ORIGINAL

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL TO MODIFY ITS MRSM TARIFF, CEASE DEFERRING DEPRECIATION EXPENSES, ESTABLISH REGULATORY ASSETS, AMORTIZE REGULATORY ASSETS, AND OTHER APPROPRIATE RELIEF	)))))))	Case No. 2020-00064

Response to the Office of the Attorney General's Supplemental Data Requests dated April 15, 2020

Part 1 of 2

FILED: April 24, 2020

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR APPROVAL TO MODIFY ITS MRSM TARIFF,
CEASE DEFERRING DEPRECIATION EXPENSES,
ESTABLISH REGULATORY ASSETS,
AMORTIZE REGULATORY ASSETS, AND
OTHER APPROPRIATE RELIEF
CASE NO. 2020-00064**

VERIFICATION

I, Robert W. ("Bob") Berry, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Robert W Berry

Robert W. ("Bob") Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Robert W. ("Bob") Berry on this the 24th day of April, 2020.

Joy P. Parsley

Notary Public, Kentucky State at Large

My Commission Expires ______

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

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VERIFICATION

I, Michael W. ("Mike") Chambliss, verify, state, and affirm that the informationa request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Michael W. Chambliss

Michael W. ("Mike") Chambliss

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Michael W. ("Mike") Chambliss on this the 24th day of April, 2020.

Joy P. Parsley

Notary Public, Kentucky State at Large

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VERIFICATION

I, Mark J. Eacret, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

M J Eacret
Mark J. Eacret

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark J. Eacret on this the 24th day of April, 2020.

Joy P. Parsley
Notary Public, Kentucky State at Large

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VERIFICATION

I, Michael T. ("Mike") Pullen, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Mike Pullen

Michael T. ("Mike") Pullen

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Michael T. ("Mike") Pullen on this the 24th day of April, 2020.

Joy P. Parsley

Notary Public, Kentucky State at Large

My Commission Expires ________

Notary Public, Kentucky State-At-Large
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VERIFICATION

I, Paul G. Smith, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Paul Smith
____
Paul G. Smith

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Paul G. Smith on this the 24th day of April, 2020.

Joy P. Parsley
____
Notary Public, Kentucky State at Large

My Commission Expires ____________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
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dated April 15, 2020**

April 24, 2020

Item 1) ***Regarding the response to Data Request AG 1-9 please provide page, paragraph, line of other detail regarding exactly where in Exhibit C of the application that the remaining useful economic lives of the Wilson plant and the two Green units is located? Is this in reference to retirement dates in Appendix D?***

Response) The reference is in Appendix D of the Book Depreciation Accrual Rate Study At December 31, 2018, which is Appendix C of Big Rivers' application in this case. That one page schedule in Appendix D provides the estimated remaining life and retirement dates for the generating units. Further, as is explained in the Depreciation Study on Page 22, in the section titled "Life Analysis," the "retirement dates are the best estimate of the current lives remaining in the generating assets."

Witness) Michael T. Pullen

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Item 2) ***Regarding the response to AG 1-36, please provide the following:***

a. On attachment AG 1-36.c.i please provide detail regarding calculation for MISO Energy and Capacity revenues. Are these values net MISO settlements for load? If so please list the loads involved, i.e. Big Rivers Members, special contracts, etc.

b. On attachment AG 1-36.c.iii was the HMP1 and HMP2 settlement location deleted after January 2019? Please explain.

Response) Big Rivers objects to this request on the grounds that it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. Notwithstanding these objections, and without waiving them, Big Rivers responds as follows:

a. The energy values shown represent day-ahead and real-time revenues realized by the Big Rivers generation fleet and contra revenues associated with hedges executed at the Indiana Hub. The capacity values represent the net MISO revenues for Big Rivers and Domtar. Domtar reimburses Big Rivers for any costs associated with capacity shortfalls.

b. Henderson Municipal Power and Light retired HMP1 and HMP2 on January 31, 2019, and the settlement location was deleted.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

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April 24, 2020

Item 3) ***Regarding the Nucor Contract provided in response to AG 1-28, please provide the following:***

a. ***Letter Agreement between Customer and Big Rivers dated May 1, 2019 discussed in Exhibit B.***

b. [redacted].

c. [redacted]

d. [redacted].

e. [redacted]

Response) Big Rivers objects to this request on the grounds that it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence because matters relevant to the Nucor Contract are being addressed by the Commission in Case Nos. 2019-00365, 2019-00270, and 2019-00417. More specifically, the issues before the Commission in Case Nos. 2019-00365, 2019-00270, and 2019-00417 were litigated or are being litigated in those proceedings, and are not subject to collateral litigation in this proceeding. Notwithstanding these objections, without waiving them, and with specific objection to collateral litigation of the issues in Case Nos. 2019-00365, 2019-00270, and 2019-00417, Big Rivers responds as follows:

a. Please find attached the Letter Agreement between Customer and Big Rivers dated May 1, 2019.

b. Big Rivers' Nucor service plan, including costs and facility descriptions, was submitted to MISO via the expansion planning process. Big Rivers' Nucor service plan was then studied as part of the comprehensive MISO Transmission Expansion Plan (MTEP). The Big Rivers' Nucor service plan is being filed with these responses as *Big Rivers Nucor Service Plan 6-4-19.pdf*. The 2019 MISO MTEP report, which was submitted after development of the Big Rivers' Nucor service plan, is being filed with these responses as *MTEP19 Executive Summary and Report.pdf*.

Since the submission of that report, Big Rivers now expects [redacted]. Also, [redacted]. Other added equipment includes [redacted] The final substation cost referenced in Exhibit A of Nucor Retail Agreement is expected to be approximately [redacted]. Please see the attached **CONFIDENTIAL** attachment showing the substation costs.

c. Please see the **CONFIDENTIAL** attachment showing substation costs provided in response to 3b, above.

d. Please see the Letter Agreement provided in response to 3a, above.

e. Please see Big Rivers' applications and responses to the Commission Staff's Initial Requests for Information in Case Nos. 2019-00270 and 2019-00417. Please also see the attachment to Big Rivers' response to Item 7a of the Attorney General's Supplemental Data Requests.

Witnesses) Michael W. Chambliss (*a., b., c., and d. only*) and
Paul G. Smith (*e. only*)

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

May 1, 2019

Mr. Randy Skagen
Vice President
Nucor Corporation
1700 Hold Road N.E.
Tuscaloosa, Alabama 35404

Re: Interim Agreement between Nucor Corporation and Big Rivers Electric Corporation

Dear Randy:

Big Rivers Electric Corporation ("Big Rivers") has evaluated the anticipated timeline and transmission facilities requirements for the Nucor Corporation ("Nucor") facility to be located at the Buttermilk Falls Site in Brandenburg, Kentucky. Based on this evaluation, we have concluded that certain long lead-time activities must be started very soon to enable Big Rivers to complete the transmission system improvements prior to the anticipated commencement date of electric service. However, before spending the funds necessary to begin the purchase of materials or the other steps required for the construction of the required transmission facilities, Big Rivers requires a written commitment from Nucor that Nucor will reimburse Big Rivers for these expenditures in the event the final power supply agreement is not consummated. For purposes of this letter agreement, consummation of the final power supply agreement means the agreement is properly executed, all required approvals are received, and all other contingencies to the effectiveness of the agreement have been satisfied or waived.

Big Rivers estimates that it will incur expenditures of $3,500,000 on the long-lead time projects that will be necessary prior to having the final agreement in place. However, until the final agreement is in place, it may be necessary to periodically revise this agreement to cover actual expenditures in excess of that amount. Big Rivers will provide Nucor with monthly updates as to the equipment orders it has placed and the expenses it has incurred, to keep Nucor apprised of its cost exposure under this agreement.

If Nucor commits to reimburse Big Rivers for the actual costs that Big Rivers incurs or irrevocably commits to incur, not to exceed $3,500,000, in the event the parties are unable to consummate a final agreement prior to March 31, 2020, then Big Rivers will be able to proceed as outlined.

Big Rivers agrees that, if Nucor provides written notice to Big Rivers of its decision not to proceed with the final agreement, Big Rivers will take all necessary steps to stop incurring expenses, to the extent possible.

If Nucor agrees with the cost reimbursement terms stated above and authorizes Big Rivers to proceed immediately, please sign a copy of this agreement in the space provided below and return it to me.

Sincerely,

Robert W Berry

Robert W. Berry
President and CEO
Big Rivers Electric Corporation

AGREED TO AS OF MAY ___, 2019:

NUCOR CORPORATION

By: ______________________
Randy Skagen
Vice President

MTEP19

In this MISO Transmission Expansion Plan, MISO staff recommends $4 billion of new transmission enhancement projects for Board of Directors' approval.

Highlights

- 480 new projects for inclusion in Appendix A to address reliability and aging infrastructure
- The first project recommendation within the MISO-PJM Coordinated System Plan
- $23 billion in projects constructed in the MISO region since 2003
- Generator Interconnection queue grew to over 600 projects totaling around 100 GW

MISO

misoenergy.org

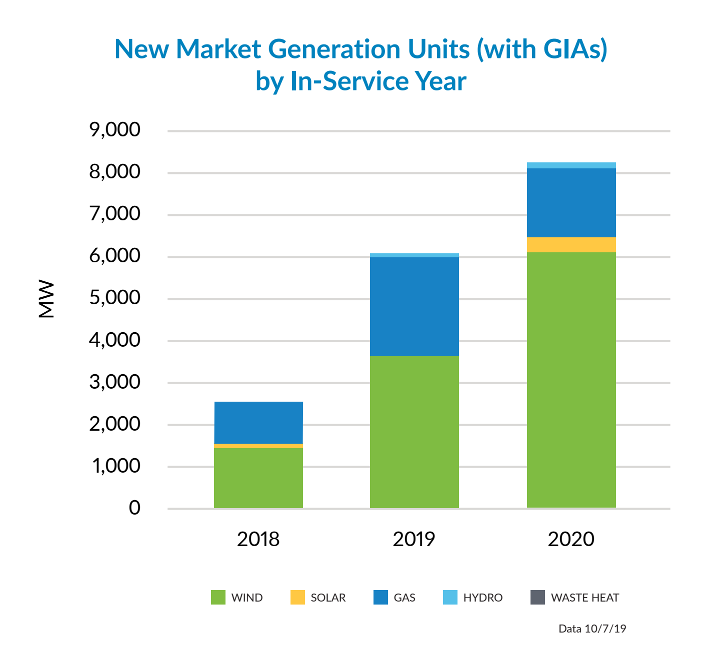
MISO portfolio evolution continues to drive the grid of the future.

The aggressive pace of transformation can be felt across every aspect of the electric industry. Along with new and more affordable technology comes the demand for changes in process, policy and our ideas about what the future will look like. One example that has already surfaced is the changing resource adequacy construct. With changing resources comes an increased need for availability and flexibility across MISO's footprint. New infrastructure will be necessary to deliver the benefits these resources provide across MISO. However, this environment that is hallmarked by digitalization, decentralization, and de-marginalization is just the context of the landscape.

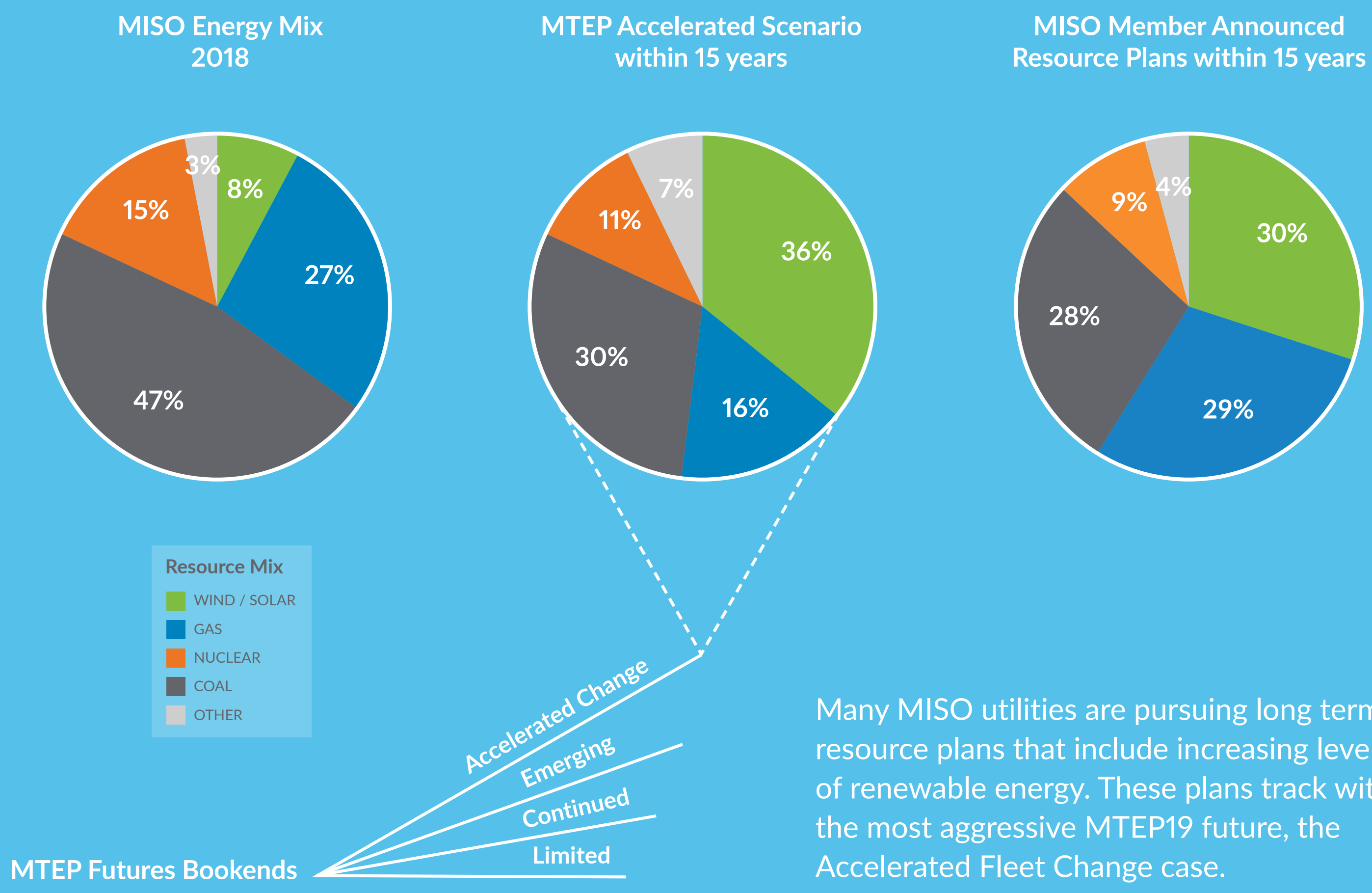
Economics, reliability, policy and consumer preference drive the decisions about how and why change occurs and the planning process must provide the flexibility and the availability to meet the changing demand. Once that has been achieved, the planning focus is then recalibrated each year for a range of issues that have emerged as quickly as seasons change.

Developed in collaboration with various stakeholders, the MISO Transmission Expansion Plan (MTEP19) takes a panoramic view of these variables to design the most economic and reliable transmission path forward to bring benefits to consumers.

MISO works with stakeholders to monitor forward risks and prepare for the future. The annual resource adequacy survey reflects the industry's ongoing shift away from traditional fossil fuel generation and increasing reliance on gas-fired resources, renewables and demand response, as well as other trends discussed in our MISO Forward report.



While wind has made up the predominance of recent new market generation units, the active Generator Interconnection queue holds 58% (57 GW) of solar and 25% (25 GW) wind.



Many MISO utilities are pursuing long term resource plans that include increasing levels of renewable energy. These plans track with the most aggressive MTEP19 future, the Accelerated Fleet Change case.

Identifying long range system planning needs

MISO Transmission Planning Guiding Principles

We are committed to robust stakeholder engagement to inform our planning process, to recommend transmission only when it is the best solution to address a reliability, economic, or public policy issue, and to ensure allocation of transmission costs are consistent with received benefits.

Understanding Viewpoints: Engaging Stakeholder Voices

With growing and changing energy demands throughout MISO's footprint, every hour matters. Our transparent and inclusive transmission planning process helps ensure reliable, least-cost delivered energy. Our planning process includes multiple

Stakeholders provided input in over 75 Committee Meetings, Working Groups, and Workshops to build the MTEP19

opportunities for diverse stakeholders, including transmission owners, market participants, state regulators, public consumer groups, utilities, competitive developers and others, to provide perspective and offer advice in developing the MTEP each year.

State regulators and other policymakers are increasingly underscoring the need for timely action to begin substantive work on long range planning efforts that allow for both flexibility and visibility toward the future grid. MISO has begun a series of planning futures workshops to better align various planning scenarios looking twenty to thirty years into the future. Information collected in these workshops will inform MISO's 2021 Transmission Expansion Planning Futures assumptions and ultimately long range planning efforts.

Some individual efforts have also been launched regionally in an effort to recognize the shared values of location-specific planning to support broad, overarching system infrastructure needs. MISO will continue to work to understand the needs of policymakers and stakeholders while providing insight and analysis to inform decisions.

With increasingly dynamic industry trends, keeping lines of communication open with stakeholders will be key to incorporating potential changes before they happen.

Delivering value to members through continuous improvement

Integration of Planning Alternatives Analysis

The MTEP19 cycle brought continued process improvement efforts to engage stakeholders with the coordinated efforts of reliability and economic studies. A consolidated issues and solutions map helps view system needs and develop solutions collectively, linking to a central issues and solutions repository workbook that can be shared with stakeholders and MISO planning staff. This consolidated issues and solution idea map helps to create a holistic regional view and identifies potential areas for coordination among transmission owners and stakeholders.

Competitive Transmission Administration

MISO focused on continuous improvement in 2019 to further optimize and enhance the capabilities of the competitive transmission process. A potential reduction in the voltage threshold for regionally cost shared projects may increase the volume of projects eligible for competition. A key initiative was “rightsizing” which sought to scale the complexity of the competitive process to match the complexity of the project.

Generator Interconnection Process Enhancement

Within the MTEP19 cycle, FERC accepted revisions to the Interconnect Request application aimed at improving the processing of hybrid generating facility proposals. The acceptance was an important step ahead of the 2019 application deadline.

Culminating an effort in 2012, MISO’s Tariff revisions for generator replacement were approved by FERC with an effective date of May 16, 2019. The new Tariff language provides a transparent and non-discriminatory mechanism that improves and expedites the existing process to allow replacement of an existing generating facility with newer and more efficient generating facilities.

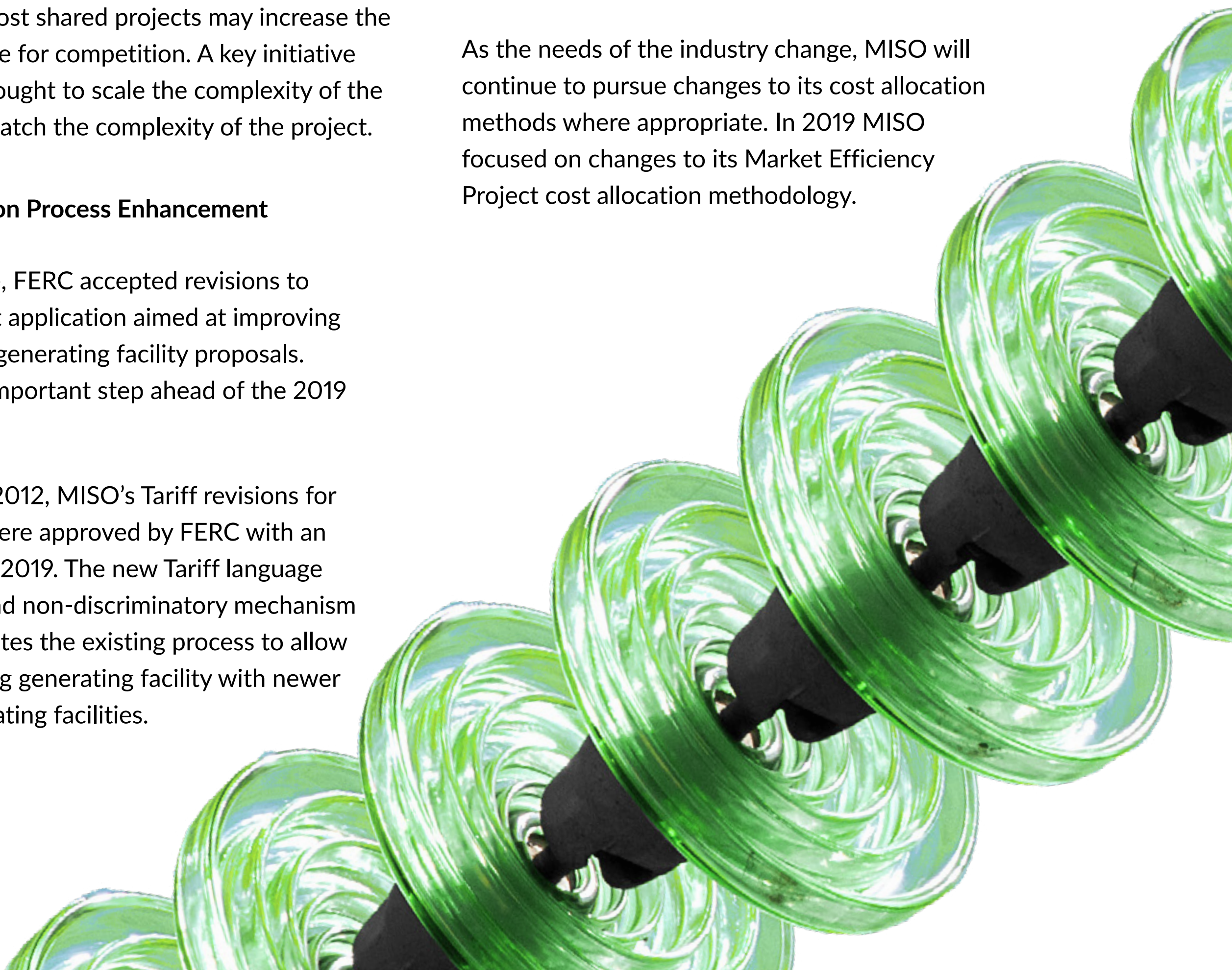
Working with Neighbors

In 2019 MISO successfully implemented a new coordinated system planning process on the SPP seam. While no projects are recommended this cycle, MISO and SPP were able to efficiently evaluate over 40 transmission solutions for six jointly identified MISO-SPP interregional needs - a process that previously took as much as two years to complete.

On the MISO-PJM seam, the MTEP19 studies evaluated 10 transmission solutions to address the three jointly identified MISO-PJM interregional needs. Through these collaborative planning efforts, the first ever MISO-PJM Interregional Market Efficiency Project (IMEP) was identified and will be recommended for approval following FERC acceptance of anticipated cost allocation changes.

Cost Allocation

As the needs of the industry change, MISO will continue to pursue changes to its cost allocation methods where appropriate. In 2019 MISO focused on changes to its Market Efficiency Project cost allocation methodology.



Facilitating the infrastructure of the future electrical grid through system planning initiatives.

Resource Availability and Need

- Improvements to resource availability and flexibility to manage operating risks efficiently
- Focus on near-term solutions to improve outage coordination and demand response
- Harness resource flexibility to ensure resource availability year-round

Generator Interconnection

- Continue to streamline the processes to speed up the study of projects in the GI queue
- Increase the requirements for projects entering the queue to reduce projects that aren't ready
- More closely integrate resources and transmission planning solutions

System Forecasting for Energy Planning

- System forecasting is a key input to transmission
- All hours matter -shifting from 'peak' hour capacity planning to every hour
- MISO in collaboration with stakeholders developed a proposal to forecast the system for MTEP planning

Electric Vehicle and Electrification Studies

- EVs have the potential to be both a disruptive and transformative technology
- Large-scale EV adoption without planning will result in additional grid volatility and cost
- EVs with controlled charging minimize grid impacts

Renewable Integration Impact Assessment

- Better understand renewable penetration limitations
- Identify integration issues and examine solutions to mitigate them
- Facilitate broader conversations on the impacts on the reliability of the electric system (operating and planning)

North-South Constraint Study

- Maximize the resource diversity in the MISO footprint
- Higher penetrations of renewable energy throughout the footprint with increased South Region solar projections in the queue
- Analysis is expected to continue throughout 2020

Long Range Transmission Planning

- Monitor how resource mix changes impact energy flows
- Define future reliability and flexibility needs to align planning processes
- Utilize targeted studies to analyze future transmission needs for the grid of the future

MTEP19 New Projects Overview

MTEP19 Appendix A projects are vetted by MISO through the planning process and are ready for execution.

Reliability (70%) **$2.8B**

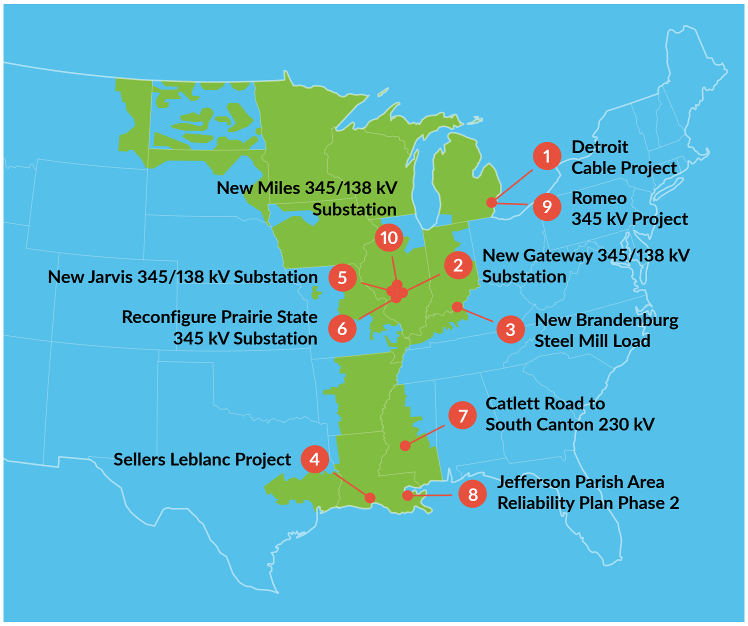
Age & Condition (20%) **$803M**

Generator Interconnection (7%) **$269M**

Local Need (3%) **$106M**

MTEP19 Investment Drivers

The 480 new Appendix A projects in MISO's 2019 Transmission Expansion Plan (MTEP19) represent **$4 billion in transmission infrastructure**



Top 10 proposed MTEP19 projects

(In descending order of cost)

The 10 largest projects represent 19 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.

MISO

misoenergy.org

MISO

misoenergy.org

MTEP19 REPORT

MTEP19 Report Table of Contents

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. MISO is committed to reliability, nondiscriminatory operation of the bulk power transmission system and collaborating with all stakeholders to create cost-effective and innovative solutions for our changing industry.

Scope of Operations

Generation Capacity

- 178,359 MW (market)
- 192,989 MW (reliability)

Historic Summer Peak Load (set July 20, 2011)

- 127,125 MW (market)
- 130,917 MW (reliability)

Historic Winter Peak Load (set January 6, 2014)

- 109,336 MW (market)
- 117,903 MW (reliability)

Transmission

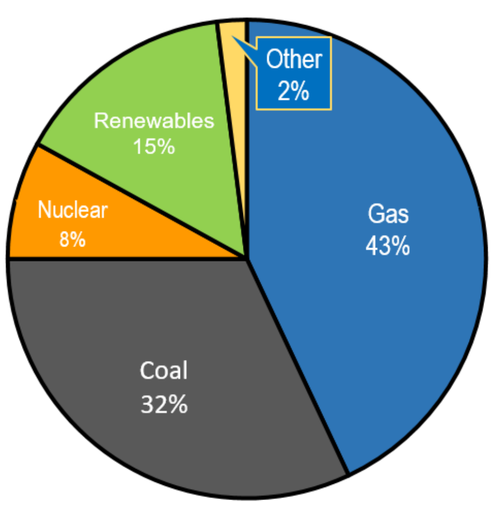
- Approximately 72,000 miles

Balancing Authorities

- 39 Local Balancing Authorities in MISO

Network Model

- 294,694 SCADA data points
- 6,653 generating units



MARKET CAPACITY

Registered Wind	22,601 MW
Registered In-Service Wind Generation Capacity	19,076 MW
Registered Solar Generation Capacity	314 MW
Registered In-Service Solar Generation Capacity	314 MW

Markets Overview

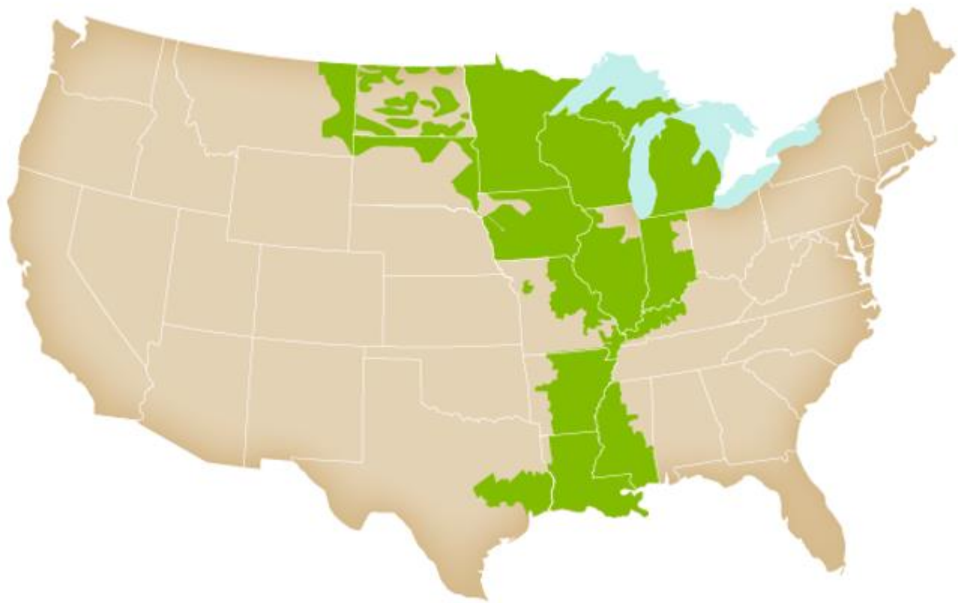
MISO manages one of the world's largest energy and operating reserve markets using security-constrained economic dispatch of generation.

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.

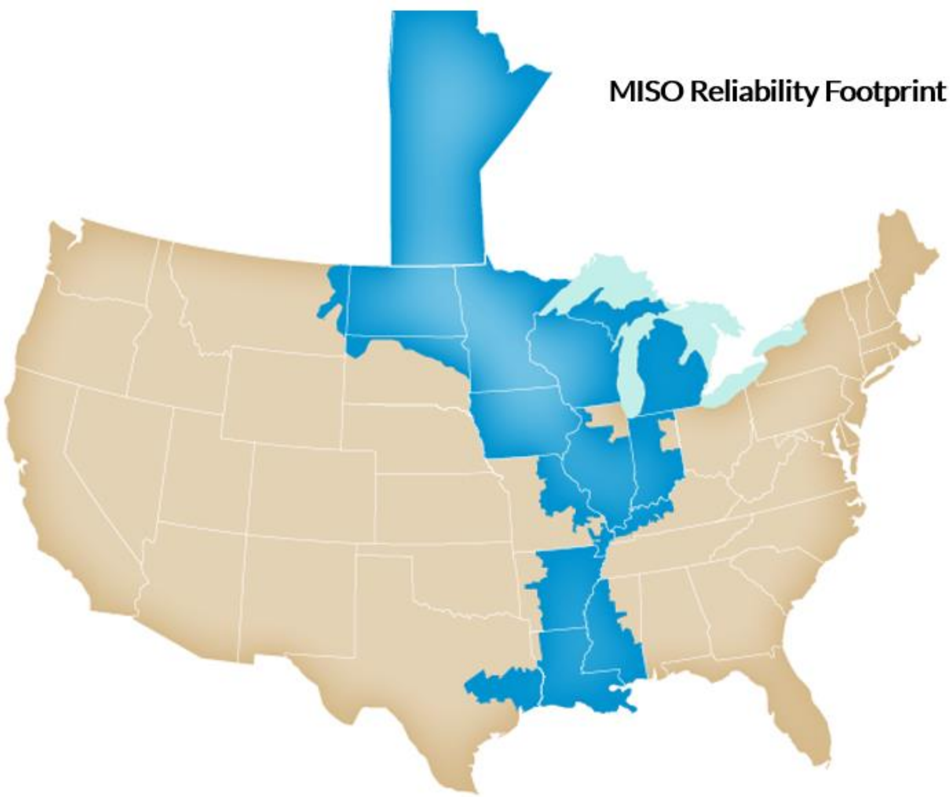
- $29.9 billion annual gross market charges (2018)
- 468 Market Participants that serve approximately 42 million people

Corporate data as of October 2019

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, MTEP19, builds and expands on the 15 prior years of projects and investment (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.

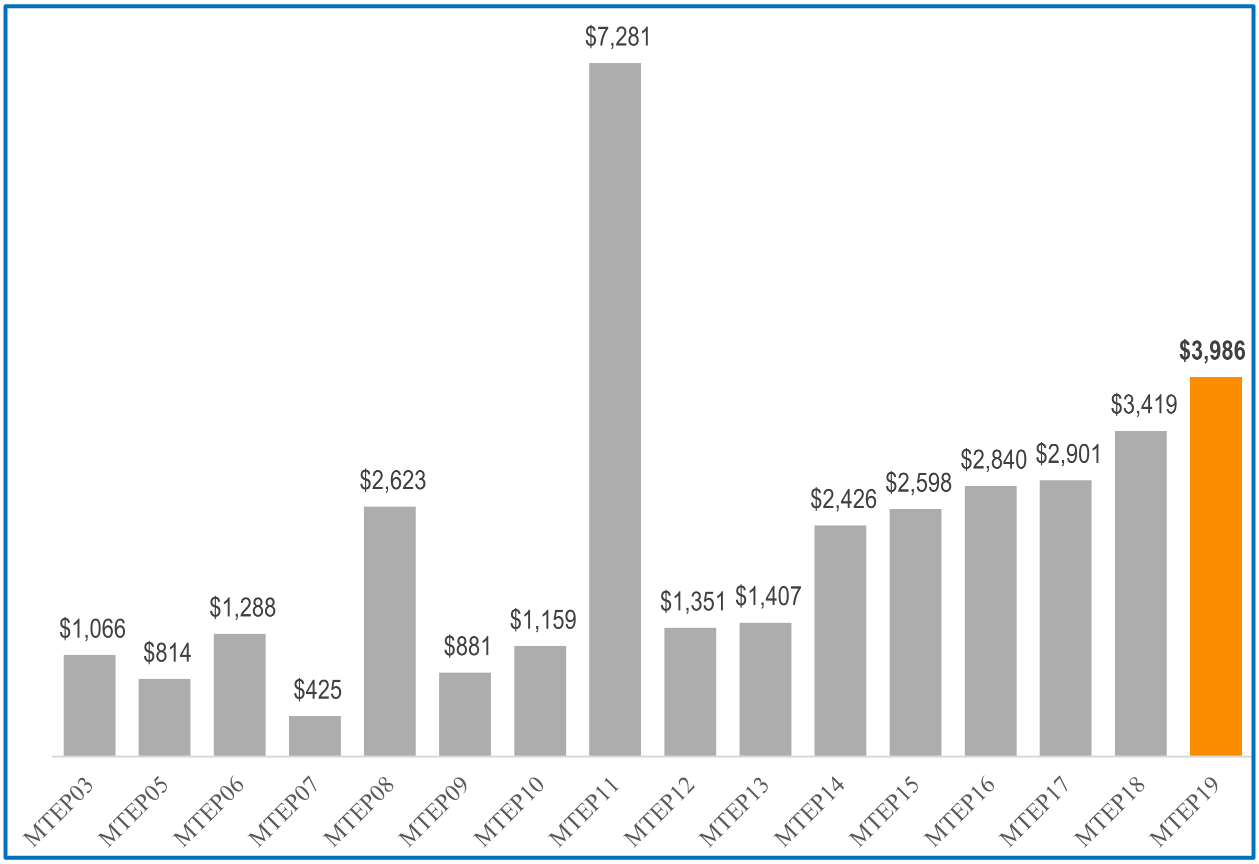


Figure 1.1-1: MTEP investment over all cycles ($million)

Reflects 2019 3rd quarter close data

MTEP11 reflects the approval of 17 Multi-Value Projects discussed later in this Section and MTEP14 saw an initial rise in investment with the first full year of the South region joining as a MISO member. 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. This trend is expected to continue in MTEP20.

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].

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

Transmission Facility Investment

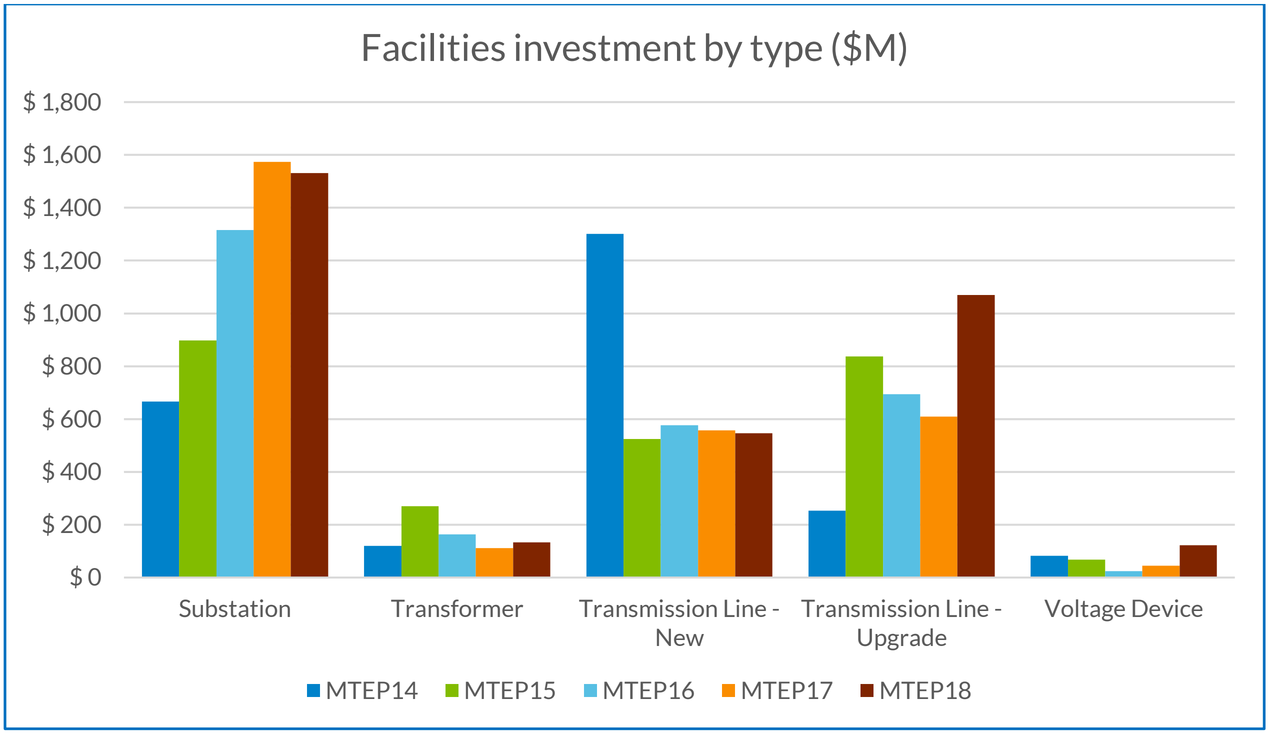


Figure 1.1-2: Appendix A Project data for previously approved five MTEP cycles

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

Line Miles Summary

MISO has approximately 72,000 circuit-miles of existing transmission lines serving as the backbone of the footprint (Figure 1.1-3).

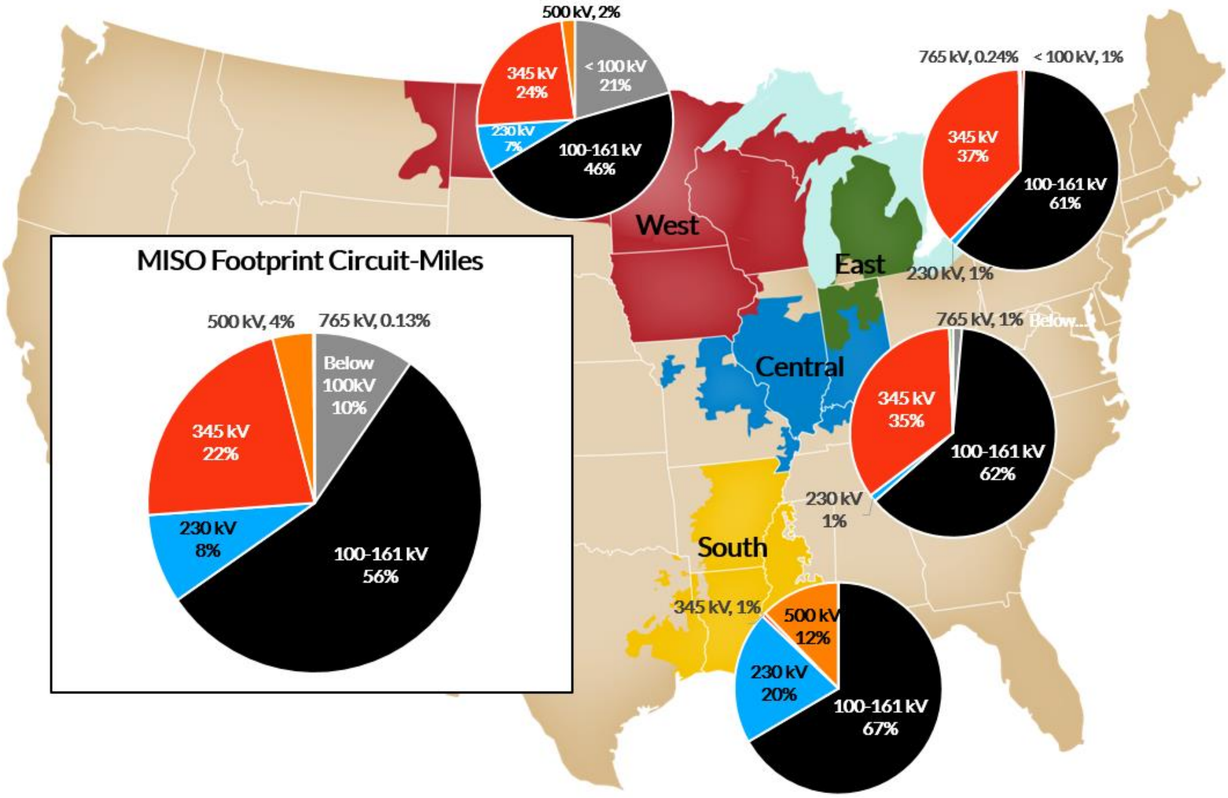


Figure 1.1-3: Existing and planned new or upgraded line circuit-miles by voltage class (kV) as of 10-15-19

Multi-Value Project Portfolio Review and Status Update

The 17 Multi-Value Projects (MVP) are a regional portfolio of high voltage transmission projects, developed and approved in MTEP11 to support public policy, reliability and economic needs throughout the MISO footprint[2]. The cost and schedule of the MVP portfolio is monitored and reported quarterly (see: MVP Dashboard at misoenergy.org). As of the second quarter of 2019, 13 MVPs have gone into service.

[2] When the MVP portfolio was approved, the MISO footprint did not include MISO South

In accordance with Attachment FF of the Tariff, MISO provides an updated annual view into the projected benefits of the MVP portfolio by recreating the analysis performed for the original business case. In the MTEP19 MVP Limited Review, the results demonstrate the MVP Portfolio:

- Provides benefits in excess of its costs, with its total benefit-to-cost ratio ranging from 1.8 to 3.1; consistent with the 2.0 to 3.1 range calculated in MTEP18
- Creates $7.3 to $39.0 billion in net benefits (using MTEP17 benefits for all categories besides congestion and fuel savings) over the next 20 to 40 years (Figure 1.1-4)

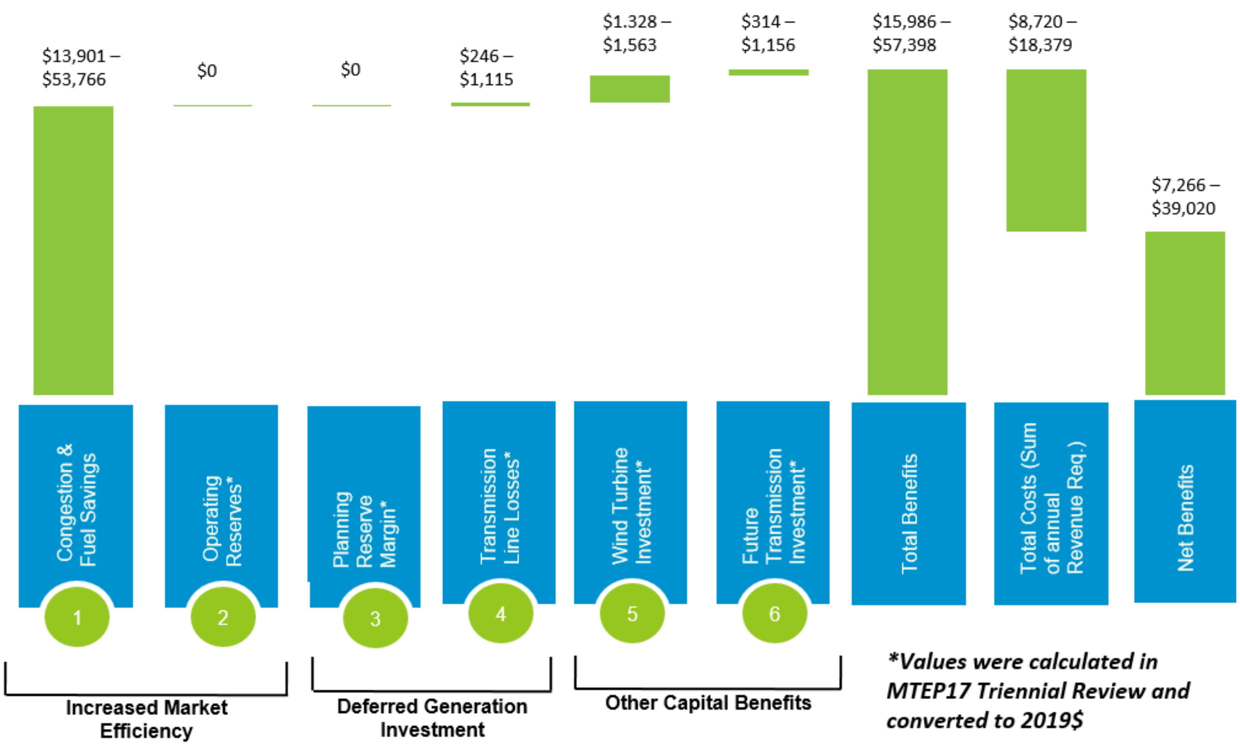


Figure 1.1-4: MVP benefits from the MTEP19 MVP Limited Review (20 – 40 year net present values in 2019$)

The cost of the MVP portfolio is allocated 100 percent in the North and Central regions and recovered from customers through a monthly energy charge that is calculated using the applicable monthly MVP Usage Rate. The MVP usage rates have been calculated for the period 2020 to 2054 and are shown by the blue line (Figure 1.1-5). The red and green lines represent an average of the estimated MVP Usage Rates over 20 and 40-year periods. For the typical residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages $1.50 per month over the next 40 years. The purple and teal lines represent the levelized annual benefit, converted to a benefit per MWh basis, in the 2019 MVP Limited Review. Typical residential households that use 1,000 kWh each month could realize an estimated $4.23 to $5.13 monthly benefit over the same 40 year period.

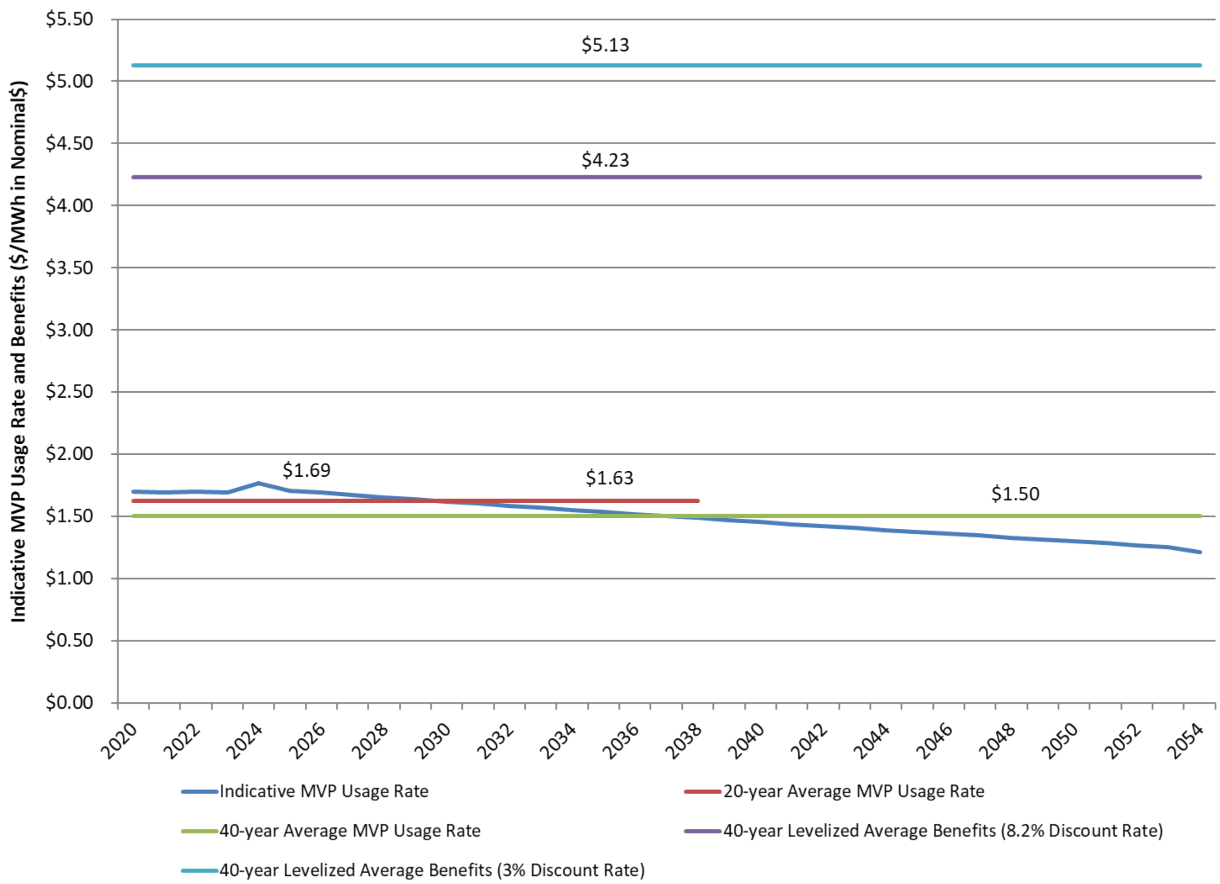


Figure 1.1-5: Indicative MVP usage rate and levelized benefits for approved MVP portfolio from 2020 to 2054

1.2 MISO Transmission Planning Process

A goal of the MTEP report is to satisfy the regulatory requirements as specified in the ISO Agreement. MISO's planning process follows established guiding principles to ensure reliability, support policy requirements, and enable a competitive market to benefit all customers.

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 occurred in March 2019.

Planning Guiding Principles

- Make the benefits of an economically efficient electricity market available to customers by identifying transmission projects which provide access to electricity at the lowest total electric system cost.
- Develop a transmission plan that meets all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs.
- Support state and federal energy policy requirements 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 state and federal energy policy makers and other stakeholders to provide context to inform regarding choices.
- Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations.

Planning Functions

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

- 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

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 digitization. Furthermore, MISO identified the critical themes to address the associated challenges and opportunities: 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.

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.

