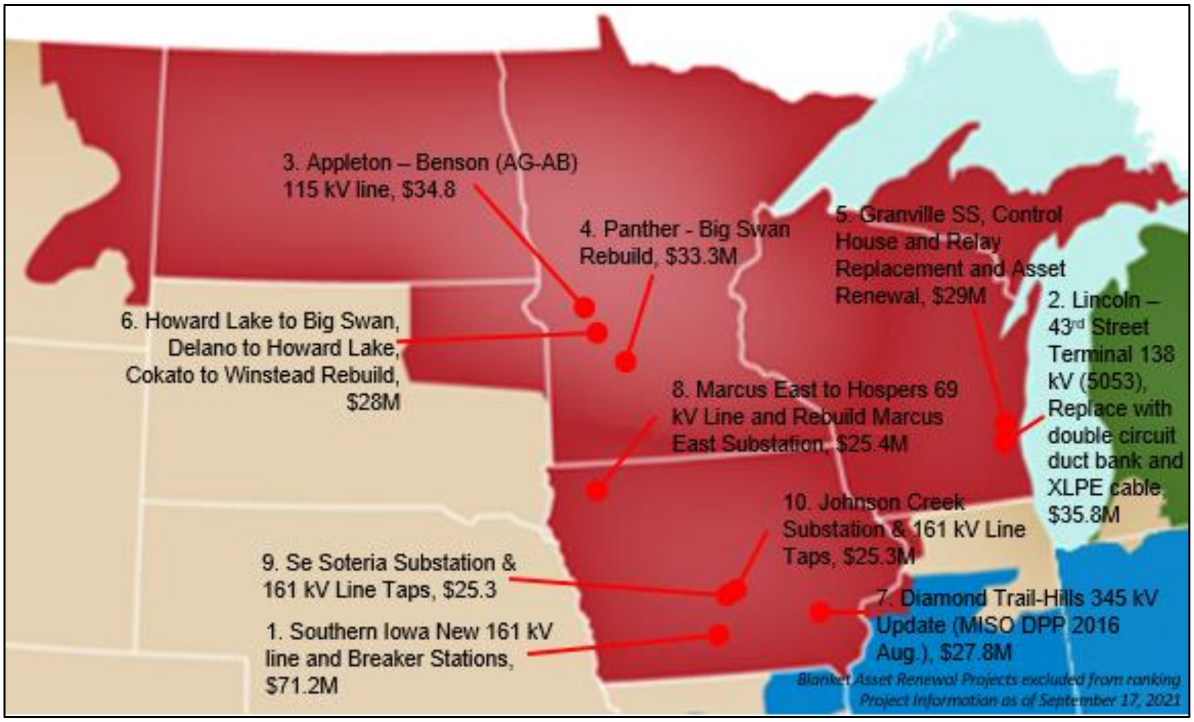

Figure 4.5-4: West region top ten projects by cost (data as of 9-17-2021)

4.5.1 American Transmission Company (ATC)

American Transmission Company proposed 21 projects at an estimated cost of $317 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the ATC area, all 21 of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $317 million. Of these projects, one is a Baseline Reliability Project, 18 are Other projects, and two are Generator Interconnection projects with signed Generator Interconnection Agreements. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

Project 20785 – Highway V -Preble 138 kV (X-154), reconductor

Project Description

The Highway V-Preble 138 kV line reconductor project consists of the following: Reconductor 138kV line from Highway V to Preble, replace five 138 kV jumpers at Highway V, and replace one 138 kV jumper at Preble. The project's estimated cost is $1.77 million, and the expected in-service date is March 15, 2023.

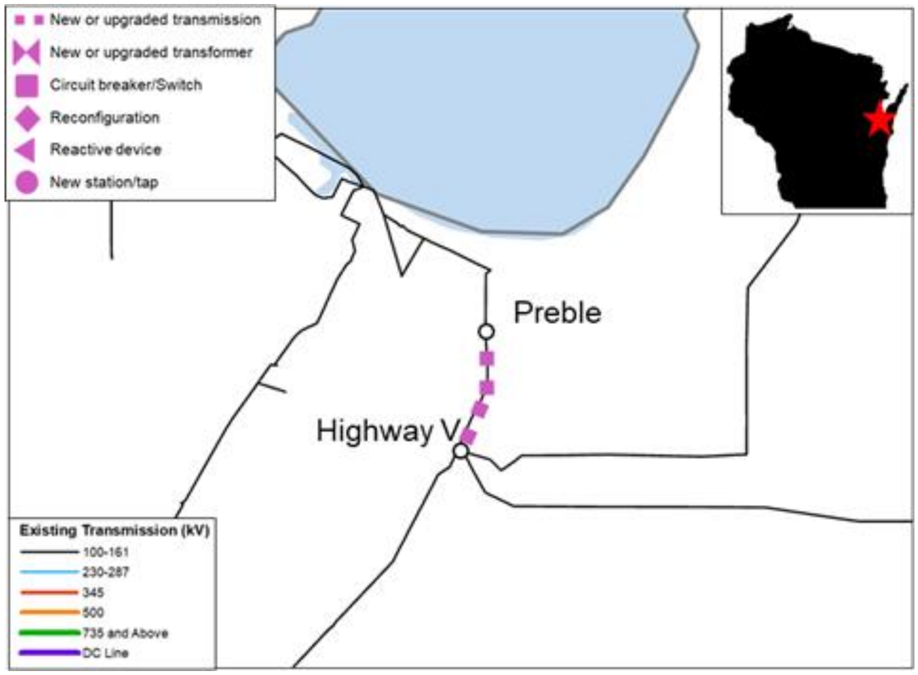

Figure 4.5.1-1: Geographic transmission map of project area

Project Need

The Highway V-Preble 138 kV line overloads under certain P6 and P7 contingencies identified during the MTEP20 cycle. Project will reconductor the Highway V-Preble line to a minimum of 1344 amps rating.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P61	699610 HIGHWAYV - 699615 X154 REACTOR 1	235	114	83.3
P61	699612 PREBLE - 699615 X154 REACTOR 1	235	114	83.3
P71	699610 HIGHWAYV - 699615 X154 REACTOR 1	235	114.5	83.7
P71	699612 PREBLE - 699615 X154 REACTOR 1	235	114.6	83.8

[1]This line overloads in the SUM22, SUM25, WINNF25 and SUM30 models, all of which are mitigated by 20785

Table 4.5.1-1: P20785 Thermal loading drivers

Alternatives Considered

No alternative was considered for the Highway V -Preble 138 kV (X-154), reconductor.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19965	Marquette County Reactive Power Project	Relocate one 138 kV line position (line 16343) to a different bus position at National substation. Install one +/- 50 MVA, 138 kV STATCOM (Static Synchronous Compensator) at National substation. Include one spare 138 kV transformer. Add a new 138 kV circuit breaker and protection package at National.	December 31, 2023	24.2
14966	Line Clearance Mitigation Program 2022	Line Clearance Mitigation projects have shorter project life cycles. Projects are driven by the ongoing assessment and analysis of field line clearances using Light Detection and Ranging (LiDAR) technology. Clearance mitigation work immediately follows data assessments and issue identification to maintain safety and system reliability. Initial capital spend for this program expected in 2022.	June 30, 2025	2.8