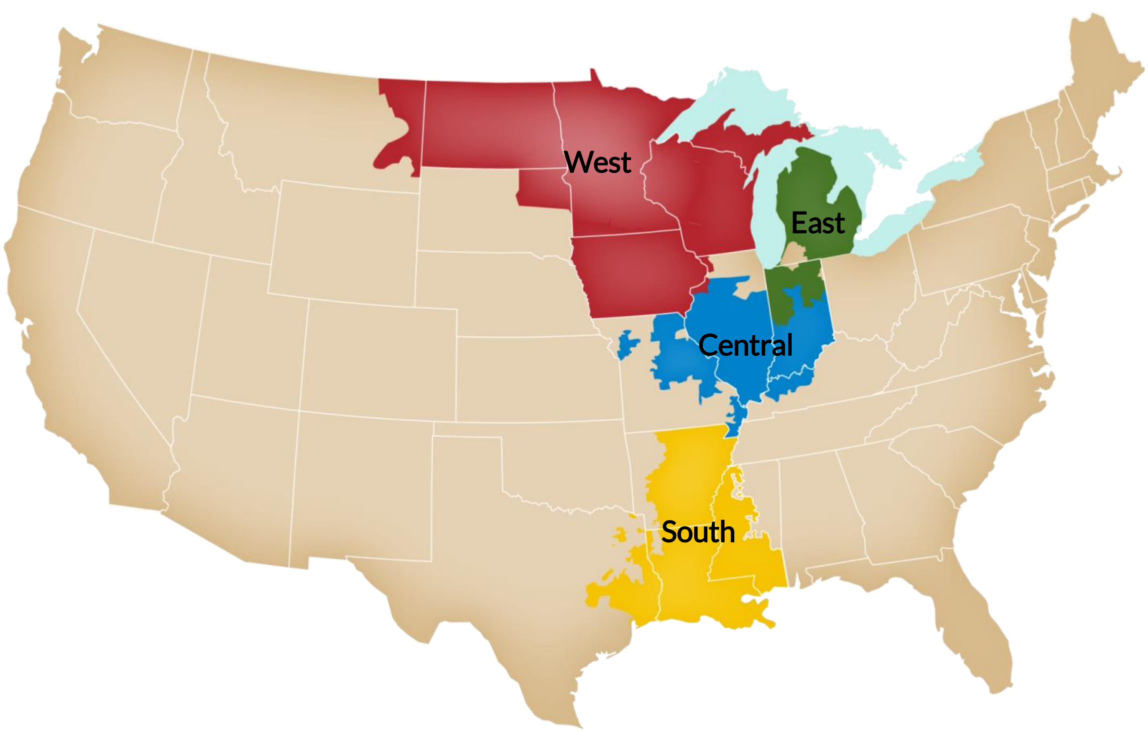


Figure 1.2-1: MISO footprint and planning regions

Key Planning Cycle Milestones

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 (Figure 1.2-2).

- Model development
- Identification and selection of transmission needs driven by public policy requirements to be included as 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

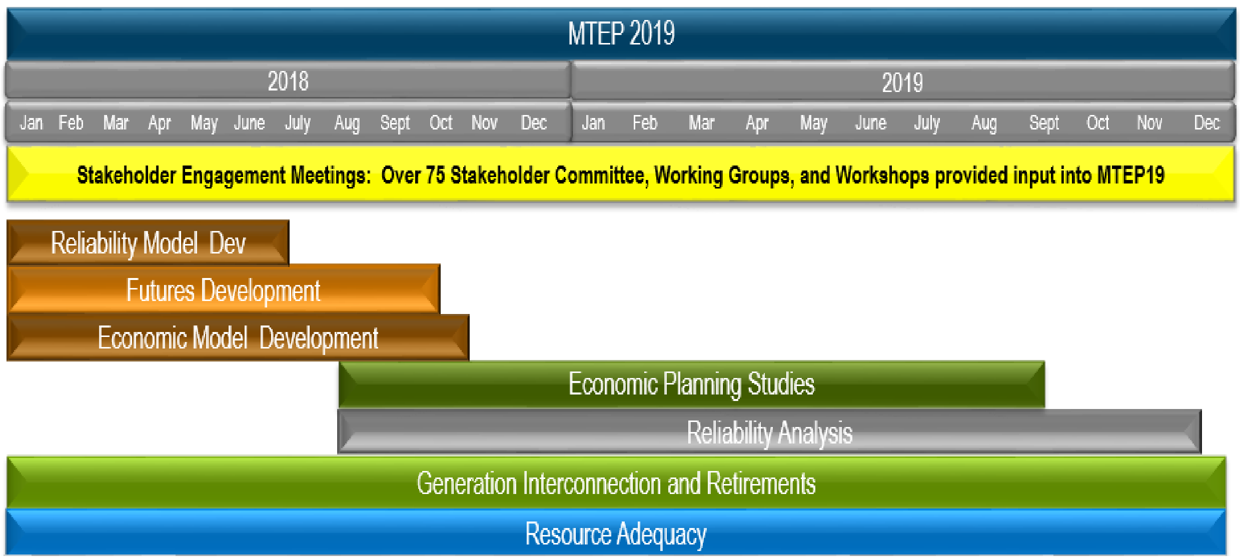


Figure 1.2-2: The MTEP19 planning process encompasses 24 months of stakeholder engagement

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 powerflow, 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 posted on an FTP site maintained by MISO and accessible 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.

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. Within the MTEP19 cycle, more than 75 formal stakeholder meetings, including 17 Sub-regional Planning Meetings were conducted (Figure 1.2-3). These projects make up Appendix A of the MTEP19 report and represent the preferred solutions to the identified transmission needs of the MISO reliability assessment.

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 MTEP19 report.

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

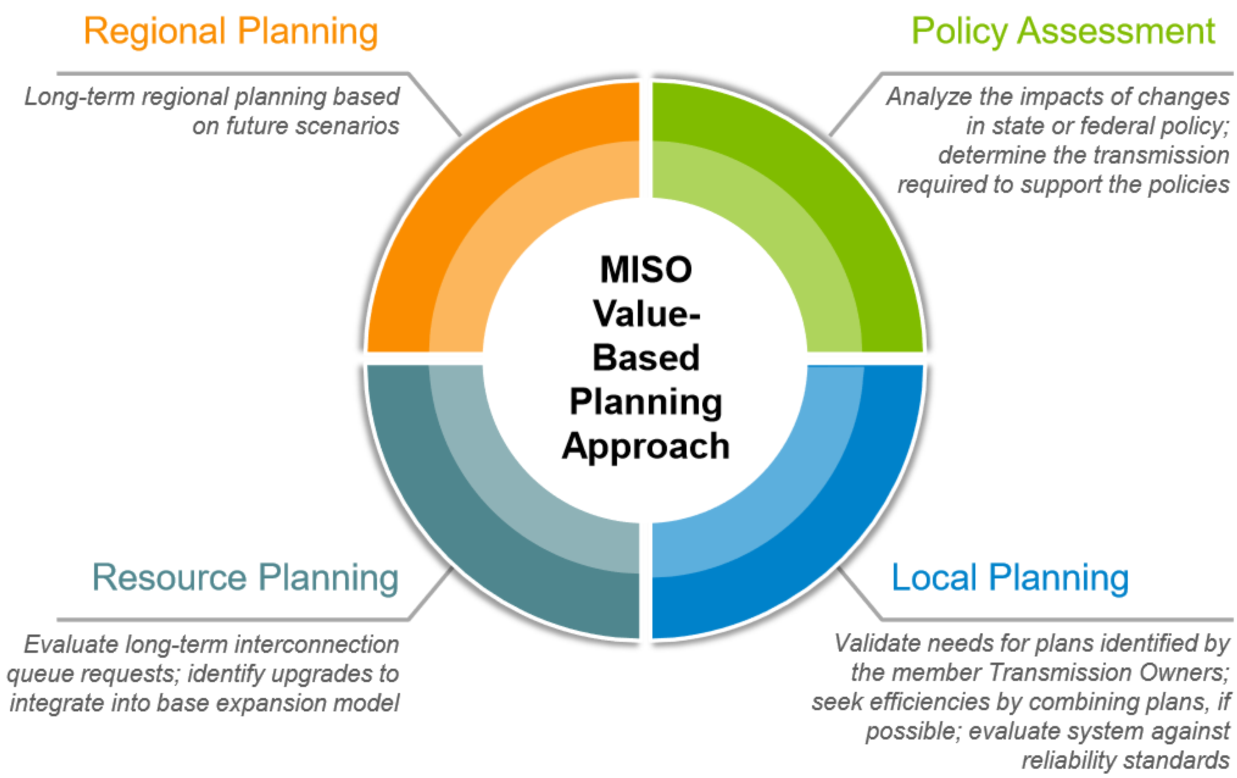


Figure 1.2-3: The MISO Value-Based Planning approach

Stakeholder Input Process Improvements

MISO continued process improvement efforts in 2019 to further coordinate and integrate reliability and economic planning studies in partnership with stakeholders. This built upon MTEP18's successful combination of stakeholder meeting forums for the Market Congestion Planning Study and Sub-regional Planning Meetings.

The MTEP19 brought visualization and consolidation of reliability and economic issues and solution ideas available to Transmission Owners and stakeholders at the Sub-regional Planning Meetings to help view system needs and develop solutions collectively. The use of consolidated issues and solutions maps provides an integrated regional view of system needs and helps identify potential areas for enhanced collaboration among Transmission Owners and stakeholders.

In conjunction with issues and solutions maps, centralized issues and solutions repository workbooks are utilized to document and consolidate identified issues and proposed solution ideas, linking to the issues and solutions maps for detailed information.

Interregional Coordination Efforts

As a part of the annual transmission planning process, MISO performs regular coordination and joint planning with neighboring regional transmission operators — Southwest Power Pool and PJM Interconnection. Under the purview of their respective Joint Operating Agreements, MISO works with PJM Interconnection and Southwest Power Pool to exchange data, evaluate common issues and develop projects that can mutually benefit more than one region.

MISO-SPP Joint Operating Agreement Enhancements

MISO and the SPP filed MISO-SPP Joint Operating Agreement revisions with FERC on May 17, 2019, which included substantive changes to the Coordinated System Plan process. The filing was accepted on July 16, 2019, with an effective date of July 17, 2019. The key revisions included:

- Remove the joint model requirement within the Joint Operating Agreement and instead rely on each Regional Transmission Operator's regional planning processes
- Remove the $5 million interregional project cost criterion
- Expand interregional benefit metrics to include Adjusted Production Costs (APC) and avoided cost benefits for all project drivers

2019 MISO-SPP Coordinated System Plan

After soliciting stakeholder feedback through the Interregional Planning Advisory Committee, the MISO-SPP Joint Planning Committee, in March 2019, voted in favor of performing a 2019 Coordinated System Plan study. Under the new process, each Regional Transmission Operator utilized their respective regional processes to evaluate solutions to identified interregional issues and as a result, all project evaluations were completed within the 2019 planning cycle.

More than 40 transmission solutions were evaluated to address identified seams issues, but ultimately no projects were recommended in 2019. Details about the MISO project evaluation and screening for MISO-SPP seams needs are discussed in Chapter 3 of this report.

2019 MISO-PJM Coordinated System Plan

MISO and PJM performed an Annual Issues Review at the March 29, 2019, Interregional Planning Stakeholder Advisory Committee, reviewing fourth quarter 2018 data, preforming an information exchange, and reviewing third-party issues. The Joint Regional Transmission Owner Planning Committee determined that there was no need for any additional studies in 2019, beyond the current two-year Interregional Market Efficiency Project study under the Coordinated System Plan.

MISO-PJM Interregional Market Efficiency Project Study Completed

As a continuation of the two-year Interregional Market Efficiency Project 2018/2019 Study, MISO and PJM reported on preliminary results at various Interregional Planning Advisory Committee meetings. Ten projects were reviewed by MISO and PJM to address congestion on three flowgates from nine entities. Details about the MISO project evaluation and screening for MISO-PJM seams needs are discussed in Chapter 3 of this report.

In addition to the joint planning efforts with Southwest Power Pool and PJM Interconnection, MISO also coordinates with neighboring entities of the Southeastern Regional Transmission Planning organization and the Independent Electricity System Operator of Ontario. As of September 2019, no formal studies were underway with either neighbor, though MISO and these entities meet regularly to review interregional issues and possible areas of collaboration.

1.3 MTEP19 Investment Summary

The MTEP19 cycle proposes 480 new Appendix A projects as justified in this MISO Transmission Expansion Plan and represents $4 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.

- **Generation 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 MTEP19 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 MTEP19 Projects

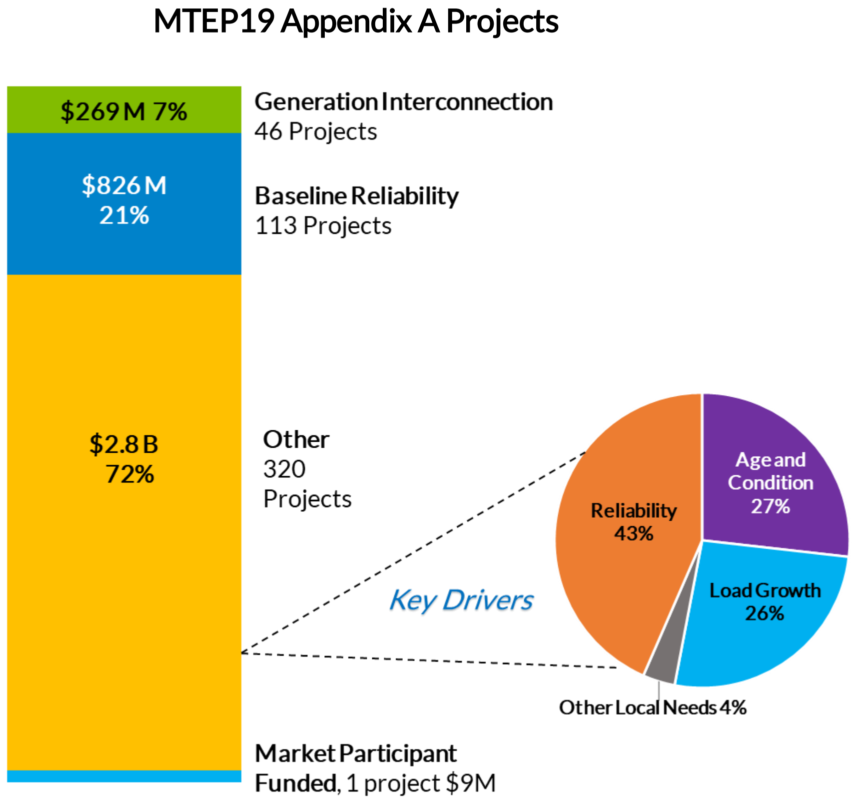


Figure 1.3-1: Appendix A New Project Investment

Of the 480 new Appendix A projects proposed in MTEP19 (Figure 1.3-1), 113 of them are Baseline Reliability; 46 are Generation Interconnection, one is Market Participant Funded, and 320 fall into the Other project category.

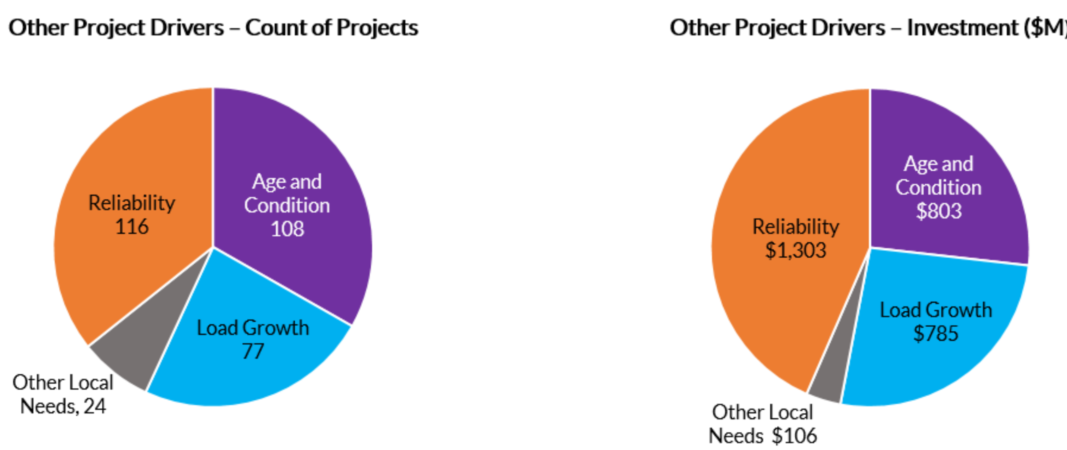


Figure 1.3-2: MTEP19 new Appendix A Other projects by category

The majority of Other projects address localized reliability issues, either due to aging transmission infrastructure, or local non-baseline reliability needs that are not dictated by NERC and regional reliability standards (Figure 1.3-2). The 36 projects that cost $20 million and above in MTEP19 Appendix A account for almost 50 percent of this category.

The remaining projects mostly address distribution concerns, with a small percentage of projects targeting localized economic benefits or line relocations to accommodate other infrastructure (Figure 1.3-3).

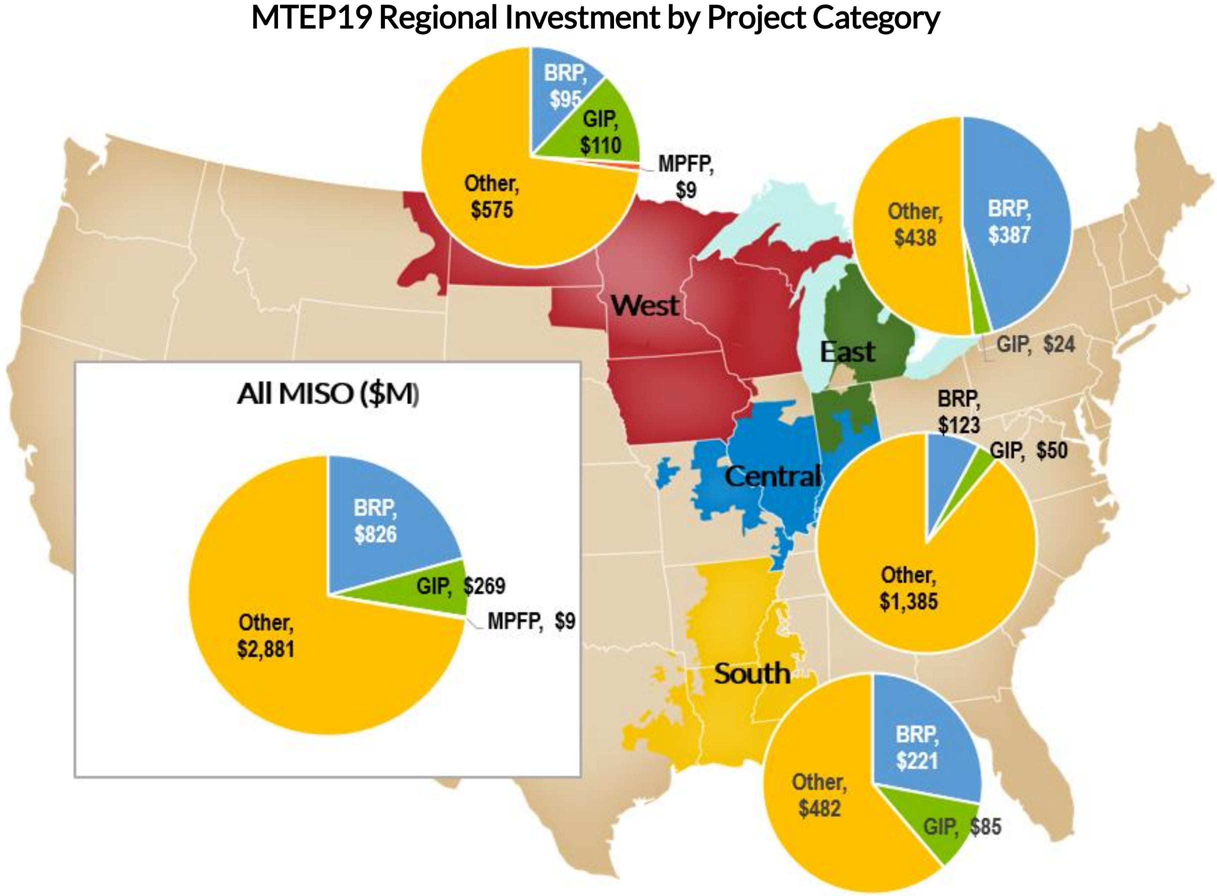


Figure 1.3-3: Regional MTEP19 investment by project category

The new projects recommended for approval in MTEP19 Appendix A are broken down by region and project type (Table 1.3-4).

MISO Region	GIP	Other	MPFP	BRP	Total
Central	$50,285,479	$1,385,079,966		$123,206,200	$1,558,571,645
East	$24,272,568	$438,320,000		$387,311,200	$849,903,768
South	$84,653,000	$482,374,237		$220,571,000	$787,598,237
West	$110,051,161	$575,129,434	$9,300,000	$95,029,102	$789,509,697
Grand Total	$269,262,208	$2,880,903,637	$9,300,000	$826,117,502	$3,985,583,347

Table 1.3-4: MTEP19 New Appendix A investment by project category and planning region

New Appendix A projects are spread over 15 states, with seven states scheduled for more than $150 million in new investment (Figure 1.3-5; Figure 1.3-6). A few projects have investment in more than one state, but the statistics in the figure are aggregated to the primary state. These geographic trends vary greatly year to year as existing transmission capacity in other parts of the system is consumed and new build becomes necessary.

MTEP19 Other projects reflect significant asset replacement in the Central region to implement updated system designs in order to operate more efficiently and reliably. Updating systems from straight buses to ring buses and breaker and a half are a priority for safety and reliability. Additionally, the East region has experienced significant load growth due to the revitalization of the Detroit area economy. See Chapter 4 and Appendix A for a detailed list of projects.

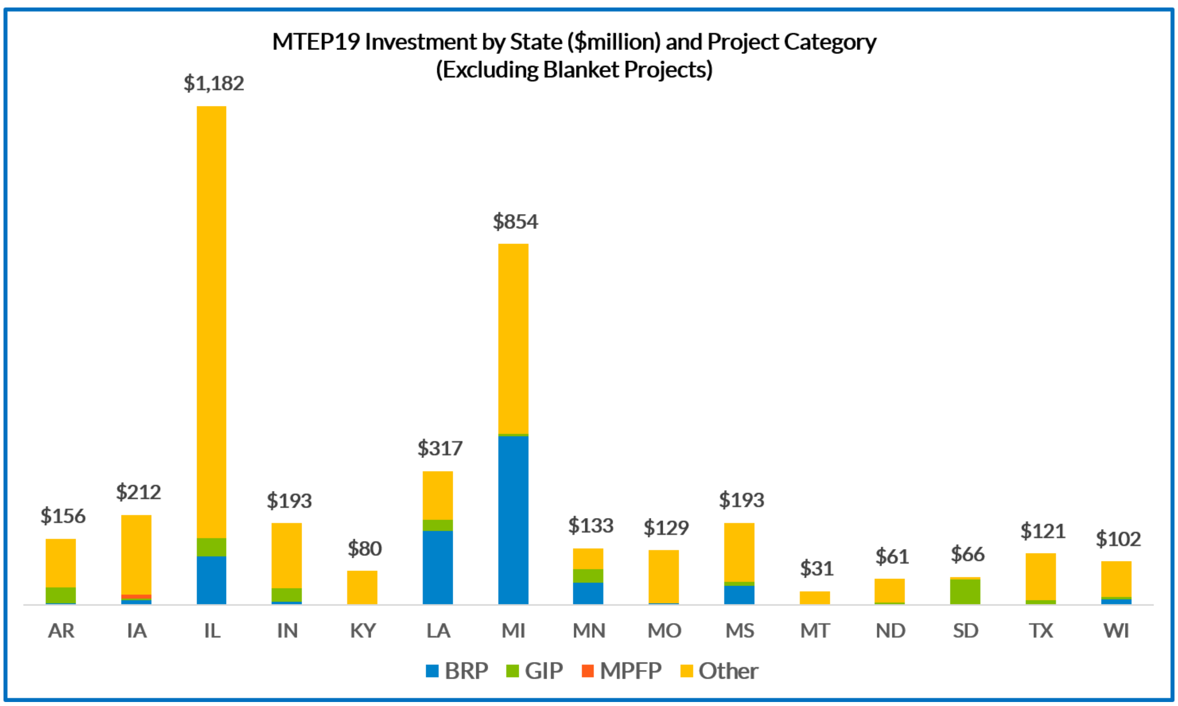


Figure 1.3-5: New MTEP19 Appendix A investment ($million) categorized by state (excluding blanket projects)

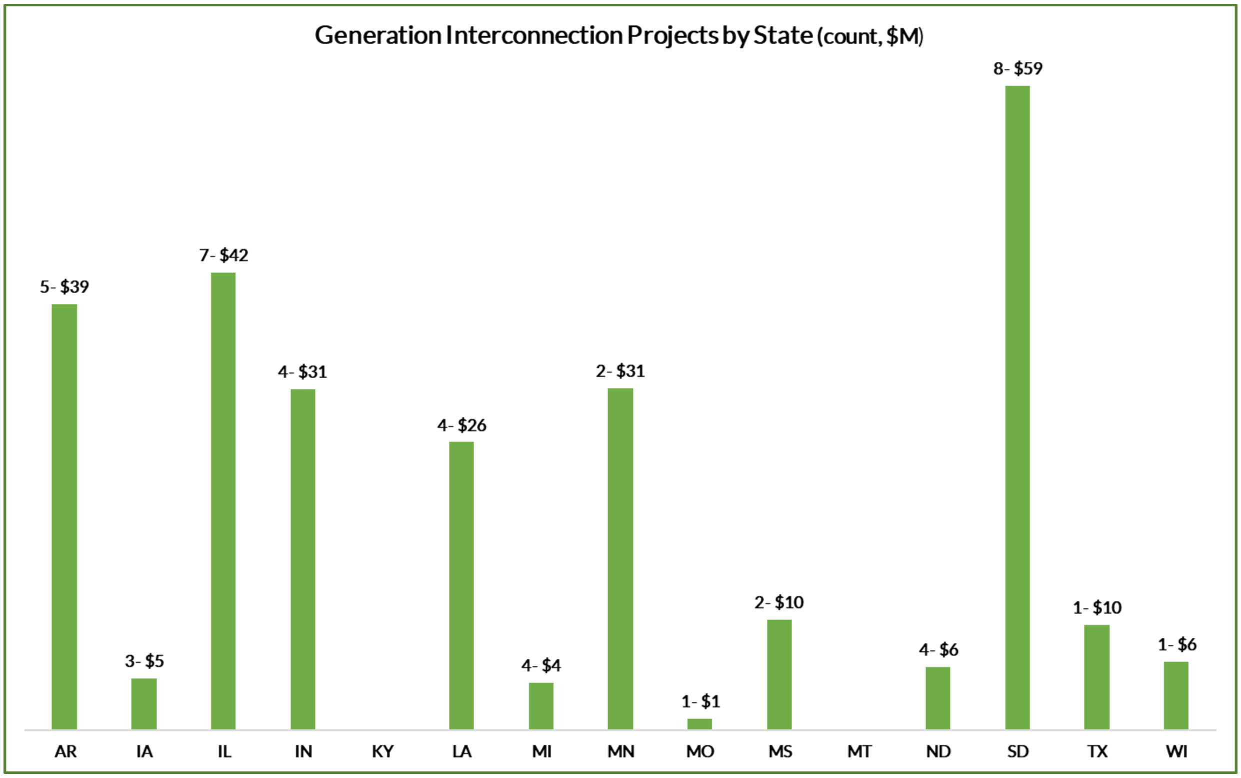


Figure 1.3-6: MTEP19 Appendix A Generation Interconnection projects by state

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, circuit breakers or various types of transmission lines (Figure 1.3-7).

The majority of facility investment in the MTEP19 cycle 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. Twenty-seven percent of MTEP facility costs go toward line upgrades, which include rebuilds, conversions and relocations. Nineteen percent of facility costs are dedicated to new lines on new right-of-way across the MISO footprint.

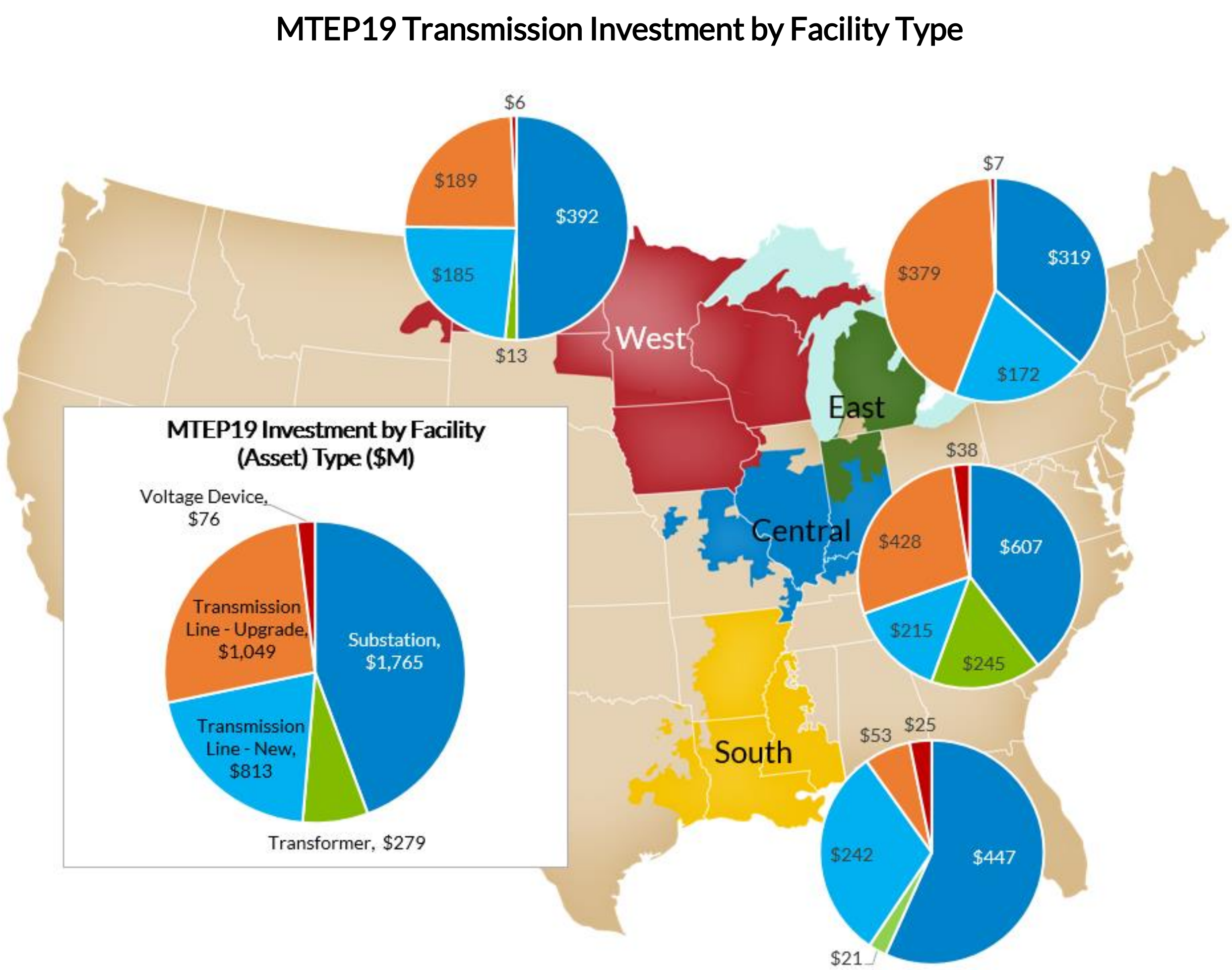


Figure 1.3-7: Facility type for new MTEP19 Appendix A projects

Allocation of Costs

MTEP19 recommends a total of 11 new cost-share eligible projects for Appendix A with an estimated eligible cost of $59.6 million. The eligible projects are:

- 11 Generation Interconnection Projects, where $7.4 million is allocated to load, and the remaining $52.2 million is allocated directly to generators.

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 posted on the MISO public website[3] here.

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

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.

CHAPTER 2: PORTFOLIO EVOLUTION

2.1 Generation Retirements and Suspensions

The permanent or temporary cessation of operation of generation resources can significantly affect the reliability of the transmission system. The MISO Tariff Attachment Y process provides a mechanism to ensure transmission system reliability in response to the retirement or suspension of a generation resource.

The MISO Tariff Attachment Y provides a mechanism to ensure transmission system reliability in response to the retirement or suspension of a generation resource.

Under the Tariff provisions, MISO may require the asset owner to maintain operation of the generation as a System Support Resource (SSR) if the generator is needed to avoid violations of applicable NERC, Regional or Transmission Owners' planning criteria. In exchange, the generator will receive compensation for its applicable costs to remain available. SSR costs are paid by the loads in areas that benefit from the SSR generation. An SSR is considered a temporary measure where no other alternatives exist to maintain reliability until transmission upgrades or other suitable alternatives are completed to address the issues caused by the unit change in status.

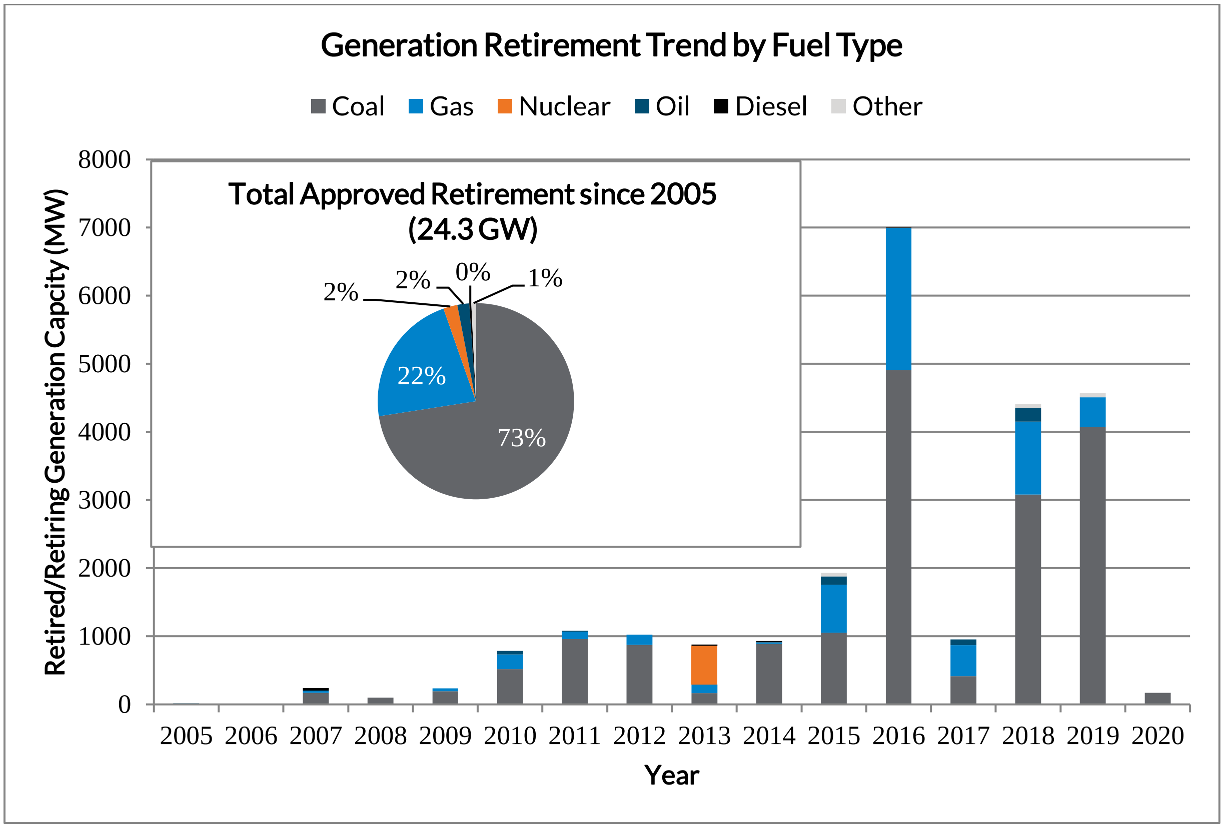
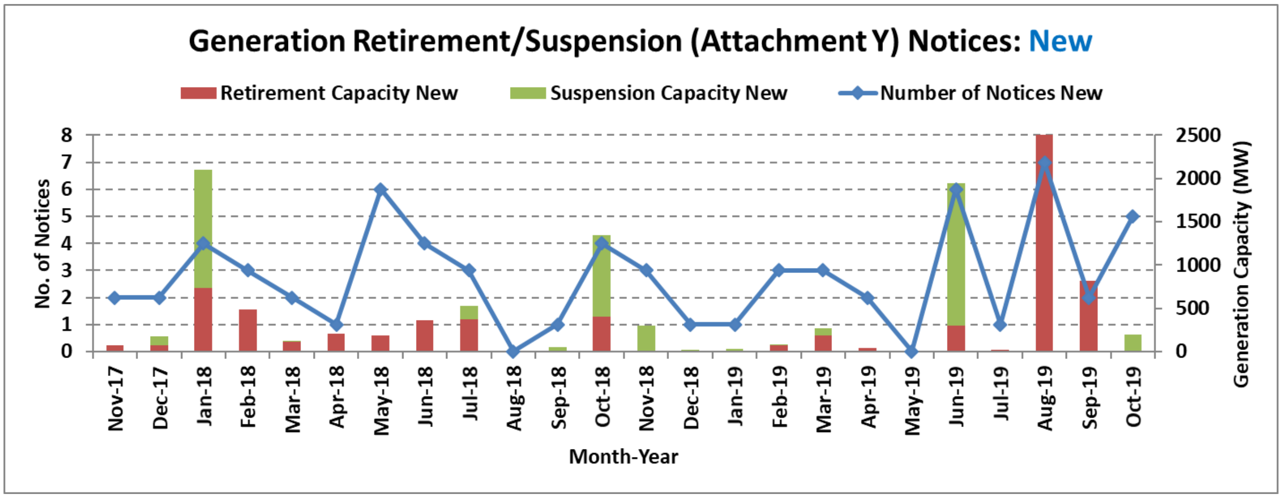


Figure 2.1-1: MW generation retirement trend by fuel type

Attachment Y Requests and Status

MISO received 23 new Attachment Y Notices (5,542 MW) for unit retirement/suspension during the first eight months of 2019, which is consistent with the 2018 activity. MISO completed assessments and approved 21 Attachment Y Notices (2,513 MW) for unit retirement/suspension in the first eight months of 2019 (Figure 2.1-2).

The continuing evolution of the generation fleet and prevailing market economics continues to drive further retirements of uneconomic and less efficient resources.



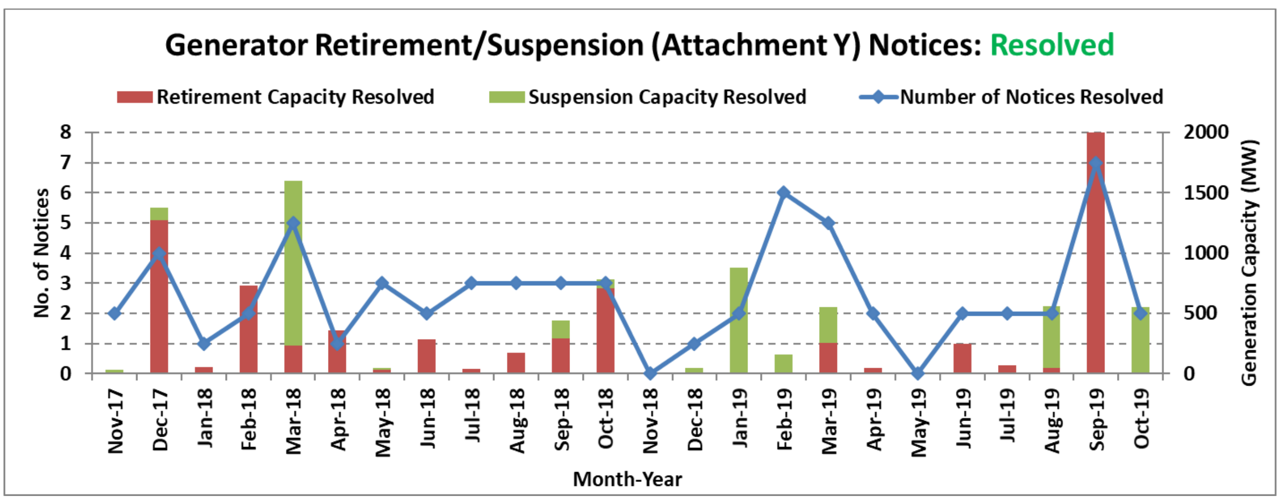


Figure 2.1-2: Generation retirement/suspension (Attachment Y) notices – new and resolved

2.2 Generation Deliverability Results

MISO performs generator deliverability analysis as a part of the MTEP process to ensure continued deliverability of generating units with firm service, including Network Resource Interconnection Service. The generation deliverability analysis results in the identification of projects which mitigate transmission system constraints that restrict generation output below the established network resource amount. Results of the assessment are determined on an analysis of near-term (five-year) summer peak scenario.

Observed constraints that restrict generation beyond the established Network Resource amounts require mitigation. The MTEP19 projects identified for mitigation to alleviate the constraints identified within the MISO region are listed in Table 2.2-1.

A total of three projects were identified to alleviate identified congestion.

MTEP19 Mitigation

In MTEP19, three projects were identified to mitigate constraints which restrict generation beyond the established network resource amount (Table 2.2-1). These projects, along with alternatives, were reviewed by stakeholders in the MTEP19 planning process and recommended for approval, as appropriate.

Overloaded Branch	Area	Mitigation MTEP19 ID	Notes
Plaisance 138 kV – Champagne 138 kV	EES / CLECO	15584	Mitigated by Appendix A in MTEP19. NERC TPL-001-4 Reliability Standards and Entergy's Planning Guidelines drive this project. MISO identified thermal overloads on the Plaisance to Champagne 138 kV line during their MTEP18 Deliverability Analysis.
Addis 230 kV – Tiger 230 kV	EES	15566	Mitigated by Appendix A in MTEP19. The MTEP18 MISO Deliverability study showed an overload on the Addis to Tiger 230 kV line for the P1.2 loss of the Dow Meter to Chenango 230 kV or the Richardson to Iberville 230 kV line in 2023.
Tezcuco 230 kV – Frisco 230 kV	EES	15605	Mitigated by Appendix B in MTEP19. MISO identified thermal overloads on the Tezcuco to Frisco circuit #1 and #2 during their MTEP18 Deliverability Analysis.

Table 2.2-1: Projects identified to alleviate constraints that limit deliverability of network resources

2.3 Generation Interconnection

The MISO Generation Interconnection Queue Forecast provides a forward-looking view of interconnection queue activity and projected resource composition to better understand the future impacts to transmission and resource planning needs.

The integration of new resources in the MISO footprint in most instances requires a substantial investment in transmission upgrades. The cost of these network upgrades is allocated to the generation projects, based on FERC's first driver "but-for" philosophy and can have a profound effect on the overall cost and viability of the project. In some sub-regions, the high cost of network upgrades is becoming a barrier to generation interconnection projects that would otherwise provide low-cost energy. Analysis of the network upgrade costs from the Generation Interconnection Queue studies provide useful insight into the need for coordinated planning of transmission expansion and resource integration to facilitate resource evolution.

Generator Interconnection Queue reforms have focused on enhancing the process to ensure timely and reliable interconnection for customers. In 2019, MISO received 301 projects with 44 GW during the application period that ended in April (Figure 2.3-1). As of September, the active projects in the queue are predominantly solar and wind. This distribution consists of 52 GW of solar and 24 GW of wind.

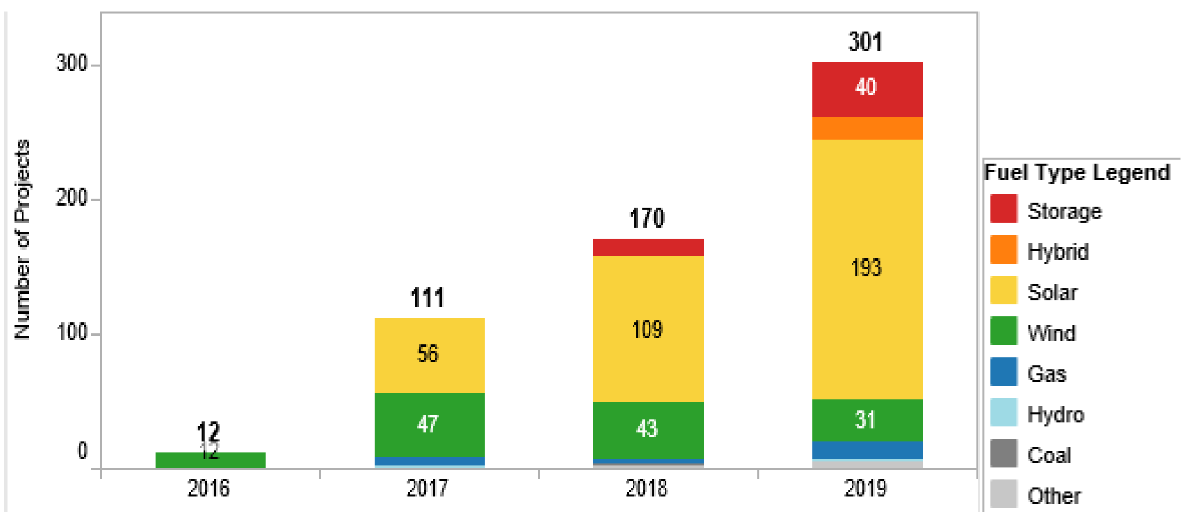


Figure 2.3-1: Generator Interconnection requests received by fuel type

In many cases, the location of large amounts of generation coincides with a lack of existing transmission infrastructure to support new interconnection. This leads to more complicated analysis efforts, including increased coordination with neighboring systems, which result in higher costs for interconnection. Costs, in particular, can cause generators to exit the process midstream, triggering rework and additional study delays.

The purpose of MISO's most recent Queue Reform is to introduce more predictability into the process and ensure viable projects proceed with minimal delay. The new process consists of scheduled restudies, defined withdrawal opportunities, and increased cash at risk milestones that all contribute to increased certainty.

Since 2016, MISO has received over 900 interconnection requests totaling over 145 GW. Currently, the active queue contains 582 projects and almost 91 GW (Figure 2.3-2). An interactive map, the MISO Interactive Generation Interconnection Queue map, is available at misoenergy.org and updated every 30 minutes.

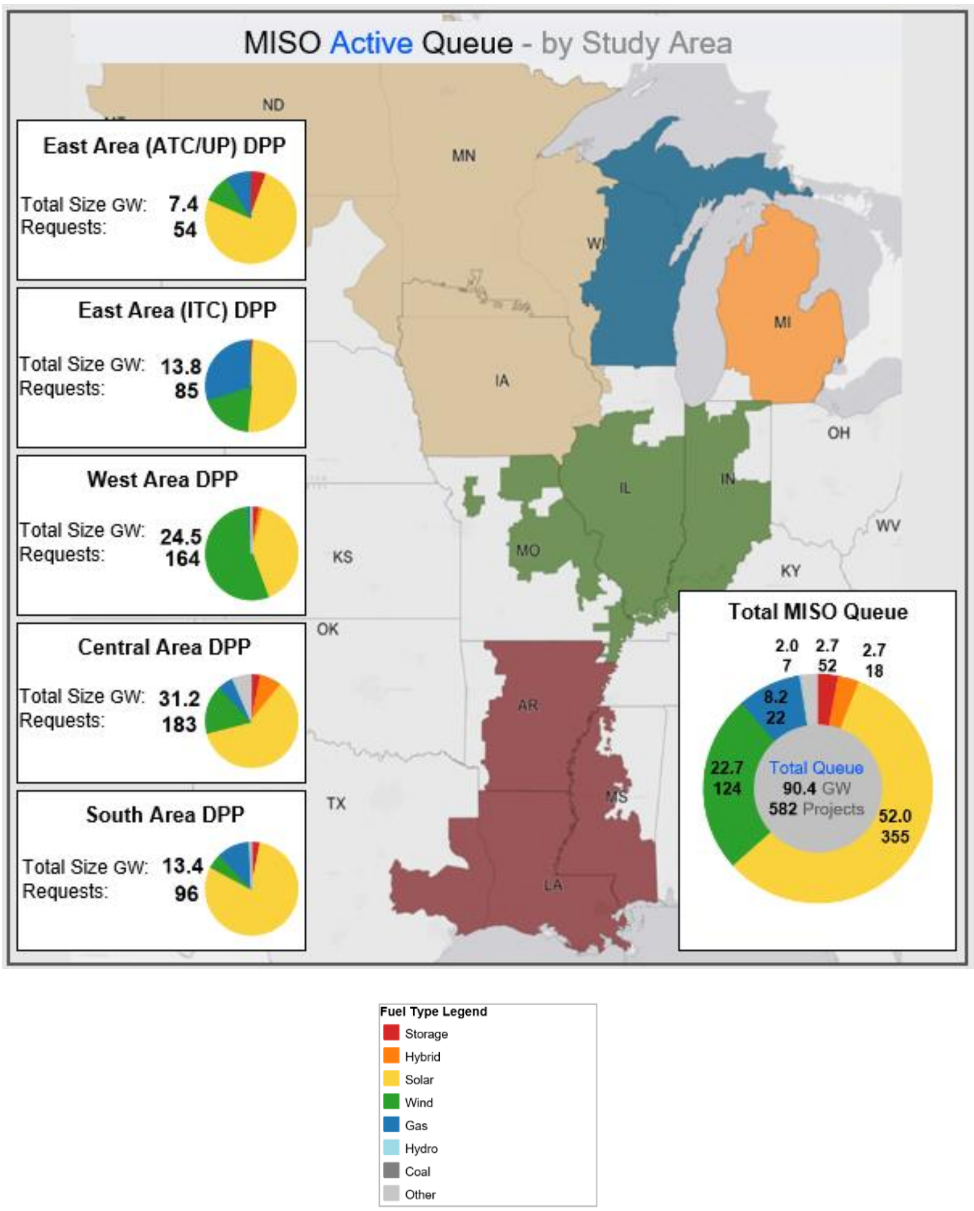


Figure 2.3-2: MISO Active Generation Interconnection queue as of October 24, 2019

MTEP19 Generation Interconnection Projects

MTEP Project ID	Project Name	Submitting Company	Planning Region	Expected ISD	Estimated Cost
17006	OTP-MRES-GRE Ortonville-Johnson Jct-Morris 115 kV Network Upgrades-J493/J526	OTP	West	8/21/2019	$26,728,127.00
16550	New Prairie State Solar (J808) interconnection	Ameren	Central	6/1/2020	$19,300,000.00
16964	OTP Astoria 345kV Switching Station - J493/J510	OTP	West	4/30/2020	$15,199,506.00
16445	Blazing Star 1 - J460	NSP (Xcel)	West	12/15/2019	$13,627,000.00
16805	OTP Deuel Switching Station - J526	OTP	West	6/29/2020	$11,886,510.00
15304	OTP Twin Brooks 345kV Switching Station - J436/J437	OTP	West	7/6/2020	$11,393,377.00
16246	Crossett South 115kV: Construct Switching Station (J680)	Entergy AR	South	4/15/2021	$9,976,000.00
16572	J483 Interconnection: Construct 138 kV Switching Substation	Entergy	South	9/1/2020	$9,540,000.00
16045	New Orleans Power Station Interconnection Project	Entergy	South	2/28/2020	$9,350,000.00
16444	J643 Network Upgrades	NIPSCO	East	9/1/2021	$8,921,164.00
16249	Ashley 115kV: Construct Switching Station (J603)	Entergy AR	South	9/15/2021	$8,887,000.00
16244	Bellaire 115kV: Construct Switching Station (J620)	Entergy AR	South	3/18/2020	$8,258,000.00
16570	J581 Interconnection: Construct 115 kV Switching Station	Entergy	South	12/31/2021	$8,125,000.00
16085	J513 Network Upgrades	NIPSCO	East	8/15/2020	$7,874,504.00
16248	Lee 115kV: Construct Switching Station (J552)	Entergy AR	South	6/1/2022	$7,858,000.00
15760	J446 Gen. Interconnect	Duke	Central	12/31/2020	$7,579,786.00
16568	Ruleville 115 kV: Install Transmission Line Bay and Breakers (J604 Interconnection)	Entergy MS	South	3/15/2021	$7,381,000.00
15224	New Hornsby 138 kV substation for Cardinal Point Wind Farm	Ameren	Central	12/1/2019	$7,283,395.00
15324	New Howlett 138 kV substation for J756 interconnection	Ameren	Central	6/1/2020	$6,900,000.00
16225	New Yates 138 kV Substation for Morgan-Scott Counties Solar Interconnection	Ameren	Central	6/1/2021	$6,722,298.00
16084	J351 Network Upgrades	NIPSCO	East	3/31/2020	$6,692,900.00
16571	Galion 115 kV: Install Transmission Line Bay and Breakers (J544 Interconnection)	Entergy	South	9/15/2021	$6,468,000.00
16493	J584 GIC Jordan SS, Generator Interconnection Facilities and Network Upgrades Information	ATC	West	5/15/2021	$6,200,000.00
16724	Hazel Creek Transformer Upgrade	NSP (Xcel)	West	9/1/2020	$4,445,000.00
16247	Crooked Lake 161kV: Install Transmission Breaker and Line Bay (J586)	Entergy AR	South	3/1/2022	$3,845,000.00
16965	OTP Big Stone Plant 230/115 kV Transformer - J488/J493/J526	OTP	West	9/24/2020	$3,389,282.00
16492	J849, Chandler SS, Interconnection Facilities and Network Upgrades	ATC	West	1/7/2022	$3,036,785.00
16565	J679 Interconnection: Construct 115 kV Switching Substation	Entergy MS	South	4/15/2021	$2,665,000.00
16924	OTP Hankinson to Ellendale 230kV Network Upgrades - J488	OTP	West	8/23/2019	$2,628,468.00
15822	New Sharon-Poweshiek 69 kV Reconductor and Replace Structures	MEC	West	12/31/2018	$2,400,000.00
16566	J683 Interconnection: Construct 138 kV Switching Substation	Entergy	South	10/30/2020	$2,300,000.00

MTEP Project ID	Project Name	Submitting Company	Planning Region	Expected ISD	Estimated Cost
15824	M Avenue-New Sharon 69 kV Reconductor and Replace Structures	MEC	West	4/1/2019	$2,100,000.00
16825	OTP Twin Brooks 345 kV Switching Station Expansion-J488	OTP	West	6/1/2020	$1,855,260.00
17005	OTP Hankinson to Wahpeton 230 kV Network Upgrades - J460/J488/J493/J526	OTP	West	8/13/2020	$1,596,087.00
16485	OTP Hankinson to Ellendale 230kV Network Upgrades – J436/J437	OTP	West	9/1/2019	$1,439,902.00
17007	OTP Hankinson to Oakes 230 kV & Big Stone to Blair 230 kV Network Upgrades - G359R	OTP	West	8/31/2020	$1,364,550.00
15325	New 345 kV ring bus for J757 Interconnection	Ameren	Central	5/31/2021	$1,000,000.00
16548	New Hughes 345 kV Substation (J541) for wind Interconnection	Ameren	Central	5/1/2020	$1,000,000.00
16424	J602 Network Upgrades	METC	East	9/1/2021	$784,000.00
16226	New Green-Scott Counties Solar (J644) interconnection	Ameren	Central	12/1/2020	$500,000.00
16494	J928 - Garden Corner SS GIC Network Upgrades	ATC	West	6/28/2020	$304,855.00
15676	Webster-Hayes 161 kV Structure Replacements	MEC	West	6/1/2020	$175,000.00
17064	J928/J849 Indian Lake Common Use Upgrades	ATC	West	10/13/2019	$173,012.00
17024	OTP Blair 230 kV Substation Switches - J488/J493/J526	OTP	West	7/1/2019	$70,000.00
16991	OTP Big Stone to Blair 230 kV - J488/J493/J526	OTP	West	10/1/2020	$38,440.00
16224	New Alta Wind Farms (J474) interconnection	Ameren	Central	3/1/2020	$0.00
				TOTAL:	**$269,262,208.00**

Table 2.3-1: Generation Interconnection projects in MTEP19 Appendix A as of October 18, 2019

2.4 Resource Adequacy Summary

The latest survey of resource adequacy in the Midcontinent Independent System Operator indicates that installed resources across the footprint are adequate through 2022. Moreover, these resources more than make up for potential capacity deficits starting in 2020 in Illinois, Indiana and Lower Michigan.

The Organization of MISO States (OMS) and MISO notified market participants that it had finalized its annual OMS-MISO Survey[4], which showed an increase in committed installed capacity in excess of expected demand for 2020, in contrast with the previous survey's potential deficit for 2020. The annual survey is an out-year resource snapshot constructed with voluntary market participant feedback.

In the MISO region, the responsibility for Resource Adequacy does not lie with MISO, but rather rests with Load Serving Entities and the states that oversee them (as applicable by jurisdiction). MISO's role is to provide sufficient transparency and market mechanisms to mitigate potential shortfalls.

The 2018 survey showed that MISO could have a reserve deficit of 100 MW to as much as a 7.3 GW surplus in 2020. However, the 2019 survey concludes that the MISO region is projected to have 3 GW to 5.8 GW of resources in excess of the regional requirement in 2020, based on responses from over 97 percent of MISO load and additional non-load-serving entity market participants.

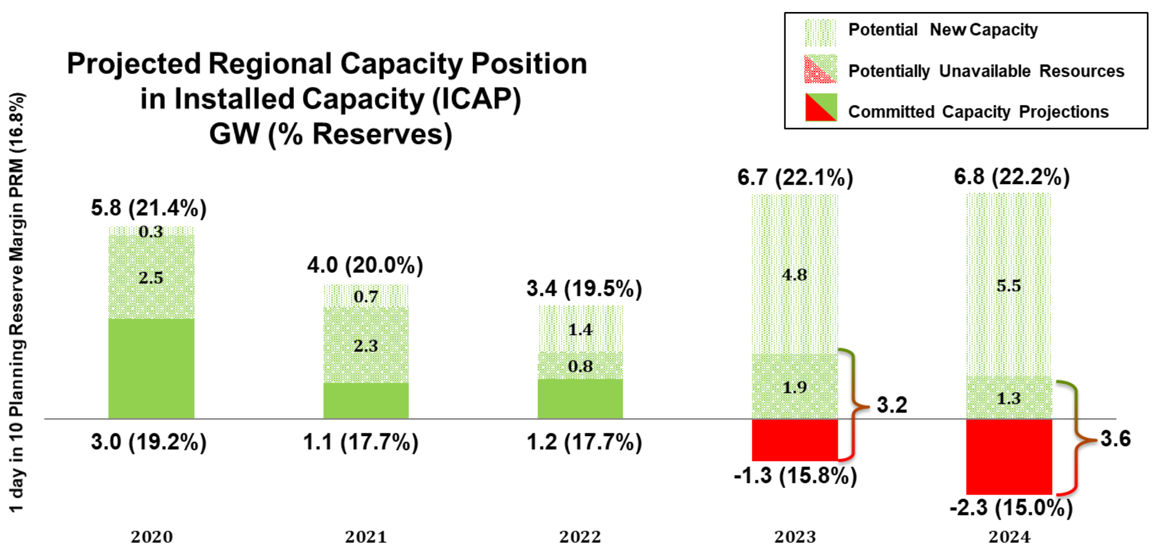


Figure 2.4-1: 2019 OMS-MISO Survey results through 2024

Shown in Figure 2.4-1, the 3 GW excess in 2020 would correspond to a 19.2 percent planning reserve margin. The 5.8 GW excess, corresponding to a 21.4 percent reserve margin, includes potential new

[4] https://cdn.misoenergy.org/20190710%20RASC%20Item%2003a%202019%20OMS-MISO%20Survey360918.pdf

capacity and resources that may be unavailable because of firm sales across the Sub-regional Power Balance Constraint between the MISO South region and the MISO North and Central regions. MISO calculates 16.8 percent as the minimum planning reserve margin needed to ensure capacity-related outages occur no more often than one day in 10 years. Figure 2.4-1 shows how the survey results measure up against this 16.8 percent reserve margin through 2024 which shows sufficient near-term resources, but increasing uncertainty and potential short-falls of required reserves into the future.

The latest report indicates demand growth continues to slow; the regional growth rate forecast for the next five years dropped from 0.5 percent two years ago, to 0.3 percent last year to 0.2 percent a year this year. Additionally, the 2019 survey shows an increasing reliance upon Load Modifying Resources (LMRs) that are accessible only under emergency operations. The larger this dependence grows, the higher the likelihood that system conditions will drive MISO to call emergency operations as has been witnessed over the last several years.

The 2019 survey shows the regional resource picture is more uncertain in 2023 and 2024, and the MISO region may be deficient if no action is taken. This range of uncertainly in the out-years is not unexpected, given the "snapshot-in-time" nature of the survey. Uncertainties considered in the survey include new generation development, changes to the load forecast, unit availability limitations, and generation retirements. Additionally, while the region may be sufficient through 2022, some areas within the footprint may require additional actions to meet local resource needs. The regional resource adequacy picture will evolve as load serving entities and states continue to firm up their future resource plans. This range of outcomes highlights the importance of continued conversation and collaboration regarding zonal and state resource plans, new unit integration and more accurate LMR accreditation.

As the resource mix and load shape change in the MISO footprint, MISO is working with stakeholders through the Resource Availability and Need (RAN) effort to increase incentives for unit availability, provide more visibility into what's needed to ensure reliability for all hours, and provide more flexibility to allow load serving entities to best utilize their resources. To that end, MISO created three guiding principles that focus on increasing reliability in the near-term, while taking into account an evolving portfolio.

1. **Reliability Needs and Requirements:** Reliability criteria must reflect required attributes in all horizons – all hours matter
2. **Reliability Contribution:** Members take responsibility for meeting reliability criteria with resources that will be accredited based upon the resource's ability to deliver those attributes
3. **Alignment with Markets and Infrastructure:** Market prices must reflect underlying system conditions and resources must use appropriate incentives for the attributes they provide; infrastructure should enable efficient utilization of resources

2.5 Futures Development

The first two steps in MISO's 7-Step value-based transmission planning process are associated with the development of multiple futures, resource forecasting, and siting of new forecasted resources. This process intends to capture a wide array of potential fleet changes and conditions for long-term transmission planning that considers economic, technology, and industry trends as well as the policy landscape. With the goal of prudently planning transmission over a 10- to 20-year period, the desire is not to find a single, most likely future definition, but to model a range of futures that comprise reasonable bookends and several points in between.

The MTEP19 Futures were developed through a collaborative stakeholder process that began at the January 17, 2018, Planning Advisory Committee meeting and concluded at the October 17, 2018, Planning Advisory Committee. Throughout this collaborative process, stakeholders had multiple opportunities to provide feedback, which influenced the final MTEP19 Futures.

The goal of MTEP futures is to bookend uncertainty by defining a wide range of potential plausible outcomes.

Due to a lack of significant changes in the policy drivers, the MTEP19 Futures are largely identical to the MTEP18 Futures, with the exception of several changes primarily around the modeling and minimum amounts of renewable energy resources (Figure 2.5-3).

The four MTEP19 Futures are:

- Limited Fleet Change (LFC)
- Continued Fleet Change (CFC)
- Accelerated Fleet Change (AFC)
- Distributed and Emerging Technologies (DET)

The Regional Resource Forecasting (RRF) process uses the assumptions defined within each future which economically identifies the least-cost portfolio of new supply-side and demand-side resources for each future. Base data assumptions in the associated PowerBase database 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 MTEP19 regional resource forecasting process are shown in Figure 2.5-1.

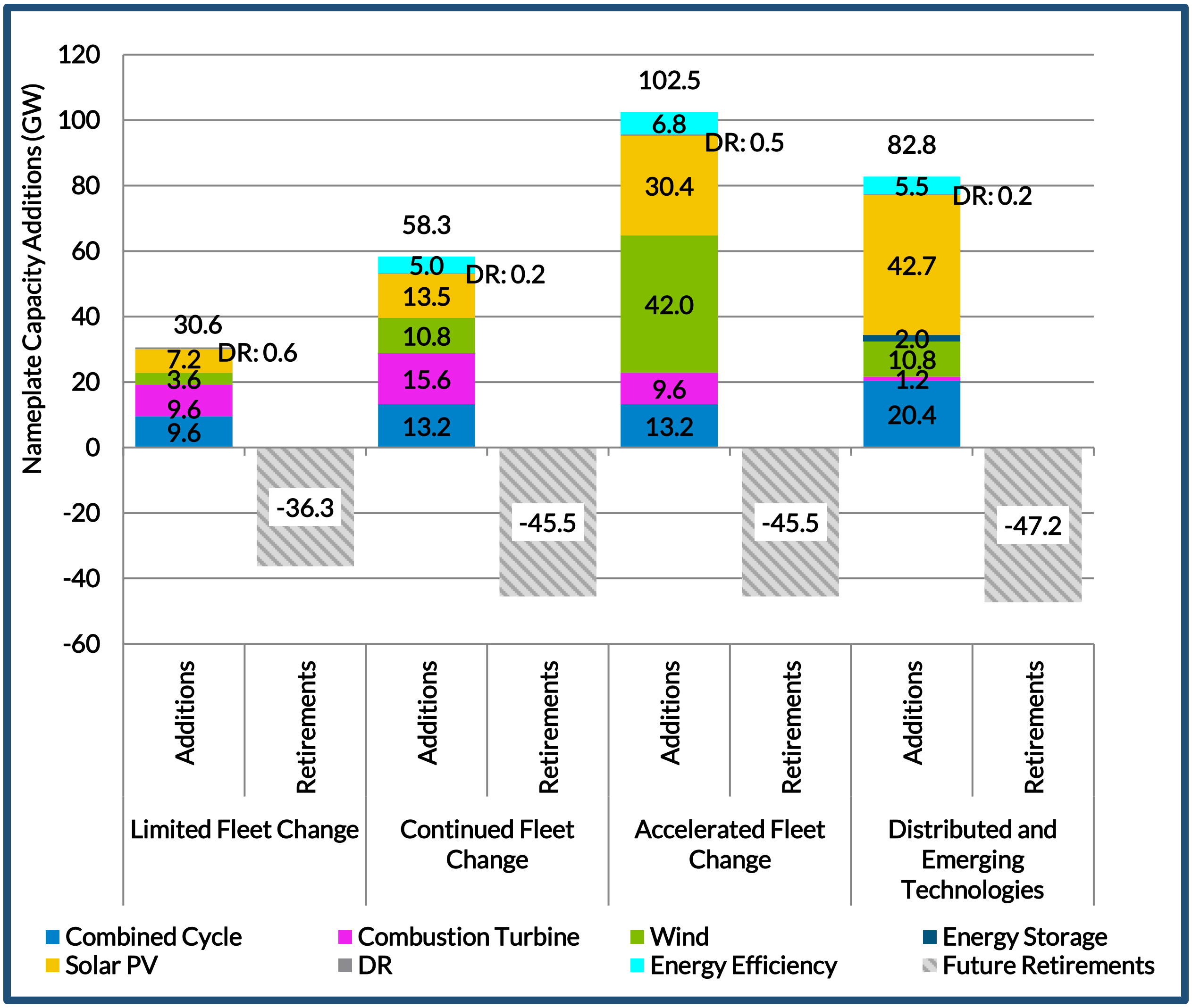


Figure 2.5-1: Resource additions and retirements by 2033

To produce the future capacity mix in 2033 for each of the MTEP19 Futures, the retirements and new resources identified from the regional resource forecasting process must be applied to the existing generation fleet (Figure 2.5-3).

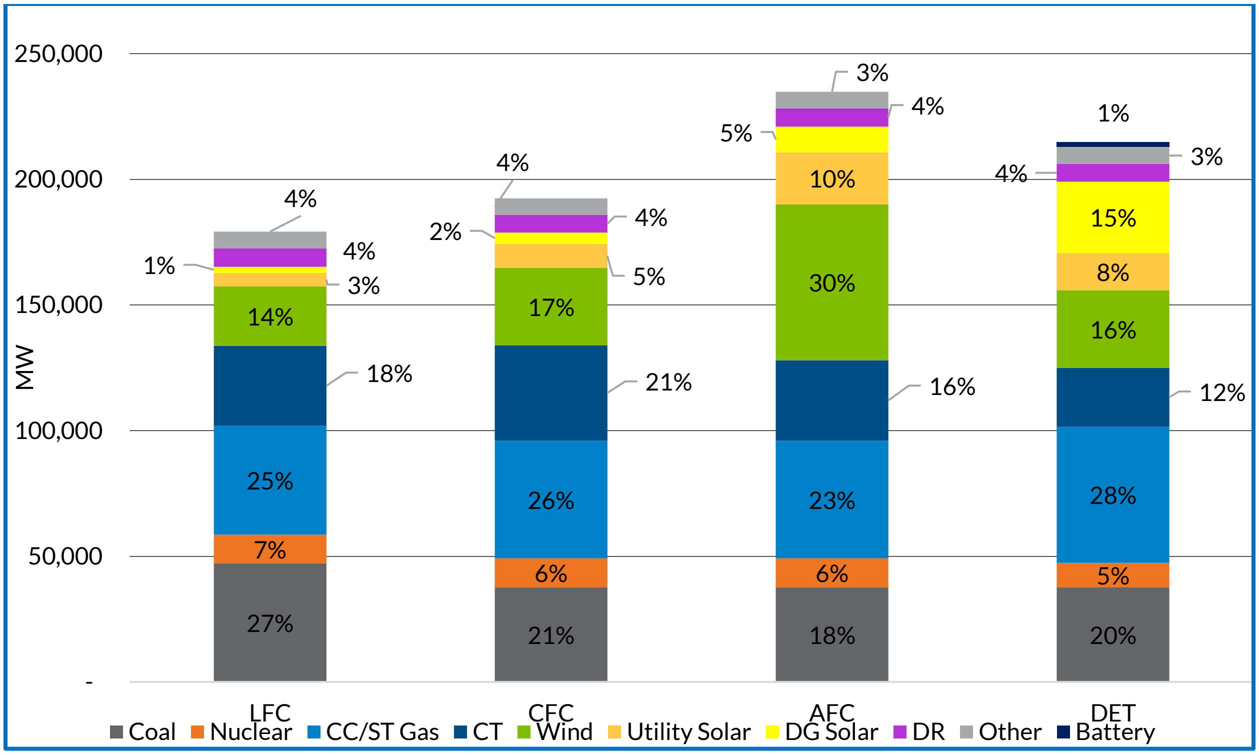


Figure 2.5-2: MISO 2033 Futures capacity mix by resource

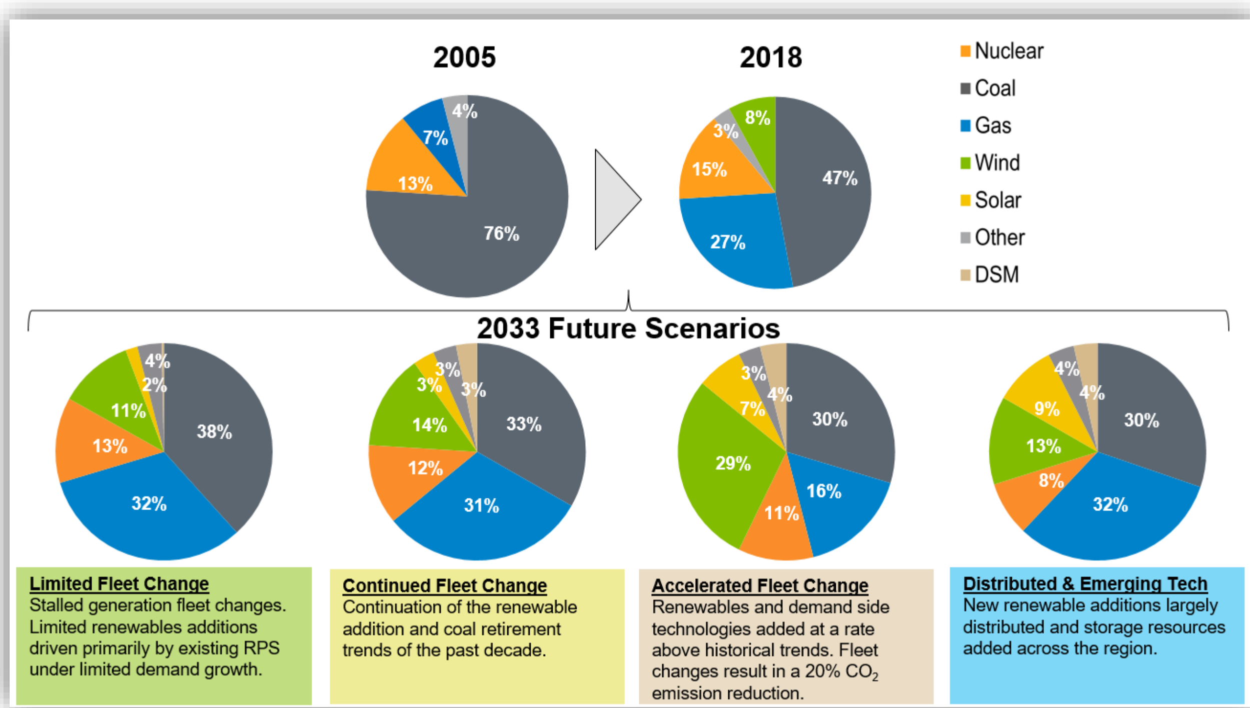


Figure 2.5-3: MISO 2033 Futures energy utilization mix

The results from the regional resource forecasting 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 MTEP19 siting process is based on stakeholder-agreed-upon rules and criteria detailed in section 4 of Appendix E (Figure 2.5-4).

Additional details regarding MTEP19 Futures development, resource forecasting, and siting processes are in Appendix E of this report.

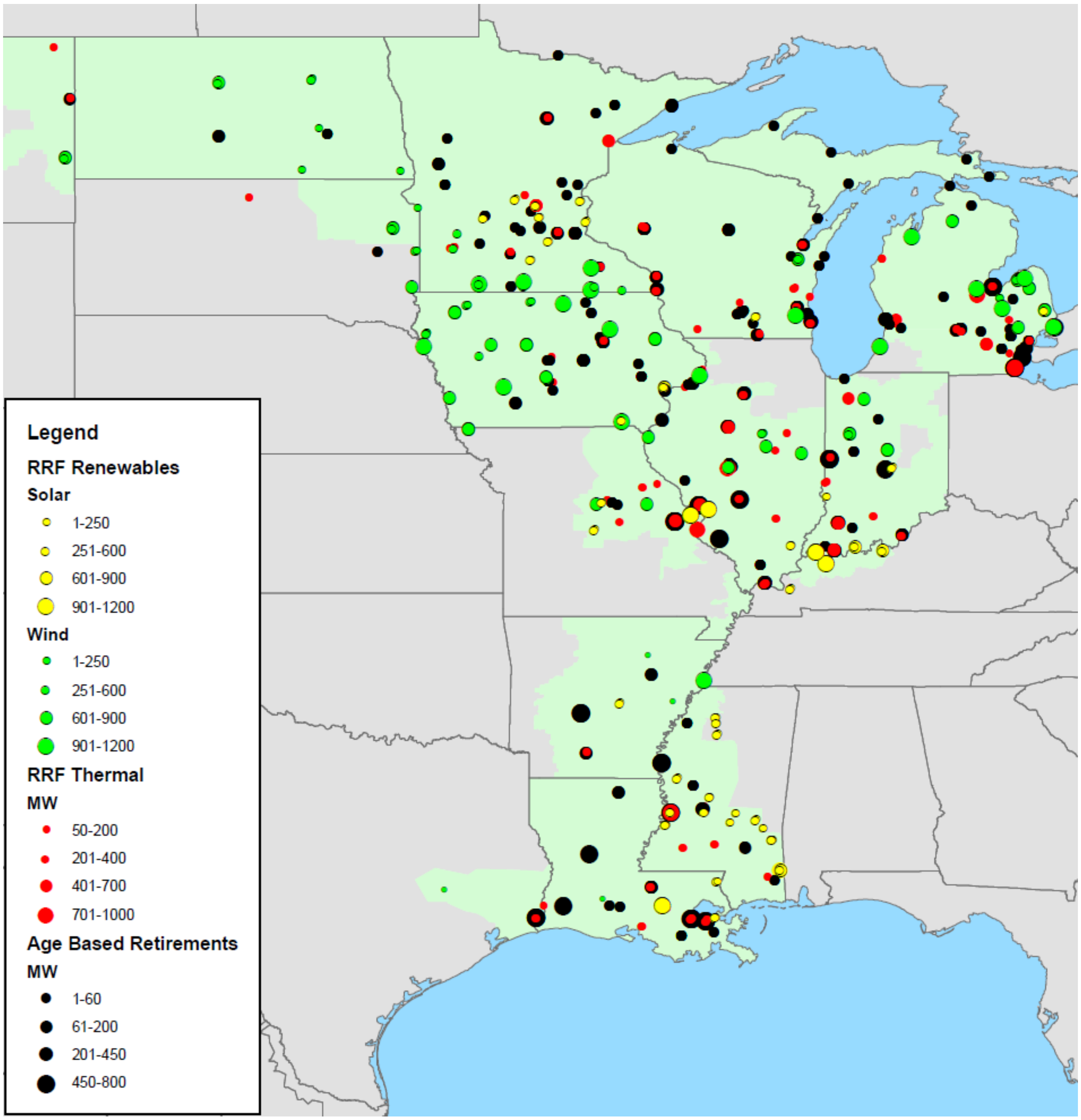


Figure 2.5-4: MISO Future supply-side resource siting results

In the MTEP19 cycle, MISO saw increasing momentum in fleet development and noted how new generation could outpace advanced bookends within the planning horizon. With the accelerated pace of fleet change in mind, MISO is engaging with stakeholders to better align the new futures cohort for MTEP21. To enhance flexibility and visibility in planning outcomes, MISO is proposing changes to new futures development and related process improvements.

CHAPTER 3: REGIONAL AND INTERREGIONAL ECONOMIC STUDIES

Market Congestion Planning Study

The Market Congestion Planning Study develops transmission plans that offer MISO customers better access to the lowest-cost energy throughout the MISO market. From a regional perspective, the study seeks to identify the appropriate transmission network upgrades that address both near-term transmission system congestion and long-term economic opportunities. The solutions may therefore vary in scale and scope, and can be classified as Economic-Other or Market Efficiency Projects. As an integral part of MISO Value-Based Planning, the Market Congestion Planning Study looks to develop the most robust transmission upgrades that offer the highest future value under a variety of both current and projected system conditions.

In MTEP19, a consolidated economic planning effort integrating the regional and interregional needs was undertaken through the Market Congestion Planning Study. The regional needs evaluation included congestion within the MISO footprint as well as the North-South (Regional Directional Transfer) interface, which limits flows between the MISO sub-regions based on the Settlement Agreement[5] with Southwest Power Pool (SPP) and the other joint parties. The interregional evaluation included congestion issues near the seam with SPP and the PJM Interconnection regions, and was coordinated with the respective Interregional Planning Stakeholder Advisory Committee groups.

Study Summary

The Market Congestion Planning Study in MTEP19 identified and evaluated transmission solutions for 16 top congested flowgates. Six of those flowgates were identified as regional needs while 10 flowgates were identified for interregional coordination with SPP and PJM. A total of 116 transmission solutions were evaluated where each solution was tested for its robustness in addressing the system needs under a wide variety of scenarios, characterized by the MTEP19 futures (described in Chapter 2.5). Following an initial screening, eight project candidates were finalized for further robustness analysis to ensure economic needs were addressed and system reliability was maintained under various projected system operating conditions. After a review of the eight project candidates, rebuilding the Michigan City to Trail Creek to Bosserman 138 kV lines was recommended for approval as an Interregional Market Efficiency Project (IMEP) in the MISO-PJM focus area.

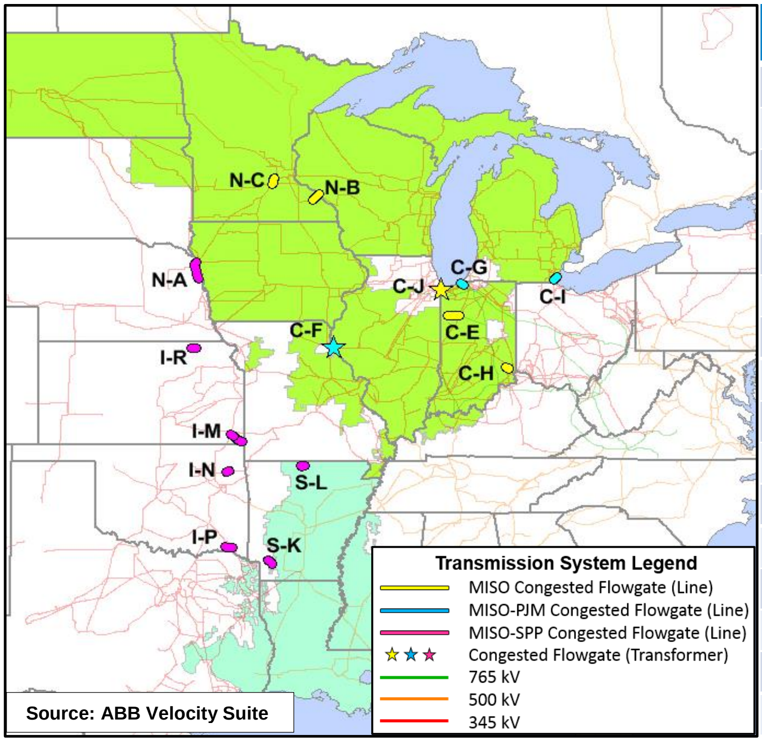
Top Congested Flowgates

The top congested flowgate analysis identified system congestion trends based on out-year production cost analysis and historical market performance data (day-ahead, real-time, and market-to-market). Sixteen top

[5] FERC dockets EL14-21 and ER14-1174

congested flowgates within the MISO market footprint and on the seam (Figure 3-1) were identified and prioritized for solution identification in MTEP19. These 16 top congested flowgates were further categorized as:

- Regional needs, including five flowgates and the North-South interface.
- MISO-SPP interregional needs, including seven flowgates along the seam with SPP and coordinated with the MISO-SPP interregional evaluation.
- MSO-PJM interregional needs, including three flowgates along the seam with PJM and coordinated with the MISO-PJM interregional evaluation.



ID	Monitored Element
N-A	Raun to Tekamah 161kV
N-B	Wabaco to Alma 161kV
N-C	Helena to Scott County 345kV
C-E	Goodland to Reynolds 138kV
C-F	Marblehead N Transformer 161/138kV
C-G	Bosserman to Trail Creek 138kV
C-H	Hubble to Batesville 138kV
C-I	Lallendorf to Monroe 345kV
C-J	Munster Transformer 345/138kV
S-K	Fulton to Patmos 115kV
S-L	Bull Shoals to Midway Jordan 161kV
I-M	Neosho to Riverton 161kV
I-N	Kerr to Maid 161kV Circuit 2
I-P	Hugo to Valliant 138kV
I-R	Marshall to Smittyville 115kV
RDT	North – South Interface

Figure 3-1: Projected top congested flowgates from MTEP19 Market Congestion Planning Study

Solution Evaluation and Project Identification

MTEP19 studies evaluated 116 solutions (Table 3-1) that addressed the congestion needs identified as the top congested flowgates. All solutions were subjected to a two-step screening process that resulted in a refined list of projects, categorized as project candidates. The first screening step was a single year analysis, which determined if a project provided congestion relief and benefits to the MISO system. The first step, for the projects addressing the six regional needs, used a benefit-to-cost ratio greater than 0.9 as the threshold. The second and final screening step included the evaluation through all MTEP futures and study years to determine if a project provided a weighted present-value benefit-to-cost ratio greater than 1.0. In MTEP19 the screening process yielded eight project candidates.

MTEP19 MCPS Overview (Number of Solutions)	Regional	Regional (North-South Interface)	MISO-SPP	MISO-PJM
Evaluated	31	35	40	10
Passed initial (one-year) screening	9	TBD	7	7
Project candidate	3	TBD	3	2

Table 3-1: Summary of MTEP19 Market Congestion Planning Study (MCPS) solution evaluation

The eight project candidates were further subjected to robustness analysis. During the robustness analysis, the project candidates were evaluated using additional sensitivity scenarios to ensure that project benefits were not driven purely by a single future assumption (such as future generation siting or age-related generation retirement). Robustness analysis also included reliability analysis on each of the project candidates to ensure that there would be no degradation of system reliability.

Projects Addressing the Regional Needs

MTEP19 studies evaluated 66 projects that addressed the six regional-needs identified as top congested flowgates. Thirty-five of these projects addressed the North-South interface, while 31 projects addressed the other five regional needs.

North-South Interface

In early 2019, MISO submitted changes to its Tariff that proposed new provisions to consider the avoided cost of future settlement payments under the Joint Operating Agreement settlement. Shortly afterward, MISO stakeholders expressed an interest in re-analyzing transmission solutions to the Joint Operating Agreement settlement. The objective of the analysis targeting the North-South interface was to determine if there are transmission projects that offer better value compared to the settlement payments and if a higher transfer capability enables additional market flows between the MISO sub-regions.

Anticipating that additional time could be required to evaluate these potential transmission projects, MISO began evaluating the North-South constraint within the MTEP19 Market Congestion Planning Study framework mid-study. MISO is currently reviewing stakeholder and internally developed solutions and expects to continue its analysis through 2020.

While not yet adopted as a benefit metric for justifying projects, MISO expects that the avoided settlement cost savings will be considered in the future. Through the course of analysis MISO is also working with stakeholders to consider other benefit metrics that would help to capture additional value that such a transmission project would offer, especially through additional MISO-owned capacity between the sub-regions.

Other Regional Needs

MTEP19 studies evaluated 31 transmission solutions to address the five other regional needs identified as top congested flowgates (Figure 3-1). Nine transmission solutions passed the initial screening and three solutions were selected as project candidates. All three project candidates addressed the Helena to Scott County 345 kV flowgate located in Minnesota (Figure 3-2).

The Helena to Scott County 345 kV flowgate was identified as a top congested flowgate due to congestion driven in part by existing wind generators, which is then exacerbated by future wind generator assumptions in Local Resource Zones 1-3. Six transmission projects targeting this flowgate were analyzed through the screening analysis. Of those six projects, three were selected as project candidates (Figure 3-3). All of the project candidates showed a benefit-to-cost ratio greater than 1.25 (Table 3-2). The Helena to Hampton Corner 345 kV second circuit project (PC-2), with estimated cost of $36.1 million, produced the highest benefit-to-cost ratio. Further robustness analysis, including the consideration of additional sensitivities, was focused around this project candidate.

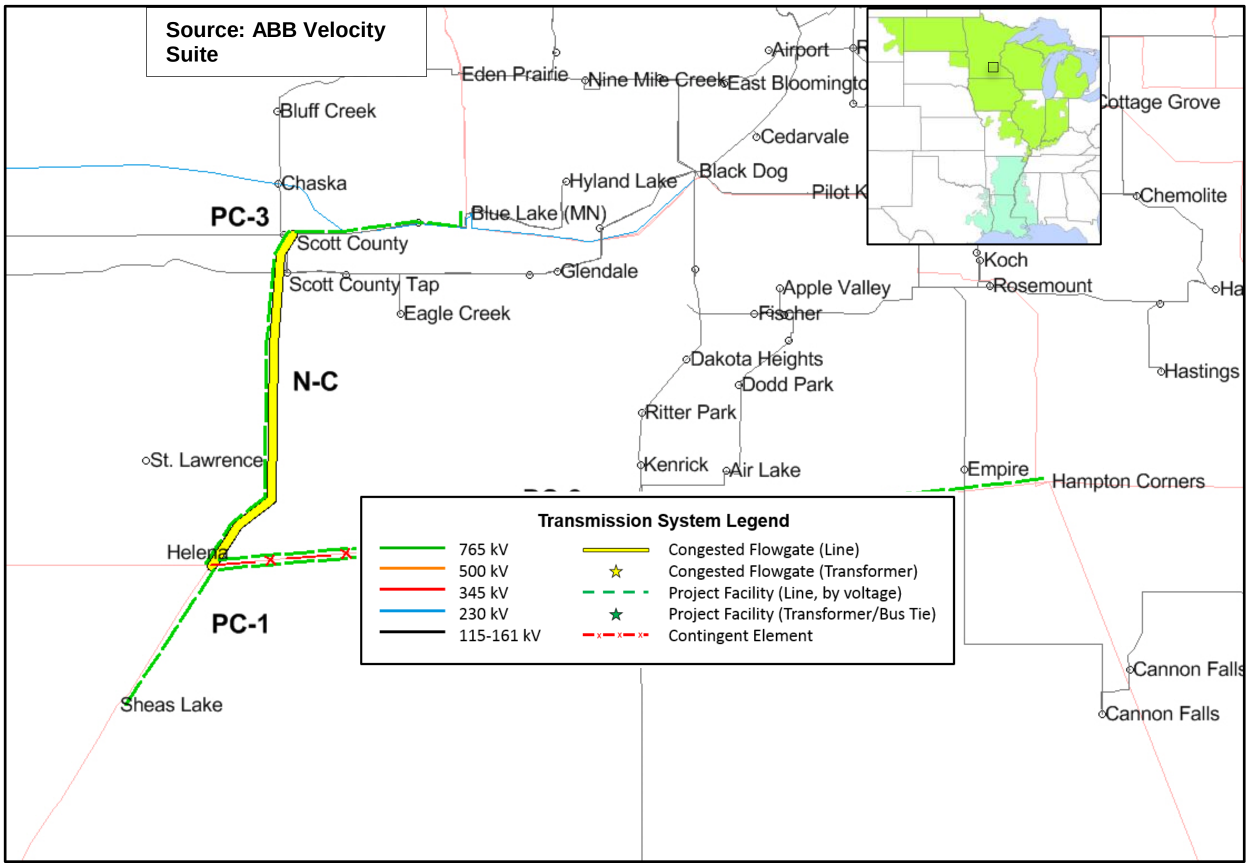


Figure 3-2: Three project candidates addressing Helena to Scott County 345 kV flowgate

Transmission Solution	Cost Estimate *(2019-$M)	Benefit-to-Cost Ratios					Congestion Relief (%)
		AFC	CFC	DET	LFC	Wtd	
PC-1: Sheas Lake to Chub Lake 345 kV	51.4	5.37	1.9	2.7	0.57	2.65	100%
PC-2: Helena to Hampton Corner 345 kV second circuit	36.1	8.65	2.98	4.38	0.87	4.22	100%
PC-3: Helena – Blue Lake 345 kV	107.7	3.08	1.04	1.54	0.32	1.50	100%

*Scoping-level cost estimate

Table 3-2: Study results by Futures B/C on project candidates addressing Helena to Scott County 345 kV

Several sensitivities were developed and evaluated to understand the impacts on the project benefits and identify the recipients of the benefits. The sensitivities considered MISO's Generator Interconnection Definitive Planning Phase queue wind generation along with their associated transmission network upgrades. There are four sensitivity scenarios:

- **Test 0**: All Regional Resource Forecast wind units sited in Local Resource Zones 1 through 3 were removed from MTEP19 PROMOD base models
- **Test 1**: Replaced all Regional Resource Forecast wind units sited in Local Resource Zones 1 through 3 with Definitive Planning Phase-Phase 2 and beyond wind units
- **Test 2**: Added major Generation Interconnection Network Upgrades associated with wind projects of Definitive Planning Phase-Phase 3 and Generator Interconnection Agreement (GIA) complete in West to MTEP19 PROMOD base models
- **Test 3**: Replaced all Regional Resource Forecast wind units sited in Local Resource Zones 1 through 3 with Definitive Planning Phase-Phase 3 and beyond wind units; added major associated Generation Interconnection Network Upgrades

Type of Test	Sensitivity	Weighted Benefit-to-Cost Ratios	Weighted 20-year Present Value Benefit ($M)
Base Case	MTEP19 Base Case	4.22	167
Generation	Test 0: No Regional Resource Forecast Wind	0.66	26
	Test 1: No Regional Resource Forecast Wind + Definitive Planning Phase -2 & beyond Wind	4.31	170
Transmission	Test 2: MTEP19 Base + Generation Interconnection Network Upgrades	0.89	35.4
Generation + Transmission	Test 3: No Regional Resource Forecast Wind + Definitive Planning Phase -3 & beyond Wind and Generation Interconnection Network Upgrades	0.49	19.6

Table 3-3: Helena to Hampton Corner 345 kV second circuit project sensitivity test results

The results of this additional analysis show that futures with the assumption of new wind units sited in Local Resource Zones 1, 2, and 3 are well correlated with the present-value benefits (Table 3-3). The analysis also shows that the network upgrades associated with future Generation Interconnection queue units in this region can largely relieve the congestion in this area, significantly lowering benefit-to-cost ratio below the threshold for the project candidate. Considering all of the analysis performed to date, the MISO staff has concluded that the Helena to Hampton Corner 345 kV second circuit project is not a robust project.

Projects Addressing MISO-SPP Interregional Needs

MTEP19 studies evaluated 40 transmission solutions to address the six MISO-SPP interregional needs identified as top congested flowgates in MTEP19 (Figure 3-1). Seven transmission solutions passed the initial screening and after further review three solutions were selected as project candidates. Two project candidates addressed the Fulton to Patmos 115 kV flowgate while one project candidate addressed the Raun to Tekamah 161 kV flowgate. The selected project candidates were evaluated in partnership with SPP.

The Fulton to Patmos 115 kV flowgate, which is a market-to-market flowgate on the MISO-SPP seam, is located in southwestern Arkansas and was identified due to congestion during a contingency on the 345 kV system nearby. Through the screening analysis, two project candidates (Figure 3-3) were selected after evaluating five different transmission projects addressing this flowgate. Although these project candidates were evaluated through the MISO-SPP coordinated process and provided significant congestion relief, the project candidates did not meet the benefit-to-cost ratio threshold of 1.25 (Table 3-4). Neither of these project candidates are recommended for Board approval in MTEP19.

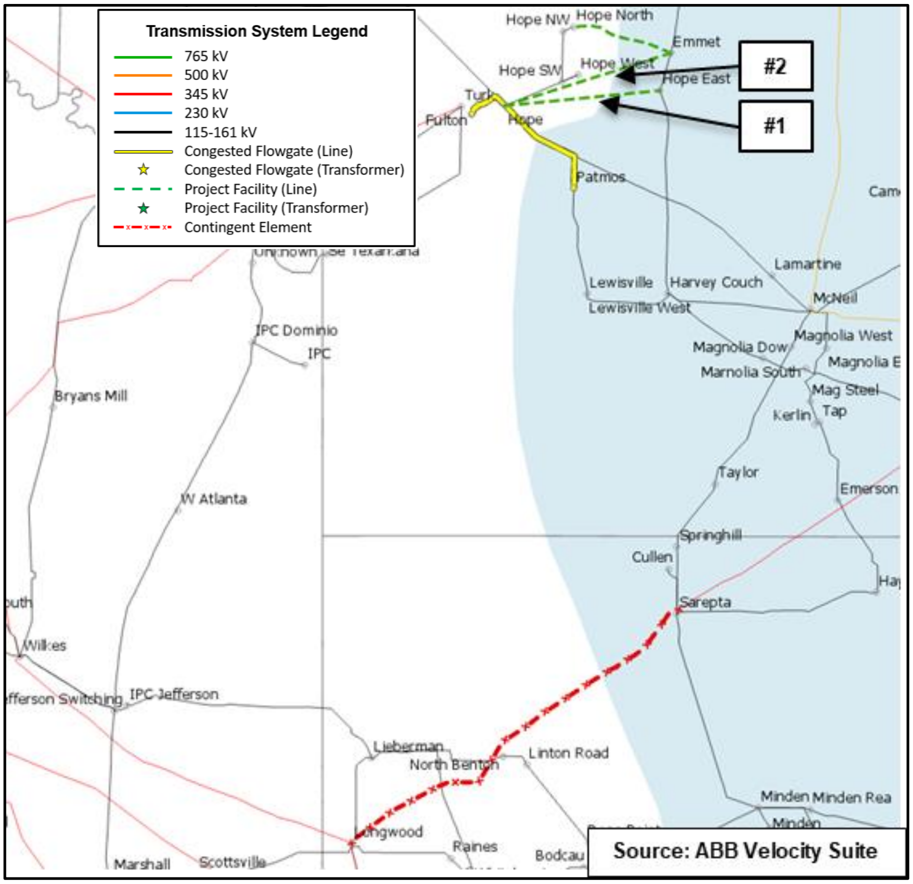


Figure 3-3: Two project candidates addressing the Fulton to Patmos 115 kV flowgate

Transmission Solution	Cost Estimate (2019-$M)	% Split (MISO/SPP)	Benefit-to-Cost Ratios				
			AFC	CFC	DET	LFC	Weighted
#1: Hope REA to Hope East 115 kV; Close Emmet to North Hope 115 kV	35	41.2/58.8	2.92	0.67	0.50	(0.02)	1.02
#2: Hope REA to Emmet 115 kV; Close Emmet to North Hope 115 kV	37	38.4/61.6	2.85	0.72	0.54	0.15	1.07

Table 3-4: Study results for project candidates addressing the Patmos to Fulton 115 kV flowgate

The Raun to Tekamah 161 kV flowgate, which is also a market-to-market flowgate on the MISO-SPP seam, is located on the Iowa/Nebraska border and was identified due to congestion caused by existing and projected future wind generation located in Southwestern Minnesota. One project candidate (Figure 3-4) was selected after evaluating 10 different transmission solutions designed to address the flowgate. Although, this project candidate provided significant congestion relief in MISO's analysis, it showed minor benefits to SPP during the MISO-SPP interregional evaluation. The project candidate did not meet the benefit-to-cost threshold of 1.25 or the cost share threshold of 5 percent with SPP (Table 3-5) and is not recommended for Board approval in MTEP19.

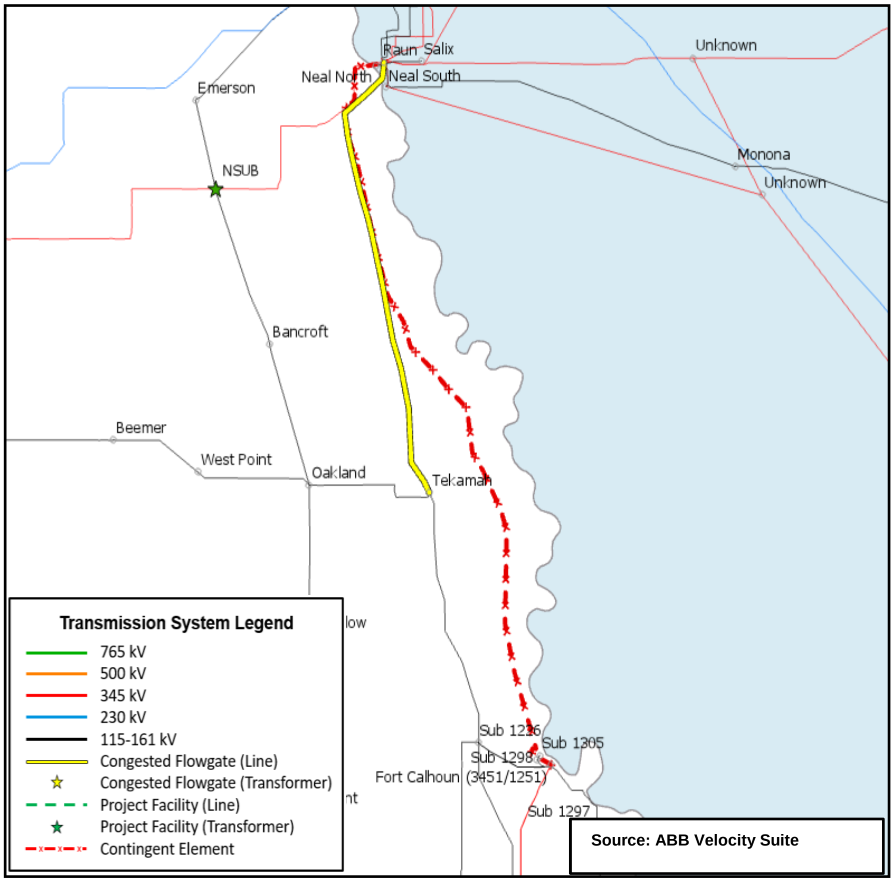


Figure 3-4: One project candidate addressing the Raun – Tekamah 161kV flowgate

Transmission Solution	Cost Estimate (2019-$M)	% Split (MISO/SPP)	Benefit-to-Cost Ratios				
			AFC	CFC	DET	LFC	Weighted
Rebuild Raun to Tekamah 161kV	58	96.3/3.7	1.14	0.62	0.67	0.45	0.72

Table 3-5: Study results for project candidates addressing the Raun to Tekamah 161kV flowgate

Projects Addressing MISO-PJM Interregional Needs

MTEP19 studies evaluated 10 transmission solutions to address the three MISO-PJM interregional needs identified as top congested flowgates (Figure 3-1). Seven transmission solutions passed the initial screening and, after further review, two solutions were selected as project candidates. Both project candidates (Figure 3-5) addressed the Bosserman to Trail Creek 138 kV flowgate and were evaluated through the interregional evaluation with PJM. Congestion on the Bosserman to Trail Creek 138 kV flowgate, which is a market-to-market flowgate on the MISO-PJM seam, is caused by significant East to West flows in Northern Indiana and is exacerbated by generation retirements in the area. MISO's regional evaluation (Table 3-6) showed significant congestion relief on this flowgate from both the project candidates. After cost allocation with PJM, the final benefit-to-cost ratios (Table 3-7) showed rebuilding the Michigan City to Trail Creek to Bosserman 138 KV lines is the best-performing project for both MISO and PJM.

The project is being recommended for approval by both MISO and PJM as the first-ever Interregional Market Efficiency Project (IMEP). MISO will not seek December 2019 Board approval of the project due to the pending MISO cost allocation filing; the project has been placed in Appendix B. Upon cost allocation approval at FERC, the project will be taken to the MISO Board of Directors for approval as an MTEP19 project.

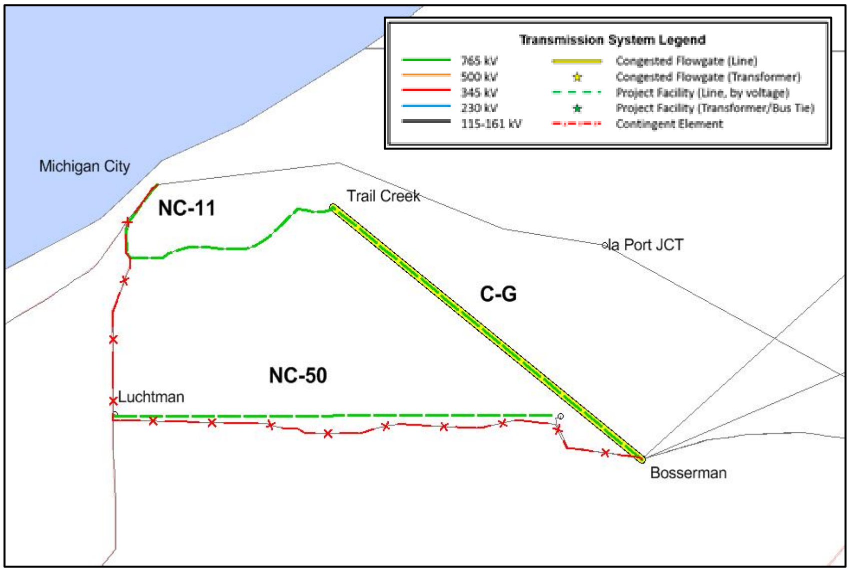


Figure 3-5: Two project candidates addressing Bosserman to Trail Creek 138 kV (C-G)

Project	Cost Estimate (2019-$M)	Proposed ISD	20-year PV Benefit to MISO ($M)	Congestion Relief (%)
Rebuild Michigan City to Trail Creek to Bosserman 138kV Lines	21.56	2023	8.42	100
Kuchar to Luchtman 138kV	23.26	2024	9.17	95

Table 3-6: Study results for project candidates addressing the Bosserman to Trail Creek 138kV flowgate

Project	Cost Estimate (2019-$M)	Benefit (Million $)		Interregional Cost Allocation		Final B/Cs	
		MISO	PJM	MISO	PJM	MISO	PJM
Rebuild Michigan City to Trail Creek to Bosserman 138kV Lines	21.56	8.42	69.2	10.90%	89.10%	3.12	2.63
Kuchar to Luchtman 138kV	23.26	9.17	60.0	13.30%	86.70%	2.70	2.14

Table 3-7: Final benefit to cost ratios after cost allocation with PJM for project candidates addressing the Bosserman to Trail Creek 138kV flowgate

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 MTEP reliability assessment process (Figure 4.1-1) begins with a roll-up of issues and potential solutions from the local planning processes of the Transmission Owners (TO), followed by an independent reliability assessment conducted by MISO to evaluate and integrate 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, such as the Market Congestion Planning Study process 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, ROW or substation impacts, expandability, operational flexibility, etc.

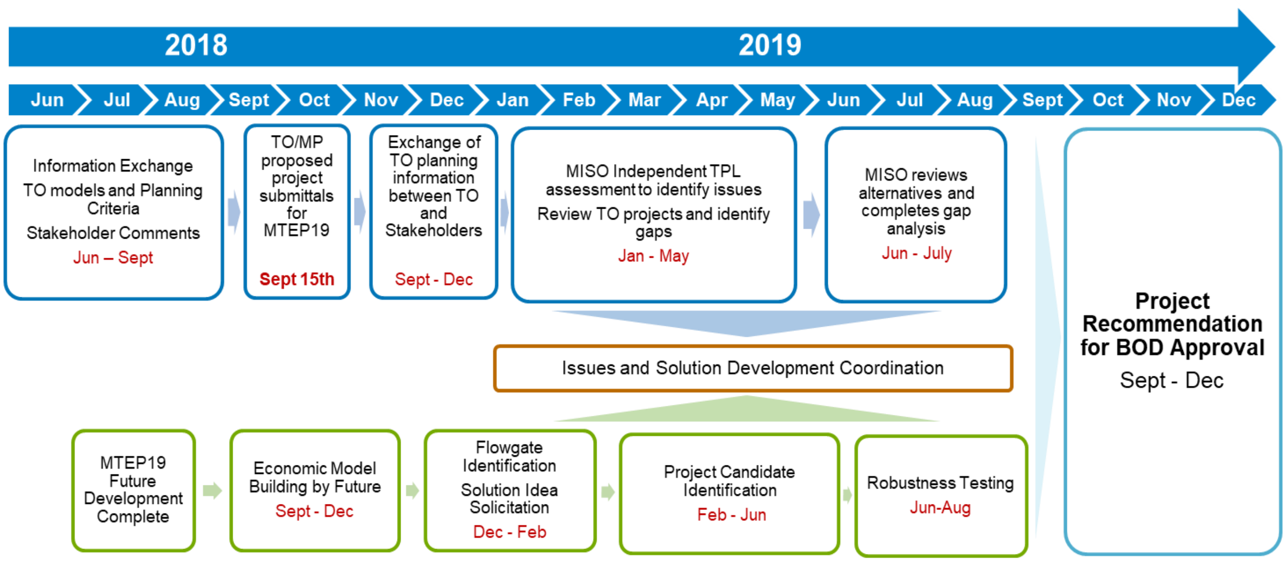


Figure 4.1-1: MTEP19 Reliability assessment process

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, and additional Technical Study Task Force 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 MTEP19 reliability assessments are detailed in Appendices D3-D10 of this report, which are available on the MISO SFTP site, 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.

MTEP19 project recommendations

As the result of the MTEP19 reliability assessments, 422 reliability projects totaling $3.6 billion are included in the MTEP19 Appendix A, accounting for 93% of total transmission infrastructure investment in MTEP19. Fourteen Expedited Project Review requests were received and evaluated. The vast majority of the recommended projects are driven by local reliability, load growth, and age condition, and are expected to be in service within five 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.