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
18048	Lincoln - 43rd Street Terminal 138 kV (5053), Replace with double circuit duct bank and XLPE cable	Rebuild existing 5053 HPFF line with new XLPE in double circuit duct bank in existing road ROW. Install ~2.2 miles of XLPE in double circuit duct bank package and new manholes.	December 31, 2024	35.8
14964	Small Capital Project and Asset Renewal Program 2022	Asset replacements and upgrades typically require limited infrastructure modifications and additions with shorter project life cycles. Transmission Line Projects typically (but not limited to): structure, cross-arm, insulator, surge-arrester, re-insulations and uprates and Pole hardware replacements. Estimated cost - $14,000,000. Substation Projects typically (but not limited to): relays, circuit breakers, switches, instrument transformers (CTs & PTs etc.), batteries, RTUs, and IT/OT/Communications hardware replacements. Estimated cost - $30,000,000. Substation Battery Replacement Program Estimated cost - $3,000,000. Substation Physical Security Asset Renewal -Estimated Cost - $1,000,000. Wood Structure Replacement Program - Estimated Cost -	June 30, 2025	52.3

		$1,000,000. Project drivers may be Asset Renewal or small system limit upgrades. These projects have limited scope and cost. Initial capital spend for this program expected in 2022.		
16489	Empire SS, Control House, Relays, and Circuit Breaker Asset Renewal	Asset renewal at the Empire SS would include: Install new control building. Retirement and replacement of circuit breakers, protective relays, and disconnect switches	December 31, 2024	9.9
19705	Crivitz SS, Transformers and Relays Asset Renewal	Replace T1, 138/69 kV power transformer with the on-site 138/69 kV system spare. Replace T3, 138/69 kV power transformer with the 138/69kV power transformer from Pioneer SS that will be taken out of service in 2023 due to elimination of the 69 kV system at that substation. Replace 69 kV Mark V circuit switcher with an existing on site circuit breaker and new disconnect switch. Replace a single line relay in an existing panel.	December 31, 2024	4.60
19706	North Appleton SS, Transformer and Reactor Asset Renewal	Replace T7 138/345 kV power transformer (three single phase units) with the on-site system spare (standard three phase). Retire two three-phase reactors, bus, structures and insulators and install a new standard 24.9 kV design connected to the tertiary of the newly installed 138/345 kV power transformer. Retire original design 34.5 kV vacuum breaker and associated disconnect switches. Install new station service on 24.9 kV bus salvaging three newer vintage reactors for use in a future project. Replace seven 138 kV disconnect switches.	December 31, 2024	7.94
10590	Academy - Columbus, 69kV (Y-21), rebuild & OPGW	The Academy - Columbus (Y-21) 69kV circuit is 3 miles long and uses 336 kcmil ACSR supported on lattice steel structures, field inspection reports indicate the 1910 vintage structures require replacement to continue reliable operation. New conductor will be installed and will be similar or slightly larger than the existing circuit capability. Optical Ground Wire (OPGW) will be installed to provide protection and SCADA communications along this ROW Substation Work Scope: Academy Substation, replace line side jumper to meet planning long term rating needs and terminate fiber. Columbus (ALTE): Remove control house, oil circuit breakers, and switches; install motor operated disconnects, gas circuit breaker, control house, and RTU for SCADA control, improve drive access to site with purchase and demolition of existing residence. Terminate fiber with line project.	December 31, 2024	8.80
16490	Granville SS, Control House and Relay Replacement and Asset Renewal	345kV Project Scope: Replace 4 1970-vintage Westinghouse 3450-GW-25000 oil breakers, replace 7 disconnect switches, 138kV Project	December 1, 2024	28.95

		Scope, replace 7 1969-vintage Westinghouse 1380-GM-15000 oil breakers, replace 2 underground HPFF lines with overhead and retire pump house at Granville and East Granville Terminal. General Project Scope: reconfigure 345kV bus to 6-position ring (5 positions plus one future position),vacate existing control house, transfer ownership to We Energies, obtain new high-security control house, replace all relays and SCADA with current standard, address planning-identified need for redundant bus differential protection, and expand yard to accommodate ring bus.		
19105	Nelson Dewey SS - Control House, Relay Asset Renewal	Replace control house and contents, including but not limited to relays and panels, relocating, and reusing five reply panels in the new house, two batteries and charger. Project team will evaluate location and elevation and relay panel design to mitigate flood risk. Replace control cabling between new control house and all station equipment.	June 1, 2022	6.17

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19806	Bonnie Road SS, DIC, New Substation	Extend approximately 0.38 miles of 69 kV double circuit transmission line on new right-of-way. Construct new 69 kV substation with a bus-tie switch and provisions for a future bus-tie breaker. Install 69 kV line breakers as sectionalizing devices.	June 1, 2023	3.50
20925	Lancaster Transformer Replacement & Substation Rebuild	ATC will retire the Lancaster 138/69 kV transformer, 69 kV bus, and associated equipment and expand the 138 kV bus (box structure) and add bus-tie switches and space provisions for a future bus-tie breaker. In addition, install 2 circuit breakers online X-1 and replace the control house and relay equipment.	December 31, 2023	3.70
14968	Load Interconnection Program 2022	Load Interconnection Project life cycles are customer need driven and typically have shorter project life cycles. These Load Interconnections typically require limited infrastructure modifications and additions. These projects have limited scope and cost. Initial capital spend for this program expected in 2022.	June 30, 2025	27.59
19961	Wells St. DIC – New West Marinette-Wells St. 69 kV line	Rebuild West Marinette-Roosevelt Rd. 69 kV as double-circuit, add a 2nd 69 kV circuit on the Roosevelt Rd.-Wells St. overhead	May 31, 2024	16.10

		structures, add underground cable to Wells St.		

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19959	Sussex to Bark River (46143/2661), 138kV, OPGW Installation	This project is to establish a direct fiber path for Relay communication between both substations as well as SCADA communications back to both ATC control centers.	December 31, 2023	3.77
19587	Petenwell – Council Creek, (X-40) 138kV, Partial Structure and OPGW Replacement	Replace 30 miles of shield wire with 48 Strand OPGW Fiber cable between Petenwell and Council Creek substations. Replace ~67 wood monopoles structures.	December 31, 2024	9.0
14965	Communication Reliability Program 2022	Communications network system upgrades typically require limited infrastructure modifications and additions with shorter project life cycles. Substation Communications Reliability Upgrade projects are typically (but not limited to): OPGW additions, replacements, relocations, or removals. Project drivers typically are communications support for SCADA, relay protection, security systems, small communications network upgrades, and telecom industry market transitions. These projects have limited scope and cost. Initial capital spend for this program expected in 2022.	June 30, 2025	19.25
14967	Physical Security Program 2022	Physical security projects typically have shorter project life cycles. The Physical Security Program is guided by the NERC Standard CIP-014 and is designed to harden substation infrastructure. Specific project locations and scopes of work are not made public. Initial capital spend for this program expected in 2022.	June 30, 2025	11.80

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20625	J986 7 Mile Creek SS, Generator Interconnection Facilities and Network Upgrades	J986 is a proposed 149.76 MW solar farm power plant in Wood County, Wisconsin. Project costs reflective of E&P agreement only, costs will be updated upon executed Interconnection Agreement at a later date.	June 1, 2022	17.56

19729	J732 Superior SS Network Upgrades and Interconnection Facilities	Interconnection of about 560 MW the facility composed of one (1) steam turbine unit and one (1) natural gas unit in a 1x1 combined cycle facility interconnecting at the new Superior Substation.	November 30, 2023	21.25

4.5.2 Cedar Falls Utilities (CFU)

Cedar Falls Utilities did not submit any new projects for MTEP21. MISO has not identified any issues in CFU area.