4.2 Project Justifications – Central Region

Central Region Overview

The MISO Central planning region consists of twelve transmission owners: Ameren (AMIL/AMMO); Big Rivers Electric Corp. (BREC); City of Columbia, Mo. (CWLD); City of Springfield, Ill. (CWLP); Duke Energy Corp. (DEI); Henderson Municipal Power & Light (HMPL); Hoosier Energy REC Inc. (HE); Indianapolis Power & Light (IPL); Prairie Power Inc. (PPI); Southern Indiana Gas & Electric (SIGE); Southern Illinois Power Cooperative (SIPC); and Wabash Valley Power Association Inc. (WVPA).

The MISO Central planning region resides in four states: Missouri, Illinois, Indiana and Kentucky. The bulk power system 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 161 kV and 138 kV networks span both north and south, and east to west. All of Ameren, BREC, CWLD, CWLP and SIPC belong entirely in the SERC Region. All of Duke, Hoosier Energy, IPL, and SIGE belong entirely in the Reliability First Region.

Ameren Illinois (AMIL) is a regulated electric and gas delivery company based in Collinsville, IL. 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 pipeline transmission and distribution mains; and twelve 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 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.

Big Rivers Electric Corp. (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.

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 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.

Duke Energy Corp. (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.

Hoosier Energy REC Inc. (HE) is a generation and transmission electric cooperative providing wholesale power and services to eighteen 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.

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.

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.

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.

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, and 562.9 miles of 69 kV transmission line. 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.

Wabash Valley Power Association (WVPA) is a G&T cooperative with twenty-three co-op members in northern Indiana, Missouri, and Illinois. The WVPA co-ops are served by Duke, NIPSCo, Ameren Illinois and Ameren Missouri.

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

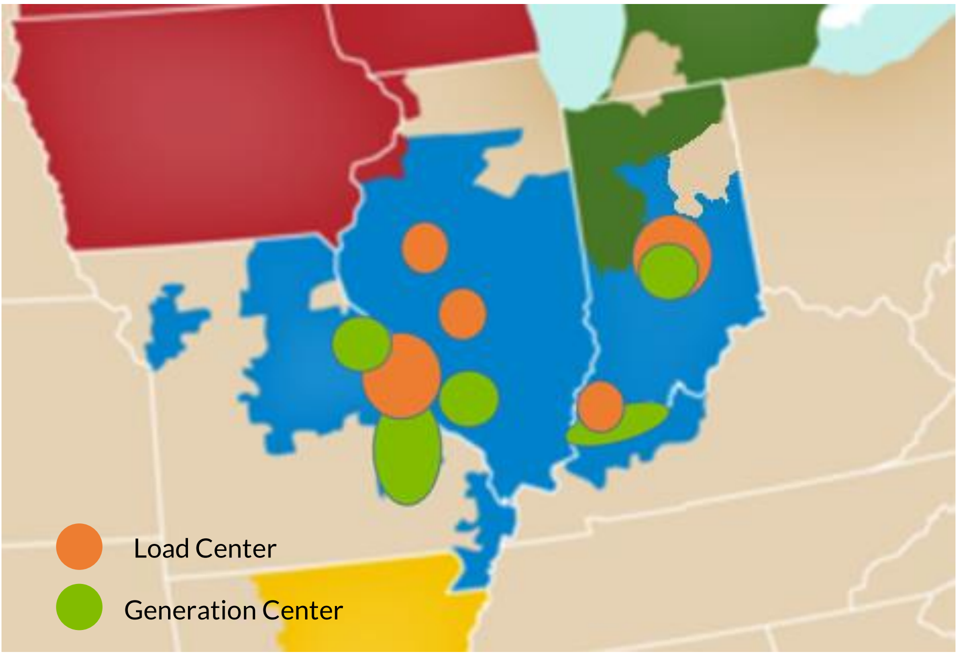


Figure 4.2-1: Major load and generation pockets in the MISO Central region

Project Summary

In the MISO Central planning region there were 148 proposed projects for the MTEP19 cycle. The total investment made by central region stakeholders is approximately $1.6 billion dollars. 85 projects have an estimated cost greater than $5 million. 39 projects have an estimated cost greater than $1 million but less than $5 million and twenty-one projects have an estimated cost less than $1 million (Figure 4.2-2).

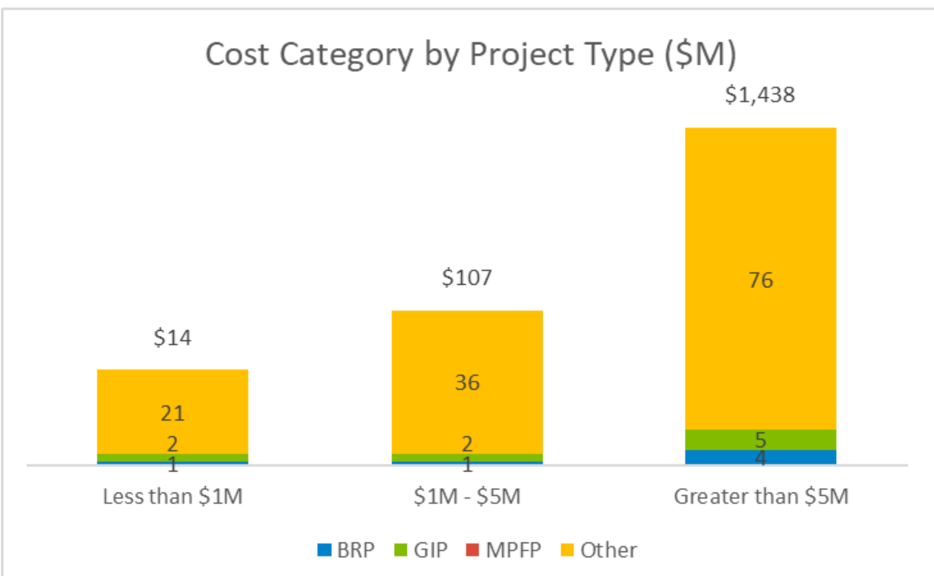


Figure 4.2-2: Estimated costs of MISO Central region MTEP19 projects

Of this investment six projects are Baseline Reliability Projects; 133 are Other Projects (i.e., age and condition, reliability or load growth); nine projects have signed Generation Interconnection agreements (GIAs) and are expected to move forward with their generation facility. The New Gateway 345/138 kV substation leads the top-10 MISO Central planning region projects by cost (Figure 4.2-3).

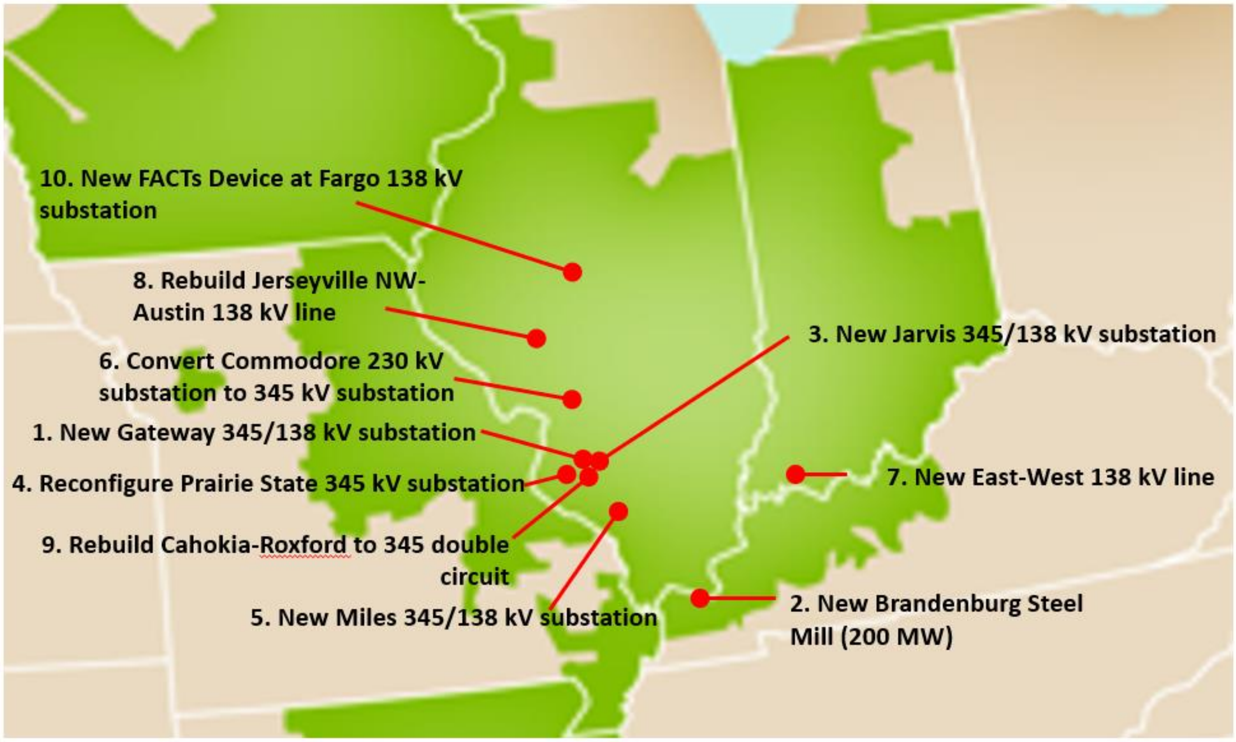


Figure 4.2-3: Central Region top ten projects, by cost

The majority of the projects in the MISO Central planning region are expected to go in service in the next three years. There were a handful of projects that are being approved in 2019 that either already went into service in 2018 or are expecting to go into service in 2019.

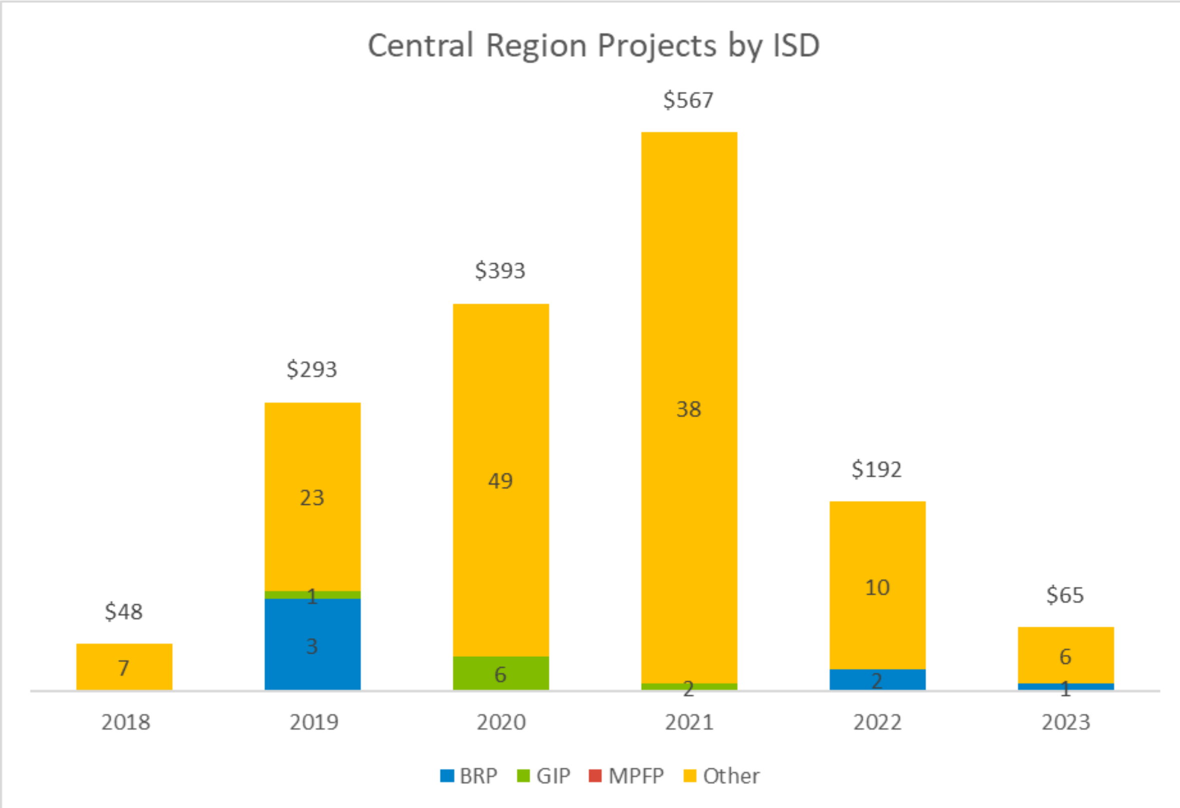


Figure 4.2-4: Central region MTEP19 projects, by in-service date

The main drivers behind most of the projects in the MISO Central planning region is the stakeholders addressing age and condition and increasing reliability across this region of the MISO bulk electric system. There are a number of load-driven projects across both Illinois, Indiana and Kentucky.

4.2.1 Ameren Illinois (AMIL) and Ameren Missouri (AMMO)

Ameren proposed 102 new projects at an estimated cost of $1.2 billion. Of these projects, five are Baseline Reliability Projects, 87 are Other Projects, and nine are Generation projects with signed Generation Interconnection Agreements.

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."

Project 9729 - Reconductor North Decatur-Clinton Rt. 54 138 kV line (AMIL)

Project Description

The project will reconductor the AMIL Decatur— Clinton SS 138 kV line. This line reconductor is due to a thermal overload caused by P6-1-1 contingency event[1]. The contingency events, marked with red Xs, are not completely shown on the geographic as one line goes off the image, the other line is farther north in the same direction (Figure 4.2-#9729-1). The project's estimated cost is $29 million and the estimated in-service date is December 1, 2019.

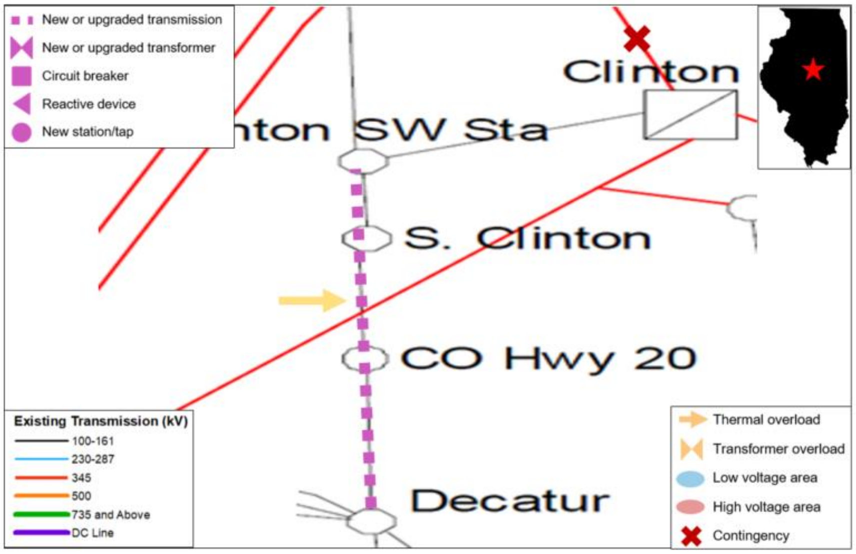


Figure 4.2-#9729-1: Geographic transmission map of project area

Project Need

The Decatur— Clinton SS 138 kV line becomes overloaded (101 percent) in year 2021 for a NERC-defined category P6-1-1 contingency event[6]. The reconductoring of the Decatur— Clinton SS 138 kV line will increase the summer emergency ratings from 161 MVA to 292 MVA (Table 4.2-#9729-1).

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (MW)	Post-Project Loading (MW)
Base case	Decatur— Clinton SS 138 kV line	161	46	163
P6-1-1	Decatur— Clinton SS 138 kV line	292	46	173

Table 4.2-#9729-1: Thermal loading drivers

Alternatives Considered

Generation redispatch or load shed is not feasible for thermal violations due to P6-1-1 contingency events if there is no applicable short-time emergency rating. Reconductoring this line is the best and most reliable option to address this reliability issue.

[6] NERC defined P6-1-1: two single P1-2 events with a system adjustment in between them. A P1-2 event is a loss of a BES transmission line.

Project 9857 – New Jarvis 345/138 kV Substation (AMIL)

Project Description

The project will build a new Jarvis 345/138 kV substation that will connect to the Prairie State-Stallings 345 kV line (Figure 4.2-#9857-1). This project also builds a new Lochman East 138 kV substation. New 138 kV lines connect between Jarvis-Lochman, Lochman-Highland Muni, Lochman-Port Road and Lochman-Collinsville. This new substation will mitigate an overload on the same line for a P6-1-1 contingency event. The project's estimated cost is $62 million and the estimated in-service date is December 1, 2019.

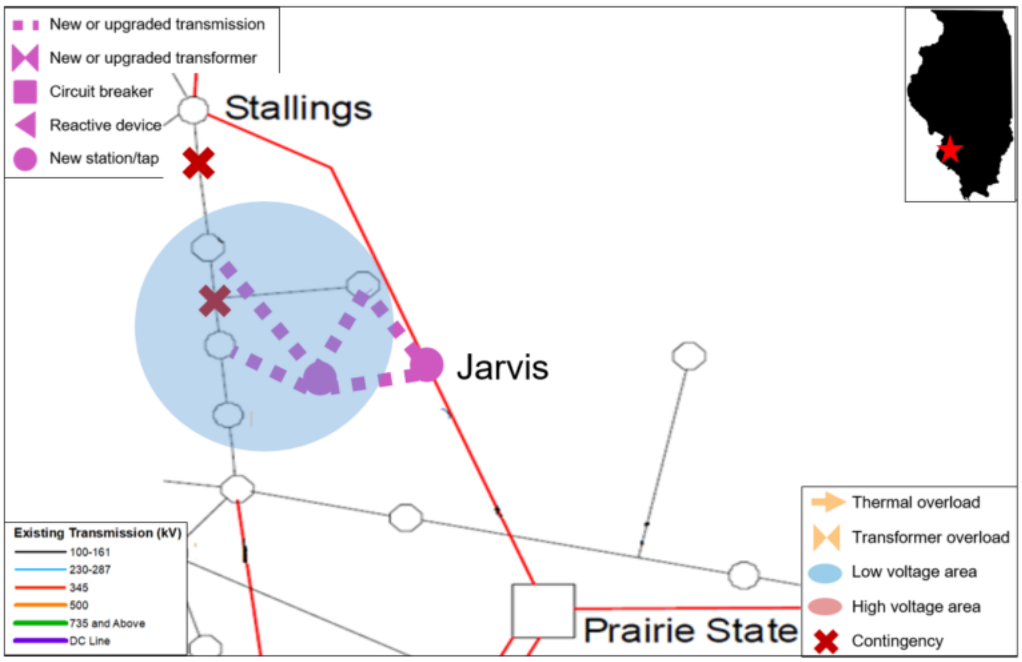


Figure 4.2-#9857-1: Geographic transmission map of project area

Project Need

Low voltages in the area drop below an acceptable threshold in year 2019 for a NERC defined category P6-1-1 contingency event. Building this new Jarvis 345/138 kV substation will help improve the voltages on the 138 kV system in the local area (Table 4.2-#9857-1).

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
Base case	Local Areas Voltages	0.90	1.0	< 0.90
P6-1-1	Local Areas Voltages	0.90	1.0	1.0

Table 4.2-#9857-1: Voltage performance 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; these line terminal upgrades are the best and cheapest options to address this reliability issue.

Project 11906 – Upgrade Casey West-Kansas 345 kV line (AMIL)

Project Description

The project will increase the ground clearance on the Casey West- Kansas 345 kV line in order to permit operation at 120 degrees Celsius. This upgrade will mitigate an overload on the same line for a P6-1-1 contingency event. The contingency events, marked with red Xs are not shown on the geographic as one line is a tie with Indiana and the other line is solely in Indiana. The project's estimated cost is $500,000 and the estimated in-service date is June 1, 2022.

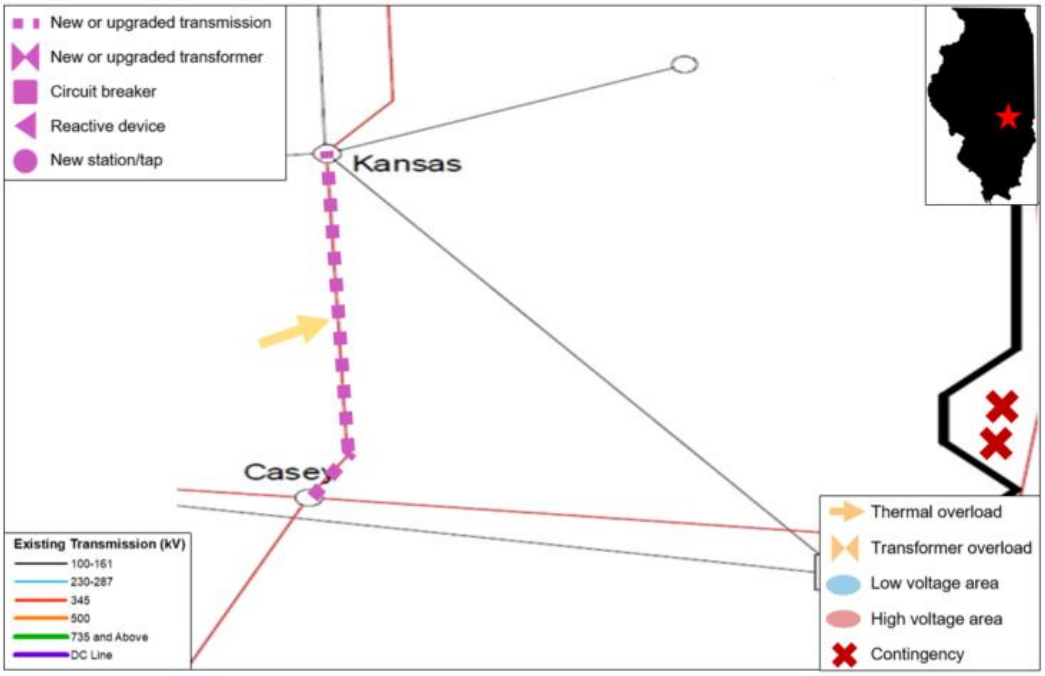


Figure 4.2-#11906-1: Geographic transmission map of project area

Project Need

The Casey West- Kansas 345 kV line becomes overloaded 100 percent in year 2022 for a NERC defined category P6-1-1 contingency event. Upgrading this line will increase the summer emergency rating from 1319 MVA to 1521 MVA (Table 4.2-#11906-1).

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (MW)	Post-Project Loading (MW)
Base case	Casey West- Kansas 345 kV line	1319	728	1331
P6-1-1	Casey West- Kansas 345 kV line	1521	728	1331

Table 4.2-#11906-1: 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. Reconductoring this 345 kV line is the best and most reliable option to address this reliability issue.

Project 13693 – New Arland 345/138 kV Substation (AMIL)

Project Description

The addition of this new Arland 345/138 kV substation will increase voltages in and around the Matoon area (Figure 4.2-#13693-1). This project will mitigate low voltages for P6-1-1 contingency event.

The project's estimated cost is $21 million and the estimated in-service date is December 1, 2022.

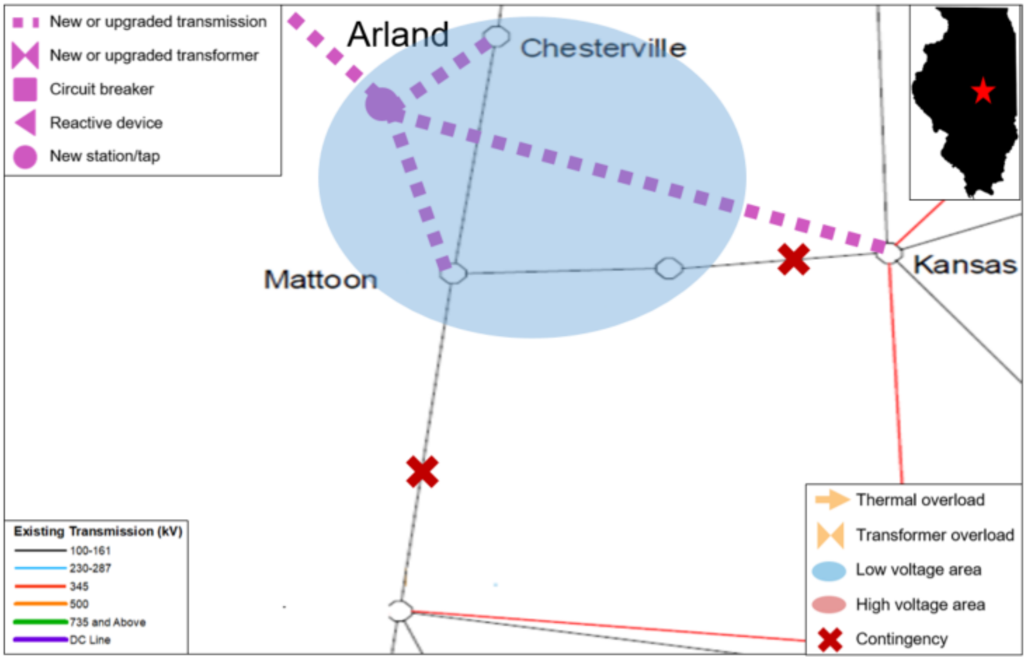


Figure 4.2-#13693-1: Geographic transmission map of project area

Project Need

The addition of the Arland 345/138 kV substation helps improve local low voltages in and around Matoon, Illinois in year 2022 for a NERC defined category P6-1-1 contingency event (Table 4.2-#13691-1).

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
Base case	Local Low voltages around Matoon W	0.90	1.005	1.006
P6-1-1	Local Low voltages around Matoon W	0.90	0.89	1.038

Table 4.2-#13693-1: Thermal loading drivers

Alternatives Considered

Generation redispatch or load shed is not feasible for low-voltage violations due to P6-1-1 contingency events. Building the new Arland 345/138 kV substation to support local voltages in the Matoon, Ill., area is the best reliability option to address this reliability issue.

Project 15424 – Upgrade Franklin 138 kV Substation Breakers (AMMO)

Project Description

The project will reconfigure the Franklin 138 kV substation by adding breakers at the Franklin terminals of the Gray Summit-Franklin 138 kV lines (Figure 4.2-#15424). This reconfiguration will mitigate low voltages in the area for a P6-1-1 contingency event. The project's estimated cost is $2 million and the estimated in-service date is June 1, 2019.

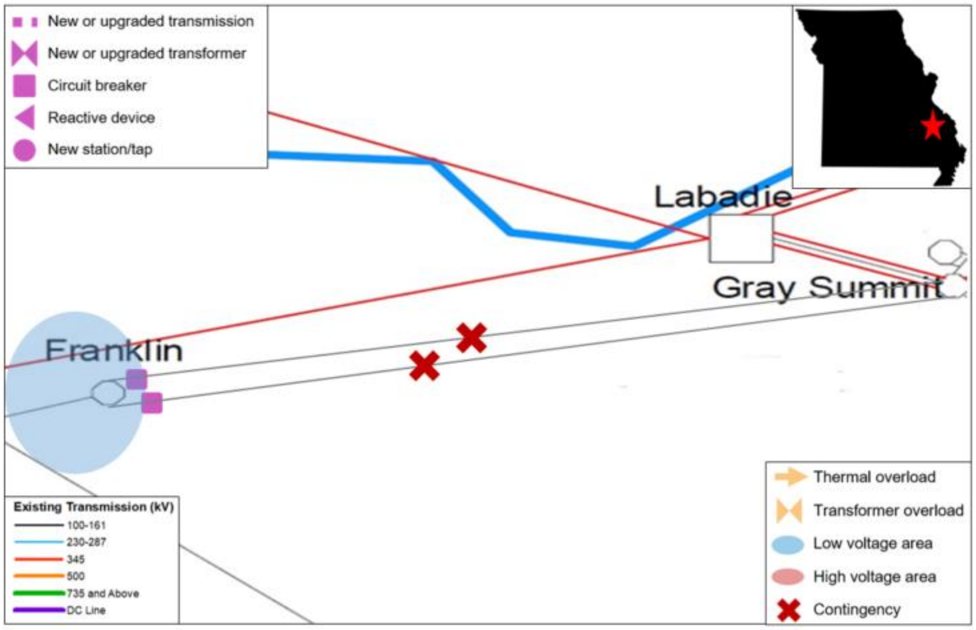


Figure 4.2-#15424-1: Geographic transmission map of project area

Project Need

Low voltages in the area are expected by year 2021 for a NERC-defined category P6-1-1 contingency event. Adding breakers at the Franklin terminals of the Gray Summit-Franklin 138 kV lines 1/2 will change the contingency definition so not to subject the local voltages to drop below an acceptable threshold (Table 4.2-#15424-1 and Figure 4.2-#15424-1).

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
Base case	Local Low voltages around Franklin	0.90	1.005	1.006
P6-1-1	Local Low voltages around Franklin	0.90	0.89	1.038

Table 4.2-#15424-1: Thermal loading drivers

Alternatives Considered

Generation redispatch or load shed is not allowed for a category P6-1-1 contingency event where low voltages are the limiting elements. Upgrading the breakers at the Franklin 138 kV substation is the best and cheapest option to address this reliability issue.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as Other Projects, according to Attachment FF of the MISO Tariff. Tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects Driven by Local Reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID[7]	Project Name	Project Description	ISD	Estimated Cost
4483	New Fargo 345/138 kV transformer No. 2	Install 2nd. 345/138 kV, 560 MVA Transformer	Jun. 1, 2021	$8.0M
7826	Reconfigure Turkey Hill 138 kV into Ring Bus	Convert existing 138 kV straight bus to a ring bus. Initial 4 positions with an ultimate of 6 positions	Dec. 1, 2019	$7.5M
7863	Reconfigure Prest (formerly Tilden) 138 kV Substation into a Ring Bus	Establish a 5 position 138 kV ring bus for 4-138 kV lines and 1-138/34.5 kV transformer	Dec. 1, 2018	$11.1M
9728	Upgrade Adair 161 kV Substation	Upgrade terminal equipment	Sep. 1, 2018	$3.0M
9731	Replace Marshall 138 kV Breakers	Replace the Marshall 138 kV substation Bus-Tie 3-4 circuit breakers	Dec. 1, 2020	$4.7M
9732	Mason Breaker Replacement	Replace overstressed Bus-Tie 1-2 138 kV breaker	Dec. 1, 2021	$0.9M
9851	Reconductor Edwards-Kewanee 138 kV line (7423)	Reconductor Ameren portion to 1200 A summer emergency capability	Jun. 1, 2019	$0.6M
11907	New Mackinaw (Lilly) 138/34.5 kV substation ring bus	Establish 138 kV ring bus	Dec. 1, 2021	$8.8M
11908	New Towerline (formerly Powerton Tap) 138 kV breaker 138 kV substation	Establish 138 kV ring bus at the intersection of Havana-Danvers-1352 and Tazewell-San Jose Rail-1367 138 kV Lines	Dec. 1, 2019	$18.3M
11910	Reconductor Page-Mason 138 kV lines (1-2 lines)	Reconductor 138 kV lines	Dec. 31, 2019	$6.0M
11923	New Ridge 138 kV substation ring bus	Establish New Ridge 138 kV ring bus	Dec. 1, 2020	$15.3M
11928	Convert Commodore 230 kV substation to 345 kV substation	Install spare 345/230/138 kV transformer. Install second 345/230 kV, 375 MVA transformer. Rebuild Commodore-North Coulterville 230 kV line for 345 kV	Dec. 1, 2022	$42.8M
11929	Convert North Coulterville 230 kV substation to 345 kV substation	138 kV ring bus on a new Aster Substation site near North Coulterville Substation. Rebuild North Coulterville-Tilden (Prest)	Dec. 1, 2021	$25.0M

[7] Project Numbers that are highlighted in red font are projects that were submitted to MISO past the MTEP19 deadline to submit projects.

		138 kV Line to double circuit with 2000A emergency capability. Rebuild 7 miles of the existing Cahokia – Pinckneyville – 1 230 kV line to 345 kV 3000 A capability between the Prairie State 345 kV.		
11933	Expand Prairie State 345 kV substation for BAAH configuration	Expand the Prairie State switchyard as a breaker-and-a-half configuration, and relocate Prairie State-Mt. Vernon West-4541 and Prairie State-Stallings-4531 345 kV lines to separate bays. Construct new Prairie State-Gateway 345 kV line.	Dec. 1, 2021	$60.0M
11935	New North LaSalle 138 kV ring bus	Establish 138 kV ring bus	Jun. 1, 2019	$9.2M
11944	Rebuild Mt. Vernon West 138 kV bus	Rebuild 138 kV bus as a breaker-and-a-half arrangement	Dec. 1, 2019	$19.2M
11947	New Greenback (formerly Monsanto) 138 kV substation ring bus	Construct 6-position 138 kV ring bus.	Jun. 1, 2022	$17.5M
11948	New Miles 345/138 kV substation	Establish 345/138 kV Substation near the tap point to Alton Steel in the Wood River-Stallings-1456 and Wood River-North Staunton-1456 Lines.	Dec. 1, 2021	$44.8M
11950	New Greenville McCord 138 kV ring bus	Establish 138 kV ring bus	Dec. 1, 2018	$12.4M
11951	New Crossville West 138 kV ring bus	Establish 138 kV ring bus	Dec. 1, 2022	$10.8M
11952	New Barrel (formerly Aviston Tap) 138 kV substation	Establish 138 kV ring bus	Dec. 1, 2021	$12.4M
11953	New Bureau (formerly Princeton Tap) 138 kV substation	Establish 138 kV ring bus	Dec. 1, 2019	$7.9M
11955	New Otego (formerly Bluff City) 138 kV substation ring bus	Establish 138 kV ring bus	Dec. 1, 2021	$17.3M
11956	New Jasper 138 kV substation ring bus	Establish 138 kV ring bus	Dec. 1, 2021	$13.1M
11966	New Gateway 345/138 kV substation	New 345-138 kV Substation, 5-345 kV breakers, new 345/138 kV transformer, 138 kV, 3000 A transformer PCB, two new 138 kV buses with 4 138 kV positions each. Install 345 kV ring bus. Reconfigure existing 138 kV Venice buses. Connect to Cahokia-Roxford-4 345 kV Line.	Dec. 1, 2021	$114.5M
11971	Reconfigure Jenkins (formerly Grand Tower) 138 kV substation to BAAH	Establish a Breaker-and-a Half 138 kV bus arrangement	Dec. 1, 2023	$22.1M
11972	Reconfigure Redhawk (formerly Midway) 138/34.5 kV substation to BAAH	Establish a Breaker-and-a Half 138 kV bus arrangement	Dec. 1, 2022	$20.6M
12173	Re-energize Miller-Zion 161 kV line	Install new breaker station at Zion. Install new 138/161 kV transformer	Jun. 1, 2021	$16M
12425	Replace Cape 161 kV breakers	Replace 3-161 kV Breakers	Dec. 1, 2019	$1.5M

12846	Reconfigure Kickapoo 138 kV substation to BAAH	Rebuild Kickapoo Substation 138 kV bus as a Breaker-and-a-Half	Dec. 1, 2021	$12.4M
12964	New Boar 138 kV breaker substation	Install 138 kV breaker station at the Kewanee South Street tap. Needed: 3-2000 A PCB's	Sep. 1, 2021	$8.5M
13545	New Oakley 138 kV breaker substation	Construct a 3-position initial/4-position ultimate 138 kV ring bus at the Schram City Tap in the Pana-Midway-1466 138 kV Line. Utilize 2000 A equipment	Dec. 1, 2021	$10.0M
13704	New FACTS Device at Fargo 138 kV substation	Install 138 kV +250/-100 MVar FACTS device. Install new breaker H5 on 138 kV BAAH to provide connection	Dec. 1, 2019	$30.3M
13706	Reconfigure Mt. Vernon 42nd Street 138 kV substation to ring bus	Install initial 4-position (ultimate 6-position) 138 kV ring	Dec. 1, 2021	$8.4M
13707	New Merlot 345 kV substation ring bus	Install 3000A 138 kV Ring bus at the Campbell Hill Junction. Add breaker at Steelville on 1636 line	Jun. 1, 2021	$10.3M
13795	Rebuild Cahokia-Roxford to 345 double circuit	Rebuild from Gateway to Roxford as double ckt 345kV. Install 345kV, 3000A SE capable conductor on each side of the tower. Replace structure 161 at Gateway Substation. OPGW required between Gateway to Roxford.	Dec. 1, 2020	$32.7M
14224	Rebuild Woodhall-Spring Bay 138 kV line 1648	Rebuild 636 ACSR Rook to 477 ACSR T2 capability	Dec. 15, 2018	$7.2M
14884	New Dillon 138 kV substation ring bus	Install initial 5 position ring bus near the west tap to Alfermann Substation. Split the Clark-Osage-2 line and route in and out of the ring bus. Split the Rivermines-Maries-1 138 kV line and terminate the western section (from Maries) into the ring bus and connect the eastern section to a 28 MVar capacitor bank to be located at Dillon. Disconnect the line to Alfer	Jun. 1, 2020	$10.0M
14885	Reconfigure Mahomet 138 kV substation	Install initial 5-position (ultimate 6-position) ring bus at Mahomet Substation. Double circuit the Mahomet tap section of the RIS-NCMP-1592 line (1.55 miles) to create an in/out supply.	Dec. 1, 2021	$12.0M
15204	Rebuild Muddy-West Frankfort East 138 kV line to 2000A	Rebuild the MUDY-WFRE-1 circuit using conductor capable of 2000A under summer emergency conditions	Jun. 1, 2019	$19.0M
15206	Rebuild Gilman South-Watseka 138 kV line 1388 to 1800A	Rebuild the GILS-WATK-1388 line from Gilman South Substation to Watseka Substation using conductor capable of 1800A under summer emergency conditions. Relay upgrades required at Gilman South and Watseka Substations. Install OPGW.	Dec. 1, 2019	$12.0M

15267	Reconfigure Herrin East 138 kV substation to ring bus	Install initial 4-position ring bus at the existing Herrin East substation location	Dec. 1, 2022	$7.5M
15488	Sheldon South - Morrison Ditch 138 kV line: Rebuild	Rebuild line from Sheldon South to Morrison Ditch	Dec. 31, 2020	$3.0M
15489	Reconfigure Meppen North Ring 138 kV substation	At the Meppen North 138 kV substation, construct a 4-position (6-ultimate) ring bus having a minimum continuous capability of 2000A	Jun. 1, 2022	$8.9M
15490	New Radnor Ring 138 kV bus addition	Install 4 position 138 kV ring bus	Jun. 1, 2022	$9.0M
15501	Upgrade Belleau-Troy 161 kV line	Upgrade the 161 kV BELU-TROY-1 line for the section from Dardenne substation to Troy substation, section 53, to allow for a maximum operating temperature during summer conditions of 100°C.	Jun. 1, 2019	$2.4M
15524	Replace Sioux 345/138 kV transformer	Replace the existing 345-138 kV transformer with a new transformer	Dec. 1, 2021	$5.0M
15525	Rebuild RS Wallace-Spring Bay 138 kV line	Rebuild 10 miles of the RSWA-SPBA-1344 line, from Str 12 to Spring Bay with conductor capable of 1300 A minimum under summer emergency conditions. A 3.7 mile section of CAT2-Hines-1357 will also be reconductored with the same conductor because it occupies the other position on the double circuit. Reconductor 1.6 miles of the RSWA-SPBA-1344 line.	Dec. 1, 2019	$15.0M
15527	New Heath 138 kV Substation (Robinson Marathon North)	Install new 6 position ring bus with 3 transformer positions and 3 line positions. Install new 0.8 mile 138 kV line from the Robinson Marathon substation to the new ring bus. Reconductor the existing 138 kV tap off the HUTY-ROBM line.	Dec. 1, 2020	$12.7M
15528	New Dirksen (East Springfield) 138 kV substation	Construct 6-position Ring Bus	Dec. 1, 2021	$17.3M
18464	Upgrade Bunsonville-Tilton 138 kV line	Replace limiting 1272 kcmil ACSR (.05 Miles) with 2156 kcmil ACSR	Dec. 1, 2018	$0.4M
16549	Upgrade Lincoln 161 kV Substation	Install 2 161 kV breakers and 3 161 kV disconnect switches including 1 motor operated switch	Jun. 1, 2020	$2.7M

Projects Driven by Age and Condition

The following projects are proposed to replace aging or degraded equipment.

Project ID[8]	Project Name	Project Description	ISD	Estimated Cost
7862	Rebuild Buick Smelter 161 kV Substation (Galena Substation)	Install new six-position ring bus near the exiting Buick Smelter site on the FLET-CMCO-1 and CLK-CMCO-2 lines. Install two breakers on the tap lines to Buick Smelter and rebuild the supply lines.	Dec. 1, 2020	$10.0M
15207	Rebuild Albion South-Olney North 138 kV line	Rebuild 28 miles of the Albion South to Olney North 138 kV line. Replace existing 556 ACSR conductor with conductor having a minimum capability of 2000A under summer emergency conditions. The rebuild will consist of replacing 229 structures. Install OPGW	May 17, 2018	$11.0M
15269	Rebuild North 27th St. Decatur-ADM North 138 kV line (1604)	Rebuild the North 27th Street Decatur-ADM North-1604 138 kV line with conductor capable of 2000A under summer emergency conditions. Replace 2500 kcmil AAC bus at ADM North with bus capable of 2000A	Dec. 1, 2019	$0.75M
15329	Rebuild St. Francois-Rivermines 138 kV lines 2 & 3	Replace structures in order to permit an operating temperature of 110 degrees C from structure 254 to 307	Dec. 1, 2021	$4.9M
15330	Rebuild Gifford-Rantoul 138 kV line (1500)	Rebuild Gifford-Rantoul-1500 138 kV line to 1200A with T-2 conductor	May 25, 2018	$3.0M
15491	Upgrade North Decatur-East Main Street 138 kV line (1522)	Increase rating to 100C. Rebuild the segment from str. 39 to Decatur North 27th St. with 954 Cardinal ACSS. OPGW required. Jumper replacements at Decatur North 27th St.	Dec. 1, 2020	$2.1M
15492	Upgrade North Decatur-North 27th Street 138 kV line (1602)	Structure replacements required. Replace 1272 Jumpers on either side of wave trap at N. Decatur.	Dec. 1, 2020	$0.5M
15494	Rebuild Rising-N Champaign-Leverett Road 138 kV line (1592)	Rebuild Champaign-Leverett Road section to 954 T-2 conductor	Dec. 1, 2020	$6.0M
15498	Rebuild Crab Orchard-Muddy 138 kV line	Rebuild line to 2000A capability	Dec. 1, 2019	$14.0M

[8] Project Numbers that are highlighted in red font are projects that were submitted to MISO past the MTEP19 deadline to submit projects.

15499	Rebuild Jerseyville NW-Austin 138 kV line	Rebuild line 10 1600A	Jun. 1, 2020	$34.3M
15500	Upgrade Troy-Pike 161 kV line	Upgrade clearances on the 161 kV TROY-PIKE-1 line for the sections from Auburn tap to Cyrene tap and Cyrene tap to Pike substation, to allow for a maximum operating temperature during summer conditions of 100°C.	Jun. 1, 2019	$4.1M
15502	Rebuild Mt. Vernon West-Mt. Vernon 42nd St. 138 kV line	Rebuild MTVS-MTVW-1336 between Mt. Vernon West and Mt. Vernon 42nd St. Provide a double circuit between Mt. Vernon West and Mt. Vernon World Color Press to eliminate the current World Color Tap on the MTVS-MTVW-1336 line.	Sep. 15, 2019	$7.3M
15503	Rebuild Mason-Wildwood 138 kV lines 1 & 2	Rebuild Conway-Clarkson section to 2000A. 7 structure replacements required on the Mason-Conway section.	Jun. 1, 2022	$8.0M
15526	Rebuild Mason–Meramec 1 & 2 138 kV lines	Replace six steel lattice structures to permit operation of the existing conductor to 120°C in the 13.97 mile section from Marshall to Meramec in the Mason – Meramec – 1 and Mason – Meramec – 2 138 kV double-circuit line. Modify under-build in 39 spans. Install OPGW from Marshall to Rudder.	Dec. 1, 2023	$10.0M
16547	Relocate Mapleridge-Tazewell 345 kV line (4528)	Relocation of approximately 0.4 miles of Ameren's existing Mapleridge-Tazewell-4528 345 kV line at the Edwards Power Plant	Jun. 1, 2020	$4.0M
16553	Rebuild Cat 2-Hines 138 kV line	Rebuild a 3.7 mile section of CAT2-Hines-1357 to 1200A minimum	Dec. 1, 2019	$6.9M
16554	Upgrade Maline 138 kV Substation	Replace bus tie 3-4 OCB, and pos S OCB	Dec. 1, 2020	$0.5M
16564	Rebuild Prest-Steelville 138 kV line (1476)	Rebuild Prest-Steelville-1476 line to 1600 minimum	Dec. 1, 2020	$12.0M
16584	Rebuild Cat 2 138 kV substation	Upgrade existing 138 kV ring bus, replacing breakers, switches and wave traps with new equipment having a minimum 2000 A capability	Dec. 1, 2020	$5.0M
16784	Rebuild Pana-Midway 138 kV line (1466)	Rebuild 27.68 miles the Pana-Midway-1466 138 kV line from Pana to structure 237 (Schram Tap) using T-2 conductor with a capability of carrying 2000 A under summer emergency conditions	Dec. 1, 2020	$21.2M

16785	Rebuild North Decatur-Latham 138 kV line (1350)	Rebuild the North Decatur-Latham-1350 line from Latham to structure 586	Dec. 1, 2020	$8.6M
16786	Replace Warson 161 kV Substation equipment	Replace Bus tie 1-2 and 3-4 breakers	Jun. 1, 2020	$2.0M
16787	Rebuild SJRL-INTR 138 kV line (1318)	Rebuild line from New Holland to Kickapoo. Replace 2 switches at Mason Substation. Replace 2 structures between Mason and New Holland. Replace 5 structures between New Holland and Interstate.	Dec. 1, 2020	$11.0M
16788	Rebuild MTVW-SCNT 138 kV line (1546)	Rebuild line to 110 degrees C	Dec. 1, 2020	$2.3M
16789	Rebuild Ashley-West Frankfort 138 kV line (1536)	Rebuild line from Ashley to West Frankfort	Dec. 1, 2020	$26.0M
16790	Rebuild Grand Tower-Steelville 138 kV line (1636)	Rebuild line from Grand Tower to Steelville	Dec. 1, 2020	$26.0M
16791	Rebuild OREA -ADMIN 138 kV line (1606)	Rebuild line from Oreana to ADM North	Dec. 1, 2020	$0.65M
16792	Rebuild Sidney-SW Campus 138 kV line (1312)	Rebuild line from Sidney to Southwest Campus	Dec. 1, 2020	$7.2M
16793	Replace equipment at Montgomery 161 kV Substation	Replace bus-tie breaker 16102 and upgrade relays at Montgomery Substation.	Dec. 1, 2020	$0.73M
16794	Replace Cahokia-Meramec 1&2 138 kV Structures	Replace structures on the Cahokia-Meramec 1 & 2 line	Dec. 1, 2020	$2.50M
16795	Replace Marion Tap-Marion 161 kV Structures	Replace structures on the Marion Tap-Marion section of the Peno-Creek-Spalding-2 line	Dec. 1, 2020	$0.55M
16796	Rebuild Oreana-ADM North 138 kV line (1610)	Rebuild line from Oreana to ADM North	Dec. 1, 2020	$0.42M

Projects Driven by Load Growth

The following projects are proposed to replace aging or degraded equipment.

Project ID[9]	Project Name	Project Description	ISD	Estimated Cost
9840	Reconfigure Washington Street 138 kV Substation into ring bus.	Install 138 kV Ring Bus	May 1, 2020	$13.0M
9844	New Normal East-McLean 138 kV Line	Construct 138 kV line	Dec. 1, 2020	$23.0M
16551	New Cincinnati 138 kV substation	Install new 138 kV ring bus with an in/out supply from the Towerline-Powerton 138 kV line at the existing Cincinnati distribution substation location.	Jun. 1, 2021	$8.0M

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed.

Project ID[10]	Project Name	Project Description	ISD	Estimated Cost
P15224	New Hornsby 138 kV substation for Cardinal Point Wind Farm (J456)	Install initial 3-position ring bus on the Macomb Niota-1 138 kV line	Dec. 1, 2019	$7.3M
P15324	New Howlett 138 kV substation for J756 interconnection	Install new ring bus breaker station on the Fogarty-Mason City West line.	Jun. 1, 2020	$6.9M
P15325	New Turner 345 kV ring bus for J757 Interconnection	Install new Turner 345 kV ring bus on the Austin-Meredosia line (4527)	May. 31, 2021	$1.0M
P16224	New Alta Wind Farms (J474) interconnection	Connect 144 MW wind farm at Tabor Substation	Mar. 1, 2020	$0.0M
P16225	New Yates 138 kV Substation for Morgan-Scott Counties Solar Interconnection. (J641)	Install new ring bus substation on the Jacksonville Industrial Park-Meredosia East-1612 138 kV line to provide the interconnection for Morgan-Scott Counties Solar (J641) solar farm connection.	Jun. 1, 2021	$6.7M
P16226	New Green-Scott Counties Solar (J644) interconnection	Connect 110 MW solar connection at Jerseyville NW Substation	Jun. 1, 2021	$0.5M
P16548	New Hughes 138 kV Substation (J541) for wind Interconnection	Install new 4-position 345 kV ring bus for new generator interconnection	May 1, 2020	$1.0M

[9] Project Numbers that are highlighted in red font are projects that were submitted to MISO past the MTEP19 deadline to submit projects.
[10] Project Numbers that are highlighted in red font are projects that were submitted to MISO past the MTEP19 deadline to submit projects.

P16550	New Prairie State Solar (J808) interconnection	Provide interconnection facilities for a 99 MW solar farm at North Coulterville. Construct new position as part of a 5-position 138 kV ring bus at Aster Substation (North Coulterville).	Jun. 1, 2020	TBD
P17324	New Mason Ring bus for J1055 Glacier Sands interconnection	Interconnection for new 144 MW wind farm at Mason (Ill.) substation. Tap existing bus at Mason to provide connection.	Oct. 10, 2020	$10.0M

4.2.2 Big Rivers Corp. (BREC)

Big Rivers proposed one new load interconnection project at an estimated cost of $80 million. Since it is a load interconnection project it is classified as an Other Project.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as Other Projects, according to Attachment FF of the MISO Tariff. Tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Project 17765 – New Brandenburg Steel Mill[11]

Project Description

The project will provide transmission service to the Brandenburg Steel Mill. Because of the size of the load two BES connections are needed to support the steel mill under (N-1) contingency events, a 345 kV and a 161 kV points of interconnection. The 345 kV Point of Interconnection (POI) is the [LGE-KU] Mill Creek-[LGE-KU] Hardin 345 kV line. The 161 kV Point of Interconnection (POI) is BREC's Meade County-Otter Creek 161 kV line (Figure 4.2-#17765-1). The project's estimated cost is $80 million and the estimated in-service date is January 1, 2021.

[11] Load Interconnection Project submitted into MTEP19 late, still being evaluated during report writing phase. This project is subject for removal pending on the outcome and/or timeliness of the results.

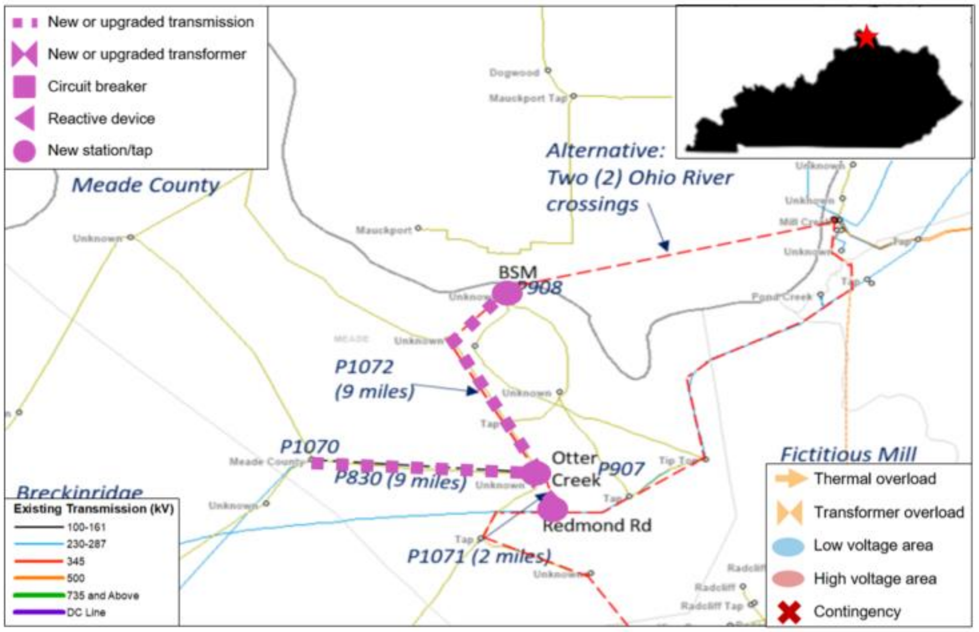


Figure 4.2-#17765-1: Geographic transmission map of project area

Project Need

Big Rivers Corporation received a request from a new customer on providing transmission service for their 200 MW steel mill, Brandenburg Steel Mill.

Alternatives Considered

This connection was the best and cheapest option to connect customer with near-unity pf, two-river crossing option was considered.

4.2.3 City of Columbia, Mo. (CWLD)

City of Columbia submitted no projects for MTEP19.

4.2.4 City of Springfield, Ill. (CWLP)

City of Springfield submitted no projects for MTEP19.

4.2.5 Duke Energy Corp. (DEI)

Duke proposed 17 new projects at an estimated cost of $86 million. All projects fall into the Other Projects category.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as Other Projects, according to Attachment FF of the MISO Tariff. Tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects Driven by Local Reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	ISD	Estimated Cost
15765	Upgrade Brownstown Switching Station 69kV Ring Bus	Brownstown Switching Station 69kV Ring Bus: install four breaker ring bus	Dec. 31, 2020	$3.7M
15766	Upgrade Columbus-Bedford line (34517)	Columbus to Bedford 34517 Structural Improvements: install 8 self-supporting steel intermediate dead-end structures	Dec. 31, 2020	$4.0M
15767	Upgrade Staunton 230 kV Ring Bus	Staunton 230kV Ring Bus: install three breaker ring bus	Dec. 31, 2020	$10.4M
15779	Upgrade Bedford 345 kV substation	Bedford 345 Ring Bus Expansion - add 2 breakers; replace/upgrade 345/138 Bk 5 to address P2 contingency - can't lose both 34517 and Bk 7 together	Dec. 31, 2021	$5.0M
15835	New Delphi Wells St. 69 kV Ring Bus	Delphi Wells St. 69 kV Ring Bus: 5 breaker positions	Dec. 31, 2020	$6.3M
15927	Convert WVPA Parke Co. 34.5 kV to 69 kV	WVPA Parke Co. 34.5 kV Conversion to 69kV: extend new 69204 ckt (established on MTEP 13849) from Clinton to Carbon West and reconfigure 6905 ckt	Dec. 31, 2021	$0.1M
16384	Rebuild WVPA 69 kV line (69130 Loop)	WVPA to build / rebuild 69130 line sections to loop feed McCordsville and Lee Hanna 69/12 kV subs	Jun. 1, 2021	$7.0M

Projects Driven by Load Growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	ISD	Estimated Cost
15757	New West Lafayette Airport 138 kV Substation	West Lafayette Airport Substation: Add 138/12kv sub in the 13820 circuit	Jun. 1, 2020	$0.95M
15770	New WVPA Brookston 69/12 kV Sub	WVPA Brookston 69/12kV Sub and 69 kV source lines	Jun. 1, 2021	$2.3M
15816	New Marathon Petroleum 69 kV Sub	Marathon Petroleum 69 kV Sub: tap the 6938 ckt to feed new customer sub	Jun. 1, 2019	$0.25M
15820	New WVPA Jackson Township 69/12 kV Sub	WVPA Jackson Township 69/12 kV Sub and 69kV source	Jun. 1, 2020	$10.6M
15829	New Greenfield 69/12 kV Substation	Greenfield 69/12kV Sub: build new sub to replace existing Greenfield sub with similar source configuration to existing via the 69166 and 6962 ckts	Dec. 31, 2020	$0.25M
15834	New Mitchell Lehigh 138/12 kV Sub	Mitchell Lehigh 138/12 kV Sub: new sub in the 13822 ckt with ATO	Jul. 1, 2021	$10.0M
15840	New Tetersburg 69/12 kV Sub	Tetersburg 69/12kV Sub: install new sub in the 69191 ckt	Jun. 1, 2020	$0.7M
16364	New WVPA Avon North 138/12 kV Sub	WVPA to build 138/12 sub and 138 kV looped lines in the 13853 ckt. between Brownsburg and Avon East	Dec. 31, 2019	$4.8M
16404	New WVPA Enterprise South 69/12 kV Sub	WVPA to build 69/12 sub and 69kV tap line from the 6943 ckt. along with a new N.O. alternate feed from WVPA Anson N. in the 69186 ckt.	Dec. 31, 2020	$11.5M

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed.

Project ID	Project Name	Project Description	ISD	Estimated Cost
15760	New Generation: J446 Gen. Interconnect	J446 Clinton Wind Farm - Gen. Interconnect: 23010 ckt.-145 MW Wind farm; 3-breaker ring	Dec. 31, 2020	$7.5M

4.2.6 Hoosier Energy (HE)

Hoosier Energy submitted no projects for MTEP19.

4.2.7 Indianapolis Power & Light (IPL)

Indianapolis Power & Light submitted no projects for MTEP19.

4.2.8 Prairie Power Inc. (PPI)

Prairie Power proposed 10 new projects at an estimated cost of $42 million. All projects fall into the Other Category.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as Other Projects, according to Attachment FF of the MISO Tariff. Tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects Driven by Load Growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	ISD	Estimated Cost
15769	New Disco 138/69/12.47 kV Substation	1) New (Ameren) Bueller-(PPI) Disco 138 kV substation 2) New Disco 138/69 kV and 69/12.47 kV substation	Dec. 31, 2023	$4.0M
15774	New Pleasant View 138/69 kV Substation	1) New (Ameren) Dempsey-(PPI) Pleasant View 138 kV line 2) New Pleasant View 138/69-34.5 kV Substation 3) The lines from Pleasant View to Grove City will initially be operated at 34.5 kV.	Dec. 31, 2023	$4.7M
15815	New Fancy Creek-Middletown Tap 69 kV Line	New Athens-Middletown Tap 69 kV line	Dec. 31, 2022	$7.1M

15817	New Grand Island-Oakford 69 kV Line	New Grand Island-Oakford 69 kV line	Dec. 31, 2022	$6.3M
15825	New Mechanicsburg-Taylorville 69 kV Line	New Mechanicsburg-Taylorville 69 kV line	Dec. 31, 2023	$7.0M
P15830	New Shelbyville S.-ISHI 138 kV line	1) New 7 mile line from (Ameren) Shelbyville S.-(PPI) ISHI 34.5 kV line (6.3 miles built to 138 kV specs, .7 miles built to 69 kV specs) 2) New ISHI 138/69-34.5 kV Switching Station, includes an 84 MVA LTC Transformer	Dec. 31, 2020	$7.0M

Projects Driven by Age and Condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	ISD	Estimated Cost
15786	Rebuild Naples 69 kV River Crossing	Rebuild Naples 69 kV Illinois River crossing which will include OPGW	Dec. 31, 2020	$0.9M
15814	Rebuild Kampsville 69 kV River Crossing	Rebuild Kampsville 69kV Illinois River crossing which will include OPGW	Dec. 31, 2020	$0.9M
15827	Rebuild Nortonville Tap-Murrayville Jct 69 kV Line	Rebuild and Reconductor Murrayville Jct-Nortonville Tap 69 kV line. Change Line from 3/0 ACSR to 336.4 MCM ACSR with OPGW.	Dec. 31, 2020	$1.3M
15828	Rebuild Nortonville Tap-Jacksonville 69 kV Line	Rebuild and Reconductor Nortonville Tap-Jacksonville 69 kV line. Replace 4/0 conductor with 336.4 MCM ACSR with OPGW.	Dec. 31, 2020	$3.0M

4.2.9 Southern Indiana Gas & Electric (SIGE)

Southern Indiana proposed 18 new projects at an estimated cost of $84 million. One project is a Baseline Reliability Project, all remaining projects fall into the Other Projects category.

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.”

Project 15943 – New Capacitor banks at Warrick North Substation

Project Description

The project will install two new 138 kV Capacitor banks (20 MVar each) at the Warrick North substation for post-contingent voltage support (Figure 4.2-#15943-1).

The project's estimated cost is $7.4 million and the estimated in-service date is November 1, 2023.

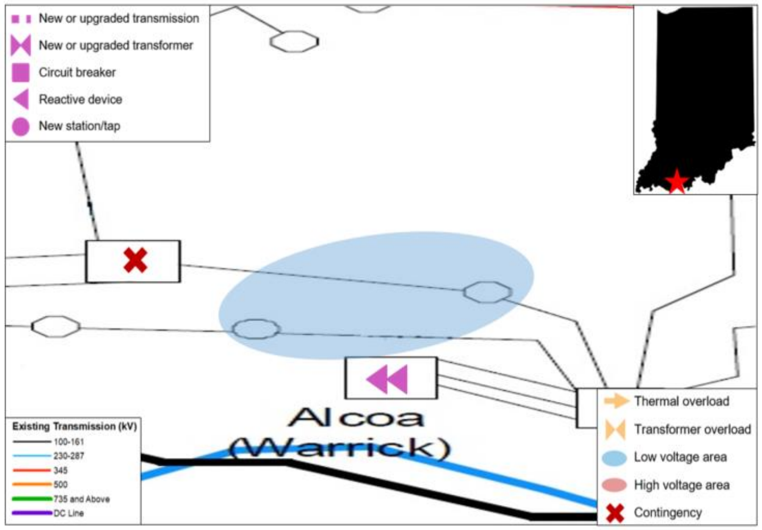


Figure 4.2-#15943-1: Geographic transmission map of project area

Project Need

Under a NERC category P1-1 generation outage MISO observed low voltages in and around southern Indiana. This was with three behind-the-meter (BTM) generating units turned off (Table 4.2-#915943-1). Those BTM units are directly for serving industrial load in the local area. When the plant load ramps down so do the BTM generators along with the local voltage support that those BTM units were providing. Southern Indiana is proposing to add two capacitor banks (20 MVar) in order to support the voltages and become less dependent on the operation of the industrial system for voltage support.

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
Base case	Local Low voltages around Warrick	0.90	1.00	1.00
P6-1-1	Local Low voltages around Warrick	0.90	0.89	1.00

Table 4.2-#915943-1: Thermal loading drivers

Alternatives Considered

Studies showed that dynamic response time of a synchronous condenser, SVC, or STATCOM was not needed hence caps banks are selected for cost reasons.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. Tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects Driven by Local Reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	ISD	Estimated Cost
4395	Convert NE cap bank tertiary winding	Remove existing cap banks from the tertiary winding of the 138/69 kV transformer at Northeast sub, and install equivalent cap banks on the 69 kV bus with breakers	Dec. 31, 2020	$0.45M
4396	New Scott-Toyota 138 kV line (Z71)	Install new approx. 13 mile 138 kV line designate Z71 (not Z75)	Dec. 31, 2021	$13.0M
15856	Replace three 138 kV oil circuit breakers at the Northeast substation	Replace three 138 kV oil circuit breakers at the Northeast substation	Dec. 31, 2021	$0.9M
15941	New East-West 138 kV Line	Install new 138 kV line from AB Brown to Pigeon Creek to Warrick North substations in order to increase transfer capability and relieve post-contingent loading concerns	May 1, 2022	$42.2M

Projects Driven by Load Growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	ISD	Estimated Cost
4398	Rebuild Y52-1 NE-Sunbeam 69 kV line	Rebuild and reconductor approx. 3 miles of 69 kV	Dec. 31, 2019	$2.2M
15821	Replace Civic Center UG Exits 69 kV	Replace two 69 kV underground circuit exits, ~0.5 miles each	Dec. 31, 2021	$2.7M
15823	Replace Civic Center 69/12 kV distribution transformer #2	Replace Civic Center 69/12 kV distribution transformer #2	Dec. 31, 2021	$1.6M
15851	Replace 138/69 kV 100 MVA transformer T2 at Dubois station with new 100 MVA unit	Replace 138/69 kV 100 MVA transformer T2 at Dubois station with new 100 MVA unit	Dec. 31, 2020	$2.7M
15853	Replace 69/12 kV distribution transformer T2 at the Givens Rd. substation	Replace 69/12 kV distribution transformer T2 at the Givens Rd. substation	Dec. 31, 2021	$1.2M

15854	Replace 138/12 kV distribution transformer T2 at the Grimm Rd. substation	Replace 138/12 kV distribution transformer T2 at the Grimm Rd. substation	Dec. 31, 2021	$1.2M
15855	Replace three 69 kV oil circuit breakers at the Pelzer station (breakers 177, 277, and 188)	Replace three 69 kV oil circuit breakers at the Pelzer station (breakers 177, 277, and 188)	Dec. 31, 2021	$0.5M
15857	Replace the 69/12 kV distribution transformer T1 at the St. Wendell substation	Replace the 69/12 kV distribution transformer T1 at the St. Wendell substation	Dec. 31, 2021	$1.2M
15858	Replace the 69/12 kV distribution transformer T2 at the Sunbeam substation	Replace the 69/12 kV distribution transformer T2 at the Sunbeam substation	Dec. 31, 2021	$1.2M
15859	Replace both 69/12 kV distribution transformers T1 & T2 at the Tekoppel substation	Replace both 69/12 kV distribution transformers T1 & T2 at the Tekoppel substation	Dec. 31, 2021	$2.4M
15946	Replace two existing underground 69 kV circuit exits at the Court St. substation	Replace two existing underground 69 kV circuit exits at the Court St. substation to increase the facility rating (0.21 miles total)	Nov. 1, 2023	$0.7M
15955	Replace and upgrade 69/12 kV distribution transformer T1 at the Kings substation	Replace and upgrade 69/12 kV distribution transformer T1 at the Kings substation due to load growth and an existing customer's planned load expansion.	Dec. 31, 2019	$1.0M
15957	Replace and upgrade 69/12 kV transformer at Berry plastics.	Replace and upgrade 69/12 kV transformer at Berry plastics. This transformer is dedicated to Berry Plastics and is being upgraded to accommodate their load expansion.	Dec. 31, 2019	$1.0M

4.2.10 Southern Illinois Power Cooperative (SIPC)

Southern Illinois submitted no projects for MTEP19.

4.2.11 Wabash Valley Power Association Inc. (WVPA)

Wabash Valley Power Association Inc. submitted no projects for MTEP19.

4.2.12 Henderson Municipal Power & Light

Henderson Municipal Power & Light submitted no projects for MTEP19.

4.3 Project Justifications – East Region

East Region Overview

The MISO East Planning Region consists of seven Transmission-Owning members within Michigan and Indiana. These Transmission Owners are: ITC Transmission (ITCT); Michigan Electric Transmission Co. (METC); Consumers Energy Transmission Owner (CETO); Wolverine Power Supply Cooperative Inc. (WPSC); Michigan Public Power Agency (MPPA); Northern Indiana Public Service Co. (NIPSCO); and Michigan South Central Power Agency (MSCPA).

The region contains 10,770 circuit miles of transmission lines ranging from 120 kV to 345 kV. It also contains 1,524 circuit miles of 69 kV sub-transmission system. The MISO East Region is interconnected with the following non-MISO systems: Hydro One Networks Inc. and American Electric Power to the east and ComEd to the west. The region is also interconnected with the following MISO systems: Duke Energy Indiana in the south and the American Transmission Co. (ATC) to the north. The interconnection with ATC's system is through a High Voltage Direct Current (HVDC) connection.

The 2021 Summer Peak planning model indicates the region contains more than 31.5 GW of generation. Installed generation capacity in the region consists mostly of coal, gas, nuclear, and wind.

Figure 4.3-1 shows the major load centers, as well as generation pockets, in the East Region. The load centers are typically found around larger cities in the region, i.e., Detroit, Lansing, Grand Rapids, and Michigan City. According to the 2021 Summer Peak planning model, the region's load exceeds 24.5 GW.

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

During the MTEP19 cycle, MISO received four projects through the Expedited Project Review process for the East region. The construction schedule for these projects was driven by new customers requesting connection to the grid on an expedited basis:

1. MTEP ID # 15704 Gramer Load Interconnection (ITCT)
2. MTEP ID # 16744 Midtown Substation Expansion (ITCT)
3. MTEP ID # 15738 Brooks Industrial Interconnection (METC)
4. MTEP ID # 15736 Butters Load Interconnection (METC)

For MTEP19 MISO Transmission Planning is recommending 119 projects from the East region for inclusion in Appendix A at an estimated cost of $849.9 million. Of these, 79 are Baseline Reliability Projects and 4 are Generation Interconnection Projects. The remaining 36 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 119 projects, that are being recommended to be included in MTEP19, 42 have an estimated cost of less than $1 million, 37 have an estimated cost between $1 million and $5 million, and the remaining 40 projects are estimated cost greater than $5 million (Figure 4.3-2 for the breakdown by project type). Additionally, all of these projects are expected to go into service between 2020 and 2024 (Figure 4.3-3).

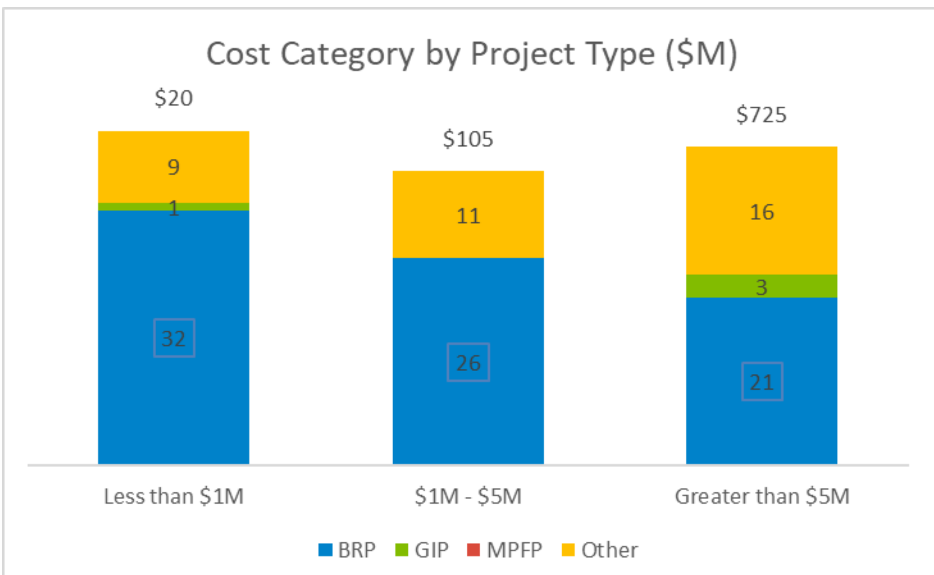


Figure 4.3-2: Project cost category by project type for MTEP19 East projects. (Project data as of October 18, 2019)

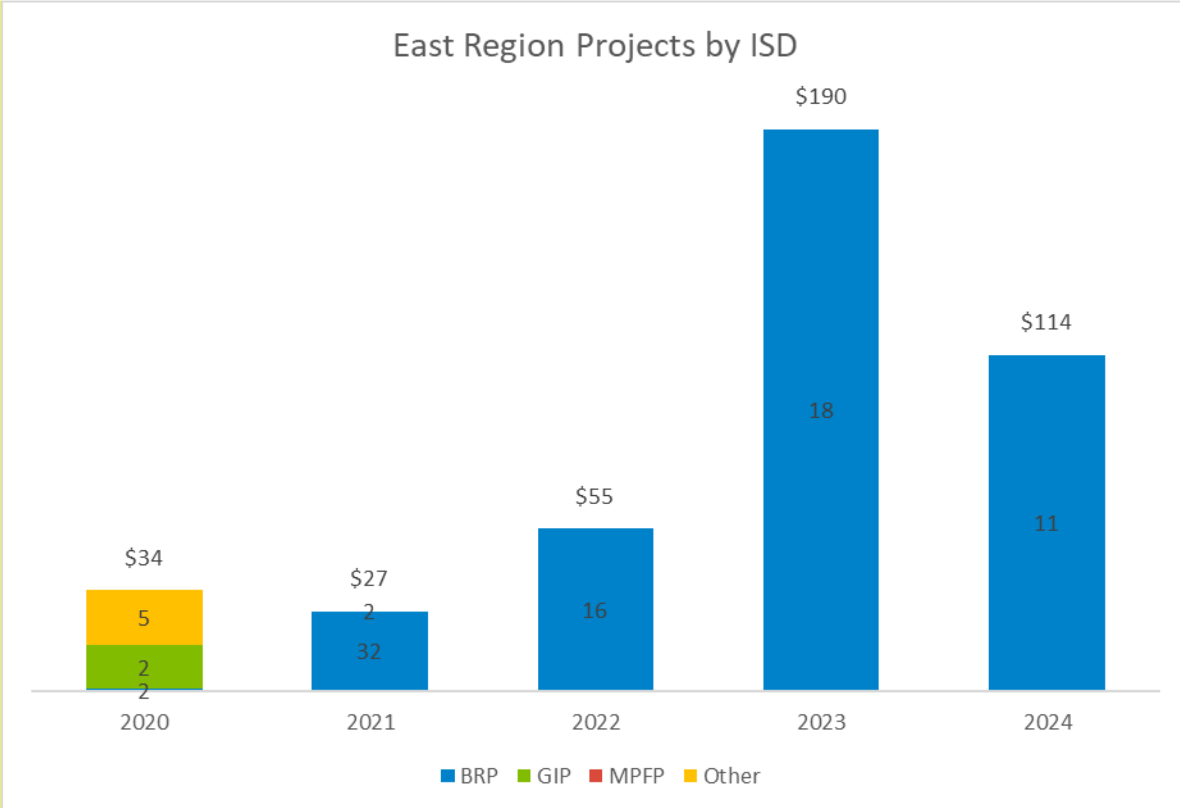


Figure 4.3-3: Project in-service date by project type for MTEP19 East projects. (Project data as of October 18, 2019)

The top 10 projects in the East region in terms of cost account for $405.3 million, excluding blanket projects for asset replacement due to age and condition, communications, physical security, etc. The locations of the top ten projects are shown on the map of Figure 4.3-4. The figure shows that these top ten projects are spread evenly throughout the East planning region, which is the Michigan Lower Peninsular and northern Indiana. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

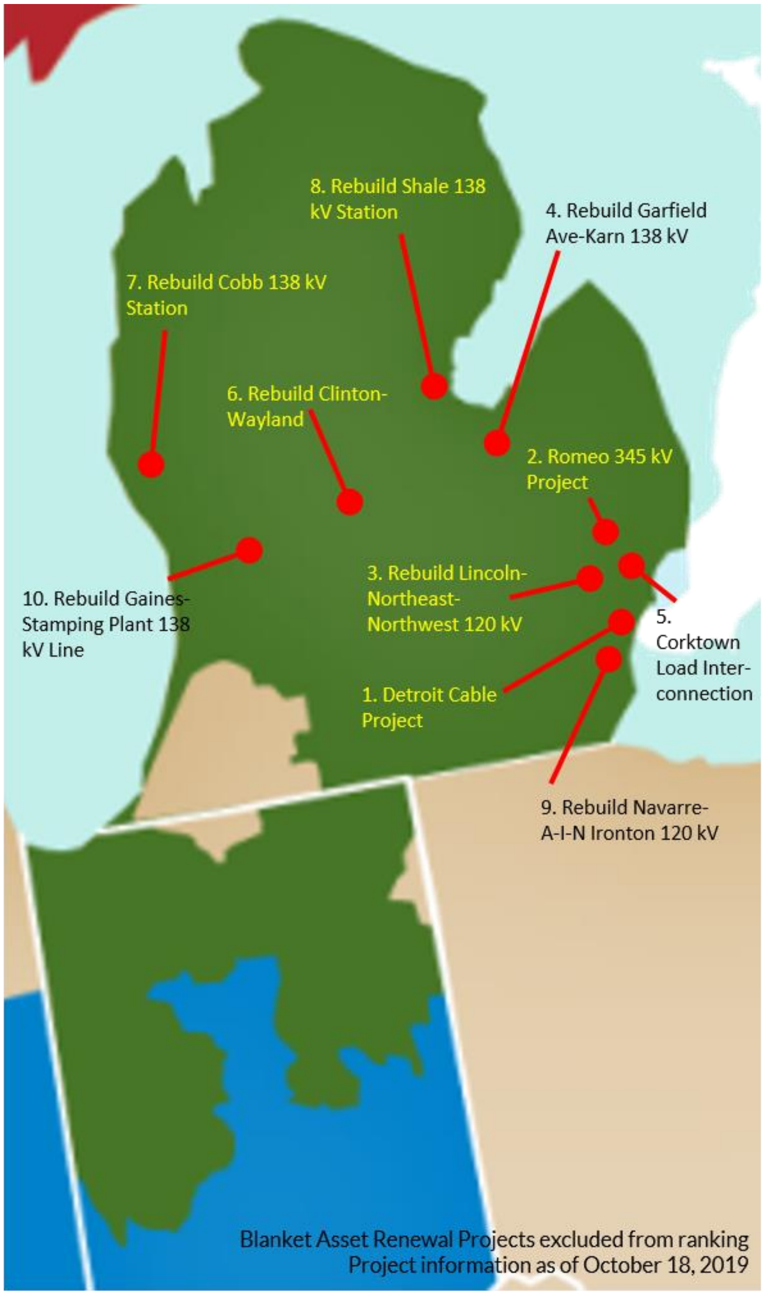


Figure 4.3-4: The Top 10 projects in terms of cost in the East planning region for MTEP19, excluding blanket asset replacement projects. (Project data as of October 18, 2019)

4.3.1 ITC Transmission (ITCT)

ITC Transmission proposed 87 projects at an estimated cost of $897 million targeting MTEP19 Appendix A. After MISO's independent reliability analysis of the ITC Transmission area, 57 of these projects were recommended by MISO to be included in MTEP19 Appendix A at an estimated cost of $462.9 million[12]. All the projects' expected in-service dates and estimated costs are provided as of October 18, 2019.

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 the reliability standards adopted by Regional Reliability Organizations and applicable within the Transmission Provider Region." This section describes the baseline reliability projects that were submitted by ITC Transmission to resolve identified reliability issues in the area and have been independently verified by MISO and recommended to be included in the MISO 2019 Transmission Expansion Plan.

Table 4.3-1 provides a summary of all NERC TPL-001-4 contingency categories and their corresponding contingency short names that are used in the Project Justification section for each ITC Transmission baseline reliability project.

NERC TPL-001-4 Category	Contingency Short Name	Contingency description
P0	Base Case	System intact (normal system)
P11	G-1	Loss of one generating unit
P12	T-1	Loss of one transmission circuit
P13	X-1	Loss of one transformer
P14	S-1	Loss of one shunt device
P15	D-1	Loss of single Pole of DC line
P21	Open Bkr	Open one end of transmission circuit (section) without a fault
P22 – P24	Bus/Bkr	Bus section fault, internal breaker fault (non-bus-tie breaker), or internal breaker fault (bus-tie breaker)
P31 – P35	G-1 + N-1	The planned outage/loss of one generator (P11) followed by system adjustment then followed by the loss of another generation/transmission facility (P11 – P15)
P41 – P46	BUS/Bkr	Fault plus stuck breaker
P51 – P55	Protection Failure	Fault plus relay failure to operate (delayed fault clearing)
P61 – P64	N-1-1 or T-2	The planned outage/loss of one transmission facility (P12 – P15) followed by system adjustment then followed by the loss of another transmission facility (P12 – P15). For peak loading conditions: T-2 is used For off-peak loading condition: N-1-1 is used (aka Shutdown-Plus-Contingency)
P7	DCT	Loss of double circuit tower (two circuits on a common structure)

Table 4.3-1: Summary of NERC TPL-001-4 Contingencies and their corresponding contingency short names for ITCT projects

[12] MTEP19 project "Monroe - Lallendorf 345 kV Sag Remediation" (P# 15878) is shared between METC and ITCT. Hence, this project is counted once under each TO to provide more accurate total estimated costs. However, in the total number of projects and the total estimated cost under the East Region, this project is counted only once using the total cost.

Project 17164 – Romeo 345 kV Project

Project Description

Close the HY breaker at St. Clair to allow a 345/120 kV step-down transformation at this station. Also, upgrade three 120 kV breakers at St. Clair due to the short-circuit impact. Cut the existing Jewell – St. Clair #1 into J793 POI (north of Belle River) to form a tie between J793 and the St. Clair station. This also relocates one of the sink paths (Jewell) to the J793 POI station, making it more balanced to the area. The cut-in will require approximately 0.8 miles of 345 kV double-circuit lines with new right-of-way. Also, remediate the sag between J793 POI and Jewell up to the conductor's limit. Construct a new 345 kV switching station (tentatively named Romeo) about 3 miles north of the Jewell station.

Cut the existing Belle River – Pontiac 345 kV line into the Romeo station. Raise the sag on Belle River – Romeo and Pontiac – Romeo 345 kV lines up to the conductor's limit. Construct a new 345 kV circuit between Romeo and Jewell using the available, de-energized 345 kV line that is on common structures with Jewell – St. Clair #1 345 kV line. This new circuit is approximately 3.2 miles long. Rebuild approximately 4.1 miles of the Hamlin – Spokane 120 kV line to 1431 ACSR. The rebuild is to use 230 kV construction on future double-circuit structures with OPGW (Figure 4.3-#17164-1).

The project's estimated cost is $52.4 million and the estimated in-service date is December 31, 2023.

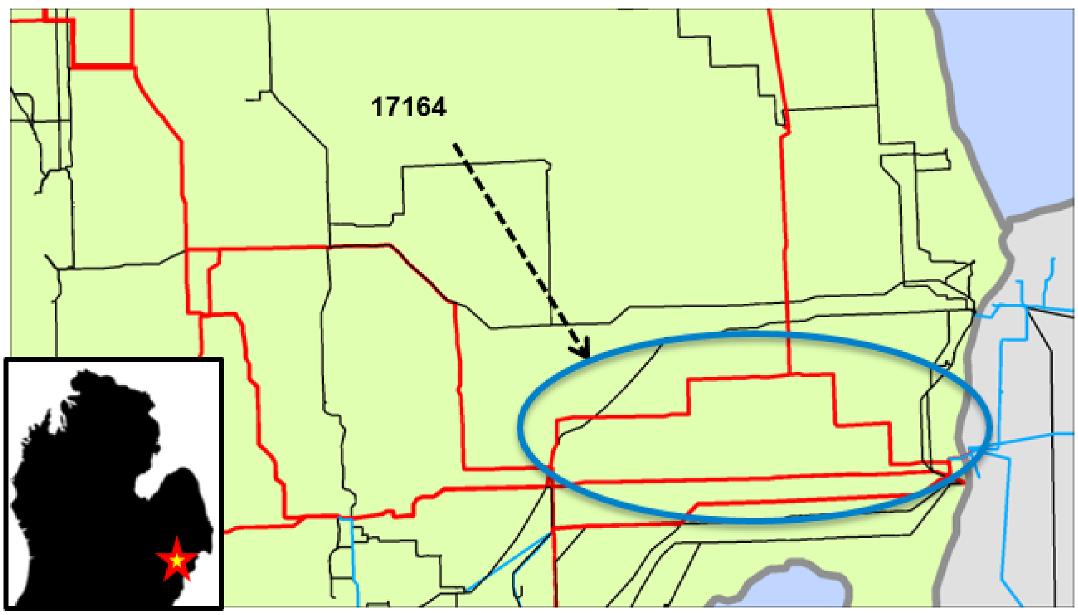


Figure 4.3-#17164-1: Geographic transmission map of project area

Project Need

Belle River – St. Clair 345 kV, Belle River – Lenox 345 kV, Jewell – Lenox 345 kV, Jewell – St. Clair No. 1 345 kV, and St. Clair – Stephens 345 kV lines are projected to overload under various contingencies. The driving reason for these overloads in the area are due to the loss of generation on the 120 kV side of St. Clair, plus the addition of J793 (Blue Water generation) on the 345 kV network in the same vicinity. Without the 120 kV source at St. Clair to help support the loads in the Oakland region, most of the output from Belle River and J739 are diverted toward the sinks (load regions) southwest of them through the step-down transformers at Bismarck, Jewell, Stephens, and Lenox. The powerflow path consequently stresses the Belle River – St. Clair 345 kV, Belle River – Lenox 345 kV, Jewell – Lenox 345 kV, Jewell – St. Clair #1 345 kV, and St. Clair – Stephens 345 kV transmission lines and eventually overloads them under various contingencies. The overloaded scenarios are worse in situations when importing power from Ontario-based Independent Electricity System Operator to ITC Transmission.

Alternatives Considered

The project is an alternative solution, which replaces all the following projects originally proposed by ITCT:

- Belle River – St. Clair 345 kV Rebuild (MTEP# 16021)
- Belle River – Lenox 345 kV Rebuild (MTEP# 16019)
- Jewell – Lenox 345 kV Rebuild (MTEP# 16018)
- Jewell – St. Clair 345 kV Rebuild (MTEP# 16017)
- Benson – Stephens 120 kV Rebuild (MTEP# 16068)
- Pontiac – Colorado Tap 120 kV Rebuild (MTEP# 16066)
- Pontiac – Joslyn 120 kV Rebuild (MTEP# 16016)
- Lenox 2nd 345/120 kV Transformer (MTEP# 16011)
- Pontiac 120 kV – Upgrade HC & GQ Station Equipment (MTEP# 16007)
- Bunce Creek – Fitz 120 kV Rebuild (MTEP# 15861)
- Burns 2 Tap – Fitz 120 kV Sag Remediation (MTEP# 15844)
- Fitz 345/120 kV Transformer No. 2 (MTEP# 15751)
- Lee – Lake Huron Pumping 1 Tap 120 kV Rebuild (MTEP# 15843)

Project 16023 – Lincoln-Northeast-Northwest 120 kV Rebuild

Project Description

Rebuild approximately 3.3 miles of underground cable on the Lincoln – Northeast – Northwest 120 kV circuit with a conductor of 3500 kcmil size, and then about 7.1 miles of overhead conductor to 1431 ACSR. Additionally, the solution upgrades the station equipment at Northeast and Northwest stations (Figure 4.3-16023-1). The project's estimated cost is $44.2 million and the estimated in-service date is June 1, 2024.

Project Need

Multiple sections of the Lincoln – Northeast – Northwest 120 kV circuit are projected to overload as a result of N-1-1 and DTC contingencies. The overloaded elements are the 477 ACSR and 795 ACSR conductors, 1500 kcmil underground cables, and equipment at the Northeast and Northwest 120 kV stations.

Alternatives Considered

Other transmission alternatives were considered but this solution was found to be the best in terms of cost and its ability to reliably resolve the identified issues.

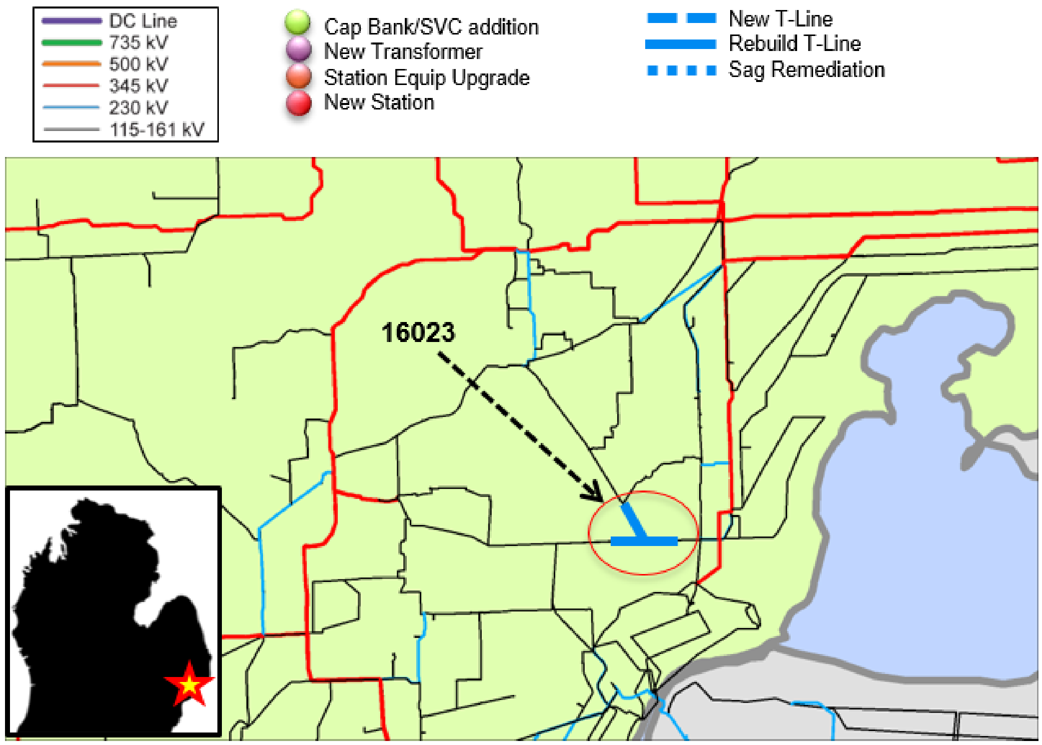


Figure 4.3-#16023-1: Geographic transmission map of project area

Project 15865 – Navarre – A-I-N – Ironton 120 kV Rebuild

Project Description

Rebuild approximately 7.7 miles from Navarre to Adelaide-Ironton-Navarre junction to Ironton with 1431 ACSR conductor. Also upgrade station equipment at both ends (Figure 4.3-#15865-1). The project's estimated cost is $18.2 million and the estimated in-service date is June 1, 2024.

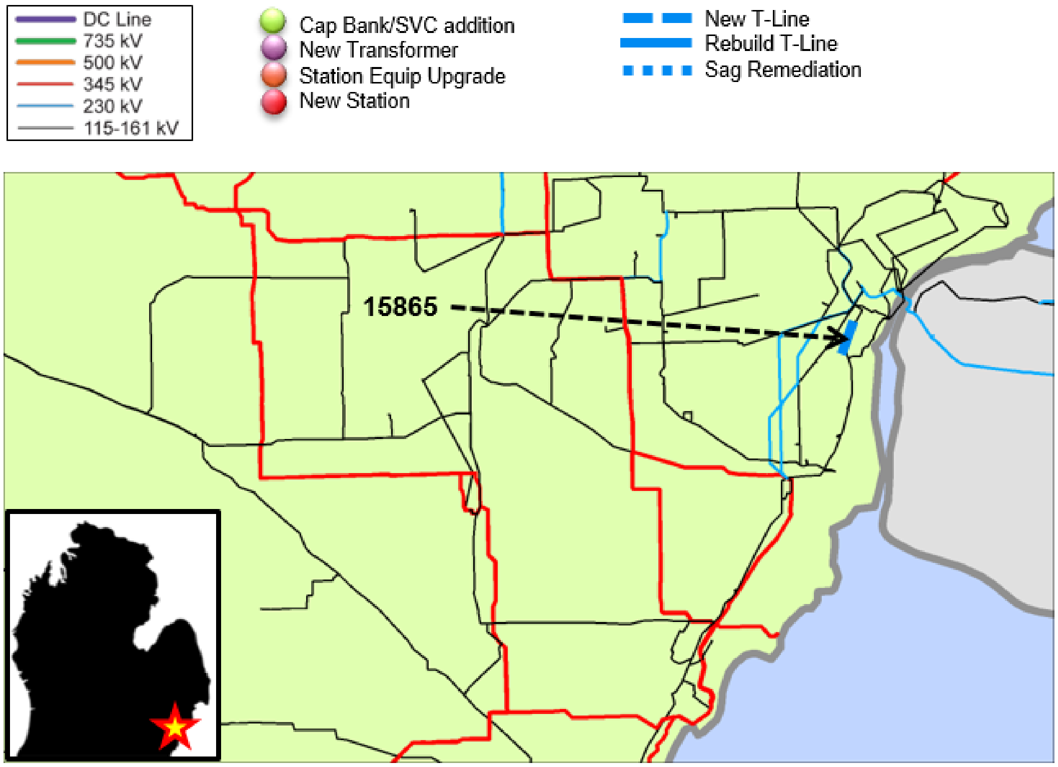


Figure 4.3-#15865-1: Geographic transmission map of project area

Project Need

The Navarre – Adelaide-Ironton-Navarre 120 kV and Adelaide-Ironton-Navarre – Ironton 120 kV sections are projected to overload for T-2 contingencies in the 5 and 10-year modeling cases. Losing another feed that supplies power to the River Rouge area will cause the Navarre – Adelaide – Ironton 120 kV circuit to overload its thermal limit.

Alternatives Considered

Several different alternatives were considered but none was identified to be the proper solution of the issue in terms of cost and the ability to resolve the issues created by the double transmission line contingency.

Project 16064 – Brownstown - Trenton Channel #1 120 kV Rebuild

Project Description

Rebuild approximately 3.9 miles of conductor on the Brownstown – Trenton Channel No.1 120 kV to 2156 ACSR and upgrade station equipment at Brownstown 120 kV and Trenton Channel 120 kV stations (Figure 4.3-#16064). The project's estimated cost is $10.3 million and the estimated in-service date is June 1, 2022.

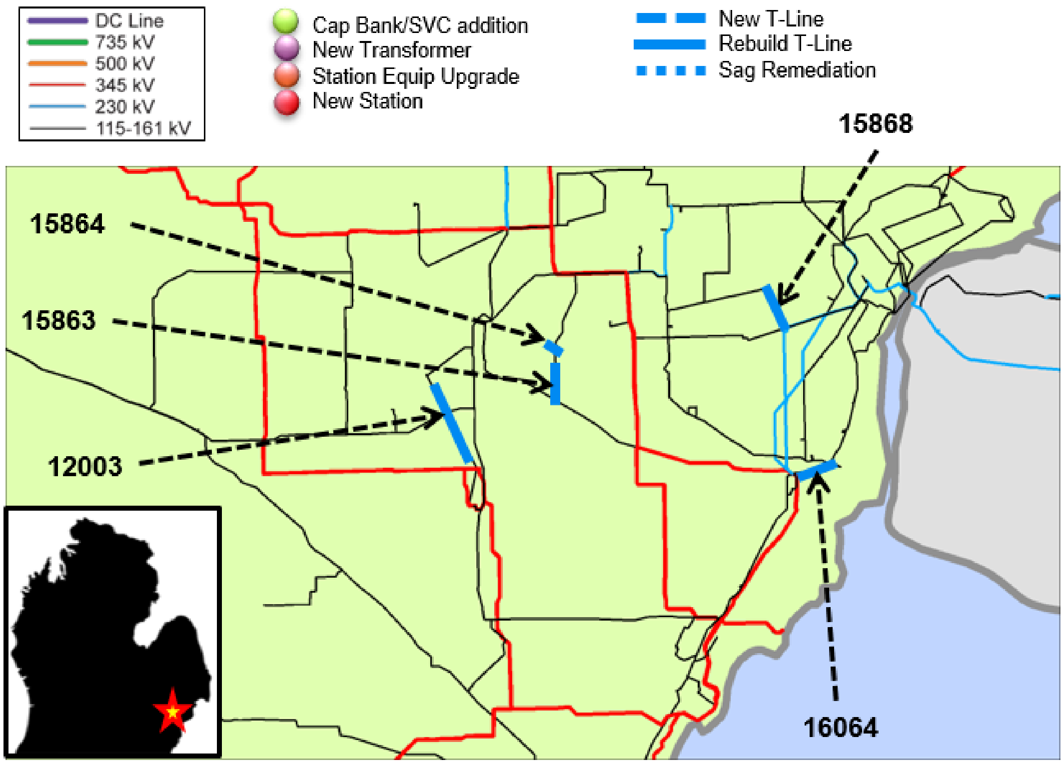


Figure 4.3-#16064, #15863, #12003, #15868, #15864, and #15905-1: Geographic transmission map of project area

Project Need

The Brownstown – Trenton Channel No. 1 120 kV circuit (line section highlighted as 16064 in Figure 4.3-#16064) is projected to be heavily overloaded for various X-1, Bus/Bkr, G-1+N-1, N-1-1, T-2, and DCT contingencies. The limiting elements on this circuit are the conductors, sag limit, and equipment at both Brownstown and Trenton Channel 120 kV stations.

Alternatives Considered

Several alternatives were considered but none was determined to be a better solution than rebuilding the section of the line with a higher capacity conductor.

Project 15863 – Arizona – Dayton 120 kV Rebuild

Project Description

Rebuild approximately 2.7 miles of 120 kV line from Arizona to Dayton using 954 ACSR conductor. This solution will also include the upgrade of station equipment at Arizona (Figure 4.3-#15863). The project's estimated cost is $7.0 million and the estimated in-service date is December 31, 2022.

Project Need

The Arizona – Dayton 120 kV circuit is projected to overload for N-1-1, T-2, and DCP contingencies.

Alternatives Considered

Several different alternatives were considered but rebuilding the line was determined to be the better solution.

Project 12003 – Milan - Pioneer 120 kV Rebuild

Project Description

Rebuild approximately a 4.0-mile-long portion of the Milan – Pioneer 120 kV line that is comprised of 477 ACSR conductor only by replacing the existing assets (all structures and 477 ACSR conductor) with new 120 kV double-circuit structures that are designed for 954 ACSR conductor, installing this new conductor along with OPGW for the Milan – Pioneer 120 kV line only, and reattaching the existing 477 ACSR conductor of the Noble – Superior 120 kV line to the other side of the new structures (Figure 4.3-#12003). The project's estimated cost is $6.0 million and the estimated in-service date is December 31, 2023.

Project Need

The Milan – Pioneer 120 kV line is projected to become overloaded for T-1, N-1-1, and T-2 contingencies. The overloads were identified in the 2021 near-term and 2026 long-term peak load models with flow to and from ITC Transmission across the Michigan-Ontario interface.

Alternatives Considered

MISO considered the remediation of an approximate 4-mile-long portion of the Milan – Pioneer 120 kV line that is comprised of 477 ACSR conductor to its summer emergency rating of 223 MVA/1074 A. Since the projected line loading is already near this rating, this alternative would only be a short-term solution.

Project 15868 – Brock - Elm 120 kV Rebuild

Project Description

Rebuild the 795 ACSR section (approximately 1 mile) on Brock – Elm 120 kV circuit to 1431 ACSR and also upgrade station equipment at Elm 120 kV substation (Figure 4.3-#15868). The project's estimated cost is $3.5 million and the estimated in-service date is December 31, 2023.

Project Need

The Brock to Elm 120 kV circuit is projected to overload for N-1-1 and T-2 contingencies. The limiting elements on this circuit are the 795 ACSR conductor and station equipment at Elm 120 kV.

Alternatives Considered

No alternative has been identified.

Project 15864 – Arizona – Scottsdale 120 kV Rebuild

Project Description

Rebuild approximately 1 mile of 120 kV line from Arizona to Scottsdale using 954 ACSR conductor and upgrade station equipment at both ends (Figure 4.3-#15864). The project's estimated cost is $2.7 million and the estimated in-service date is December 31, 2022.

Project Need

Arizona – Scottsdale 120 kV circuit is projected to overload for N-1-1, T-2, and DCP contingencies.

Alternatives Considered

No better alternative was identified than to rebuild that section of the transmission line.

Project 15905 – Willow Run - Zebra 120 kV Rebuild

Project Description

Rebuild approximately 4.6 miles of 120 kV line from Willow Run to Zebra using 954 ACSR conductor and upgrade station equipment at both ends (Figure 4.3-#15905). The project's estimated cost is $6.2 million and the estimated in-service date is December 31, 2022.

Project Need

Scottsdale – Willow Run 120 kV circuit is projected to overload for N-1-1, T-2, and DCP contingencies.

Alternatives Considered

No alternative was identified to resolve the issue in a cost effective manor and reliability wise other than this project.

Project 16014 – Jewell – Stephens 345 kV Sag Remediation

Project Description

Completely remove the sag limit on the Jewell – Stephens 345 kV line and upgrade equipment at Stephens 345 kV station (Figure 4.3-#16014). The project's estimated cost is $5.7 million and the estimated in-service date is December 31, 2022.

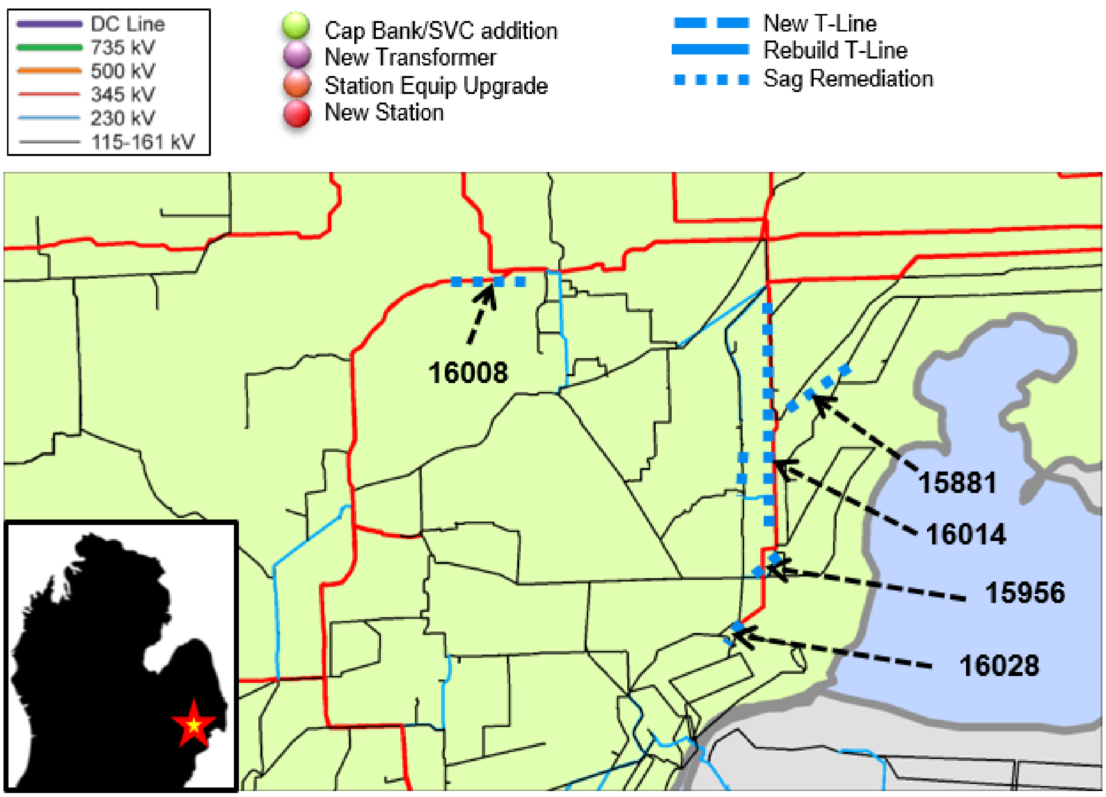


Figure 4.3-# 16014, 16008, 15881, 15956, and 16028-1: Geographic transmission map of project area

Project Need

The Jewell – Stephens 345 kV circuit (marked by #16014 of Figure 4.3-#16014) is projected to overload for N-1-1 and T-2 contingencies. There are two issues on this circuit, the line is sag limited and there is limiting equipment at Stephens 345 kV station.

Alternatives Considered

No better alternative to resolve the issues were identified than the solution reported here.

Project 16008 – Pontiac – Placid 345 kV Sag Remediation

Project Description

Remediate the sag limit on the Pontiac - Placid 345 kV line (Figure 4.3-#16008) to 1,543 MVA (2,582 Amps) for summer emergency rating. The solution also upgrades station equipment at Pontiac to at least 1,500 MVA (2,510 Amps). The project's estimated cost is $2.5 million and the estimated in-service date is December 31, 2022.

Project Need

The Pontiac – Placid 345 kV circuit is projected to overload for T-2 contingencies.

Alternatives Considered

No better alternative was identified to resolve the issues than the project that was selected and described in this section.

Project 15881 – Bismarck - Golf 120 kV Sag Remediation

Project Description

Raise the sag limit on the Bismarck – Golf 120 kV line to at least 253 MVA (Figure 4.3-#15881). The project's estimated cost is $630,000 and the estimated in-service date is December 31, 2021.

Project Need

The Bismarck – Golf 120 kV circuit is projected to be overloaded for several N-1-1 and T-2 contingencies. The identified overloaded equipment on this circuit is the sag limit.

Alternatives Considered

No better alternative than this project was identified.

Project 15956 – Northeast – Stephens 230 kV Sag Remediation

Project Description

Raise the sag limit on the Northeast – Stephens 230 kV line to at least 686 MVA and upgrade station equipment at Northeast 120 kV position HE (Figure 4.3-#15956). The project's estimated cost is $780,400 and the estimated in-service date is December 31, 2022.

Project Need

The Northeast – Stephens 230 kV circuit is projected to overload for many N-1-1 and T-2 contingencies. The limiting element on this circuit are sag limit and equipment at Northeast 120 kV position HE.

Alternatives Considered

There was no better alternative identified than the project described in this section.

Project 16028 – Caniff – Saturn 120 kV Sag Remediation

Project Description

Raise the sag limit on the Caniff – Saturn 120 kV line to at least 218 MVA (Figure 4.3-#16028). The project's estimated cost is $250,000 and the estimated in-service date is December 31, 2021.

Project Need

The Caniff – Saturn 120 kV circuit (Figure 4.3-#16028) is projected to overload for Bus/Bkr, N-1-1 and T-2 contingencies. This circuit is the sag limited.

Alternatives Considered

There were no better alternatives than to raise the sag limit as indicated by the preferred project.

Project 16020 – Cut Skylark – Sloan 120 kV into Redrun

Project Description

Cut the Skylark – Sloan 120 kV line into Redrun station with the installation of two new 120 kV breakers (Figure 4.3-#16020-1). Upgrade the station equipment at Sterling and rebuild approximately 1.6 miles of 795 ACSR conductor on the 120 kV sections from Sterling to Mustang2 to Van Dyke2 tap with 1431 ACSR.

The project's estimated cost is $5 million and the estimated in-service date is December 31, 2022.