4.5.3 Central Minnesota Municipal Power Agency (CMMPA)

CMMPA proposed three projects at an estimated cost of $8.35 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the CMMPA area, these projects are recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $8.35 million. These projects are classified as Other projects. The projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20166	Delano Municipal Utilities Sub A XFMR Upgrade	Replace the Sub A 10 MVA 69/12.47kV transformer with a new 12/16/20 MVA 69/12.47kV transformer	April 5, 2021	1.75
20168	Delano Municipal Utilities Sub B XFMR Upgrade	Replace substation B transformer with new 12/16/20 MVA 69/12.47kV transformer	April 4, 2022	2.50
20169	Delano Municipal Utilities New 69 kV Industrial Park Sub	Build a new 69kV substation to serve expected residential and future industrial park load growth	April 4, 2022	4.10

4.5.4 City of Ames, IA (COA)

City of Ames, IA did not submit any new projects for MTEP21. MISO has not identified any issues in COA area.

4.5.5 Dairyland Power Cooperative (DPC)

Dairyland Power Cooperative proposed two projects at an estimated cost of $16.9 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the DPC area, both of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $16.9 million. Of these projects, both are Other projects. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19953	Frenchville Tap N223 Rebuild	Rebuild 11.1 miles of the N-223 line from the N-122 tap to the XEL Ettrick substation with 4/0 conductor.	April 14, 2023	$3.85
20136	Pine Lake to Dunn Ethanol N4 Rebuild	This project is a mix of a rebuild of DPC's existing 69 kV line in the area and construction on new right-of-way. The recommended plan in this area is to construct new transmission line with 477 ACSR conductor, a mix of replacement of existing line and new right-way from XEL's Pine Lake transmission substation to the east towards the Dunn Ethanol distribution substation. The recommended plan will address the age and condition issues, constructing the line with new poles and 477 ACSR conductor. The plan will also address the longer tap lines to distribution substations with individual taps to all five distribution substations served from this line. Finally, building to the Dunn Ethanol distribution substation will provide backup service.	February 9, 2024	$13.05

4.5.6 Great River Energy (GRE)

Great River Energy proposed seven projects at an estimated cost of $67.21 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the GRE area, all of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $67.21 million. Of these projects, six are Other projects, and one is a Generator Interconnection project with a signed Generator Interconnection Agreement. Great River Energy did not propose any Baseline Reliability projects for MTEP21. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
17996	Willmar 230/115 kV Transformer	Add a 230/115 kV LTC transformer at Willmar substation.	May 1, 2022	12.29
20139	Winthrop McLeod - Winthrop Xcel (MC-WW) 69 kV Rebuild	Rebuild MC-WW (9 miles) to upgradable 69kV with T2 capable of 1500-1600 amps. Remove SS2950 Winthrop tap switch.	May 1, 2024	6.62
20141	Decoria - Decoria Tap - Stoney Creek (BE-MD) 69 kV Rebuild	Rebuild BE-MD segments 1 and 2 (4.02 miles) and SS2826 to 69kV with T2 1200 amp capable conductor.	April 28, 2023	3.02
20143	Wing River 230 kV Ring Bus	Convert the 230 kV portion of the Wing River substation into a ring bus.	August 26, 2022	3.72
20148	Appleton - Benson (AG-AB) 115 kV Line	Construct about 27 miles of 115 kV transmission line from Appleton to GRE's AG-BK line and about 1.75-mile 115 kV transmission line from AG-BK line to Benson Muni substation with associated tap switch, distribution sub, and retirement projects.	July 31, 2026	34.77
20151	Milaca Breaker Addition 69 kV	Move ECE's Milaca delivery points from the auxiliary bus onto the main bus and with circuit breaker protection.	December 31, 2021	0.42

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
18865	Square Butte - Stanton 230 kV Upgrade (J302/J503)	Upgrade Square Butte - Stanton 230 kV line for generator interconnections J302 & J503	July 10, 2021	6.38

4.5.7 ITC Midwest (ITCM)

ITC Midwest proposed 17 projects at an estimated cost of $184.7 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the ITCM area, 17 of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $184.7 million. Of these projects, zero are Baseline Reliability Projects, 16 are Other projects, and one is a Generator Interconnection project with a signed Generator Interconnection Agreement. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
17968	Thisius 161/69kV Substation	ITCM will construct a 161:69kV substation at the crossing of the Huntley – Freeborn 161kV and Huntley – Walters 69kV circuits.	May 31, 2023	7.89
19928	Marion-Old Settlers 115kV Ckt#2	To better serve the Northeast Cedar Rapids load pocket, ITC will energize the second circuit on the Marion – Old Settlers 115kV structures and terminate it into Marion & Old Settlers substations.	December 31, 2025	4.23
19931	Dickinson County-Triboji 161kV Sag Remediation	Remove all existing sag limits on Dickinson County – Triboji 161 kV line to raise 636 ACSR to full summer conductor rating at 212 F (953/953/953 amps SN/SE/SSE 266/266/266 MVA SN/SE/SSE).	December 31, 2022	0.37
19993	Triboji 69kV Cap Bank	ITC will install a 11.25MVAR Effective cap bank, zero crossing/sync breaker and 0.5 mH pre-insertion reactor on the Triboji J2 bus. All new substation equipment should have a minimum rating of 1200A.	December 31, 2023	0.81
19995	West Union 69kV Cap Bank	ITC will install a 11.25MVAR Effective cap bank, zero crossing/sync breaker and 0.5 mH pre-insertion reactor on the West Union J2 bus. All substation equipment should have a minimum rating of 1200A.	December 31, 2023	0.81
19996	Monona 69kV Sub Rebuild & Cap Bank Addition	ITC rebuild the Monona 69kV substation and install a 11.25MVAR effective cap bank, zero crossing/sync breaker and 0.5 mH pre-insertion reactor at a new Monona Substation adjacent to the existing site. All substation equipment should have a minimum rating of 1200A. This will allow for two 69kV buses and the cap bank installation at the new Monona site improving operational flexibility and addressing voltage concerns in the area.	December 31, 2023	1.15
20029*	Southern Iowa New 161kV line and Breaker Stations	ITC will be building about 29 miles of 161kV line from CIPCO's Winterset Jct. to Osceola's new substation. In addition, a new 161/69kV, 150 MVA transformer will be needed at the Osceola substation. ITC will be building a new breaker station northeast of the Albia substation. This station will connect the 69kV line from Albia to Court and the 69kV line from Bridgeport to Centerville. ITC will be building a new breaker station at the "Lenox Tap" position. This station will replace the 3-way switch currently in use and connect our Lenox line and substation (IPL owned) to the new 69kV transmission	May 1, 2026	71.2

		system being built by CIPCO from the northwest (Corning/Brooks). ITC will be installing a 2-way switch outside IPL's Lenox substation, building a new 69kV line (about 2.6 miles), and connecting it into CIPCO's substation "Lenox Muni".		

***Project 20029 – Southern Iowa New 161kV line and Breaker Station** (in table above)

Alternatives Considered

An alternative was provided to construct a new 345/161 kV substation on the Orient – Madison County 345 kV line to support the new 161 kV Osceola station. A new 17 mile 161 kV line from the new 345 kV substation would connect to the new Osceola 161 kV station. No changes were proposed to the 69 kV portion of the original project. MISO compared the reliability of the alternative to the proposed project by using the appropriate MTEP models, reviewing NERC TPL and local planning criteria requirements, and determining if any reliability concerns (either new or existing violations) were addressed. MISO's reliability evaluation showed the alternative produces new thermal violations on local transferred facilities for high wind scenarios. For P6 events in the project area, local wind curtailment would be required to mitigate those violations. The alternative would require an agreement between ITCM and MEC to connect to the 345 kV line owned by MEC. Based on the reliability impact of the alternative and the need to obtain new agreements, all impacted parties agree to recommend the original proposed project for MTEP21 Appendix A. See Figure 4.5.7-1 for project area and alternative area.