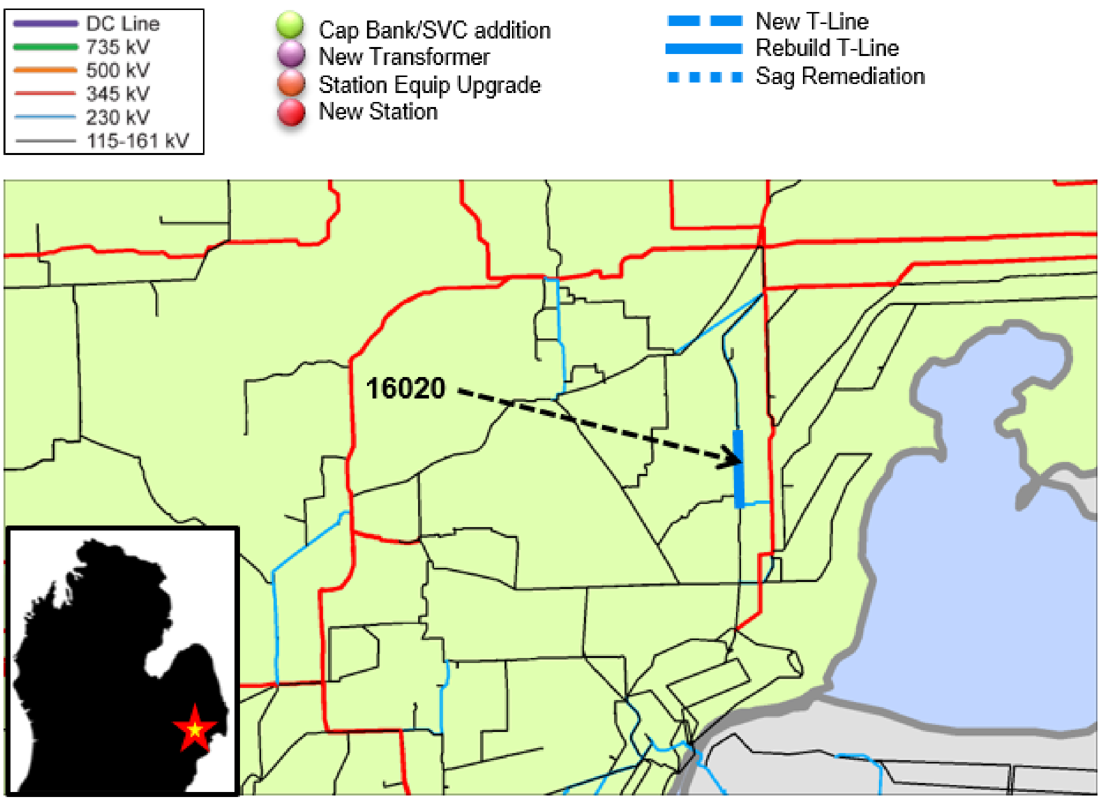


Figure 4.3-#16020-1: Geographic transmission map of project area

Project Need

Many buses in the region between Skylark and Sterling 120 kV stations are projected to experience low voltages for N-1-1 and T-2 contingencies (Figure 4.3-#16020-1).

Alternatives Considered

Several solutions were explored but none of these were identified to be better than the preferred project described in this section.

Project 13816 – Pioneer – Superior 120 kV Rebuild

Project Description

Rebuild approximately 3.16 miles of 477 ACSR to 954 ACSR from Pioneer to McAuley to Superior on double-circuit, 120 kV towers. The project also upgrades station equipment at Superior to 954 ACSR. Also, 3.16 miles of 477 ACSR conductor of the Noble to Superior 120 kV line that shares common structure with Pioneer – Superior 120 kV will be upgraded to 954 ACSR, installation of OPGW on the rebuilt section. The project's estimated cost is $4.9 million and the estimated in-service date is December 31, 2023.

Project Need

The Pioneer – McAuley – Superior 120 kV circuit is projected to overload for T-2 contingencies in the 5 and 10-year modeling cases.

Project 15866 – Newburgh – Peru 120 kV Rebuild

Project Description

Rebuild approximately 2.2 miles of 477 ACSR conductor to 1431 ACSR on the Newburgh – Sport 2 120 kV section to match with the rest of the circuit (Figure 4.3-#15866-1). The project's estimated cost is $4.5 million and the estimated in-service date is December 31, 2023.

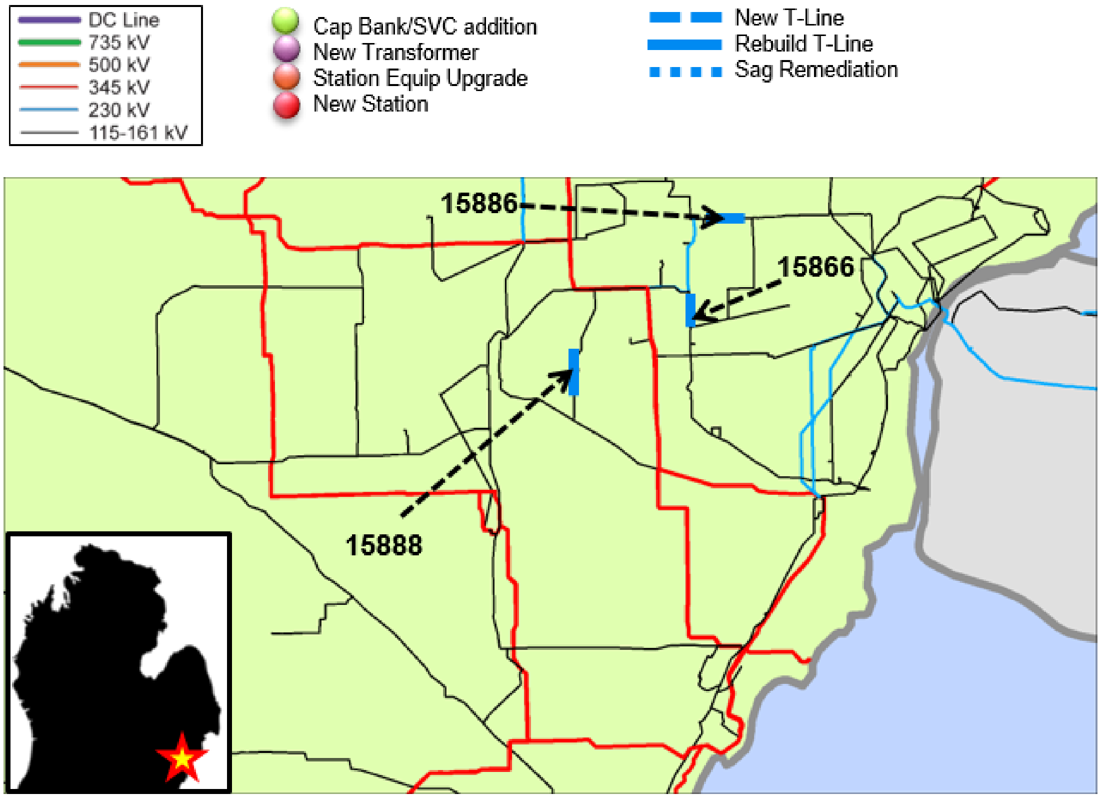


Figure 4.3-#15866, #15888, and #15886-1: Geographic transmission map of project area

Project Need

The 120 kV section from Newburgh to Sport 2 tap of the Newburgh – Peru 120 kV circuit is projected to be overloaded for a double-circuit tower (P7) and multiple T-2 contingencies. The overloaded facility is the 477 ACSR conductor section of this circuit.

Alternatives Considered

Other alternatives were considered, however, none was better able to resolve the issue in terms of cost and reliability as this project described for project E-15866.

Project 15888 – Scottsdale - Willow Run 120 kV Rebuild

Project Description

Rebuild approximately 0.4 miles of 120 kV line from Scottsdale to Willow Run using 954 ACSR conductor and upgrade station equipment at both ends (Figure 4.3-#15888). The project's estimated cost is $2.0 million and the estimated in-service date is December 31, 2022.

Project Need

The Scottsdale – Willow Run 120 kV circuit is projected to overload for N-1-1, T-2, and DCP contingencies.

Project 15886 – Ottawa - Yost 120 kV Reconductor

Project Description

Reconductor one span of 954 ACSR to 1431 ACSR at each end of the Ottawa – Yost 120 kV circuit and upgrade the equipment at both stations (Figure 4.3-#15886). The project's estimated cost is $500,000 and the estimated in-service date is December 31, 2021.

Project Need

The Ottawa – Yost 120 kV circuit is projected to overload for N-1-1, T-2, and DCP contingencies. The limiting elements on this circuit are the 954 ACSR conductor and equipment at both Ottawa and Yost 120 kV stations.

Alternatives Considered

The described project is best out of all the alternatives that were considered.

Project 17630 – 120 kV Cable Reactors

Project Description

Install 1 percent reactors on the Caniff – Cortland, Caniff – Bristol, and Caniff – Cyril 120 kV lines (Figure 4.3-#17630). The project creates a better balance of system flows in the area by re-directing more power to flow down the 120 kV overhead path and relieves the overloads on the cables. The project's estimated cost is $4.5 million and the estimated in-service date is June 1, 2023.

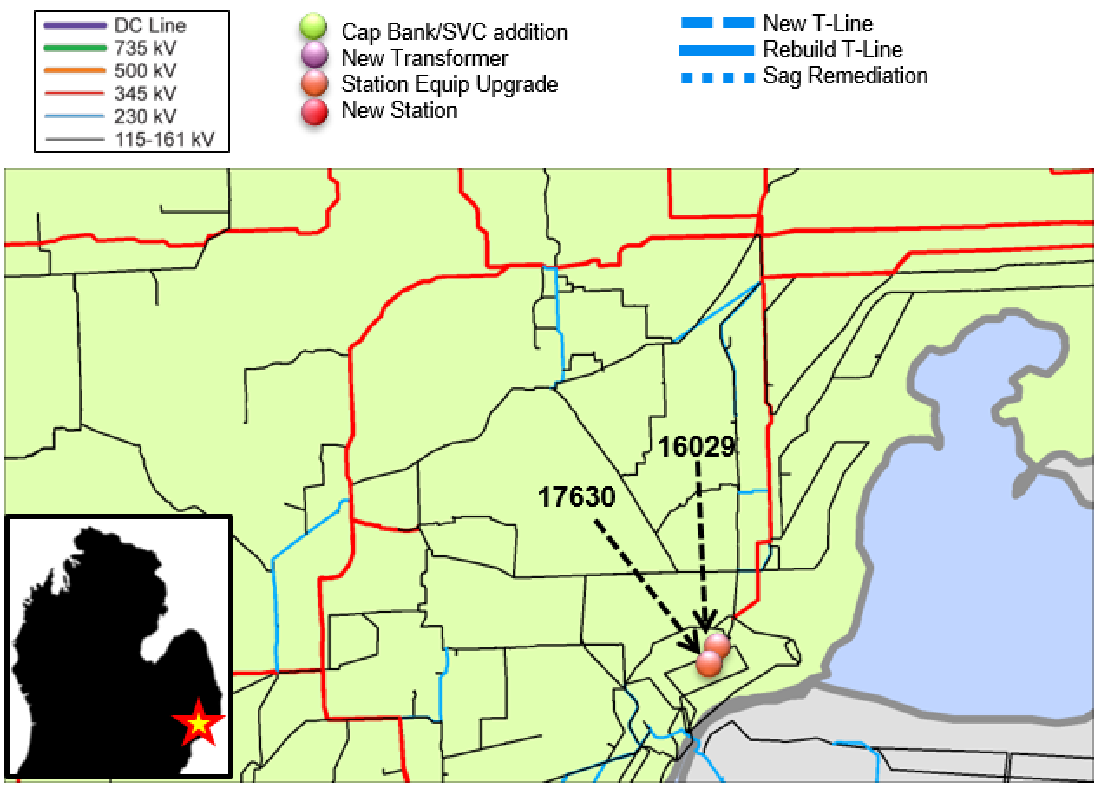


Figure 4.3-#17630 and #16029: Geographic transmission map of project area

Project Need

High flows and overloads were seen on the Caniff – Bristol 120 kV, Caniff – Cortland 120 kV, and Caniff – Cyril 120 kV lines for G-1, T-1, Open Breaker, Bus/Bkr, N-1-1, and T-2. These three underground cables are in parallel with each other as well as a 120 kV overhead line. Because of the significantly lower impedances on the cables compared to the overhead conductor, most of the power flows through the cables instead of the overhead path creating an unbalanced system flow in the area.

Alternatives Considered

No better alternative was identified to resolve this issue.

Project 16029 – Caniff 120 kV – Upgrade KU & LBX Station Equipment

Project Description

Upgrade the station equipment at Caniff 120 kV positions KU and LBX (Figure 4.3-#16029). The project's estimated cost is $360,000 and the estimated in-service date is December 31, 2021.

Project Need

The 345/120 kV transformer and phase shifter at Caniff are projected to be overloaded for G-1, T-1, and Bus/Bkr, and N-1-1, and T-2 contingencies. The limiting elements on this transformer branch are the equipment at Caniff 120 kV station.

Alternatives Considered

No better alternative was identified to resolve this issue.

Project 17544 – Belle River - Lenox 345 kV Sag Remediation

Project Description

Fully remediate the sag on the Belle River - Lenox 345 kV line up to its conductor's limit. The project's estimated cost is $1.5 million and the estimated in-service date is December 31, 2023.

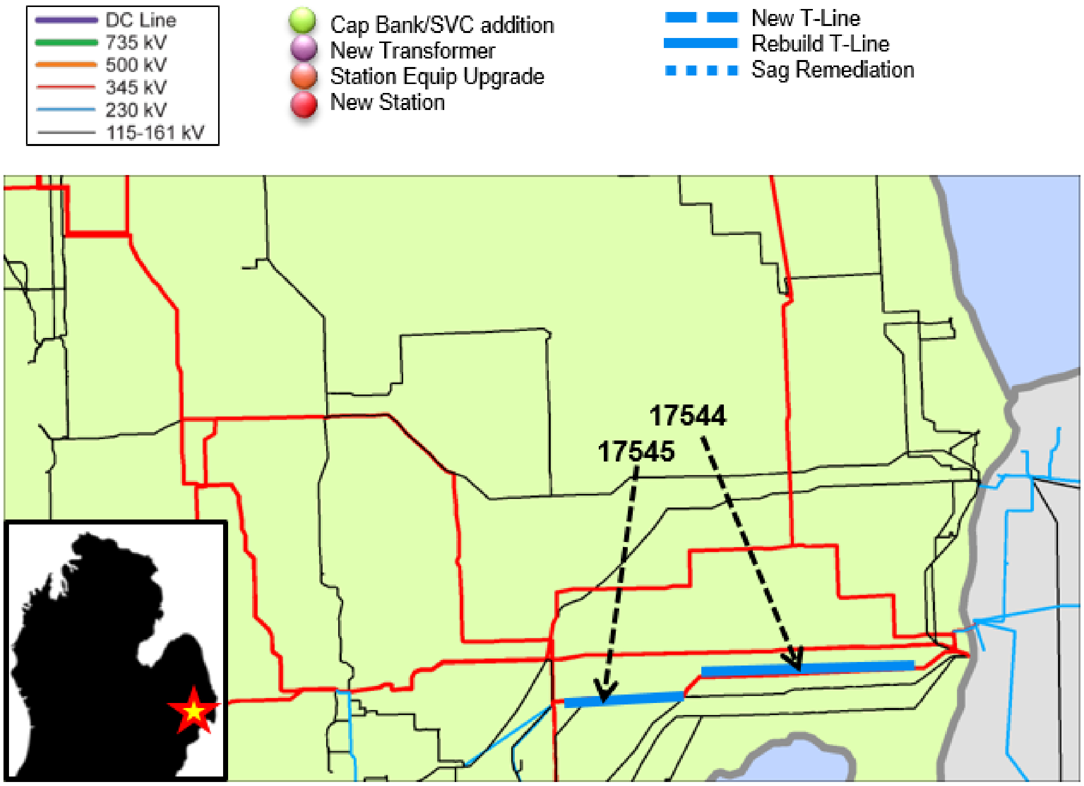


Figure 4.3-#17544 and #17545-1: Geographic transmission map of project area

Project Need

The Belle River – Lenox 345 kV circuit is projected to overload for numerous T-1, N-1-1, and T-2 contingencies. The overloaded facilities are the 2-954 ACSR conductor, sag limit, and station equipment at Belle River 345 kV (Figure 4.3-#17544).

Alternatives Considered

This project, together with Romeo project (#17164), are the alternative to the Belle River - Lenox 345 kV Rebuild (project ID #16019) that was originally proposed at the beginning of MTEP19 cycle.

Project 17545 – Jewell – Lenox 345 kV Sag Remediation

Project Description

Remediate the sag limit on the Jewell – Lenox 345 kV line to at least 1,500 MVA (2,510 Amp). The project's estimated cost is $520,000 and the estimated in-service date is December 31, 2023.

Project Need

The Belle River – Lenox 345 kV circuit is projected to overload for numerous T-1, N-1-1, and T-2 contingencies. The overloaded facilities are the 2-954 ACSR conductor, sag limit, and station equipment at Belle River 345 kV, refer to Figure 4.3-#17545.

Alternatives Considered

This project, together with Romeo project (#17164), are the alternative to the Belle River - Lenox 345 kV Rebuild (project ID #16018) that was originally proposed at the beginning of MTEP19 cycle.

Project 16006 – St. Clair - Stephens No. 2 345 kV Sag Remediation and Station Equipment Upgrade

Project Description

The proposed solution is to completely remove sag limit on the St. Clair – Stephens No. 2 345 kV to conductor limit and replace station equipment at Stephens and St. Clair substations (Figure 4.3-#16006). The project's estimated cost is $3.6 million and the estimated in-service date is December 31, 2021.

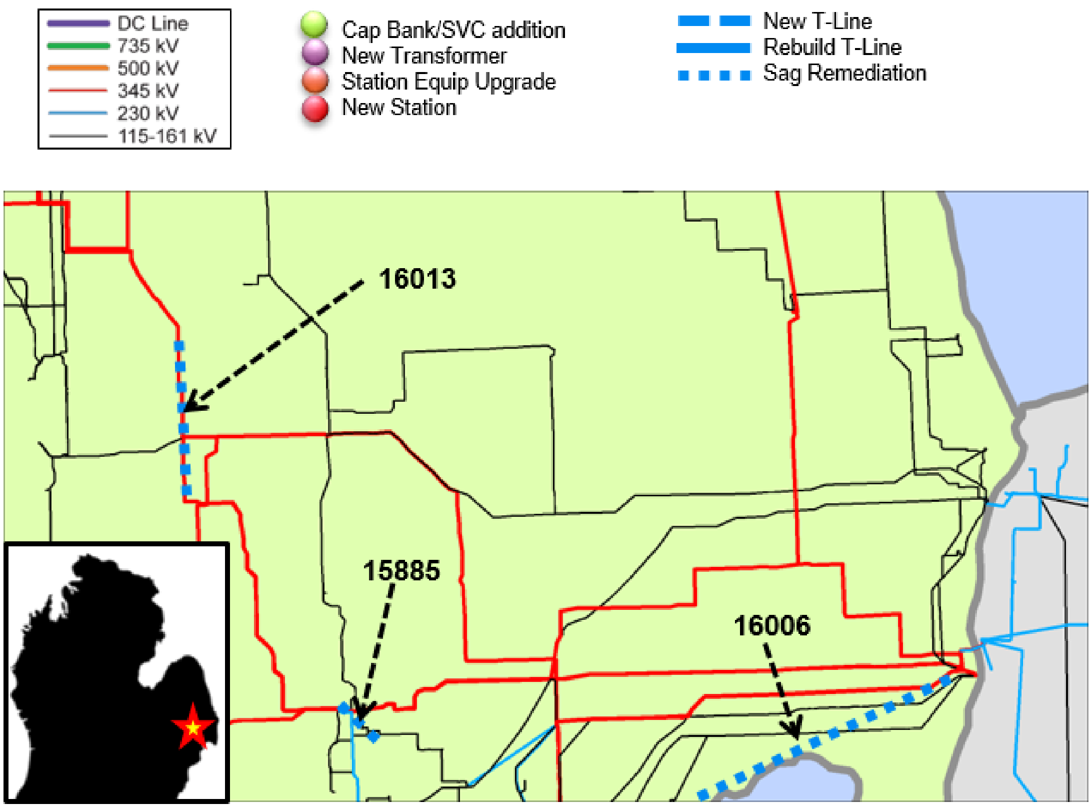


Figure 4.3-#16006, #16013, and #15885-1: Geographic transmission map of project area

Project Need

The St. Clair – Stephens #2 345 kV circuit is projected to overload for various N-1-1 and T-2 contingencies. The identified overloaded equipment on this circuit is the sag limit and station equipment at St. Clair and Stephens substations. The thermal violations are determined to be associated with the on peak and off peak cases.

Alternatives Considered

No better alternative was identified than to remove the sag limit as described for Project 16006.

Project 16013 – Thetford – Jewell 345 kV Sag Remediation

Project Description

Raise the sag limit on the Thetford – Jewell 345 kV line to at least 1537 MVA and upgrade equipment at Thetford 345 kV station (Figure 4.3-#16013). The project's estimated cost is $700,000 and the estimated in-service date is June 5, 2020.

Project Need

The Thetford – Jewell 345 kV circuit is projected to overload for many T-1, G-1+N-1, N-1-1, and T-2 contingencies. The rating of this circuit is limited by sag and equipment at Thetford 345 kV station.

Alternatives Considered

No better alternative was identified than to raise the sag limit as described for Project 16013.

Project 15885 – Giddings - Colorado 120 kV Sag Remediation

Project Description

Raise the sag limit on the Giddings – Colorado 120 kV section to at least 272 MVA (Figure 4.3-#15885). The project's estimated cost is $360,000 and the estimated in-service date is December 31, 2021.

Project Need

The 120 kV section between Giddings 1 tap and Colorado 2 tap of the Bloomfield – Sunbird 120 kV circuit is projected to be overloaded for several N-1-1 and T-2 contingencies. The identified circuit is overloaded due to sag limitations.

Alternatives Considered

No better alternative was identified than to raise the sag limit of the conductor as described for Project 15885.

Project 16009 - Northeast 120 kV - Upgrade KD Reactor

Project Description Upgrade the Northeast 120 kV reactor at position KD (Figure 4.3-#16009). The project's estimated cost is $1.02 million and the estimated in-service date is December 31, 2022.

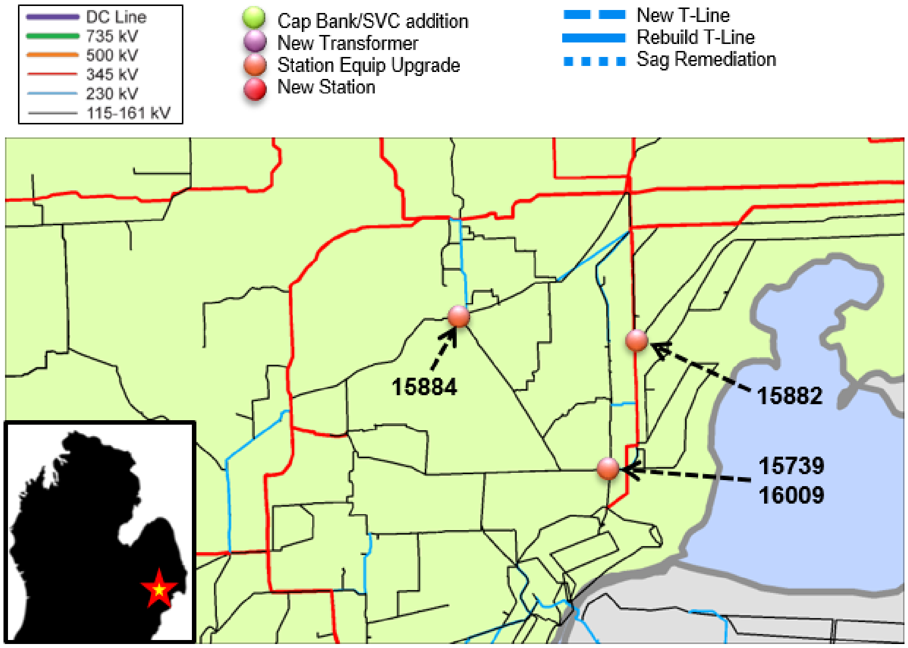


Figure 4.3-#16009, 15739, 15884, and 15882-1: Geographic transmission map of project area

Project Need

The Northeast 120 kV reactor at position KD, which connects to the Caniff – Northeast 120 kV line, is projected to overload for N-1-1 and T-2 contingencies.

Project 15739 - Northeast 120 kV Breaker HE Replacement

Project Description

Replace the existing Northeast 120 kV circuit breaker HE with a circuit breaker capable of interrupting at least 50 kA (Figure 4.3-#15739). The project's estimated cost is $254,000 and the estimated in-service date is December 31, 2020.

Project Need

The 2018 ITC short circuit analysis demonstrates that the Northeast 120 kV circuit breaker HE is at risk of having to interrupt faults as high as 98.2 percent of its capability.

Alternatives Considered

No better alternative was identified than to replace the over-duty circuit breaker.

Project 15884 - Bloomfield - Hood 120 kV Station Equipment Upgrade

Project Description

Upgrade the station equipment at Bloomfield 120 kV position HE (Figure 4.3-#15884). The project's estimated cost is $86,000 and the estimated in-service date is December 31, 2021.

Project Need

The Bloomfield – Bartlett (toward Hood) 120 kV circuit is projected to overload N-1-1 and T-2 contingencies. The overloaded facility is the station equipment at Bloomfield 120 kV position HE. This thermal violation only occurs in the 5-year, 85 percent-peak case with high import level from Canada case.

Alternatives Considered

No better alternative was identified than to upgrade the station equipment as described for the project 15884.

Project 15882 - Bismarck 120 kV – Upgrade JC Station Equipment

Project Description

Upgrade the station equipment at Bismarck 120 kV position JC (Figure 4.3-#15882). The project's estimated cost is $34,000 and the estimated in-service date is December 31, 2021.

Project Need

The 345/120 kV transformer #301 at Bismarck is projected to overload for N-1-1 and T-2 contingencies. The limiting element on this transformer branch is station equipment at Bismarck 120 kV position JC.

Alternatives Considered

No better alternative was identified than to upgrade the station equipment as described for Project 15882.

Project 15878 - Monroe - Lallendorf 345 kV Sag Remediation

Project Description

Completely remove the sag limit on the Monroe – Lallendorf 345 kV line (ITCT side) (Figure 4.3-#15878). The project's total estimated cost is $1.2 million and the estimated in-service date is December 31, 2021. This project is shared between METC and ITCT and the cost of ITCT's share is $214,000.

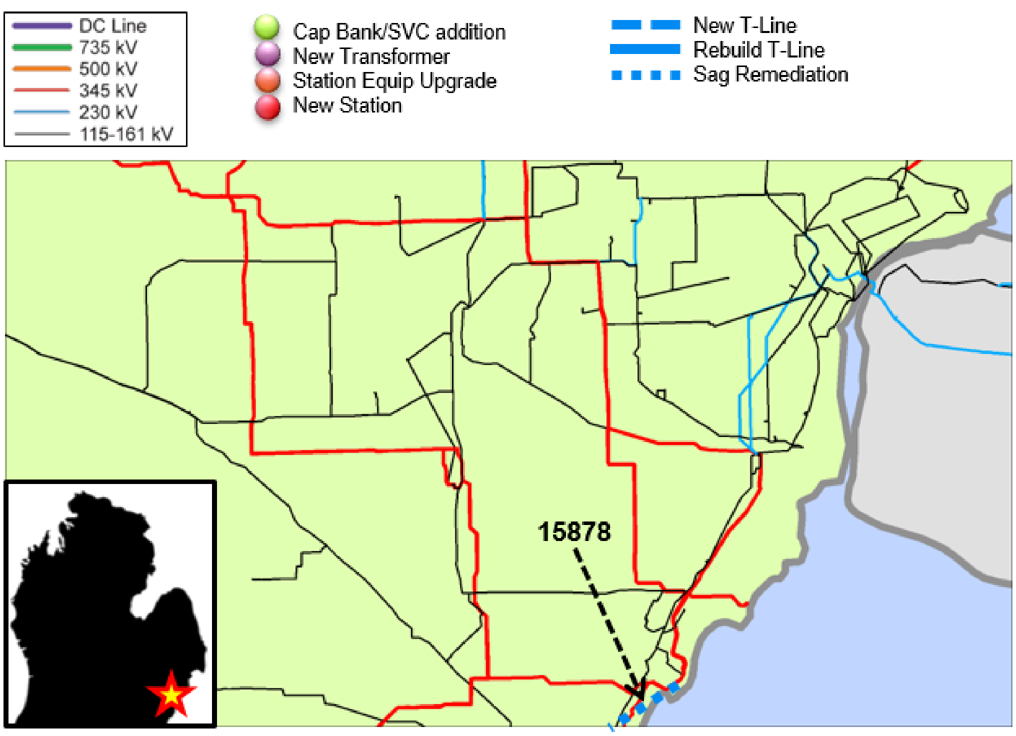


Figure 4.3-#15878-1: Geographic transmission map of project area

Project Need

The Monroe – Lallendorf 345 kV line is projected to be overloaded for N-1-1 and T-2 contingencies. The identified circuit is over loaded due to sag limitations. The thermal violations are found in all cases.

Alternatives Considered

The most cost effective alternative to resolve this issue is to remediate the sag as proposed by Project 15878.

Project 15862 - Adams – Burns 2 120 kV Rebuild

Project Description

Rebuild approximately 0.3 miles of 795 ACSR conductor to 1431 ACSR to match the rest of the conductor on the Adams – Burns 2 120 kV branch (Figure 4.3-#15862). The project's estimated cost is $1.13 million and the estimated in-service date is June 1, 2024.

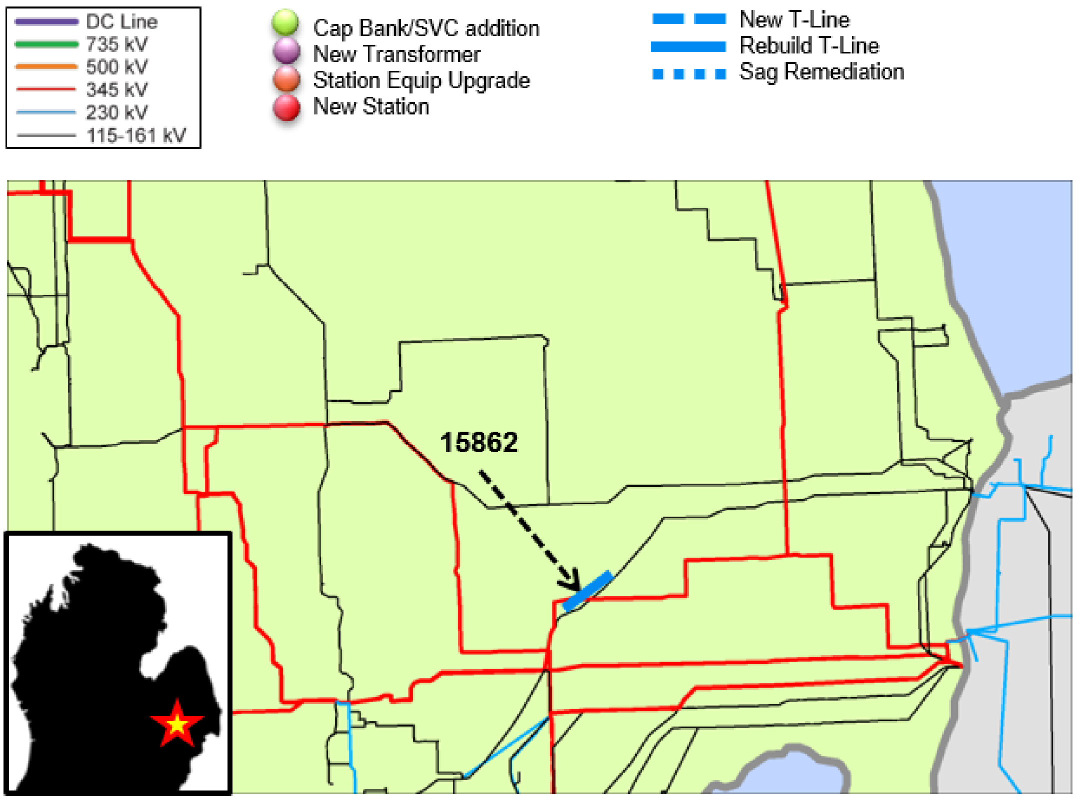


Figure 4.3-#15862-1: Geographic transmission map of project area

Project Need

The 120 kV section between Adams and Burns 2 tap is projected to overload for various contingencies, including T-1, Bus/Bkr, G-1+N-1, N-1-1, and T-2 for the 2, 5, and 10-year modeling cases. The overloaded facility is the 795 ACSR conductor. This section is also sag limited.

Alternatives Considered

Several alternatives were considered including remediating the sag but rebuilding the line was determined to be the most cost effective project to reliably mitigate the identified issue.

Project 15887 - Durant 120 kV 33.3 MVAR Capacitor

Project Description

Install a 33.3 MVAR capacitor at Durant 120 kV station (Figure 4.3-#15887-1). The project's estimated cost is $1.1 million and the estimated in-service date is December 31, 2022.

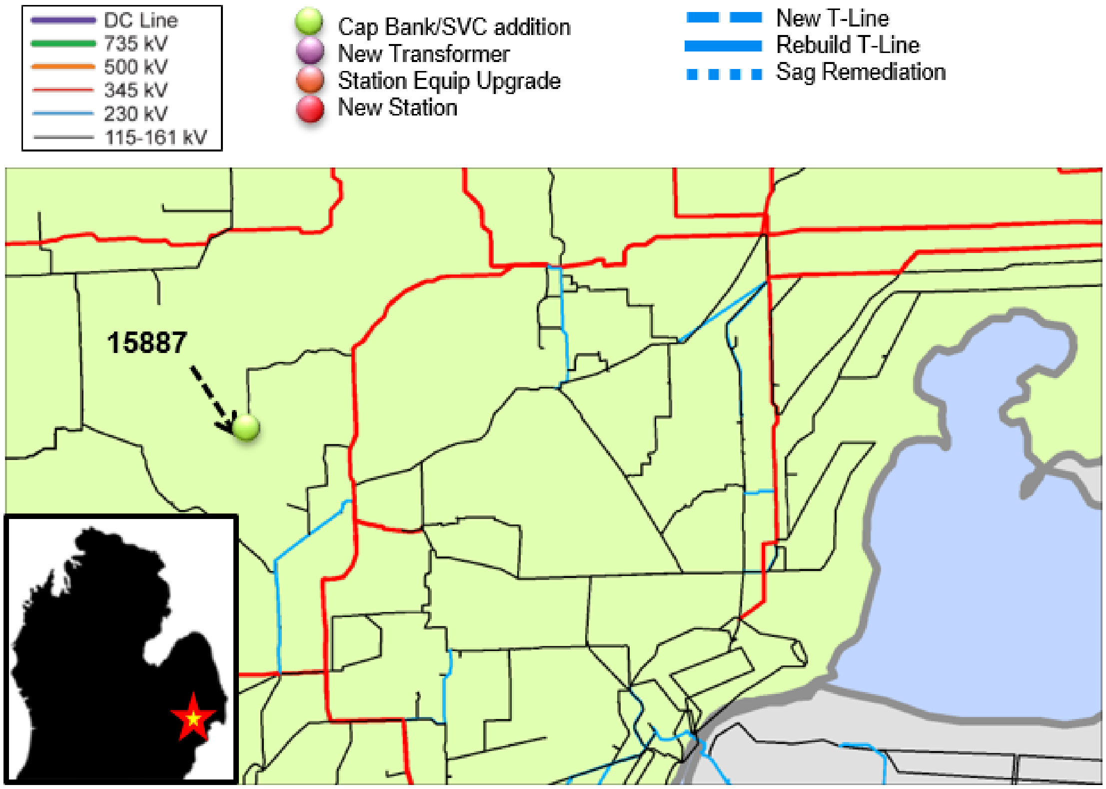


Figure 4.3-#15887-1: Geographic transmission map of project area

Project Need

The Durant buses are projected to experience low voltages for N-1-1 and T-2 contingencies. These buses are at the area indicated on Figure 4.3-#15887-1.

Alternatives Considered

The only alternative that was identified to resolve these low voltage issues is the installation of the capacitor bank indicated for this project.

16025 - Trenton Channel 120 kV Capacitor

Project Description

Install a three-bank of 18 MVAR capacitors at Trenton Channel 120 kV station. The project's estimated cost is $1.15 million and the estimated in-service date is December 31, 2021.

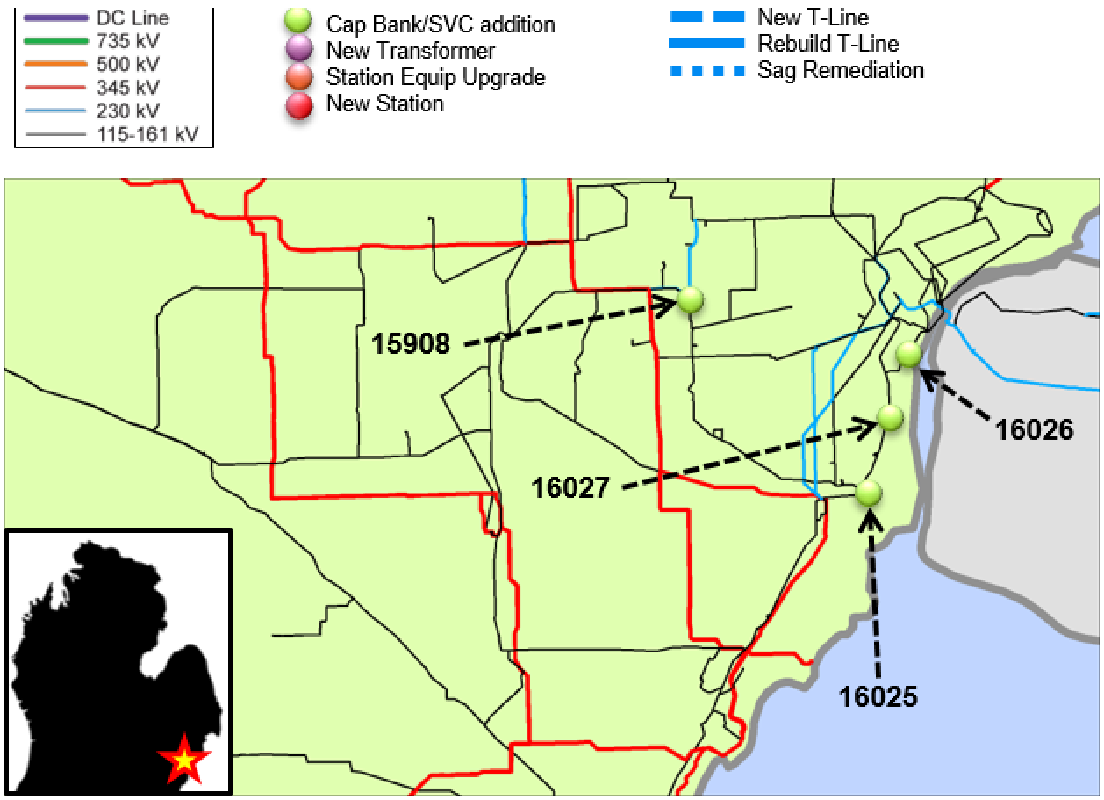


Figure 4.3-#16025, #16027, #15908, and #16026-1: Geographic transmission map of project area

Project Need

There are numerous voltage issues in the region near River Rouge, Riverview, and Trenton Channel 120 kV stations. The main driving contingency for these voltage violations is the loss of at least one of two transformer contingencies (X-1) combined with other single-event contingencies (X-1 or T-1). Refer to Figure 4.3-#16025, 16027, 15908, and 16026-1 for the location of these low-voltage buses.

Alternatives Considered

No better alternative was identified to mitigate the low voltage issues than the capacitor bank installation proposed for Project 16025.

Project 16027 - Riverview 120 kV Capacitor

Project Description

Install a three-bank 18 MVAR capacitor at the Riverview 120 kV station. The project's estimated cost is $1.26 million and the estimated in-service date is December 31, 2021.

Project Need

There are numerous voltage issues in the region near River Rouge, Riverview, and Trenton Channel 120 kV stations. The main driving contingency for these voltage violations is the loss of at least one of two transformer contingencies (X-1) combined with other single-event contingencies (X-1 or T-1). Refer to Figure 4.3-#16025, 16027, 15908, and 16026-1 for the location of these low-voltage buses.

Alternatives Considered

Installing the capacitors was the only solution that best resolves the low voltages issues. No better alternative was identified.

Project 15908 - Newburgh 120 kV 33.3 MVAR Capacitor

Project Description

Install a 33.3 MVAR capacitor at Newburgh 120 kV station on bus 101. The project's estimated cost is $1.71 million and the estimated in-service date is December 31, 2022.

Project Need

The Newburgh buses are projected to experience low voltages for N-1-1 and T-2 contingencies (Figure 4.3-#15908).

Alternatives Considered

No better alternative was identified to mitigate these low voltage conditions.

Project 16026 - Ironton 120 kV Capacitor

Project Description

Install a three-bank of 18 MVAR capacitors at Ironton 120 kV station to resolve these low-voltage conditions near River Rouge, Riverview and Trenton Channel (Figure 4.3-#16026). The project's estimated cost is $515,000 and the estimated in-service date is December 31, 2021.

Project Need

There are numerous voltage issues in the region near River Rouge, Riverview, and Trenton Channel 120 kV stations. The main driving contingency for these voltage violations is the loss of at least one of two transformer contingencies (X-1) combined with other single-event contingencies (X-1 or T-1). Refer to Figure 4.3-#16025, 16027, 15908, and 16026-1 for the location of these low voltage buses.

Alternatives Considered

Installing the bank of 18 MVAR capacitors was the best alternative ITC identified.

Project 15879 - Monroe - Lulu 345 kV Station Equipment Upgrade

Project Description

Upgrade the station equipment at Monroe 345 kV positions MF and MM (Figure 4.3-#15879). The project's estimated cost is $970,000 and the estimated in-service date is December 31, 2021.

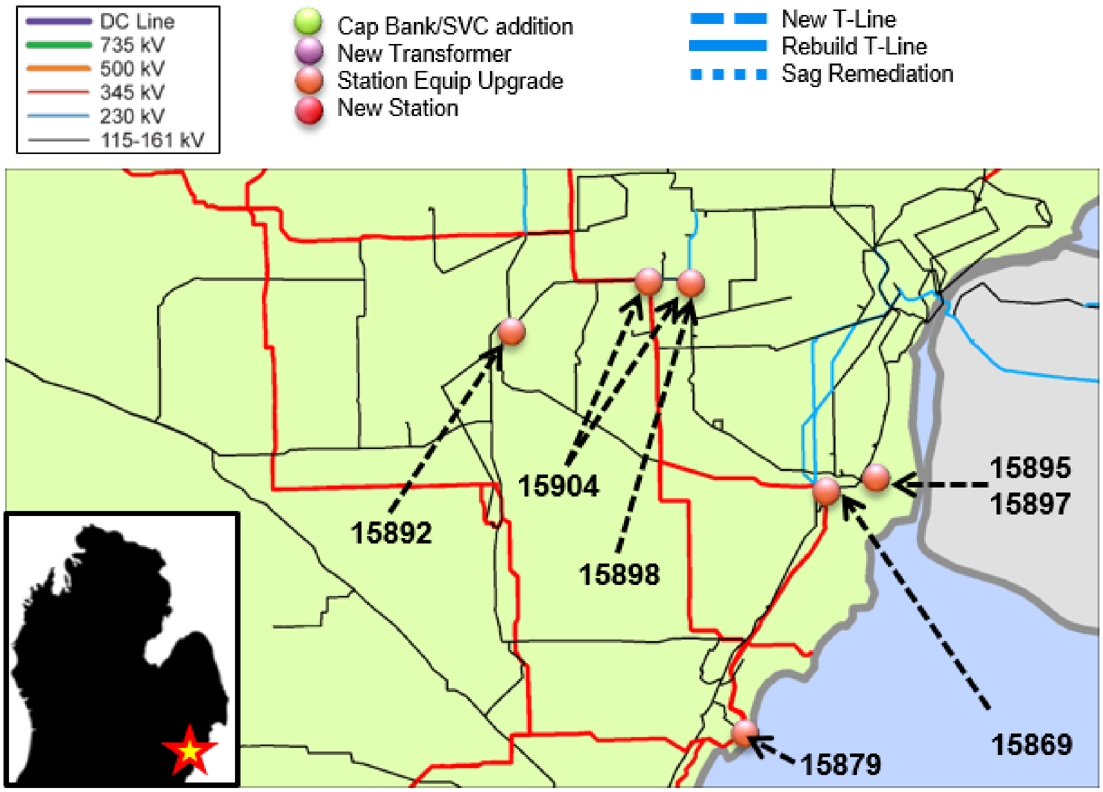


Figure 4.3-#15879, #15904, #15892, #15869, #15895, #15898, and #15897-1: Geographic transmission map of project area

Project Need

The Monroe – Lulu section of the Milan-Monroe-Morocco 345 kV circuit is projected to be overloaded for N-1-1, T-2, and DCP contingencies. The overloaded facilities are the station equipment at Monroe 345 kV positions MF and MM.

Alternatives Considered

No better alternative was identified than to replace the station equipment as described by ITCT Project 15879.

Project 15904 - Wayne - Newburgh No. 2 120 kV Station Equipment Upgrade

Project Description

Upgrade the equipment at Wayne 120 kV station position GP and Newburgh 120 kV station position HQ (Figure 4.3-#15904). The project's estimated cost is $1.0 million and the estimated in-service date is December 31, 2021.

Project Need

The Wayne-Koppernick-Newburgh 120 kV line is projected to be overloaded for N-1-1, T-2, and DCP contingencies. The overloaded facilities are the equipment at Wayne and Newburgh 120 kV stations.

Alternatives Considered

The reported project is the best among all solutions that were considered.

Project 15892 - Superior 120 kV – Upgrade HJ Station Equipment

Project Description

Upgrade the station equipment at Wayne 120 kV position HJ (Figure 4.3-#15892). The project's estimated cost is $330,000 and the estimated in-service date is December 31, 2021.

Project Need

The 120 kV bus-tie between bus 101 and 102 at Superior is projected to overload for N-1-1 and T-2 contingencies. The limiting element on this 120 kV bus-tie branch is the station equipment at Wayne station, position HJ.

Project 15869 - Brownstown 120 kV - Upgrade GB Station Equipment

Project Description

Upgrade the station equipment at Brownstown 120 kV position GB (Figure 4.3-#15869). The project's estimated cost is $325,000 and the estimated in-service date is December 31, 2021.

Project Need

The 345/120 kV transformer #301 at Brownstown is projected to be marginally overloaded for N-1-1 and T-2 contingencies. The limiting element on this transformer branch is the 120 kV station equipment at Brownstown station, position GB.

Project 15895 - Trenton Channel 120 kV – Upgrade JP Station Equipment

Project Description

Upgrade the station equipment at Trenton Channel 120 kV station, position JP (Figure 4.3-#15895). The project's estimated cost is $252,000 and the estimated in-service date is December 31, 2021.

Project Need

The 120 kV bus-tie between buses 11 and 13 at Trenton Channel is projected to overload for several N-1-1 and T-2 contingencies. The limiting element on this 120 kV bus-tie branch is the station equipment at Trenton Channel station, position JP.

Project 15898 - Wayne 120 kV – Upgrade GQ Station Equipment

Project Description

Upgrade the station equipment at Wayne 120 kV station, position GQ (Figure 4.3-#15898). The project's estimated cost is $75,000 and the estimated in-service date is December 31, 2021.

Project Need

The 345/120 kV transformer #301 at Wayne station is projected to be marginally overloaded for N-1-1 and T-2 contingencies. The limiting element on this transformer branch is the station equipment at Wayne 120 kV station, position GQ.

Project 15897 - Trenton Channel - Taurus 120 kV Station Equipment Upgrade

Project Description

Upgrade the station equipment at Trenton Channel 120 kV position JR (Figure 4.3-#15897). The project's estimated cost is $45,000 and the estimated in-service date is December 31, 2021.

Project Need

The Trenton Channel – Taurus 120 kV circuit is projected to overload for N-1-1 and T-2 contingencies. The overloaded facility is the station equipment at Trenton Channel 120 kV position JR.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as Other Projects, according to Attachment FF of the MISO Tariff. Tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Project 15981 - Detroit Cable Project

Project Description

Construct two new 120 kV substations named Promenade and Island View. The proposed project will also include the construction of approximately 7 miles of new underground cable from Alfred 120 kV substation to Island View 120 kV substation; from new Island View 120 kV substation to Promenade 120 kV substation; and from Promenade 120 kV substation to Mack 120 kV substation. This project is driven mainly by load growth in addition to the long term goal to improve the local reliability within the Detroit Area (Figure 4.3-#15981-1).

The project's estimated cost is $139.5 million and the estimated in-service date is June 1, 2023.

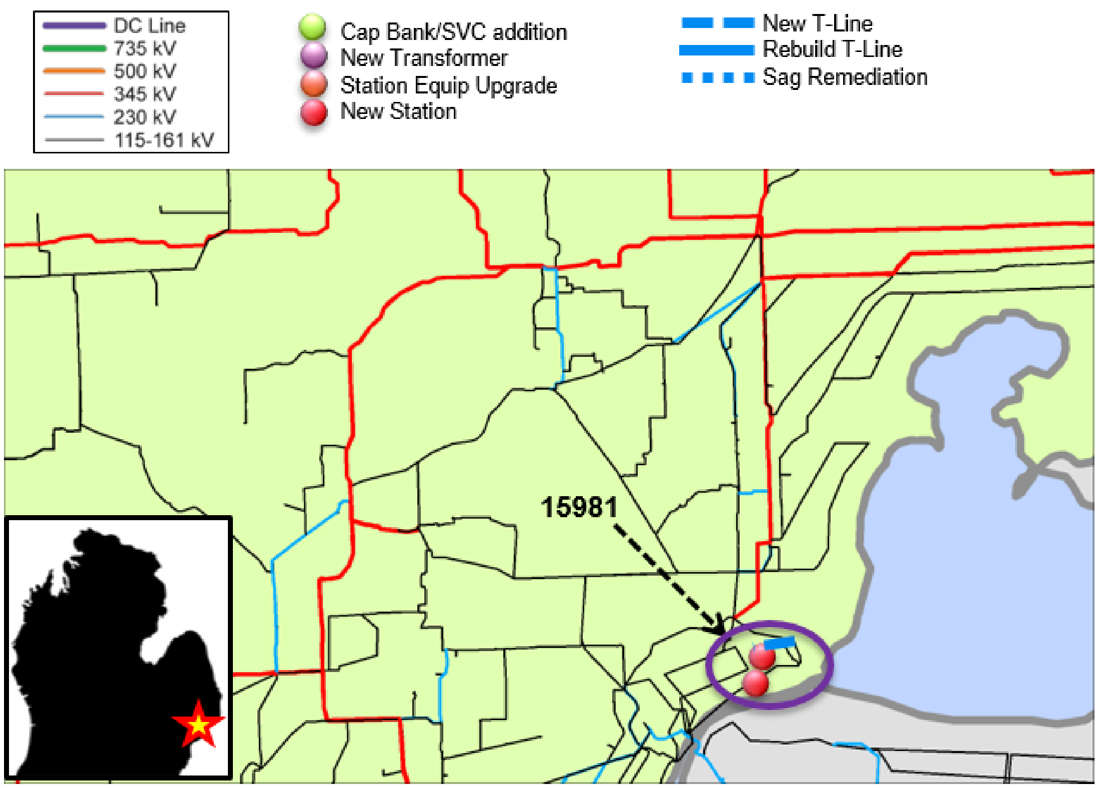


Figure 4.3-#15981-1: Geographic transmission map of project area

Project Need
DTE submitted interconnection requests to ITC Transmission to interconnect two new loads (Promenade and Island View) in the Northeast Detroit area. Some of this load is added to the Mack/Essex load pocket area. As the system exists today, there is little margin for load growth in the area before the circuits become overloaded for two successive single element contingencies (N-1-1 conditions).

The area in and around downtown Detroit is experiencing rapid economic growth. As a result, requests to study load growth in this area have been increasing in recent time. To that end, this project represents a forward-looking approach that would accommodate future load growth in the area.

Alternatives Considered
Other alternatives were considered but none were determined to be a better alternative since Project 15981 is able to resolve the load interconnection issues and other local reliability issues better than those alternatives. In addition, Project 15981 has long term reliability benefits that the other alternatives do not have.

Projects Driven by Local Reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16004	ITCT Pole Top Switch Additions/Replacement Program 2021	Installing, or replacing as appropriate, pole-top switches at tap points of circuits will provide the operational flexibility to sectionalize parts of the line to isolate faults or perform maintenance work on it without having to shut down the entire circuit.	Dec. 31, 2021	MI	$2.4M
15741	Quaker 230 kV Breaker Installation Project	Install a 230 kV breaker on the high side of T251 at Quaker for the Quaker – Wixom line. The new breaker would have a dedicated breaker control relay.	Dec. 31, 2021	MI	$0.5M

Table 4.3-2: MTEP19 projects driven by local reliability

Projects Driven by Load Growth

For the following projects, load growth is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15768	Corktown	ITCT will construct a new 4-breaker ring bus 120 kV substation, named Corktown. ITCT will loop the St. Antoine - Waterman 120 kV circuit into the new station.	Mar. 31, 2022	MI	$28.3M
15704	Gramer Interconnection	Gramer 120 kV is a straight bus station with 1 section breaker and 2 line breakers. This will require 2 miles of new 120 kV DCT to loop in the Jewel - St. Clair #2 120 kV line for transmission service. DTE will have 2 120/40 kV transformers which will be networked with DTE's existing 40 kV system.	Mar. 31. 2021	MI	$10.2M
15783	Croswell	ITCT will install a new 120 kV breaker with associated disconnects at the Lee substation. ITCT will construct approximately 7.5 miles of a new 120 kV circuit between Lee and the new substation at Croswell.	Dec. 31, 2021	MI	$8.7M
16744	Midtown Expansion	ITCT will expand the Midtown 120 kV GIS from the existing 4-breaker ring bus to a 5-breaker ring bus	Dec. 31, 2020	MI	$7.9M
16644	Sigma Interconnection	Sigma is a 120 kV station in a straight bus configuration with two line breakers and a section breaker. ITCT will cut in the Bismarck - Lenox 120 kV line for transmission service. DTE will install two 120/13.2 kV transformers with circuit switchers for high side protection. DTE bus 11 and bus 12 will be tied via an A.T.O. Sigma will serve about 28.7 MVA of load relocated from Grayling and Jewell.	Apr. 1, 2022	MI	$4.5M
15776	Juliet	ITCT will construct a new straight bus 120 kV substation tentatively named Juliet. ITCT will loop in the Adams – Fitz 120 kV circuit into the new substation. ITCT will install OPGW between Adams and new substation.	Dec. 31, 2020	MI	$4.2M
14924	Morton Interconnection	Morton is a new 120 kV interconnection. Station will be a straight bus with a section breaker and two line breakers. Morton will be fed by cutting in the Douglass - Visteon 120 kV line.	Dec. 31, 2021	MI	$3.5M
16624	Mountain	DTE interconnection request. ITC will tap the Pontiac - Sunbird 120 kV line and the Bloomfield - Sunbird 120 kV line to provide transmission service to DTE's new Mountain station. DTE will install 2 120/13.2kV transformers to serve about 12.5 MVA of load.	Mar. 31, 2021	MI	$1.9M

15891	ITCT Customer interconnections - Year 2022	Customer interconnection requests and retirements less than $1 million with in service date in year 2022.	Dec. 31, 2022	MI	$2.0M

Projects Driven by Age and Condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15976	2022 ITCT Asset Replacement Program	Replace aging and outdated equipment on a cycle that will ensure each piece of equipment is replaced near its expected end of life. Modern equipment can improve reliability, use state of the art technology, and typically will allow for longer maintenance intervals. New equipment is also commonly equipped with better monitoring and alarming functionality giving improved remote supervision. All of this will help to reduce overall maintenance costs.	Dec. 31, 2022	MI	$49.0M

4.3.2 Michigan Electric Transmission Co.

METC proposed 76 projects at an estimated cost of $627.8 million targeting MTEP19 Appendix A. After MISO's independent reliability analysis of the METC area, 47 of these projects were recommended by MISO to be included in MTEP19 Appendix A at an estimated cost of $310.4 million[12]. All the projects' expected in-service dates and estimated costs are provided as of October 18, 2019.

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."

Project 15794 – Rebuild Garfield Avenue – Karn 138 kV

Project Description

Rebuild 32.2 miles of the Garfield Avenue – Karn 138 kV line (Figure 4.3-#15794) utilizing 1431 ACSR conductor and remediate the sag limit on 14.8 miles of 1431 ACSR conductor to increase the summer emergency rating to a minimum of 223 MVA/934 A. The project's estimated cost is $40.0 million and the estimated in-service date is December 31, 2023.

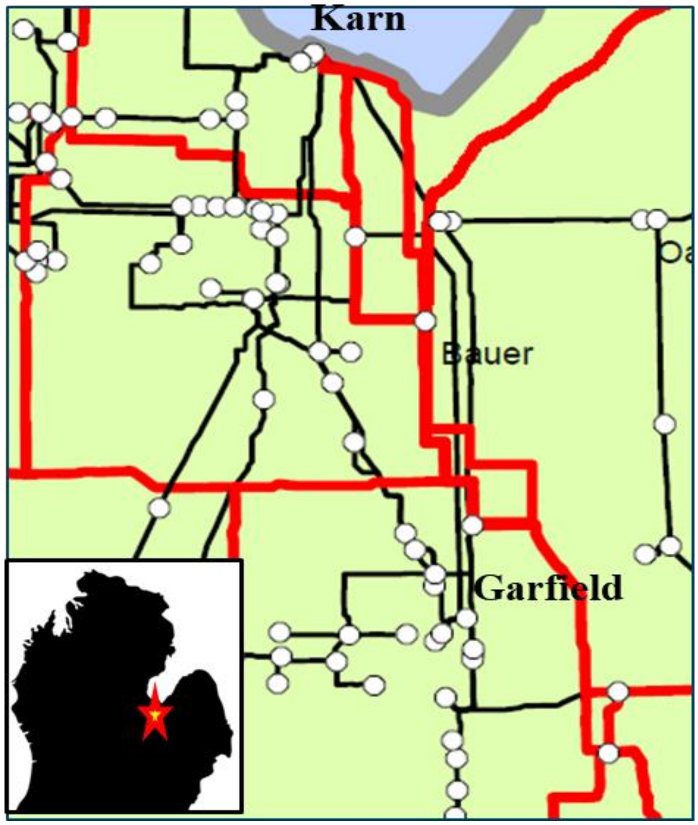


Figure 4.3-#15794: Rebuild Garfield Avenue – Karn 138 kV

Project Need

Facilities are overloaded for numerous shutdown plus contingency (P6) scenarios.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15942 – Rebuild Cobb 138 kV Station

Project Description

Rebuild Cobb 138 kV station at a new site 3.9 miles to the east (Figure 4.3-#15942) utilizing new equipment in a six-row, breaker-and-a-half scheme configuration. The project's estimated cost is $23.1 million and the estimated in-service date is December 31, 2023.

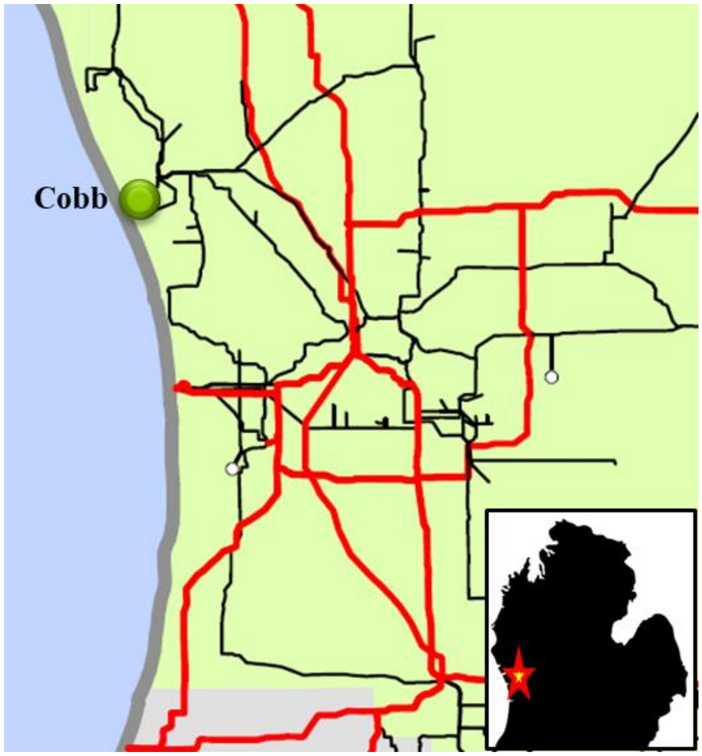


Figure 4.3-#15942: Rebuild Cobb 138 kV Station

Project Need
Facilities violate thermal and voltage criteria for breaker failure event.

Alternatives Considered
Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15755 – Rebuild MCV - Tittabawassee NO. 2 345 kV

Project Description
Rebuild the entire 2.5 mile-long MCV – Tittabawassee NO. 2 345 kV line (Figure 4.3-#15755) that is comprised of 2156 ACSR conductor utilizing 2-1431 ACSR conductor and upgrade station equipment at both MCV and Tittabawassee. The project's estimated cost is $10.5 million and the estimated in-service date is December 31, 2023.

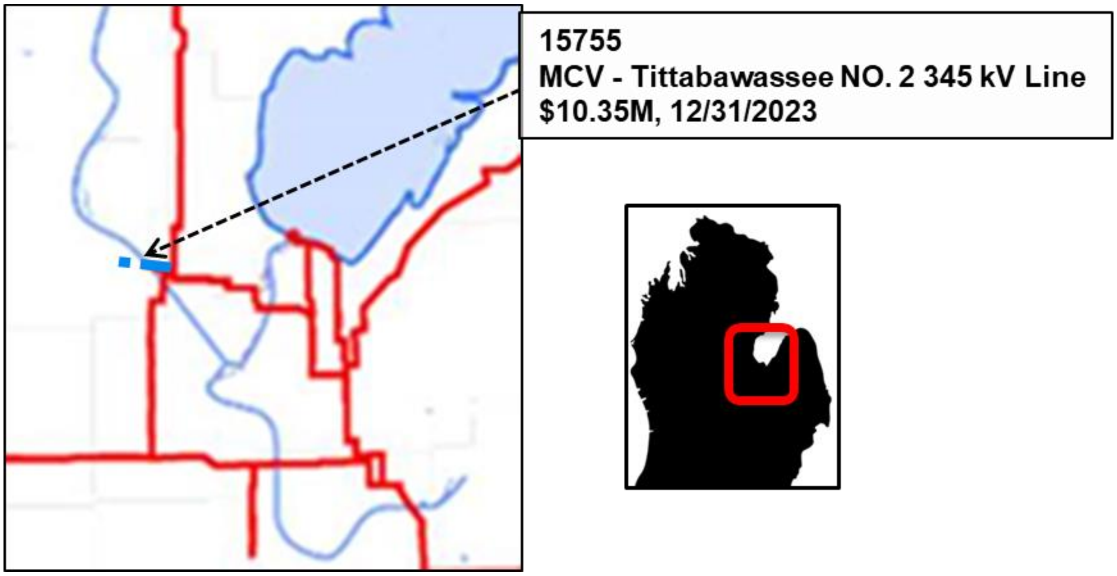


Figure 4.3-#15755: Rebuild MCV – Tittabawassee NO. 2 345 kV

Project Need

The MCV – Tittabawassee NO. 2 345 kV line is projected to become overloaded for numerous contingency types with the most severe loadings caused by shutdown plus contingencies (P6). The overloads were identified in the peak load models with the Ludington units generating regardless of the flow across the Michigan-Ontario interface.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15756 – Rebuild MCV – Tittabawassee NO. 1 345 kV

Project Description

Rebuild the entire 2.5 mile-long MCV – Tittabawassee NO. 1 345 kV line (Figure 4.3-#15756) that is comprised of 2156 ACSR conductor utilizing 2-1431 ACSR conductor and upgrade station equipment at both MCV and Tittabawassee. The project's estimated cost is $10.23 million and the estimated in-service date is December 31, 2023.

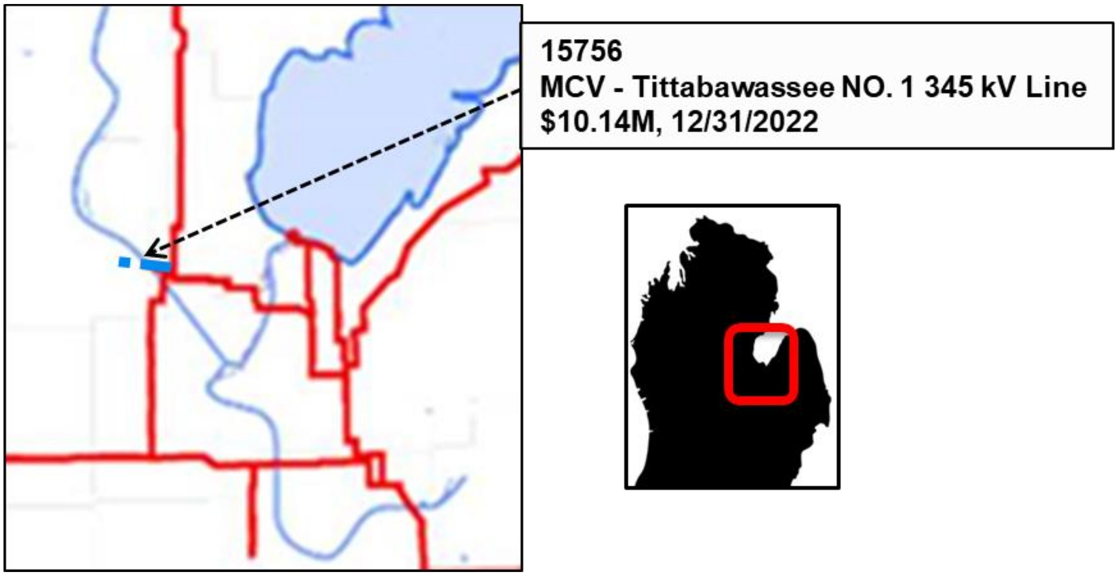


Figure 4.3-#15756: Rebuild MCV – Tittabawassee NO. 1 345 kV

Project Need

The MCV – Tittabawassee NO. 1 345 kV line is projected to become overloaded for numerous contingency types with the most severe loadings caused by shutdown plus contingencies (P6). The overloads were identified in the peak load models with the Ludington units generating regardless of the flow across the Michigan-Ontario interface.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15791 – Rebuild Hemphill – Sabine 138 kV

Project Description

Rebuild 2.8 miles of the Hemphill – Sabine 138 kV line (Figure 4.3-#15791) that is comprised of 336 ACSR conductor only utilizing 954 ACSR conductor and remediate the sag limit on 477 ACSR conductor to increase the line's summer emergency rating to a minimum of 199 MVA/832 A. The project's estimated cost is $4.81 million and the estimated in-service date is June 1, 2023.

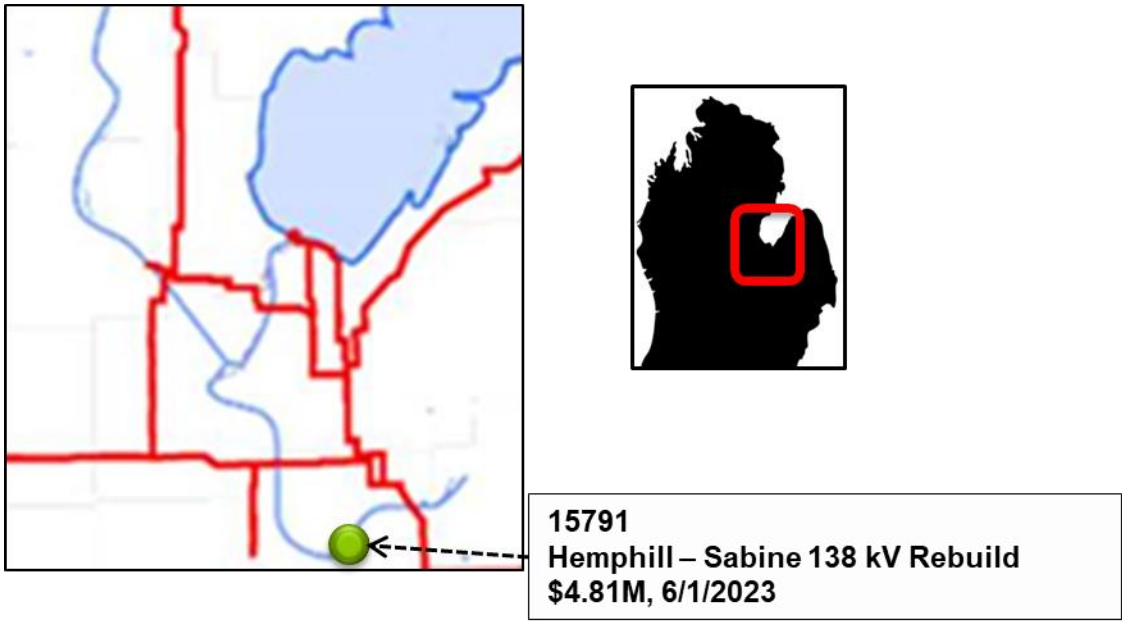


Figure 4.3-#15791: Rebuild Hemphill – Sabine 138 kV

Project Need

The Hemphill – Sabine 138 kV line is projected to become overloaded for numerous contingency types with the most severe loadings caused by shutdown plus contingencies (P6). The overloads were identified in the peak load models with the Ludington units generating and the flow is mainly to ITCT across the Michigan-Ontario interface.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15792 – Rebuild Halsey - Sabine 138 kV

Project Description

Rebuild the entire 5.3 mile long Halsey – Sabine 138 kV line (Figure 4.3-#15792) that is comprised of 336 ACSR conductor utilizing 954 ACSR conductor and upgrade the 336 ACSR line entrance at Halsey. The project's estimated cost is $6.73 million and the estimated in-service date is June 1, 2024.

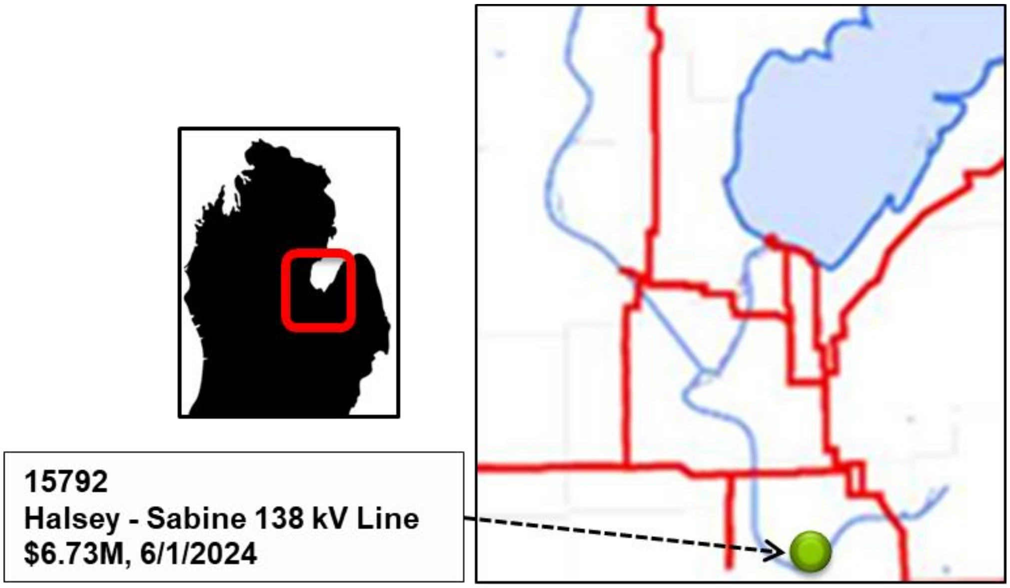


Figure 4.3-#15792: Rebuild Halsey - Sabine 138 kV

Project Need

The Halsey – Sabine 138 kV line is projected to become overloaded for numerous contingency types with the most severe loadings caused by shutdown plus (P6). The overloads were identified in the peak load models with the Ludington units generating and flow is mainly to ITC Transmission across the Michigan-Ontario interface.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15893 – Rebuild Batavia - Morrow 138 kV

Project Description

Rebuild 5.18 miles of the Morrow – ParkVille section of the Batavia – Morrow 138 kV circuit using 954 ACSR conductor with steel structures. Also, remediate sag limit on the 795 ACSR section of the circuit to a minimum of 210 MVA/880 A. Also replace terminal equipment at Morrow station. The project's estimated cost is $5.42 million and the estimated in-service date is December 31, 2024.

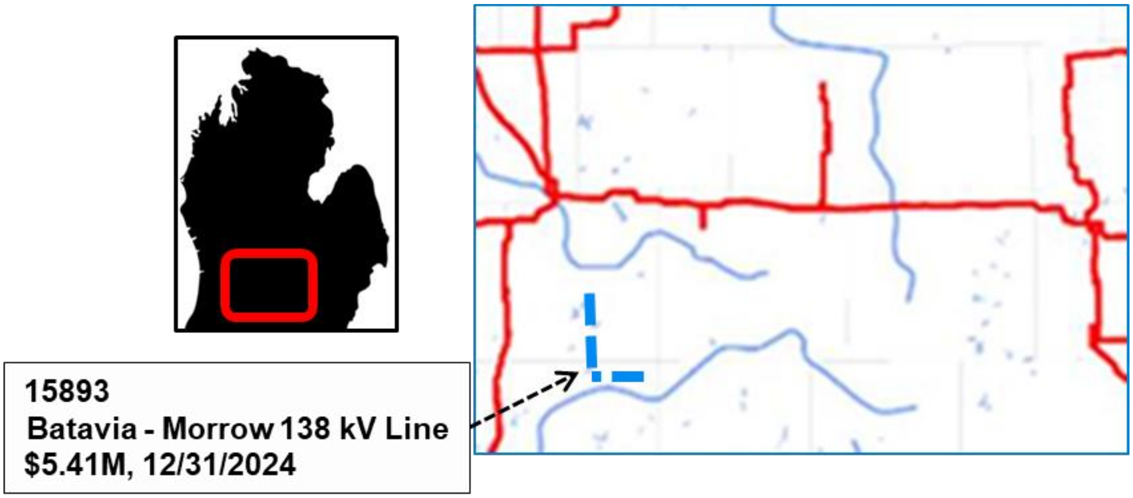


Figure 4.3-#15893: Rebuild Batavia - Morrow 138 kV

Project Need
The Morrow – ParkVille section of the Batavia – Morrow 138 kV circuit is projected to overload for contingency scenarios. The identified overloaded equipment on this circuit are the conductor, sag limit, and terminal equipment at Morrow station. The thermal violations are found on peak cases.

Alternatives Considered
Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 16067 – Rebuild Bradley - Morrow 138 kV

Project Description
Rebuild 7.73 miles of the Bradley – Barry Jct. section of the Bradley – Morrow 138 kV circuit (Figure 4.3-#16067) using 954 ACSR conductor with single circuit steel structures. The project's estimated cost is $7.9 million and the estimated in-service date is December 31, 2023.

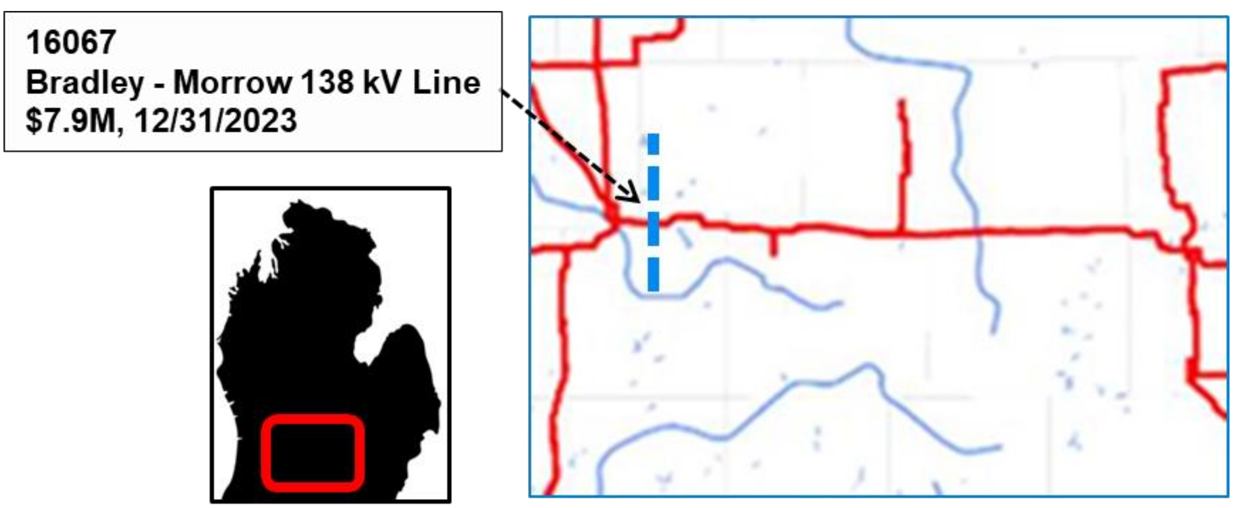


Figure 4.3-#16067: Rebuild Bradley - Morrow 138 kV

Project Need

The Bradley – Barry Jct. section of the Bradley – Morrow 138 kV line is projected to overload for a shutdown plus contingency (P6). The identified overloaded equipment on this circuit is the conductor. The thermal violations are found on peak and off peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15808 – Reconductor Black River - Tyler 138 kV

Project Description

Reconductor 10.91 miles of Black River – Tyler (Figure 4.3-#15808) using 954 ACSS conductor. Also, remove station equipment at Black River and Tyler. The project's estimated cost is $5.3 million and the estimated in-service date is December 31, 2023.

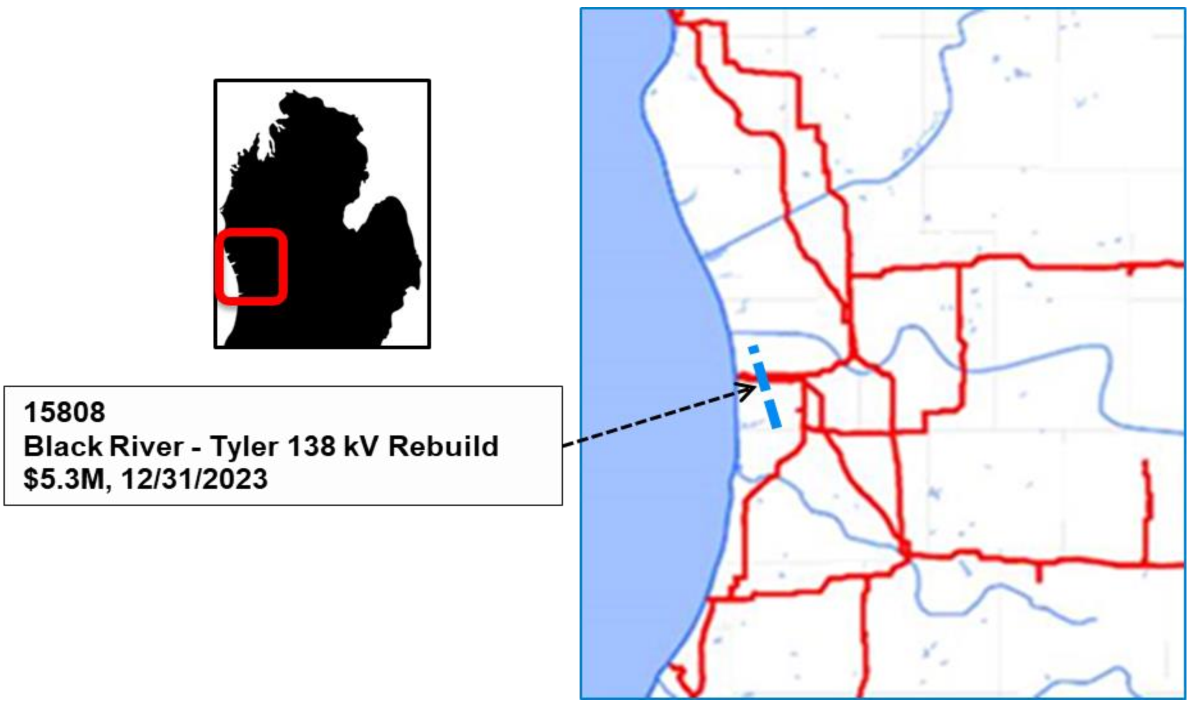


Figure 4.3-#15808: Reconductor Black River - Tyler 138 kV

Project Need

The Black River – Tyler 138 kV line is projected to overload under various contingency scenarios, the worst involving shutdown plus contingencies (P6). The identified overloaded equipment on this circuit is the conductor and station equipment. The thermal violations are only found on off peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15800 – Rebuild Bass Creek - Black River 138 kV

Project Description

Rebuild 3.77 miles of the Bass Creek – Black River (Figure 4.3-#15800) using 954 ACSR conductor with single circuit steel structures. The project's estimated cost is $4.45 million and the estimated in-service date is December 31, 2023.

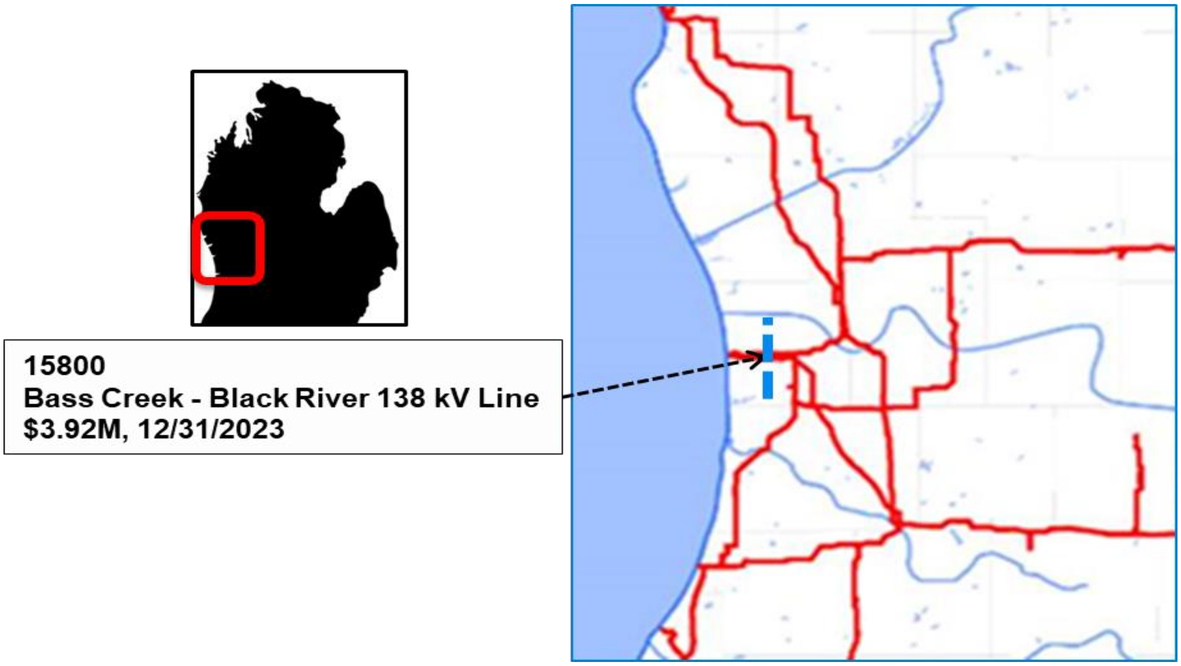


Figure 4.3-#15800: Rebuild Bass Creek - Black River 138 kV

Project Need

The Bass Creek – Black River 138 kV line is projected to marginally overload for shutdown plus contingencies (P6). The identified overloaded equipment on this circuit is the conductor. The thermal violations are only found on off peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15806 – Rebuild Cobb - Meyer 138 kV

Project Description

Rebuild 5.74 miles of 477 ACSR conductor to 1431 ACSR conductor from Meyer to Arthur Jct. of the Meyer – Cobb 138 kV circuit (Figure 4.3-#15806). The rebuild will be 138 kV construction using future double – circuit steel structures with OPGW. Also remediate sag on the Cobb – Arthur Jct. section to conductor limit of 908 A (217 MVA). The project's estimated cost is $7.4 million and the estimated in-service date is June 1, 2024.

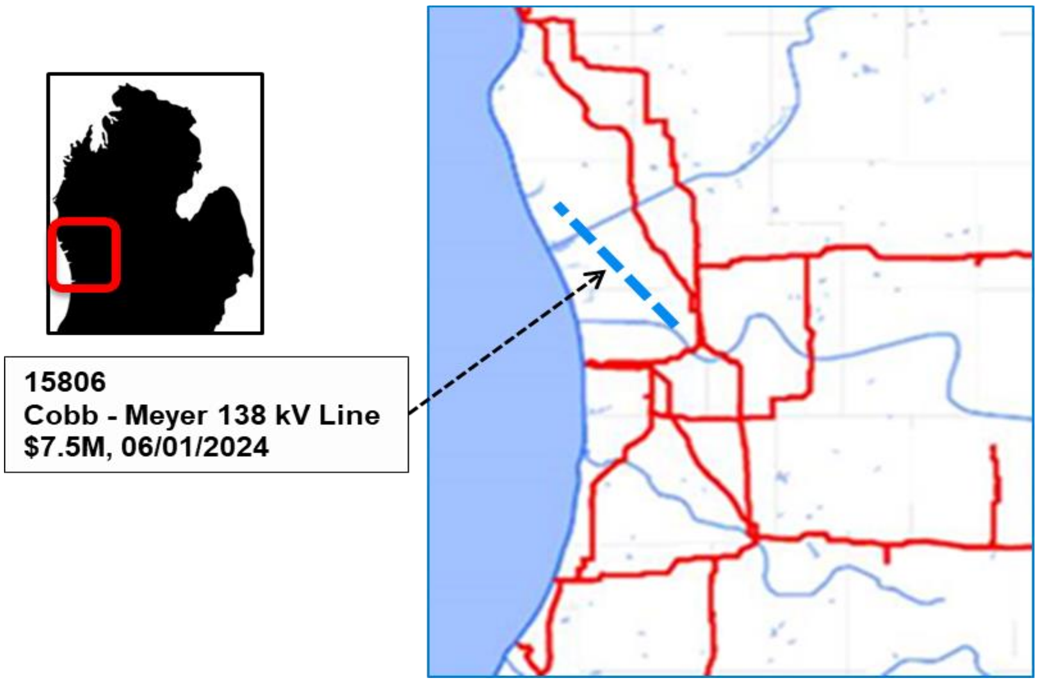


Figure 4.3-#15806: Rebuild Cobb - Meyer 138 kV

Project Need

The Cobb – Meyer 138 kV line is projected to severely overload under various contingency scenarios, the worst involving shutdown plus contingencies (P6). The identified overloaded equipment on this circuit is the conductor on the Meyer – Wilson St. circuit and sag limit on the Wilson St. – Cobb 138 kV circuit. The thermal violations are only found on peak and off peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15801 – Rebuild Beals Road - Stamping Plant 138 kV

Project Description

Rebuild 1.22 miles of the Stamping Plant – Beals Road 138 kV circuit (Figure 4.3-#15801) using 954 ACSR conductor with single circuit steel structures. The project's estimated cost is $2.50 million and the estimated in-service date is June 1, 2023.

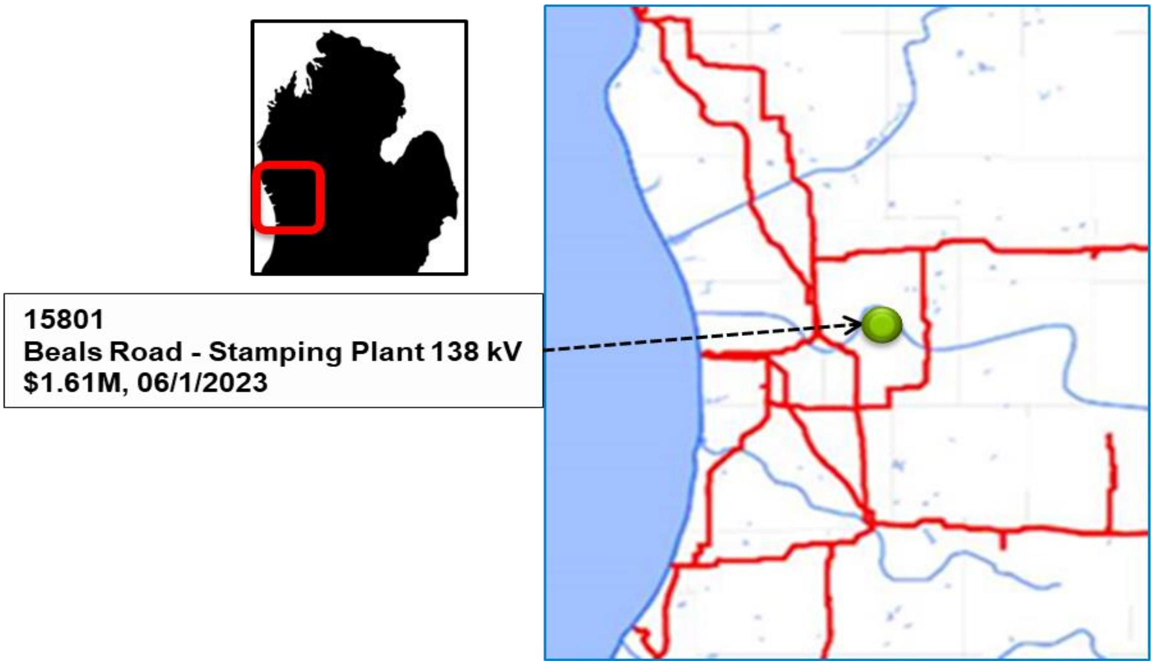


Figure 4.3-#15801: Rebuild Beals Road - Stamping Plant 138 kV

Project Need

The Stamping Plant – Beals Road 138 kV circuit is projected to overload for shutdown plus contingencies (P6). The identified overloaded equipment on this circuit is the conductor. The thermal violations are found on peak and off peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15802 – Rebuild Beals Road - Wealthy 138 kV

Project Description

Rebuild a 3.15-mile, 6-wire 336 ACSR section of the Wealthy-Beals Road 138 kV circuit (Figure 4.3-#15802) using 1431 ACSR conductor with single circuit steel structures. The project's estimated cost is $4.16 million and the estimated in-service date is June 1, 2024.

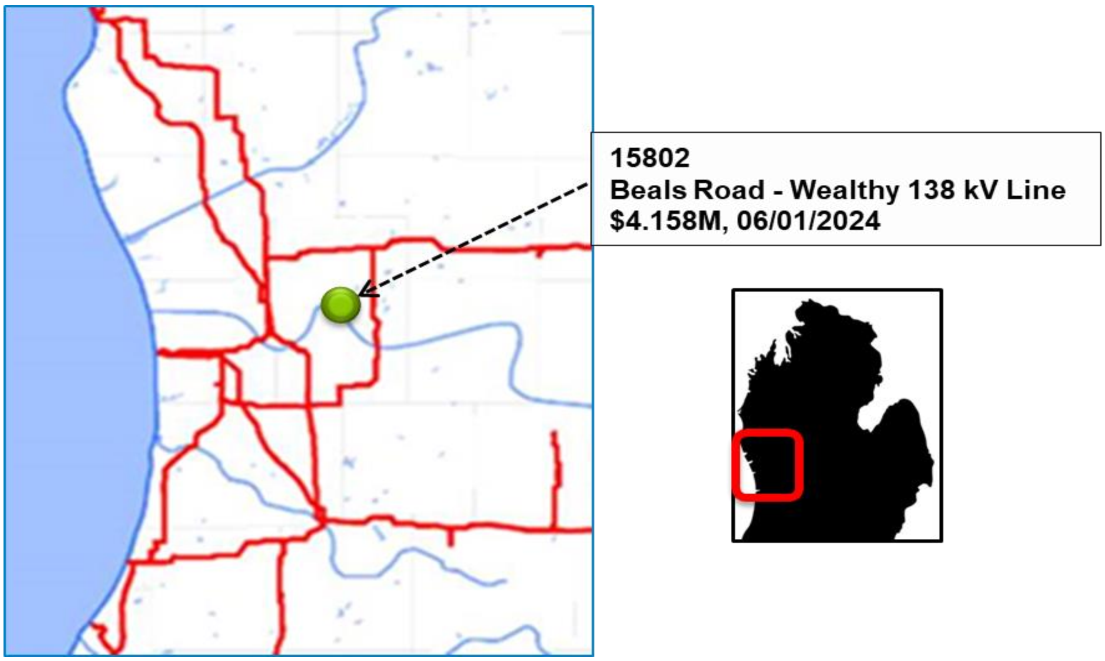


Figure 4.3-#15802: Rebuild Beals Road - Wealthy 138 kV

Project Need

The Beals Road – Wealthy 138 kV circuit is projected to overload for shutdown plus contingencies (P6). The identified overloaded equipment on this circuit is the conductor. The thermal violations are only found on peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15804 – Rebuild Gaines - Stamping Plant 138 kV

Project Description

The Gaines – Stamping Plant 138 kV circuit (Figure 4.3-#15804) is projected to overload for shutdown plus contingency scenarios involving Beals – Wealthy and Gaines – Henry 138 kV lines. The identified overloaded equipment on this circuit is the conductor. The thermal violations are found on peak and off peak cases. The project's estimated cost is $16.0 million and the estimated in-service date is June 1, 2024.

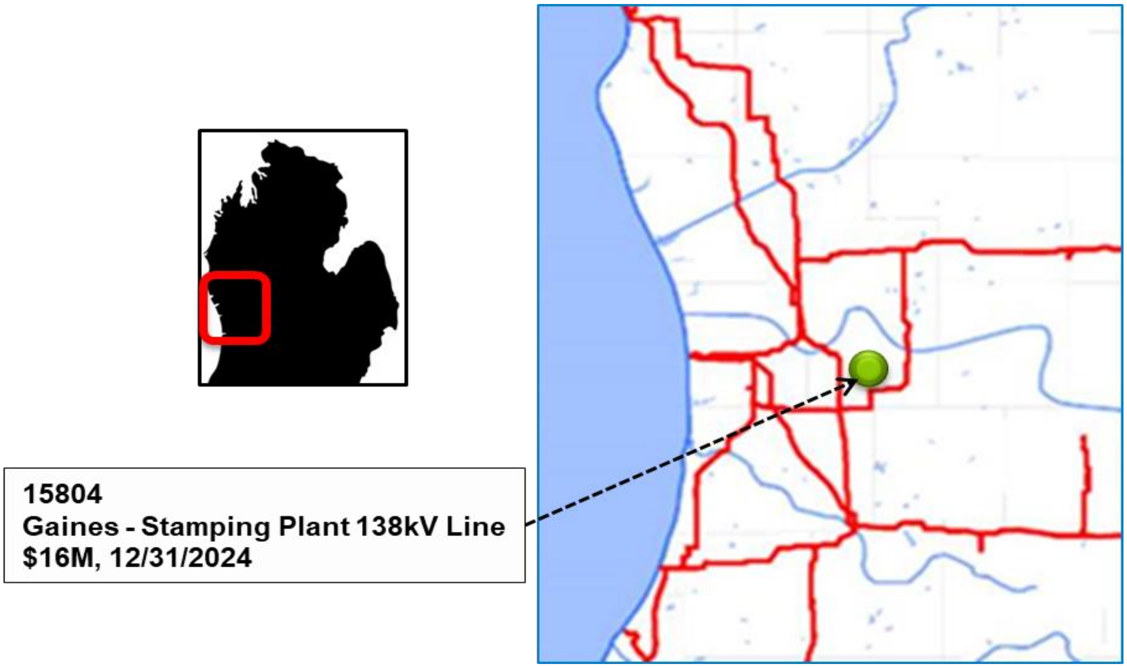


Figure 4.3-#15804: Rebuild Gaines - Stamping Plant 138 kV

Project Need

Rebuild 10.98 miles of the Gaines – Stamping Plant 138 kV circuit using 954 ACSR conductor with single steel structures.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15805 – Rebuild Spaulding - Vergennes 138 kV

Project Description

Rebuild 7.17 miles the Vergennes – Spaulding circuit (Figure 4.3-#15805) using 1431 ACSR conductor with single circuit steel structures. Also replace terminal equipment at Spaulding and Vergennes. The project's estimated cost is $6.20 million and the estimated in-service date is June 1, 2024.

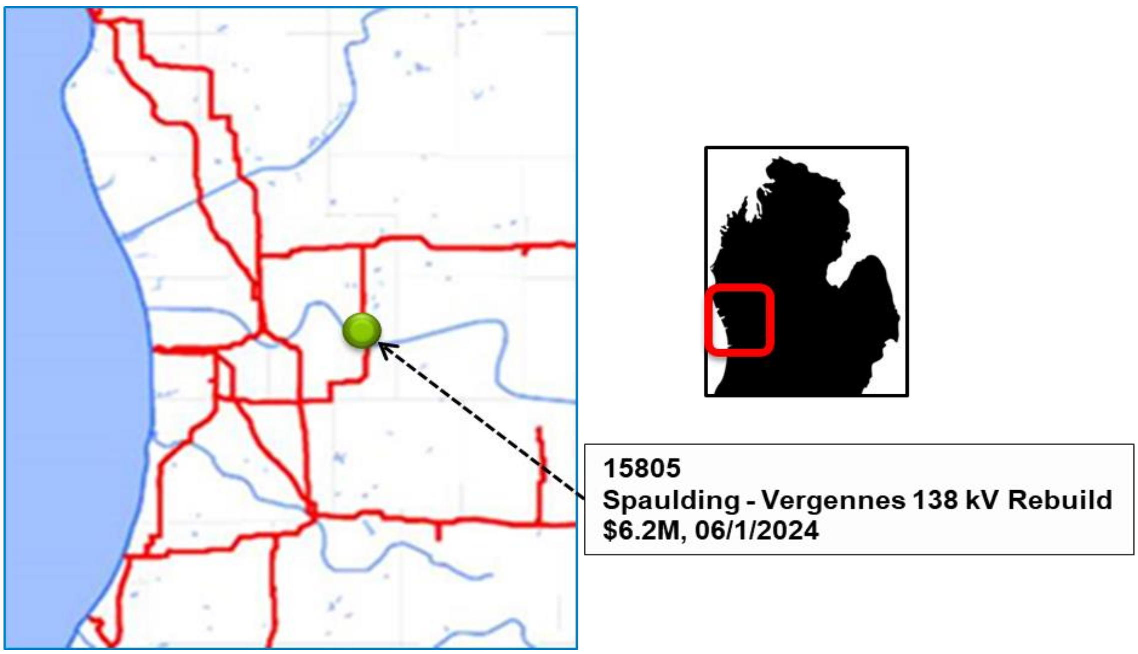


Figure 4.3-#15805: Rebuild Spaulding - Vergennes 138 kV

Project Need

The Spaulding – Vergennes 138 kV circuit is projected to overload for shutdown plus contingencies (P6). The identified overloaded equipment on this circuit is the conductor and terminal equipment at Spaulding and Vergennes. The thermal violations are only found on peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15803 – Rebuild Gaines - Meadowbrooke 138 kV

Project Description

Rebuild 0.09 mile Gaines – Meadowbrooke section of the Gaines – Plaster Creek 138 kV circuit (Figure 4.3-#15803) using 2156 ACSR with steel structures and replace terminal equipment. The project's estimated cost is $486,000 and the estimated in-service date is December 31, 2024.

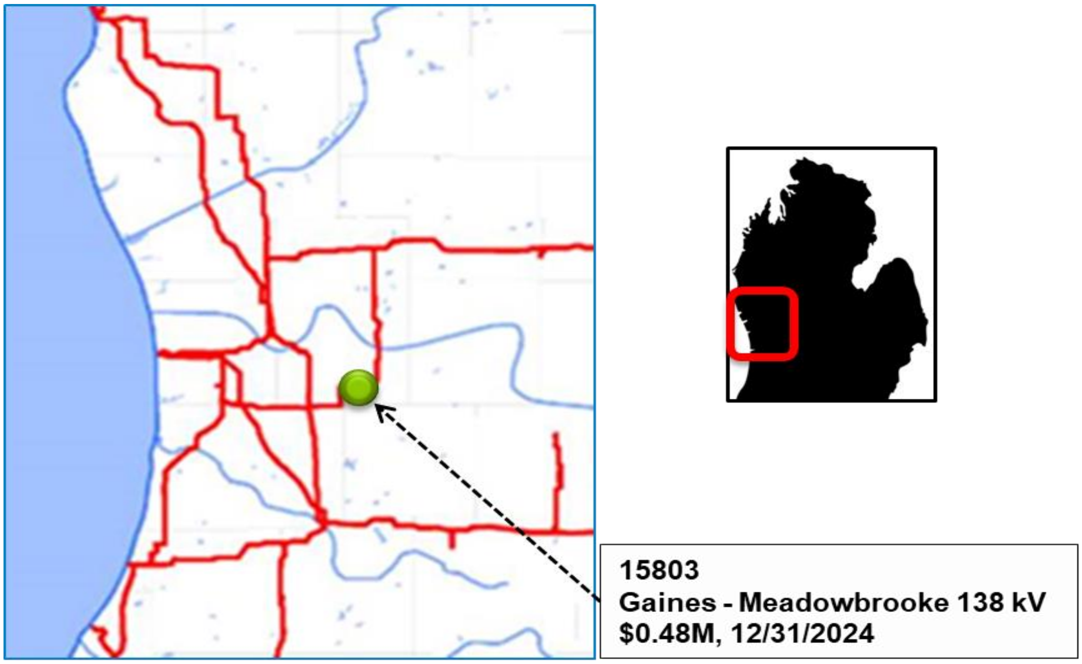


Figure 4.3-#15803: Rebuild Gaines - Meadowbrooke 138 kV

Project Need

The Gaines – Meadowbrooke section of the Gaines – Plaster Creek 138 kV circuit is projected to overload for various shutdown plus contingencies (P6). The identified overloaded equipment on this circuit is the conductor and terminal equipment. The thermal violations are only found on peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15878 - Monroe - Lallendorf 345 kV Sag Remediation

Project Description

Completely remove the sag limit on the Monroe – Lallendorf 345 kV line (METC side) (Figure 4.3-#15878 under ITCT's section). The project's total estimated cost is $1.2 million and the estimated in-service date is December 31, 2021. This project is shared between METC and ITCT and the cost of METC's share is $970,000.

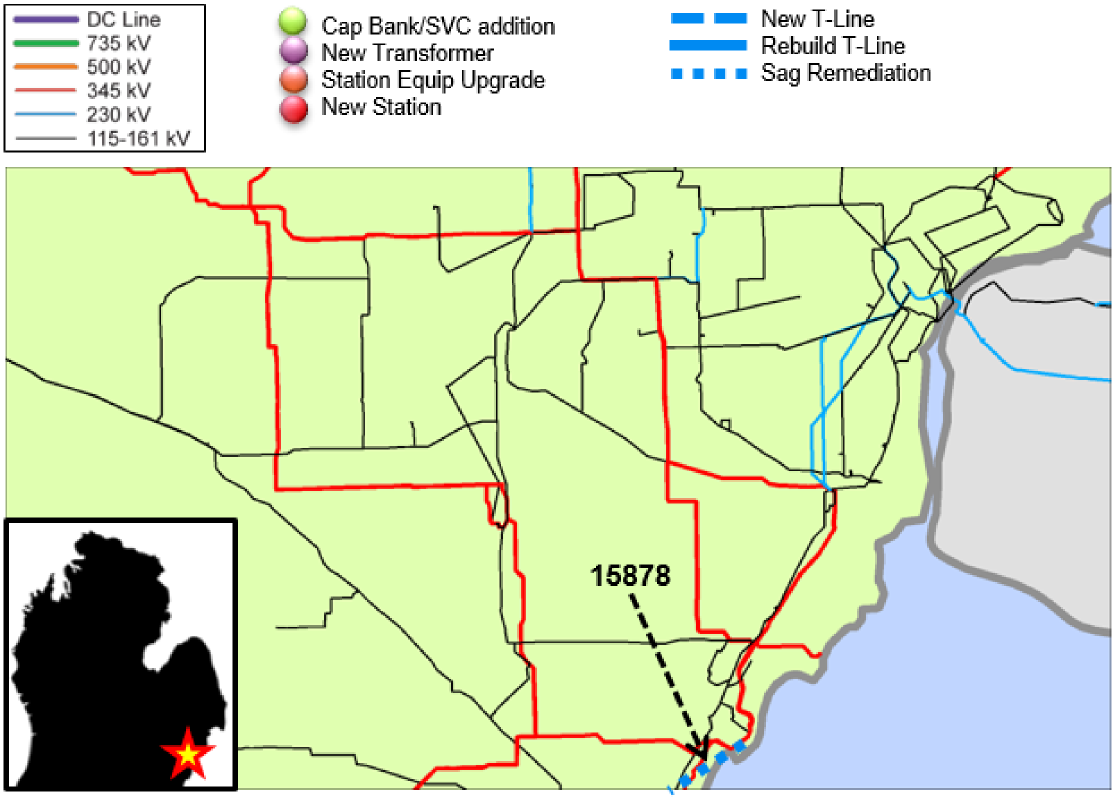


Figure 4.3-#15878-1: Geographic transmission map of project area

Project Need

The Monroe – Lallendorf 345 kV line is projected to be overloaded for N-1-1 and T-2 contingencies. The identified circuit is overloaded due to sag limitations. The thermal violations are found in all cases.

Alternatives Considered

The most cost effective alternative to resolve this issue is to remediate the sag as proposed by Project 15878.

Project 15901 – Remediate Cornell - Claremont Sag

Project Description

Remediate sag limit on the Cornell – Claremont 138 kV circuit (Figure 4.3-#15901) to increase its summer emergency rating to a minimum of 165 MVA/692 A on the Cornell – Layton section. Also, increase its summer emergency rating to a minimum of 203 MVA/850 A on the Claremont – Layton section. The project's estimated cost is $1.90 million and the estimated in-service date is June 1, 2021.