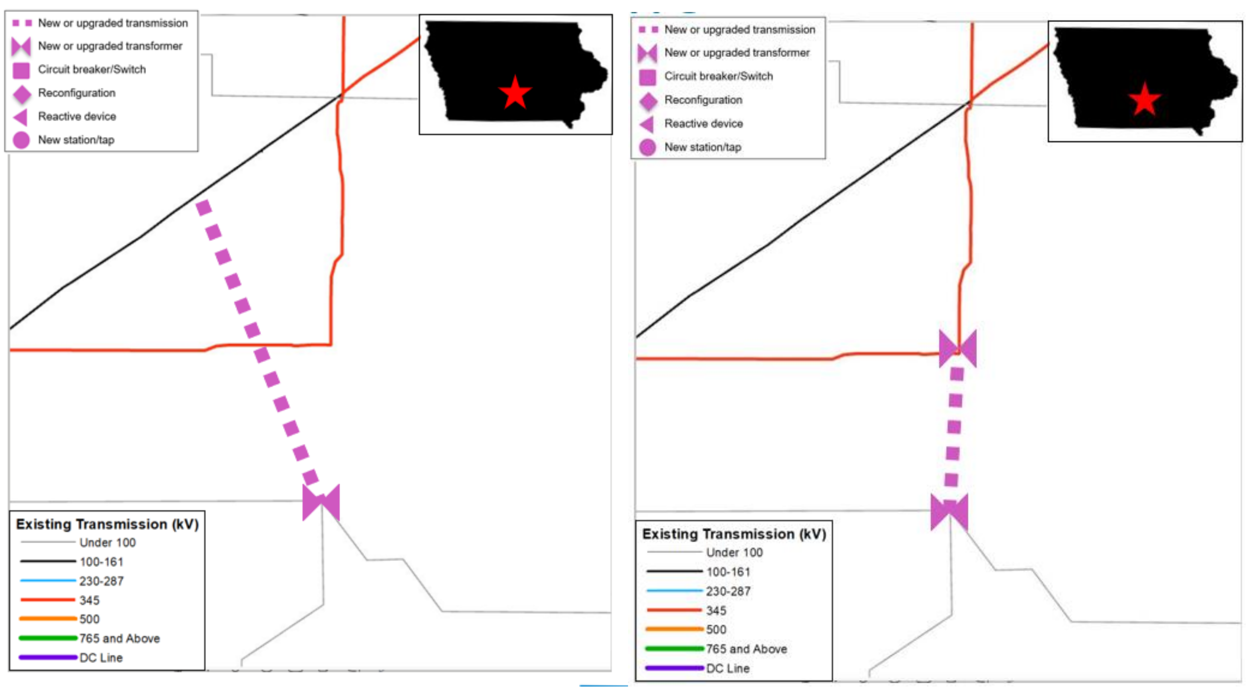

Figure 4.5.7-1 Geographic transmission map of #20029 project area (left) and alternative area (right)

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)

19925	Albia-Melrose 69kV Rebuild	The majority of the Albia to Melrose 69kV line is near end of life and in poor condition. The line between the Albia and Melrose substations (~17.25 miles) will be rebuilt to current 69kV standards. All new equipment should be rated at 600A or higher minimum summer normal rating.	December 31, 2024	16.29
19926	Osceola North-Woodburn Jct 69kV Rebuild	The majority of the Osceola North to Woodburn 69kV line is near end of life and in poor condition. The line between the Osceola North, Osceola Rec, and Woodburn Jct. substations (~9.57 miles) will be rebuilt to current 69kV standards. All new equipment should be rated at 600A or higher minimum summer normal rating.	December 31, 2024	8.96
20025	Bethel-Tripoli 69kV Rebuild	The majority of the Bethel-Tripoli 69kV line is near end of life and in poor condition. The line between the Bethel substation and Fredericksburg Tap (~8 miles) will be rebuilt to current 69kV standards. All new equipment should be rated 600A or higher minimum summer normal rating.	December 31, 2024	7.74
20026	Osage Jct-Rice 69kV Rebuild	The majority of the Osage JCT-Rice 69kV line is near end of life and in poor condition. The line between Osage JCT and Douglas Tap (~13.9 miles) and Riceville to Rice (~9.8 miles) will be rebuilt to current 69kV standards. All new line equipment should be rated 600A or higher.	December 31, 2024	22.98
20028	Emery-6th Ave 69kV Rebuild	Beginning at where the double circuit ends (~0.35 miles outside Emery) - IPL's 6th Ave substation will be rebuilt (~5.54 miles of line) to current 69kV standards. All new line should be rated 1200A or higher.	December 31, 2024	7.2

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20037	Carbide-Viele 161kV Rebuild	ITC Midwest has entered into an agreement with Northeast Missouri Electric Cooperative to rebuild approximately 12.3 miles of the ITC Carbide – Viele 161 kV line to double circuit to allow Northeast to connect a new 161 kV line from their Franklin Substation in Lee County, Iowa to their Winchester Substation in Clarke County, Missouri. Per the terms of the agreement, Northeast will be responsible for design and construction for this project. ITC will contribute a fixed amount of $6,120,00 for the project as a credit for planned maintenance ITC needs to perform on this line. The ITC portion of the rebuild will be constructed with T2-795 ACSR conductor and OPGW. ITC will own the double circuit poles, conductor, insulators, and 1 OPGW static wire.	December 31, 2024	6.20
20180	ITCM Customer Interconnects with short lead time 2024	These projects are being done at the request of an interconnection customer in order to facilitate new load, re-distribute existing load, improve the performance of the sub-transmission and distribution systems, or to accommodate a new Transmission-to-Transmission connection request.	December 31, 2024	2.40
21429	Tiffin Crossroads Substation Interconnection	IPL will be building a new 69/25x12.5 kV substation named "Tiffin Crossroads" adjacent to the existing MidAmerican Tiffin Sub K substation. This new substation will replace the existing IPL Tiffin distribution substation and accommodate future area load growth. IPL will be installing one 12/20 MVA transformer initially but is planning the substation to accommodate a 2nd 12/20 MVA transformer in the future. For the ITC owned portion of Tiffin Crossroads, ITC will	December 31, 2024	5.13

		build a new 69 kV substation with two single boxes, two line breakers, and a bus tie breaker. As part of this, the existing Sub K Tiffin double circuit line tap will be reconfigured to two single circuits, to avoid having a double circuit line tap going into the distribution substation and avoid issues with planned outages on the double circuit requiring the distribution substation to be taken out of service.		
21625	Keokuk Geode 69kV Substation Interconnection	IPL will be building a new 69/25x12.5 kV Substation named Keokuk Geode. The new Keokuk Geode Substation will replace the Messenger Substation and Commercial Substation. IPL will be installing one 69/24.9x12.5 kV 20/33MVA transformer initially but is planning the substation to accommodate a second 69/24.9x12.5 kV transformer when all the load is transferred from the Messenger Substation and Commercial Substation.	October 20, 2022	4.76

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20027	Meservey 69kV Tap Retirement	Retire ~6.9 miles of 69kV line to the IPL owned Meservey substation. Also remove line switches 4122 and 4123. All poles with underbuild should be topped per underbuild owner specification. All necessary outages should be coordinated with IPL.	December 31, 2022	0.42

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20035	MPFCA - Hickory Creek and Killdeer 345 kV Cap Bank TO-Funded Network Upgrades	ITC Midwest entered into a Multi-Party Facilities Construction Agreement ("MPFCA") with MISO and the Interconnection Customers for MISO Projects J302, J476, J503, J512, J555, J569, J583, J587, J590, J611 and J614 for the construction of Network Upgrades at Killdeer 345 kV and Hickory Creek 345 kV. The MPFCA provides for ITC Midwest to fund the cost of 2 x 84 MVAR (rated) capacitor banks at Killdeer 345 kV substation and 2 x 84 MVAR capacitor banks at Hickory Creek 345 kV substation.	July 1, 2022	16.1

4.5.8 MidAmerican Energy Company (MEC)

MidAmerican Energy Company proposed 48 projects at an estimated cost of $351.8 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the MEC area, all of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $351.8 million. Of these projects, four are Baseline Reliability, 33 are Other projects, and 11 are Generator Interconnection projects with signed Generator Interconnection Agreements. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Baseline Reliability Projects

Project 20000– Bondurant Substation: Add 345-161 Xfmr

Project Description

The project will consist of adding a 345-161 kV autotransformer to the Bondurant Substation along with associated bus work and breaker additions. The estimated cost is $11.9 million with an expected in service date of December 1, 2024.

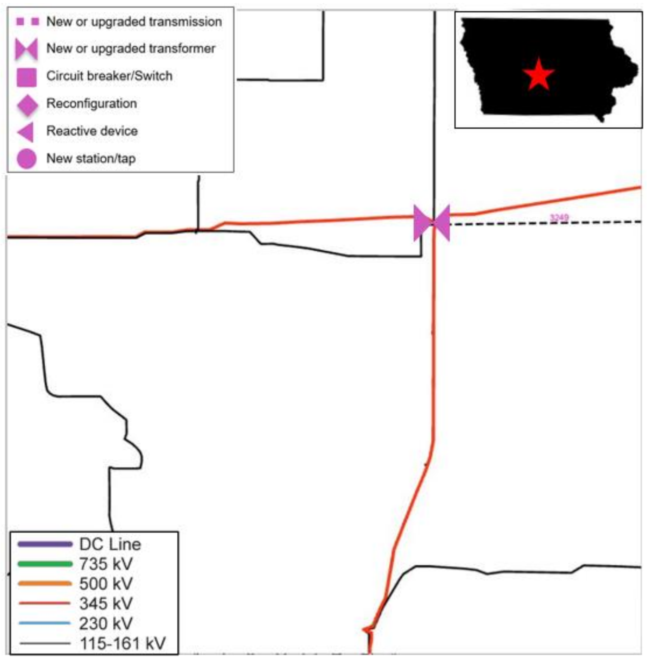

Figure 4.5.8-1 Geographic diagram of the project area

Project Need

Load growth in the Altoona area is continuing to increase the demand on the Bondurant Substation served 161 kV load after P6 N-1-1 contingencies. This project will mitigate thermal overloads of DPS–Metro East, Metro East–Altoona and Sycamore–Delaware 161 kV lines after P6 contingencies. There is also potential low voltage on area buses after P6 events. Adding a 345-161 kV autotransformer to the Bondurant Substation will improve system reliability to customers served in the area of the Bondurant Substation.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	635701 'SYCAMORE 5' 161.000 - 635703 'DELAWARE5' 161.000 1	345	110	75
P6	635670 'DMOINES5' 161.000 - 635672 'METRO E5' 161.000 1	257	145	62
P6	635672 'METRO E5' 161.000 - 635673 'ALTOONA 5' 161.000 1	335	103	81

Table 4.5.8-1: P20000 limiting elements

Alternatives Considered

Reconductor and replace structures as needed on the affected lines. This alternative does not mitigate the issue of the load driving the need for additional 345-161 kV transformation in the Des Moines area or the voltage issues in the Bondurant area, and the cost of the reconductor exceeds the benefit that would be received.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project is included in the competitive developer selection process.

Project 20006– DPS 161 kV Strain Bus Uprate

Project Description

The project will consist of replacing the existing 500 kcmil copper jumpers and strain bus elements on the DPS 161 kV breaker-and-a-half with 1590 AAC Coreopsis. The estimated cost is $300,000 with an expected in service date of 6/1/2022.

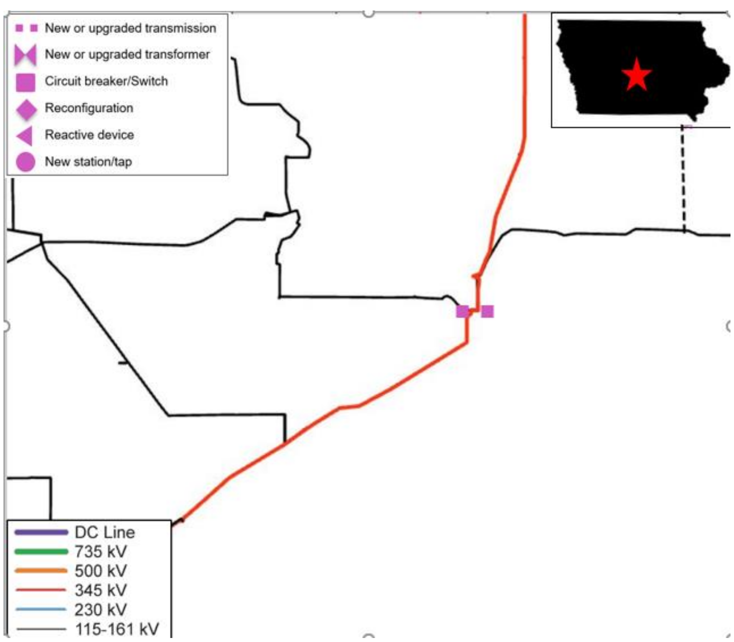

Figure 4.5.8-2 Geographic diagram of the project area

Project Need

Customer load growth in the Altoona area is continuing to increase the demand on the DPS-Metro East 161 kV line after N-1-1 contingencies. The 500 kcmil copper jumpers are limiting the ring open rating to 257 MVA, which makes the strain bus the most limiting element at DPS. Replacing the 500 kcmil copper jumpers with 1590 AAC Coreopsis would increase the ring open rating to 430 MVA, which is greater than the conductor rating of 410 MVA for DPS–Metro East 161 kV line. Using 1590 AAC Coreopsis jumpers will mitigate overloads and increase system reliability at DPS.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	635701 'SYCAMORE 5' 161.000 - 635703 'DELAWARE5' 161.000 1	345	110	75
P6	635670 'DMOINES5' 161.000 - 635672 'METRO E5' 161.000 1	257	145	62
P6	635672 'METRO E5' 161.000 - 635673 'ALTOONA 5' 161.000 1	335	103	81

Table 4.5.8-2: Project #20006 limiting elements

Alternatives Considered

Install a new 345-161 kV autotransformer at the Bondurant Substation to reduce post-contingent loading on the DPS–Metro East 161 kV line. This future project involves more implementation time and cost.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 19999– Booneville: Second 345-161 kV Xfmr

Project Description

The project will consist of adding a second 345-161 kV autotransformer to the Booneville Substation along with associated bus work and breaker additions. The estimated cost is $16.7 million with an expected in service date of 6/1/2023.

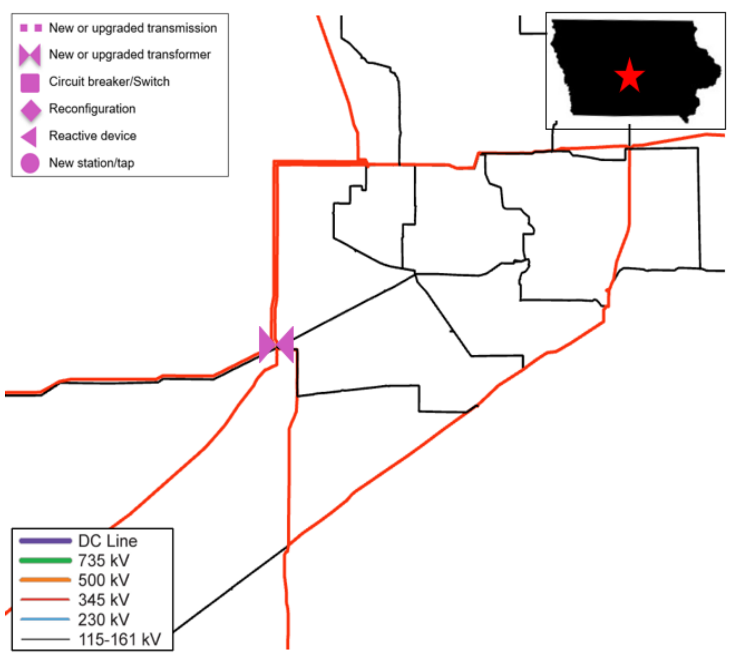

Figure 4.5.8-3 Geographic diagram of the project area

Project Need

Load growth in the West Des Moines area is continuing to increase the demand on the Booneville 345-161 kV autotransformer after P6 N-1-1 contingencies resulting in an overload in the shoulder peak model. Adding the second 345 – 161 kV autotransformer to the Booneville substation mitigates the overload and improves system reliability.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	635630 'BOONEVILLE 3' 345.000 - 635631 'BOONEVILLE 5' 161.000	558	119	79
P23	635630 'BOONEVILLE 3' 345.000 - 635631 'BOONEVILLE 5' 161.000	558	110	62

Table 4.5.8-3: P19999 limiting elements

Alternatives Considered

Adding more 161 kV lines into the area. This alternative does not mitigate the issue of the load driving the need for additional 345-161 kV transformation in the Des Moines area. Obtaining the franchises and right-of-way for new transmission lines would not be timely.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Project 2938– Uprate Sub 39 – Cordova 345 kV Line

Project Description

Replace transmission line structures to increase the allowable conductor operating temperature and rating of the Substation 39-Cordova 345 kV line. The estimated cost is $500,000 with an expected in service date of 6/1/2022.

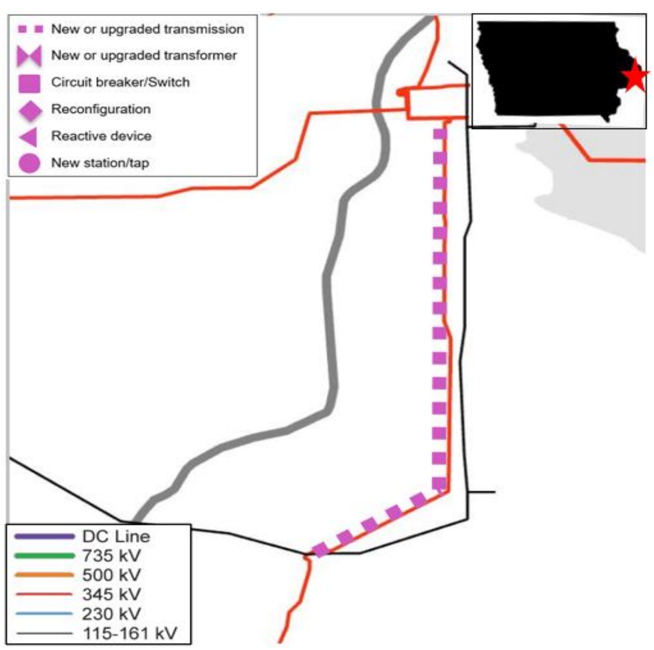

Figure 4.5.8-4 Geographic diagram of the project area

Project Need

The Substation 39-Cordova 345 kV line overloads in the MTEP20 2022 Summer Peak model for the Category P6 N-1-1 contingency in the Quad Cities area. A Corrective Action Plan is required for NERC Standard TPL-001-4 compliance.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	636600 SUB 39 3 - 636605 MEC CORDOVA3 1	1333	135	81

Table 4.5.8-4: P2938 limiting elements

Alternatives Considered

Generation redispatch of Cordova Energy Center combined cycle gas plant.

Immediate Need Reliability Project

In accordance with Attachment FF Section VIII.A.3, the following project was not identified as an Immediate Need Reliability Project and is included in the competitive developer selection process.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
18890	Clarksville-Donald Feldman 69 kV Line	Construct a new 69 kV line between MidAmerican's Clarksville East Substation and Corn Belt Power Cooperative's Donald Feldman Switching Station.	December 1, 2021	5.39
19745	100th & 54th Avenue: Replace 161 kV Breaker 803	Replace the 161 kV breaker 803 at 100th & 54th Avenue Substation with a breaker that has interrupting rating of 40 kA.	June 1, 2022	0.25
19997	Circuit Breaker Additions and Replacements 2022-2024	Blanket project to add new 345 kV and 161 kV circuit breakers and replace existing 345 kV, 161 kV and 69 kV circuit breakers to increase reliability and operating flexibility.	December 31, 2024	17.73
20002	Waukee: Add 69 kV Capacitor Bank	Install 69 kV capacitor bank and 69 kV breakers.	December 1, 2023	1.6
20007	Clarion: Add 69 kV Breakers	Presently, Clarion Substation is tapped off the Hampton West--Eagle Grove 69 kV line. Reconfigure the 69 kV lines into Clarion Substation from a single tapped arrangement to an in and out breakered configuration, similar to Goldfield Substation. Build new 69 kV bus on MEC owned property adjacent to existing substation footprint. Install 69 kV circuit switcher between 69 kV bus and existing 69-13 kV transformer. Construct new 69 kV bus to accommodate a future 69 kV bus tie breaker, a future 69 kV circuit switcher, and a future second 69-13 kV transformer.	March 1, 2022	0.38

20010	Substation 73: 69 kV Line Taps	69 kV line tap work to support converting Sub 73 from a tapped substation to an in-and-out substation with 69 kV line circuit breakers.	December 31, 2021	0.5
20011	Sub 84: 69 kV Line Taps and Line Upgrades	69 kV line tap work to support converting Sub 84 from a tapped substation to an in-and-out substation with 69 kV line circuit breakers. Install OPGW from Valley Drive to Sub 84 to Sub 55 for communications and replace structures and conductor on sections of line subject to galloping.	June 1, 2023	5.4
20013	Sub 113: 161-69 kV Substation	Add a new 161-69 kV substation bisecting the Oak Grove-Mercer 161 kV line and Sub 108-Sub 111 69 kV line.	December 31, 2022	5.0
20171	Red Oak-Emerson 69 kV Structure Replacements	Replace structure to obtain the maximum conductor rating at 212F.	April 1, 2022	0.2
20172	Percival– Hamburg 69 kV Structure Replacements	Replace structure to obtain the maximum conductor rating at 212F.	December 31, 2021	0.06
20173	Quick-Sub 701 161 kV Line and Line Terminals	Construct a new Quick-Sub 701 161 kV line and line terminals.at Quick and Sub 701.	June 1, 2023	17
20176	Hitchcock 69-13.2 kV Substation	Construct a new 69-13.2 kV distribution substation and associated 69 kV line work.	June 1, 2022	3.6
20177	Missouri Valley East 69-13.2 kV Substation	Construct a new 69-13.2 kV distribution substation and associated 69 kV line work.	June 1, 2023	0.8
20189	Washburn: 161 kV Bus A Improvement	Washburn Bus A: Same upgrades needed on Bus A as are being completed on Bus B under T91PK. The 161 kV circuit switcher on 161-69 kV transformer does not interrupt faults.	June 1, 2021	1.0

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19994	Marcus East to Hospers 69 kV Line and Rebuild Marcus East Substation	Construct a new 69 kV line from Hospers-Marcus East, construct new 69 kV line terminal at Hospers Substation, rebuild Marcus East Substation to install 69 kV breakers and a 69 kV capacitor bank.	December 1, 2022	25.4
19998	NW 2nd Street Substation	Construct a new 69 kV substation and associated 69 kV line work.	December 1, 2022	10.0
20003	Highway 6 161/13.2 kV Substation	Construct a new 161 kV substation and associated 161 kV line work. New substation will have 161 kV connections to Grimes & South Waukee substations from line taps on future 161 kV lines.	December 1, 2024	6.0
20008	Hampton West –Latimer 69 kV Line Uprate	Replacing line structures to obtain maximum conductor rating.	June 1, 2021	0.93

20012	Sub 17: Add 161-13.2 kV Transformer	Add 161 kV line circuit breaker at Sub 17 on the Sub 28 line terminal to support the addition of a new 161-13.2 kV transformer.	June 1, 2023	1
20154	69 kV Substation Line Tap Blanket 2021-2024	Blanket project to add new 69 kV line taps into new or existing substations to serve new distribution substations or to increase reliability.	December 31, 2024	5.15
20626	Se Soteria Substation & 161 kV Line Taps	New 161 kV distribution substation and associated 161 kV line reconfiguration and construction.	February 4, 2022	25.3
20627	Johnson Creek Substation & 161 kV Line Taps	New 161 kV distribution substation and associated 161 kV line reconfiguration and construction.	January 1, 2022	25.3

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
18885	Clarinda to Braddyville 161 kV Line Rebuild	The project will consist of rebuilding the Clarinda-Braddyville 161 kV line and adding OPGW to improve relaying communication and reduce the potential for mis-operations. The line is approximately 12.3 miles.	October 1, 2020	6.75
18891	Plymouth Substation 161 kV Switches and Jumpers Replacement	Replace seven 161 kV switches and remove one 161 kV switch at Plymouth Substation. Also, replace the jumpers associated with the switches.	November 1, 2020	0.35
20153	69 kV Line Rebuilds Blanket 2021 - 2024	Blanket project to rebuild 69 kV lines due to condition and to improve reliability and operational flexibility.	December 31, 2024	27.7
20192	Rock Valley: Replace 69 kV Breakers & Relays	Replace two 69 kV oil circuit breakers and electromechanical line and bus relaying at Rock Valley Substation.	December 31, 2021	1.1
21265	Sub A Riverside 69 kV Upgrades	Replace 69 kV breakers and protective relaying. Also replace 161-69 kV Transformer Bank 8T1 and 8T2 with a new 161-69 kV, 125 MVA transformer.	December 31, 2022	4.1
21266	Plymouth 161-69 kV Transformer Replacement	Replace the 161/69 kV (150 MVA) transformer at Plymouth substation which failed recently. The replacement transformer will be a spare 161/69 kV 167 MVA with a load tap changer (LTC). Replace the 13 kV tertiary reactors.	September 30, 2022	3.6
21430	Grimes 345/161 kV Transformer Replacement	Replace 345/161 kV (560 MVA) transformer at Grimes substation which failed recently. The replacement transformer will be a spare 345/161 kV 560 MVA transformer. Retire the 13.8 kV tertiary reactors of the transformer.	September 30, 2022	3.85
21545	Diamond Trails to Hills 345 kV Line Structure Replacements	Diamond Trail-Hills 345 kV line structure replacements.	September 15, 2022	3.75

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
4247	Sub 18 - Sub 85 161 KV reconductor	Reconductor the 161 kV line from Sub 85 to Sub 18 and uprate substation terminal equipment.	December 31, 2022	1.6
20038	Sub 56 - Sub 85 161 kV Line Uprate	Replace substation terminal equipment at Sub 56 to uprate the Sub 56-Sub 85 161 kV line.	December 31, 2022	0.9
20155	Relaying, Communication and Control Equipment Replacements 2021-2024	Blanket project to replace existing relaying, communication equipment and control house equipment to increase reliability and operating flexibility.	December 31, 2024	39.0

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20685	J535 Gard Ave.	J535 Network Upgrades and Interconnection Facilities.	April 1, 2020	12.7
20121	Hills 345 kV: Add Two 150 MVAR Capacitors	Expand the Hills 345 kV substation yard from a ring bus to a breaker-and-a-half configuration. Add two 150 MVAR, 345 kV capacitor banks.	December 31, 2022	12.0
20123	Grimes 345 kV Breaker Addition	Add a new 345 kV breaker to the Grimes 345 kV ring bus to eliminate a NERC TPL-001 Category P2 breaker failure contingency.	December 31, 2021	1.3
20125	Deep River to Parnell 161 kV Uprate	Replace structures to uprate the rating of the J438 POI Deep River-Parnell 161 kV line.	December 31, 2020	0.23
20126	Braddyville-MO State Line 161 kV Uprate	Reconductor the 161 kV line between the J611 POI Braddyville substation and the Iowa-Missouri border.	October 1, 2020	0.5
20127	Macksburg-Winterset 161 kV Uprate	Replace structures to uprate the rating of the Macksburg-Winterset 161 kV line.	August 5, 2020	0.12
20128	Montezuma-Diamond Trail 345 kV Uprate	Replace structures to uprate the rating of the Montezuma-J530 POI Diamond Trail 345 kV line.	June 1, 2020	0.25
20129	Diamond Trail-Hills 345 kV Uprate (MISO DPP 2016 Aug.)	Reconductor the J530 POI Diamond Trail-Hills 345 kV Line and uprate Hills substation terminal equipment.	December 31, 2021	27.8
20130	Bondurant-Montezuma 345 kV Uprate (MISO DPP 2016 Aug.)	Replace structures to uprate the rating of the Bondurant-Montezuma 345 kV Line.	December 31, 2021	0.62
20175	Remsen Township Substation & Line Taps	Construct a new substation and 345 kV line taps to accommodate wind farm interconnection (J748).	September 15, 2021	13.2
20178	Webster 161 kV Expansion	Expansion of Webster 161 kV to accommodate J524.	December 1, 2021	3.05

4.5.9 Minnesota Municipal Power Agency (MMPA)

Minnesota Municipal Power Agency did not submit any new projects for MTEP21. MISO has not identified any issues in MMPA's area.

4.5.10 Minnesota Power (MP)

Minnesota Power proposed five projects at an estimated cost of $14.3 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the TO area, all of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $14.3 million. Of these projects, there are no Baseline Reliability Projects and all are Other projects. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20032	Canosia Road Transformer Addition	Complete ring bus and add 115/34.5 kV transformer to existing Canosia Road Substation. This project includes the transmission equipment necessary to accommodate the new transformer.	December 31, 2022	1.5

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
18066	Badoura 115kV Substation Modernization	Relocate existing 115 kV lines into ring bus and remove/retire old substation yard.	December 31, 2022	1.82
18945	98 Line Asset Renewal	Structure replacements on Iron Range - Arrowhead 230 kV line.	March 31, 2021	2.13
20075	Forbes 230 kV Modernization	Replace aging 230 kV cap bank and 230 kV oil circuit breaker at Forbes Substation.	December 31, 2023	7.35
20081	Stinson Asset Renewal Project	Replace aging capacitor bank, 115W breaker, switches, PT's, and relay panels.	December 31, 2022	1.53

4.5.11 Missouri River Energy Services (MRES)

Missouri River Energy Services proposed five projects at an estimated cost of $9.31 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the MRES area, all of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $9.31 million. All these projects are classified as Other projects. Missouri River Energy Services did not propose any Baseline Reliability or Generator Interconnection projects for MTEP21. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19846	Willmar Plant Sub Relocate	The Willmar Power Plant building is being decommissioned and removed. Substation protection and controls were in the building and will need to be moved. This will require the entire substation to be moved to a new location.	December 31, 2021	3.0
20608	Worthington Substation	This project is for the construction of a 69/12.47 kV substation, preliminary referred to as the New Worthington Sub, on the east side of Worthington, MN. In addition, MRES and GRE are recommending a two-stage capacitor bank (2 x 7.0 MVAR) to address transmission needs and improve operations.	November 1, 2022	4.8

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19845	Willmar South Breaker Replacement	Replace oil filled breakers due to age and condition.	December 31, 2021	0.80
19986	Willmar Sub Upgrades	Upgrading bus jumpers, switches, and oil filled breakers at the Willmar 230/69 kV substation.	December 30, 2022	0.61
20445	Atlantic Breaker Replacement	Replace 69 kV oil breaker at NIPCO J8 substation.	December 31, 2021	0.10

4.5.12 Montana-Dakota Utilities Co. (MDU)

Montana-Dakota Utilities Co. proposed two projects at an estimated cost of $7.5 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the TO area, both projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $7.5 million. Both projects are classified as Other projects. Montana-Dakota Utilities Co. did not propose any Baseline Reliability or Generator Interconnection projects for MTEP21. The projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19605	Beulah 115/46 kV substation	Replacement of the existing Beulah 115/46 kV substation.	June 30, 2022	6.0

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19205	Tioga Loop	Build a 60 kV loop line around Tioga, ND	December 31, 2021	1.5

4.5.13 Muscatine Power and Water (MPW)

Muscatine Power and Water did not submit any new projects for MTEP21. MISO has not identified any issues in MPW area.

4.5.14 Northwestern Wisconsin Electric (NWEC)

Northwester Wisconsin Electric did not submit any new projects for MTEP21. MISO has not identified any issues in NWEC area.

4.5.15 Otter Tail Power Company (OTP)

Otter Tail Power proposed five projects at an estimated cost of $6 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the Otter Tail Power area, all of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $6 million. All of these projects are Other projects. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20485	OTP Ortonville 115 kV Capacitor Reduction	Reduce capacitor size from 30 MVAR to 17 MVAR.	September 24, 2020	0.1

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
16286	Donaldson-Hallock 41.6 kV Line Upgrades	Re-pole and reinsulate 8.8 miles to a 69 kV level on the transmission line between Donaldson-Hallock 41.6 kV for reliability.	December 15, 2020	1.4
19929	OTP Finley to McVille 41.6 kV Line Upgrade	Rebuild 5.75 miles of 41.6 kV line and add automation to existing switches to improve reliability performance and restoration time of this line.	December 1, 2021	1.0
19930	OTP Doyon/Bartlett – Rebuild 41.6 kV Line	Rebuild 5.6 miles of 41.6 kV line, replace conductor and reroute existing line out of the water to improve reliability performance and restoration time of this line.	December 1, 2021	0.95
20606	OTP Maple River 345/230/13.8 kV Transformer Replacement	Like-for-like replacement of the failed Maple River 345/230/13.8 kV transformer #1. Additionally, a new control house will be built.	December 31, 2021	2.6

4.5.16 Rochester Public Utilities (RPU)

Rochester Public Utilities did not submit any new projects for MTEP21. MISO has not identified any issues in RPU area.

4.5.17 Southern Minnesota Municipal Power Agency (SMMPA)

Southern Minnesota Municipal Power Agency did not submit any new projects for MTEP21. MISO has not identified any issues in SMMPA area.

4.5.18 Wilmar Municipal Utilities (WMU)

Wilmar Municipal Utilities did not submit any new projects for MTEP21. MISO has not identified any issues in WMU area.

4.5.19 WPPI Energy (WPPI)

WPPI Energy did not submit any new projects for MTEP21. MISO has not identified any issues in WPPI area.

4.5.20 Xcel Energy (Northern States Power)

Xcel Energy proposed 17 projects at an estimated cost of $116.2 million targeting MTEP21 Appendix A. After MISO's independent reliability analysis of the Xcel Energy area, all of these projects were recommended by MISO to be included in MTEP21 Appendix A at an estimated cost of $116.2 million. Of these projects, 16 are Other projects, and one is a Generator Interconnection Project with a signed Generator Interconnection Agreement. All the projects' expected in-service dates and estimated costs are provided as of September 17, 2021.

Other Projects

Projects Driven by Local Reliability

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19889	Black Oak to Sauk Center Line Rebuild	Rebuild and upgrade conductor on approximately 6.64 miles from Black Oak to Sauk Center.	June 1, 2024	4.0
19893	Great Plains Substation	Construct new 115kV substation in Sioux Falls, SD between West Sioux Falls - Cherry Creek 115kV; 4 rows breaker-and-a-half; 3 TRs, 4 lines, 115 kV cap.	October 15, 2022	10.60
19906	Prentice Cap Bank Replacement	Upgrade the cap bank to 10MVAR and replace the circuit switcher at Prentice substation.	December 15, 2021	1.0

19913	Howard Lake to Big Swan, Delano to Howard Lake, Cokato to Winstead Rebuild	Howard Lake to Big Swan - Rebuild 16.0 miles , Delano to Howard Lake – Rebuild 19.7 miles , Cokato to Winstead – Rebuild 14.3 miles to current 69kV standard for end of life asset renewal.	June 15, 2024	28.0
19914	High Bridge-Rogers Lake Bifurcation to Double Circuit	Convert the bifurcated 115 kV line from High Bridge to Rogers Lake to a double circuit 115 kV line to alleviate curtailment on the High Bridge Generating Plant. Construct new breaker positions at High Bridge and Rogers Lake to accommodate the second 115kV circuit.	May 1, 2023	3.42

Projects Driven by Age and Condition

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19165	Fieldon Retirement	This project bypasses and retires the Fieldon series capacitor and removes the substation, whose only function is for the series capacitor. This facility is no longer required and has a significant recurring maintenance cost.	July 1, 2022	3.0
19886	Minnesota Valley TR12 ELR	Like for like replacement of Minnesota Valley TR12. Transformer is 68 years old and is experiencing performance issues.	December 15, 2021	1.50
19887	Eau Claire TR10 ELR	End of life, like for like replacement of Eau Claire TR10.	December 15, 2021	3.0
19888	Northfield to Farmington Line Rebuild	Rebuild approximately 18.6 miles of existing Northfield to Farmington line to current Transmission Design Standards. Reconductor 1.3 miles.	December 15, 2022	8.0
19915	Replace Alma Substation	Replace the existing Alma sub which is at end of life and in a poor access location with new sub with 7MVA TR with two regulated feeders at new site.	October 15, 2021	3.0
19916	Rebuild Genoa Substation	Rebuild Genoa sub which is at end of life with New sub with 7MVA TR with two feeders on the existing site.	October 15, 2022	2.7
20135	Panther - Big Swan Rebuild	Rebuilding most of the line to 477 standard due to age and condition. Adding a breaker station at Adams Wind tap to sectionalize the line. Converting the City of Litchfield tap structure to a double circuit structure.	June 1, 2024	33.3

Projects Driven by Load Growth

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19890	Watkins - Kimball Line Rebuild	Rebuild and upgrade approximately 6.56 miles of existing line. Replace EOL switches and MODs.	December 15, 2022	3.20
19891	Replace Green Isle Substation	Replace existing Green Isle substation with a new 69/13.8 kV substation on a new site.	March 15, 2021	3.50

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
19892	Elm Creek TR4	Install Elm Creek TR4 at 115kV/34.5kV with one new 34.5kV feeders exiting the substation to remediate N-1 overloads and allow proposed new customer load.	December 15, 2021	4.07
19905	2589 - Barnes Grove Interconnection	Install 3-way switch on 69kV line between Inver Grove - Keagan Lake Tap to accommodate GRE's new Barnes Grove interconnection (MTEP 2589).	May 14, 2021	0.35

Generator Interconnection Projects

Project ID	Project Name	Project Description	ISD	Estimated Cost ($M)
20229	J732 Stone Lake XFMR Upgrade	Transformer upgrade for J732 in Aug 17 ATC DPP cycle.	November 10, 2023	3.60