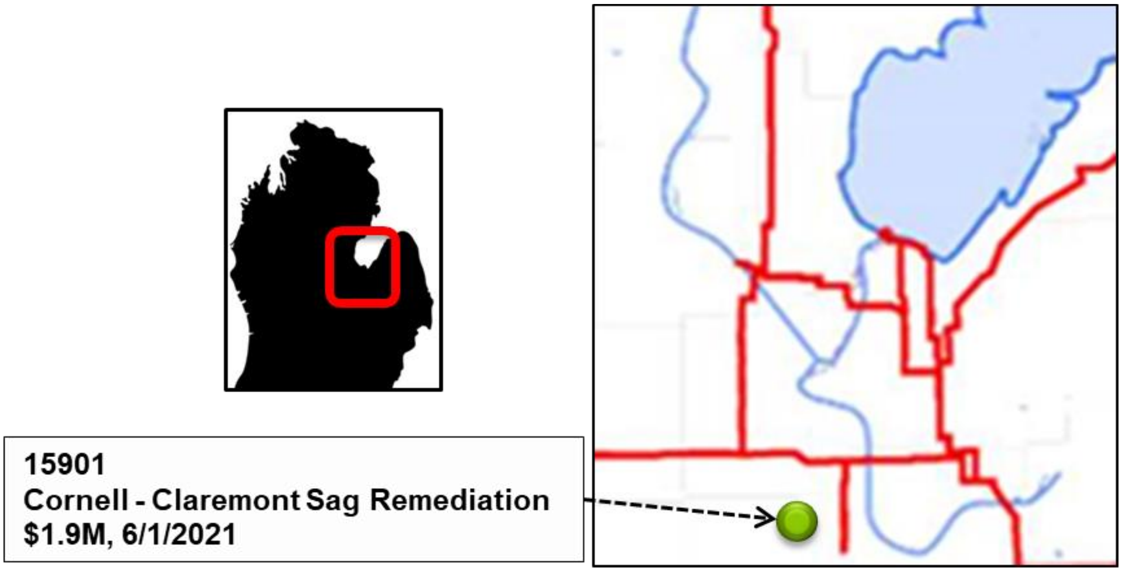


Figure 4.3-#15901: Remediate Cornell - Claremont Sag

Project Need
The Cornell – Claremont 138 kV circuit is projected to overload for shutdown plus contingencies (P6). The identified overload on this circuit is the sag limit. The thermal violations are found on peak cases.

Alternatives Considered
Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15836 – Remediate Bell Road - Claremont 138 kV Sag

Project Description

Remediate the sag limit on 3.0 miles of 477 ACSR conductor of the Bell Road – Claremont 138 kV section of the Claremont – Cornell 2 138 kV line (Figure 4.3-#15836) to at least the planned target summer normal/summer emergency rating of 188 MVA/787 A. The project's estimated cost is $410,000 and the estimated in-service date is December 31, 2022.

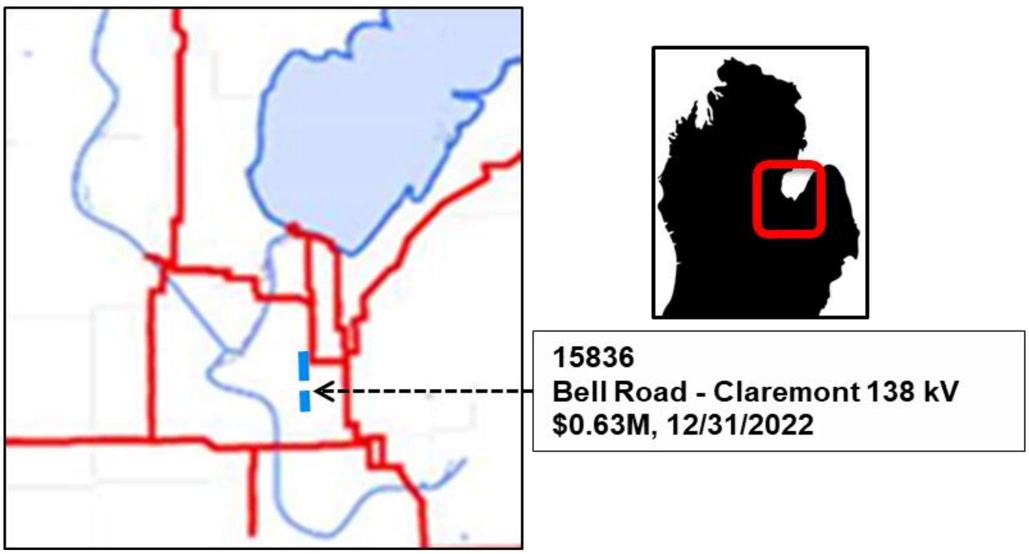


Figure 4.3-#15836: Remediate Bell Road - Claremont 138 kV Sag

Project Need

The Bell Road – Claremont 138 kV section of the Claremont – Cornell 2 138 kV line is projected to become overloaded for shutdown plus contingencies (P6). The overloads were identified in the peak load models with either zero flow or flow to ITCT across the Michigan-Ontario interface while the Ludington units are generating.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15798 – Remediate Cornell - Goss 138 kV Sag

Project Description

Remediate the sag limit on the Cornell – Goss 138 kV line (Figure 4.3-#15798) to increase its summer emergency rating to a minimum of 277 MVA/1158 A. The project's estimated cost is $581,000 and the estimated in-service date is December 31, 2021.

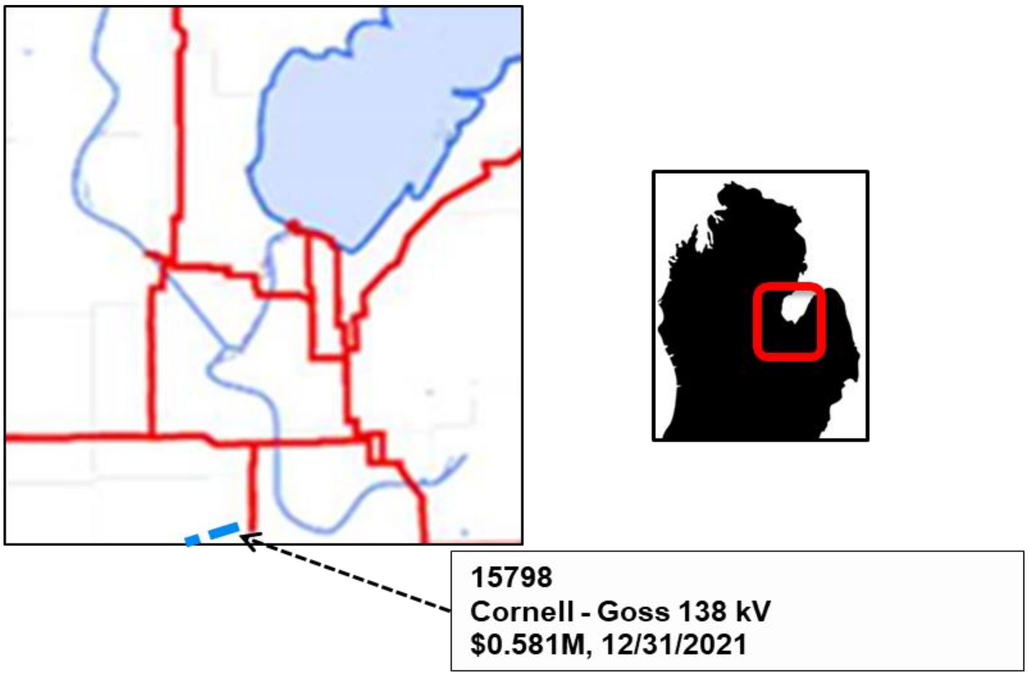


Figure 4.3-#15798: Remediate Cornell - Goss 138 kV Sag

Project Need

The Cornell – Goss 138 kV line is projected to become overloaded for breaker fault (P23) or for shutdown plus contingencies (P6). The overloads were identified in the peak load models with either zero flow or flow to ITCT across the Michigan-Ontario interface while the Ludington units are generating.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15793 – Rebuild Gaylord - Livingston 138 kV

Project Description

Rebuild 1.3 miles of the Gaylord – Livingston 138 kV line (Figure 4.3-#15793) that is comprised of 266 ACSR conductor only utilizing 954 ACSR conductor on 230 kV double-circuit structures. The project's estimated cost is $ 3.53 million and the estimated in-service date is June 1, 2023.

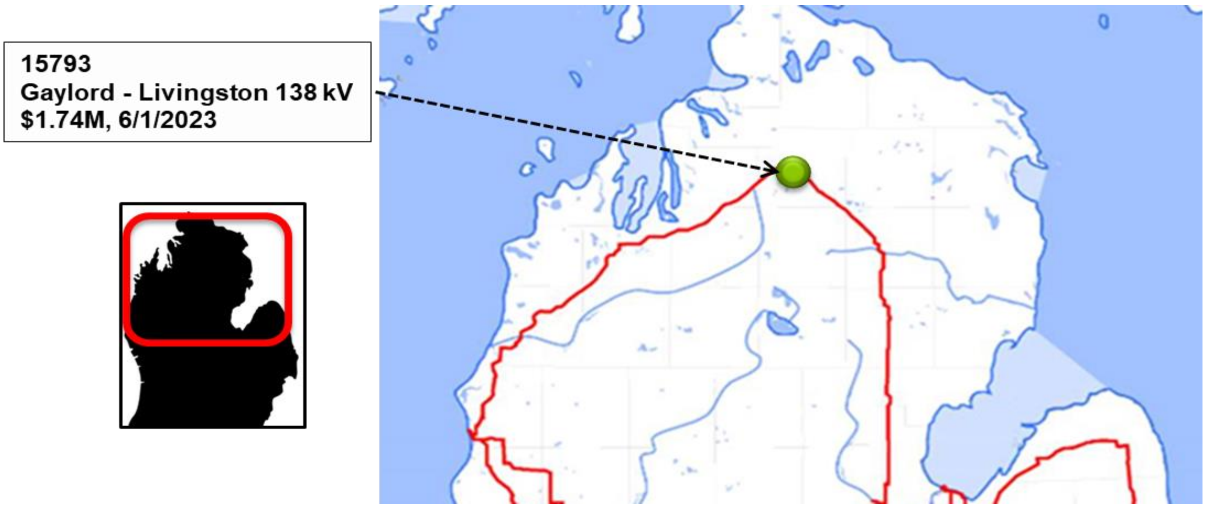


Figure 4.3-#15793: Rebuild Gaylord - Livingston 138 kV

Project Need

The Gaylord – Livingston 138 kV line is projected to become overloaded for shutdown plus contingencies (P6). The overloads were identified in the 85 percent peak load models with the Ludington units generating and flow is to Toronto-based Independent Electricity System Operator (IESO) across the Michigan-Ontario interface.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15833 – Rebuild Bagley Tap - Gaylord 138 kV

Project Description

Rebuild the entire 1.2 mile long Bagley Tap – Gaylord 138 kV section of the 40.4 mile long Gaylord – Mio Dam 138 kV line (Figure 4.3-#15833). Pre-build it to 230 kV construction to facilitate potential future 230 kV expansion in northern Michigan. Replace the existing assets (all structures, 266 ACSR conductor, and the 266 ACSR line entrance at Gaylord) with new double-circuit structures that are designed for 954 ACSR conductor on each side and install this conductor along with OPGW for the existing line only. The project's estimated cost is $3.95 million and the estimated in-service date is June 1, 2024.

Figure 4.3-#15833: Rebuild Bagley Tap - Gaylord 138 kV

Project Need

The Bagley Tap – Gaylord 138 kV section of the Gaylord – Mio Dam 138 kV line is projected to become overloaded for shutdown plus contingencies (P6). The overloads were identified in the peak and off-peak load models with the Ludington units generating and the flow is to Independent Electricity System Operator across the Michigan-Ontario interface.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15797 – Remediation & Equipment Upgrade for Donaldson Creek - White Lake 138 kV Sag

Project Description

Remediate the sag limit on the Donaldson Creek – White Lake 138 kV line (Figure 4.3-#15797) and upgrade station equipment at White Lake to increase the line's summer emergency rating to a minimum of 171 MVA/715 A. The project's estimated cost is $1.18 million and the estimated in-service date is December 31, 2021.

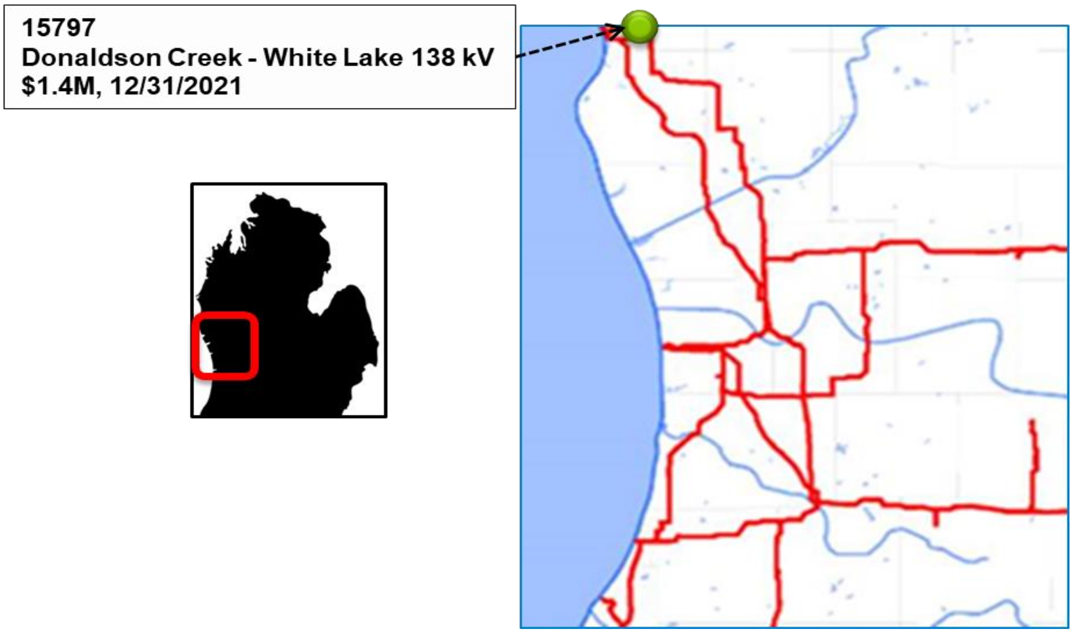


Figure 4.3-#15797: Remediation & Equipment Upgrade for Donaldson Creek - White Lake 138 kV Sag

Project Need

The Donaldson Creek – White Lake 138 kV line is projected to become overloaded for shutdown plus contingencies (P6). The overloads were identified in the near-term peak and shoulder peak load models with the Ludington units generating while flow is to ITC Transmission across the Michigan-Ontario interface.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15899 – Remediate Campbell - Blendon 138 kV Sag

Project Description

Remediate sag limit on the Bill Mar – Port Sheldon section of the Campbell – Blendon 138 kV circuit (Figure 4.3-#15899) to increase its summer emergency rating to a minimum of 390 MVA/1633 A. The project's estimated cost is $390,000 and the estimated in-service date is June 1, 2021.

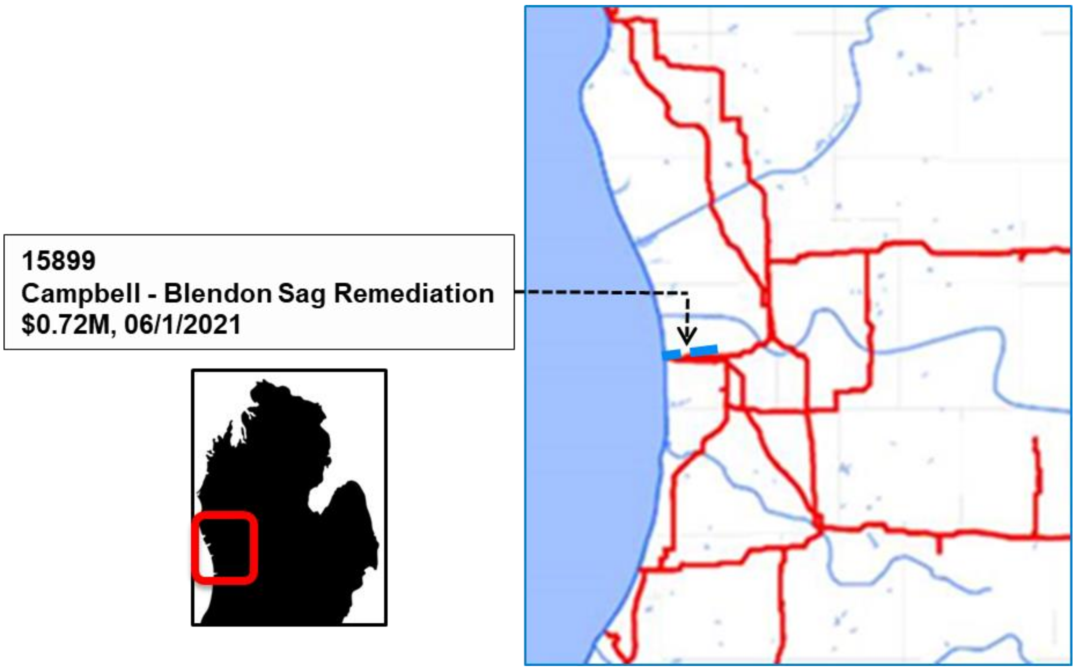


Figure 4.3-#15899: Remediate Campbell - Blendon 138 kV Sag

Project Need

The Campbell – Blendon 138 kV circuit is projected to overload for a shutdown plus contingencies (P6). The identified overload on this circuit is the sag limit. The thermal violations are found on peak and off peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15906 – Remediate Campbell - Black River 138 kV Sag

Project Description

Completely remove the sag limit on the Campbell – Black River circuit (Figure 4.3-#15906) to conductor limit. The project's estimated cost is $807,000 and the estimated in-service date is June 1, 2021.

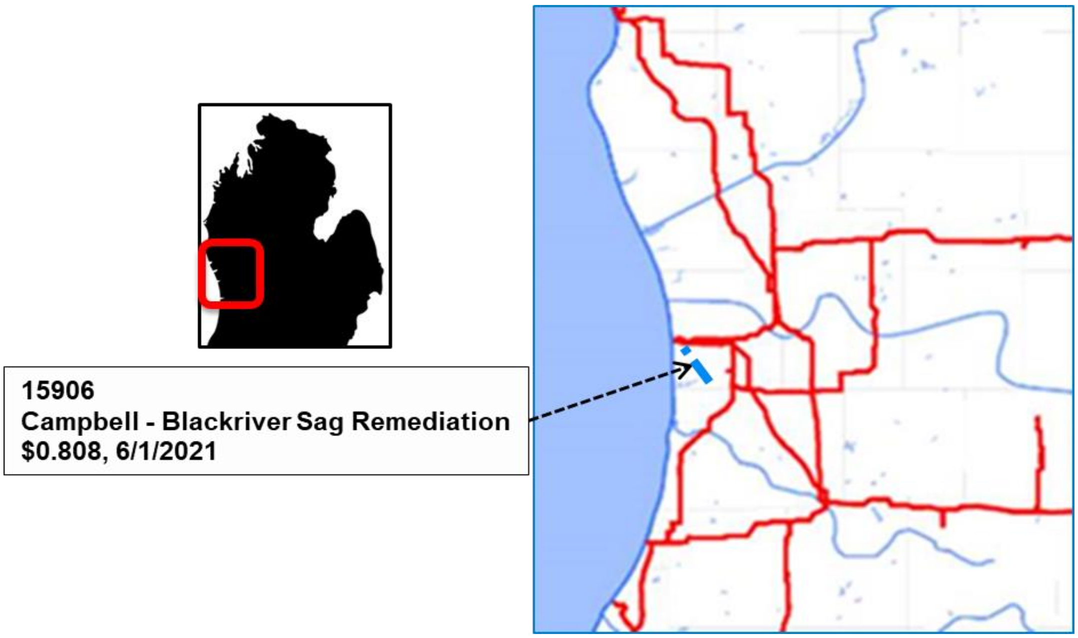


Figure 4.3-#15906: Remediate Campbell - Black River 138 kV Sag

Project Need

The Campbell – Black River 138 kV circuit is projected to overload for shutdown plus contingencies (P6). The identified overload on this circuit is the sag limit. The thermal violations are found on peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15909 – Remediate Tallmadge - Tyler 138 kV Sag

Project Description

Remediate sag limit on the Tallmadge – Tyler 138 kV circuit (Figure 4.3-#15909) to increase its summer emergency rating to a minimum of 367 MVA/1535 A. The project's estimated cost is $5.4 million and the estimated in-service date is June 1, 2021.

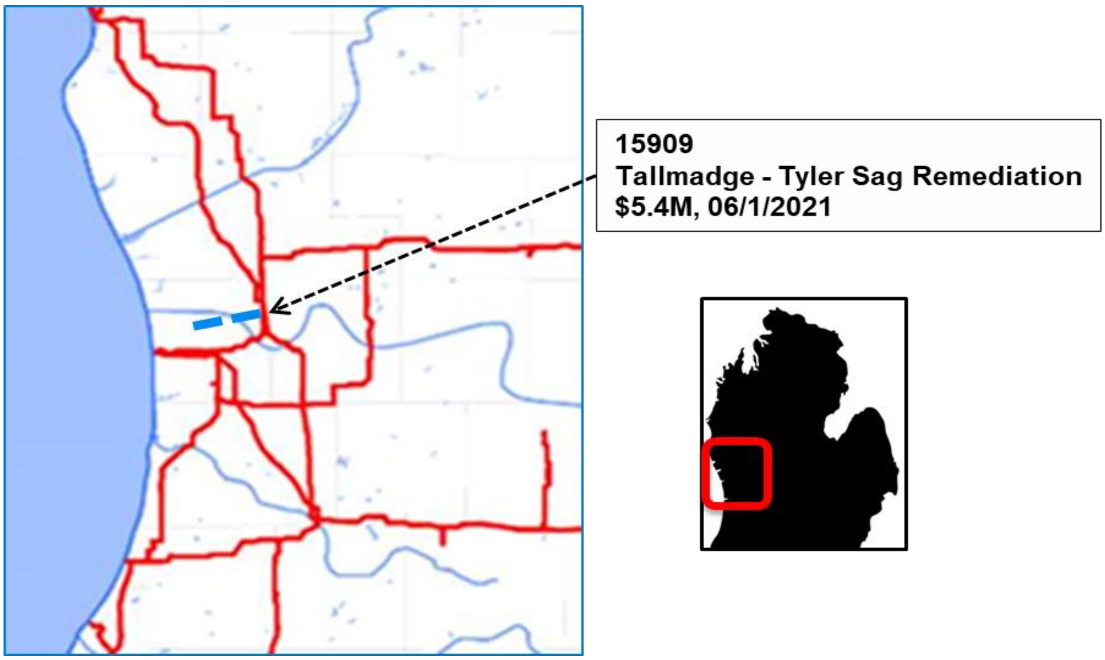


Figure 4.3-#15909: Remediate Tallmadge - Tyler 138 kV Sag

Project Need

The Tallmadge – Tyler 138 kV circuit is projected to overload for shutdown plus contingencies (P6). The identified overload on this circuit is the sag limit. The thermal violations are found on off peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15754 – Remediate Mio Dam - Plywood Tap 138 kV Sag

Project Description

Remediate the sag limit on the Mio Dam – Lewiston Tap 138 kV section of the Gaylord – Mio Dam 138 kV line (Figure 4.3-#15754) to increase its summer emergency rating to a minimum of 147 MVA/615 A and remediate the sag limit on the Lewiston Tap – Plywood Tap 138 kV section of the Gaylord – Mio Dam 138 kV line to increase its summer emergency rating to a minimum of 147 MVA/615 A. The project's estimated cost is $875,000 and the estimated in-service date is December 31, 2021.

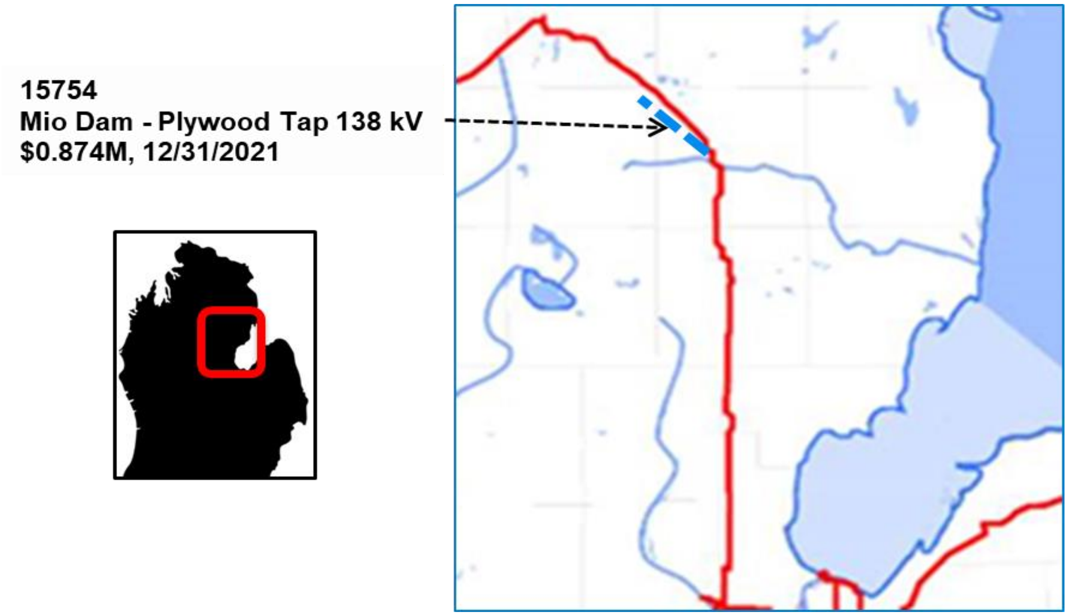


Figure 4.3-#15754: Remediate Mio Dam - Plywood Tap 138 kV Sag

Project Need

The Mio Dam – Lewiston Tap 138 kV and Lewiston Tap – Plywood Tap 138 kV sections of the Gaylord – Mio Dam 138 kV line are projected to become overloaded for shutdown plus contingencies (P6). The overloads were identified in the near-term peak and off-peak load models with the Ludington units generating and flow is to Independent Electricity System Operator across the Michigan-Ontario interface.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15749 – Remediate Abbe Tap - Hillman Tap 138 kV Sag

Project Description

Remediate the sag limit on the Abbe Tap – Hillman Tap 138 kV section of the Airport – Mio 138 kV line (Figure 4.3-#15749) to increase its summer emergency rating to a minimum of 91 MVA/382 A. The project's estimated cost is $590,000 and the estimated in-service date is December 31, 2021.

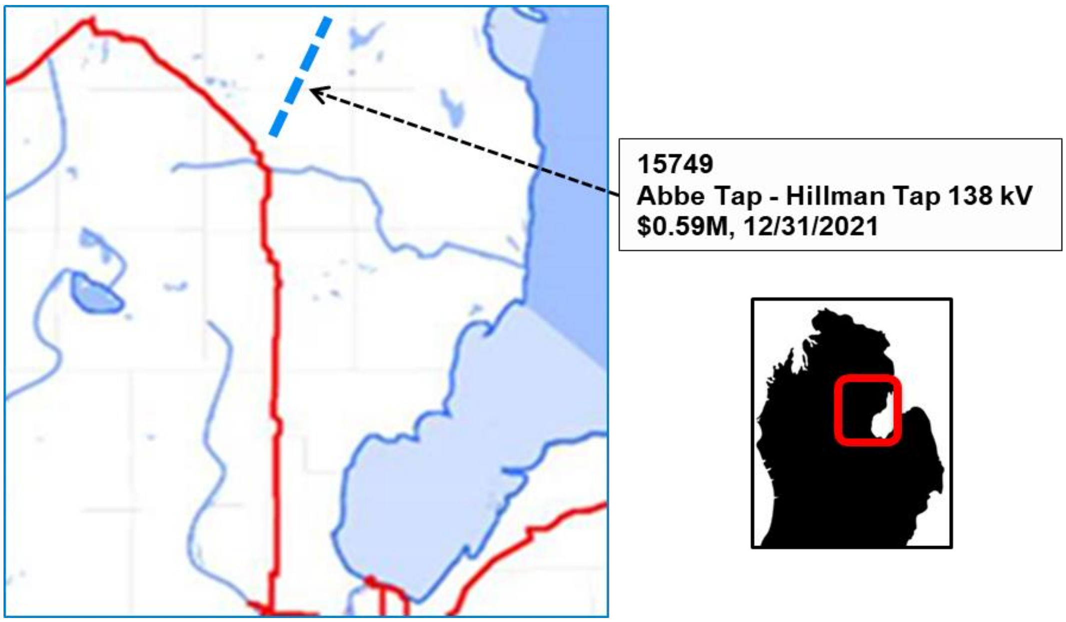


Figure 4.3-#15749: Remediate Abbe Tap - Hillman Tap 138 kV Sag

Project Need

The Abbe Tap – Hillman Tap 138 kV section of the Airport – Mio 138 kV line is projected to become overloaded for shutdown plus contingencies (P6). The overloads were identified in the near-term peak load models with flow to Independent Electricity System Operator across the Michigan-Ontario interface.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15912 – Remediate Battle Creek - Verona NO. 2 138 kV Sag

Project Description

Completely remove sag limit on the Battle Creek – Verona NO. 2 138 kV (Figure 4.3-#15912) to conductor limit. Also, upgrade station equipment at Verona position 577 to increase its summer emergency rating to a minimum of 440 MVA/1839 A. The project's estimated cost is $186,000 and the estimated in-service date is December 31, 2021.

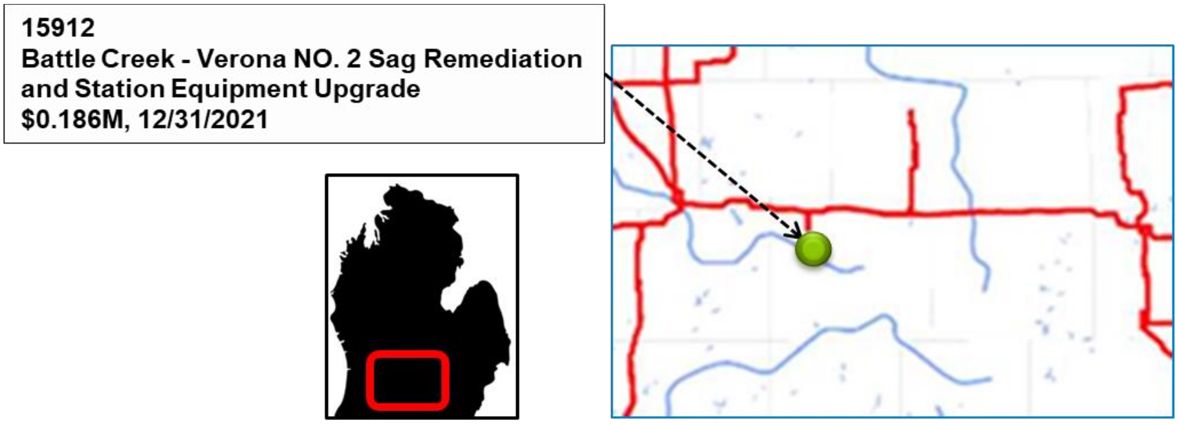


Figure 4.3-#15912: Remediate Battle Creek - Verona NO. 2 138 kV Sag

Project Need

The Battle Creek – Verona NO. 2 138 kV line is projected to become marginally overloaded for P6 contingencies. The identified overload on this circuit is the sag limit and station equipment. The thermal violations are found on off peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15913 – Remediate Morrow - Battle Creek NO. 2 138 kV Sag

Project Description

Completely remove sag limit on the Lafayette – Morrow section of the Morrow – Battle Creek NO. 2 138 kV (Figure 4.3-#15913) to conductor limit. The project's estimated cost is $940,000 million and the estimated in-service date is December 31, 2021.

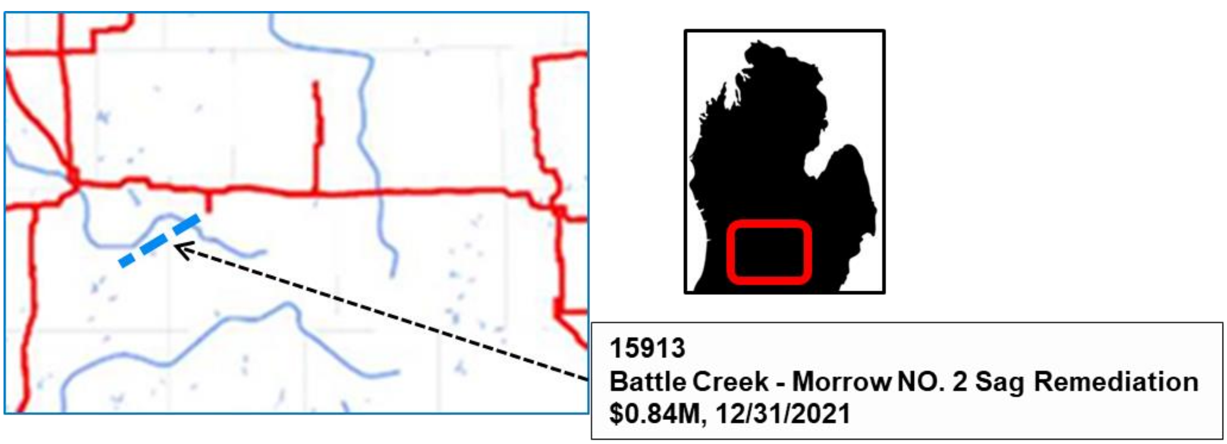


Figure 4.3-#15913: Remediate Morrow - Battle Creek NO. 2 138 kV Sag

Project Need

The Lafayette - Morrow section of the Morrow - Battle Creek NO. 2 138 kV line is projected to overload for shutdown plus contingencies (P6). The identified overload on this circuit is the sag limit. The thermal violations are found on peak and off peak cases.

Alternatives Considered
Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15938 – Remediate Leoni - Parr Road 138 kV Sag

Project Description
Remediate sag limit on the Leoni – Parr Road 138 kV line (Figure 4.3-#15938) to increase its summer emergency rating to a minimum of 167 MVA/700 A. The project's estimated cost is $725,000 and the estimated in-service date is June 1, 2021.

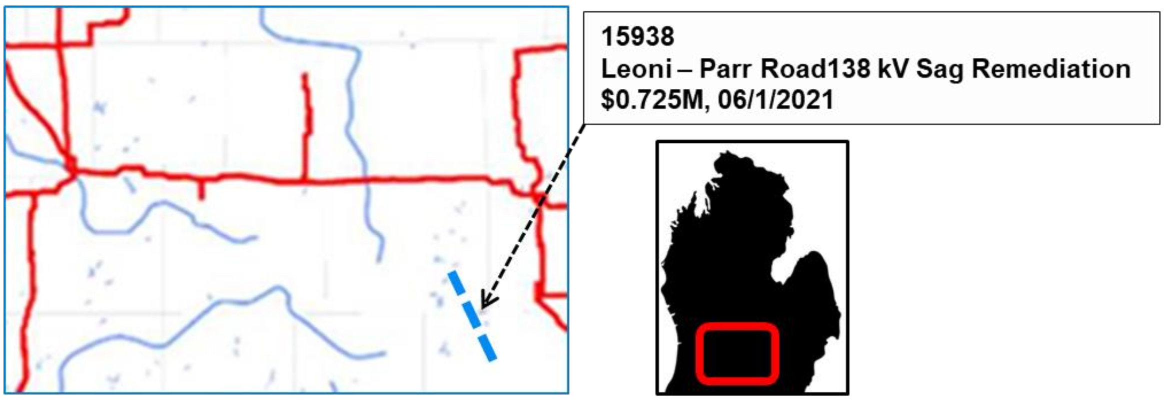


Figure 4.3-#15938: Remediate Leoni - Parr Road 138 kV Sag

Project Need
The Leoni – Parr Road 138 kV line is projected to overload for shutdown plus contingencies (P6). The identified overload on this circuit is the sag limit. The thermal violations are found on peak cases.

Alternatives Considered
Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15790 – Remediation Hemphill - Thetford 138 kV Sag

Project Description

Remediate the sag limit on the Hemphill – Thetford 138 kV line (Figure 4.3-#15790) and reset or replace the thermal relaying at Hemphill to increase the line's summer emergency rating to a minimum of 306 MVA/1280 A. The project's estimated cost is $386,000 and the estimated in-service date is December 31, 2022.

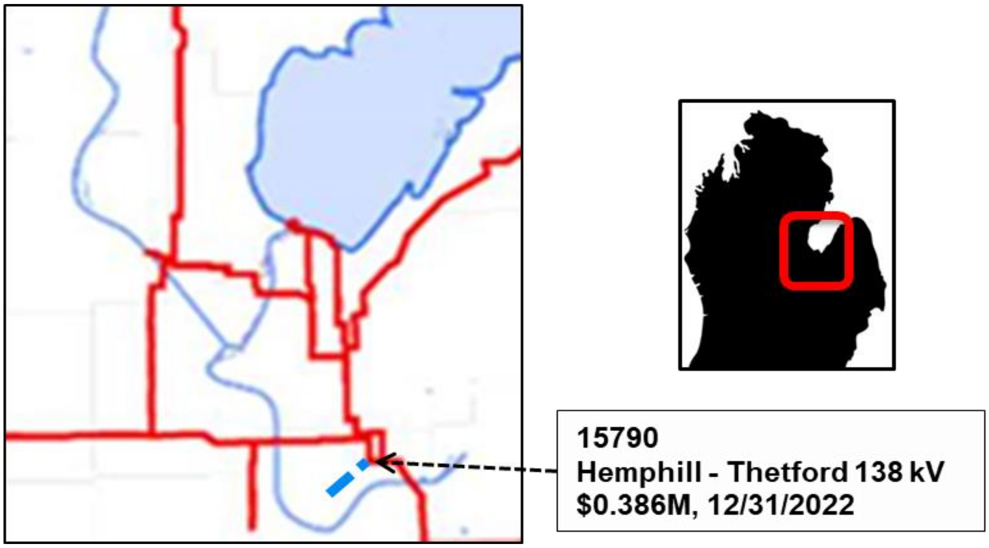


Figure 4.3-#15790: Remediation Hemphill - Thetford 138 kV Sag

Project Need

The Hemphill – Thetford 138 kV line is projected to become overloaded for shutdown plus contingencies (P6). The overloads were identified in the peak load models with the Ludington units generating regardless of the directional flow across the Michigan-Ontario interface.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15750 – Remediate Saginaw River - Weadock 138 kV Sag

Project Description

Remediate the sag limit on the Saginaw River – Weadock 138 kV line (Figure 4.3-#15750) to increase its summer emergency rating to a minimum of 159 MVA/667 A. The project's estimated cost is $276,000 and the estimated in-service date is December 31, 2021.

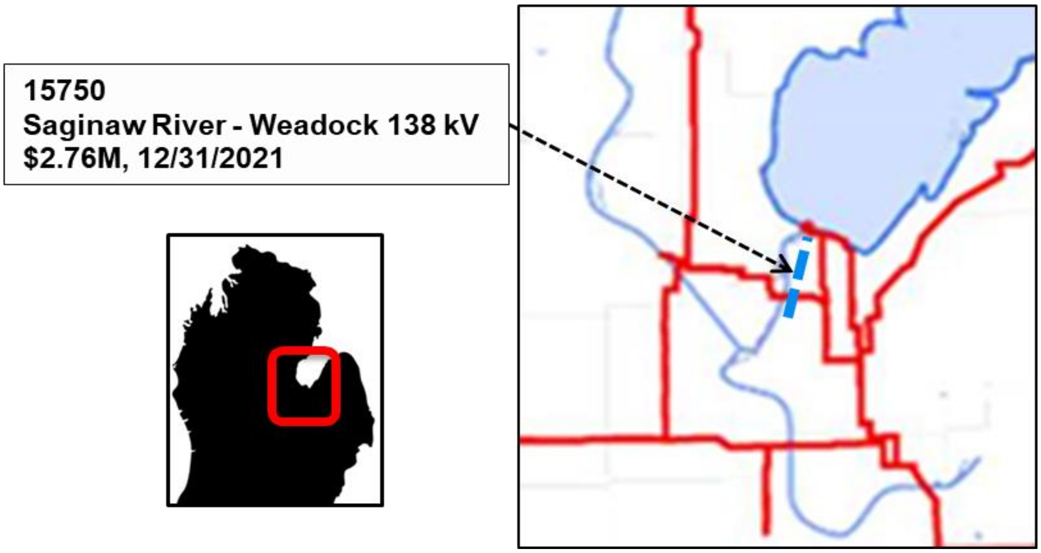


Figure 4.3-#15750: Remediate Saginaw River - Weadock 138 kV Sag

Project Need

The Saginaw River - Weadock 138 kV line is projected to become overloaded for shutdown plus contingencies (P6). The overloads were identified in the peak load models with the Ludington units generating and flow to IESO across the Michigan-Ontario interface.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15852 – Remediate Cornell - Tihart 138 kV Sag

Project Description

Remediate sag limit on the Cornell – Tihart 138 kV circuit to increase its summer emergency rating to a minimum of 182 MVA/763 A on the Bennington – Scenic Lake and Van Atta – Scenic Lake sections to increase its summer emergency rating to a minimum of 191 MVA/801 A (refer to Figure 4.3-#15852). The project's estimated cost is $425,000 and the estimated in-service date is December 31, 2021.

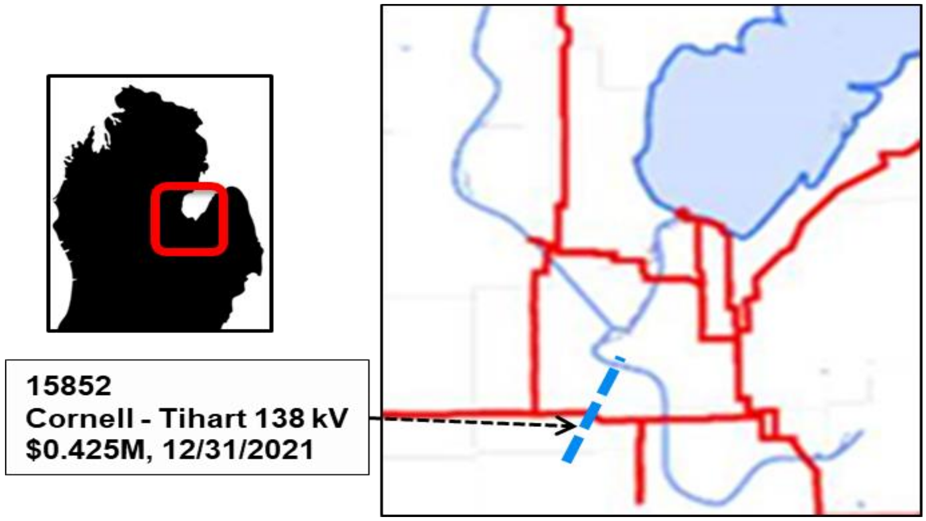


Figure 4.3-#15852: Remediate Cornell - Tihart 138 kV Sag

Project Need

The Cornell – Tihart 138 kV circuit is projected to become marginally overloaded for shutdown plus contingencies (P6). The identified overload on this circuit is the sag limit. The thermal violations are found on peak cases.

Alternatives Considered

Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Project 15839 – Remediate AKT (Atlanta - Karn - Thetford) Tap - Karn 138 kV Sag

Project Description

Remediate the sag limit on the entire 15.3 mile-long length of 1431 ACSR conductor of the AKT (Atlanta - Karn - Thetford) Tap - Karn 138 kV section of the Atlanta - Karn - Thetford 138 kV line (Figure 4.3-#15839) and upgrade terminal equipment at Karn to achieve at least the planned target summer normal/summer emergency rating of 371 MVA/1552 A. The project's estimated cost is $803,000 and the estimated in-service date is December 31, 2022.

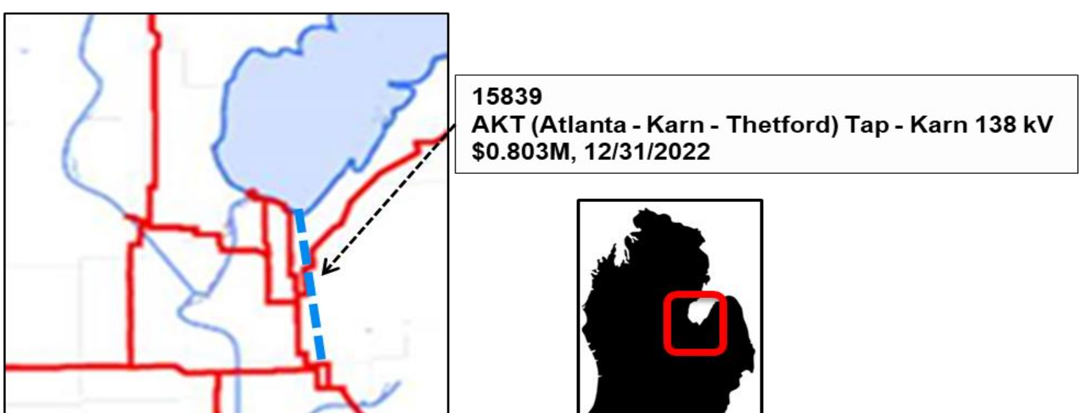


Figure 4.3-#15839: Remediate AKT (Atlanta - Karn - Thetford) Tap - Karn 138 kV Sag

Project Need
The AKT (Atlanta - Karn - Thetford) Tap - Karn 138 kV section of the Atlanta - Karn - Thetford 138 kV line is projected to become overloaded for shutdown plus contingencies (P6). The overloads were identified in the peak and shoulder peak load models regardless of the directional flow across the Michigan-Ontario interface or the Ludington generating/pumping condition.

Alternatives Considered
Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as Other Projects, according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects Driven by Local Reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16002	Rebuild Four Mile 138 kV Station	Rebuild Four Mile 138 kV station at a new site approximately half a mile to the west (Northridge) in a five row, breaker-and-a-half scheme configuration and redirect all circuits currently at the Four Mile 138 kV station into the new 138 kV station.	Dec. 31, 2022	MI	$16.0M
13957	Connect Sternberg WPSC 138 kV	Expand METC's Sternberg 138 kV station to a ring bus to connect a new WPSC 138 kV circuit (to Casanova)	Jun. 1, 2023	MI	$4.16M
15719	Rebuild Bingham 138 kV Bus	Rebuild the 138 kV portion of Bingham Substation to a breaker-and-a-half design with five breakers	Jun. 1, 2022	MI	$7.50M
15740	Replace Stover 138 kV Circuit Switcher 256	Replace Stover 138 kV circuit switcher 256 with a synchronous circuit breaker capable of interrupting at least 40 kA	Dec. 31, 2020	MI	$0.48M
15990	METC Pole Top Switch Additions/Replacement Program 2021	Installing, or replacing as appropriate, pole-top switches at tap points of circuits will provide the operational flexibility to sectionalize parts of the line to isolate faults or perform maintenance work on it without having to shut down the entire circuit	Dec. 31, 2021	MI	$3.60M

15996	2022 METC Asset Replacement Program	Replace aging and outdated equipment on a cycle that will ensure each piece of equipment is replaced near its expected end of life. Modern equipment can improve reliability, use state of the art technology, and typically will allow for longer maintenance intervals. All of this will help to reduce overall maintenance costs.	Dec. 31, 2022	MI	$42.0M

Projects Driven by Load Growth

Growing load is the principal driver for the following projects.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15736	Butters Interconnection	New interconnection in Coldwater, MI. Butters will be a 138 kV station with 4 breakers in a ring bus configuration. The Coldwater - Michigan Ave 138 kV line will be looped in to provide transmission service. Coldwater will install 2 138/13.8 kV transformers to serve 21.75 MW of load	Dec. 31, 2020	MI	$6.08M
15738	Brooks Industrial	Interconnection request from the City of Marshall for transmission service. METC will build Brooks Industrial 138 kV station as a breaker and half station with 6 breakers in a ring bus configuration. Brooks Industrial 138 kV will be fed by installing 3.5 miles of new line to loop in the Verona - Marshall 138 kV line. To solve local voltage issues, an 18 MVAR capacitor will be located at the station as well.	Dec. 1, 2021	MI	$15.7M
15894	METC Customer Interconnections - Year 2022	Customer interconnection requests and retirements less than $1 million with in service dates in the year 2022	Dec. 31, 2022	MI	$2.50M

Projects Driven by Age and Condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
14824	Shale 138 kV Station	Rebuild Saginaw River 138 kV station at a new site approximately 1.5 miles to the west. The new 138 kV station to be built will be called Shale.	Dec. 31, 2022	MI	$20.0M
16003	Rebuild Morocco-Whiting_Samaria-Whiting 138 kV	Rebuild 10.3 miles of wood pole construction from Samaria to Whiting consolidating Samaria-Whiting and Morocco-Whiting into one corridor on 138 kV double circuit steel poles with 954 ACSR conductor. The rebuild will be 138 kV construction using double-circuit steel structures with 954 ACSR conductor on both Samaria - Whiting and Morocco – Whiting 138 kV circuits. Also install OPGW from Whiting to existing splice box near Samaria.	Dec. 31, 2024	MI	$12.1M

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation. The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed.

Project ID	Project Name	Project Description	ISD	Estimated Cost
16424	J602 Network Upgrades	Network Upgrades necessary for J602 Wind Farm to interconnect at METC's Goss 138 kV substation	Sep. 1, 2021	$0.78M

4.3.3 Consumers Energy

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as Other Projects, according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects Driven by Local Reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15717	CE Substation Equipment Replacement Program - 2021	Replace damaged or defective substation equipment, not including breakers, with new equipment	Dec. 31, 2021	MI	$0.84M

Projects Driven by Age and Condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15718	CE Pole & Line Equipment Replacement Program - 2021	Replace damaged or defective poles, towers, cross arms, insulators, guying, and switches, as needed, to maintain the lines' condition	Dec. 31, 2021	MI	$0.57M
15720	Muskegon Heights #1 Line Rebuild	Rebuild a portion of the Muskegon Heights #1 138 kV Line, approximately 1.8 miles, utilizing 138 kV single circuit construction	Jun. 1, 2021	MI	$0.79M
15721	Verona-Elm Street Line Rebuild	Rebuild the Verona-Elm Street 138 kV Line, approximately 2.2 miles, utilizing 138 kV double circuit construction and 336.4 ACSR conductor	Dec. 31, 2021	MI	$1.0M

Projects Driven by Other Local Needs

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15722	Saginaw River-Shale Line	Construct a new 138 kV line from Saginaw River Substation to the new Shale Substation	Dec. 31, 2022	MI	$0.2M
16044	Cobb Rebuild - CETO 138 kV Lines	Construct new 138 kV lines from the existing Cobb & Muskegon Heights Substations to METC's rebuilt Cobb Station	Dec. 31, 2023	MI	$0.8M

4.3.4 Wolverine Power Supply Cooperative Inc.

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."

Project 12220 – Portland to Clinton Line Rebuild

Project Description
Rebuild line to 138 kV design with 795ACSS conductor.

The project's estimated cost is $7.5 million and the estimated in-service date is December 31, 2022.

Project Need
Aging Infrastructure. Line was constructed in 1952 and currently has 31 percent condemned or damaged poles.

Resolves overloads of up to 110.9 percent seen in the MTEP18 cycle.

Alternatives Considered
Several alternatives were considered but the project described was identified to be the best in terms of cost and the ability to reliably resolve the overload conditions.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as Other Projects, according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects Driven by Local Reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16344	Weidman 69kV Bus rebuild	Rebuild 69kV Bus at Weidman station.	Dec. 31, 2020	MI	$0.17M
16345	2022 Transmission Battery Bank Replacement project	Replace battery bank at transmission station.	Dec. 31, 2022	MI	$0.035M

Projects Driven by Age and Condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
9895	Graves Crossing to Central Lake Rebuild	Rebuild the Graves Crossing to Central Lake 69kV line, install new poles and hardware with 336ACSR conductor	Dec. 31, 2022	MI	$4.08M
15646	Atlanta to Lewiston Rebuild	Rebuild and upgrade 12 miles of 69 kV to 138 kV design, 795ACSS conductor and OPGW	Dec. 31, 2021	MI	$6.12M
15651	Clinton to Wayland Rebuild	Rebuild and upgrade 41 miles of 69 kV line to 138 kV design, 75ACSS conductor and OPGW.	Dec. 31, 2022	MI	$23.7M
16104	Altona to Pierson Rebuild	Rebuild and upgrade 14 miles of 69 kV line to 138 kV design, 795ACSS conductor and OPGW	Dec. 31, 2022	MI	$7.3M

4.3.5 Northern Indiana Public Service Company

Northern Indiana Public Service Company LLC submitted three (3) generation interconnection projects at an estimated cost of $24 million.

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation. The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed.

Project ID	Project Name	Project Description	ISD	Estimated Cost
16084	J351 Network Upgrades	Network Upgrades necessary for J351 Generating Facility to interconnect at NIPSCO's Stillwell 345 kV substation.	Mar. 31, 2020	$6.69M
16085	J513 Network Upgrades	Network Upgrades necessary for J513 to connect to Reynolds 138 kV as stated in the GIA.	Aug. 15, 2020	$7.87M
16444	J643 Network Upgrades	J643 Network Upgrades. 138 kV Interconnection Ring bus substation.	Sep. 1, 2021	$8.92M

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. It contains approximately 16,700 miles of transmission ranging from 115 kV to 500 kV. There is also a significant 69 kV network interspersed across the footprint.

In the 2021 Summer Peak planning model, the region contains more than 37.2 GW of generation. The MISO South generation profile consists of mostly combine cycle, nuclear, gas, and coal fuel types, serving major loads center such as Little Rock, New Orleans, etc. Approximately 40 percent (19.7 GW) of the South region's generation capacity is made up of Combine Cycle (CC) units. Major generation centers are located in central Arkansas, lower Louisiana, and western Mississippi (Figure 4.4-1).

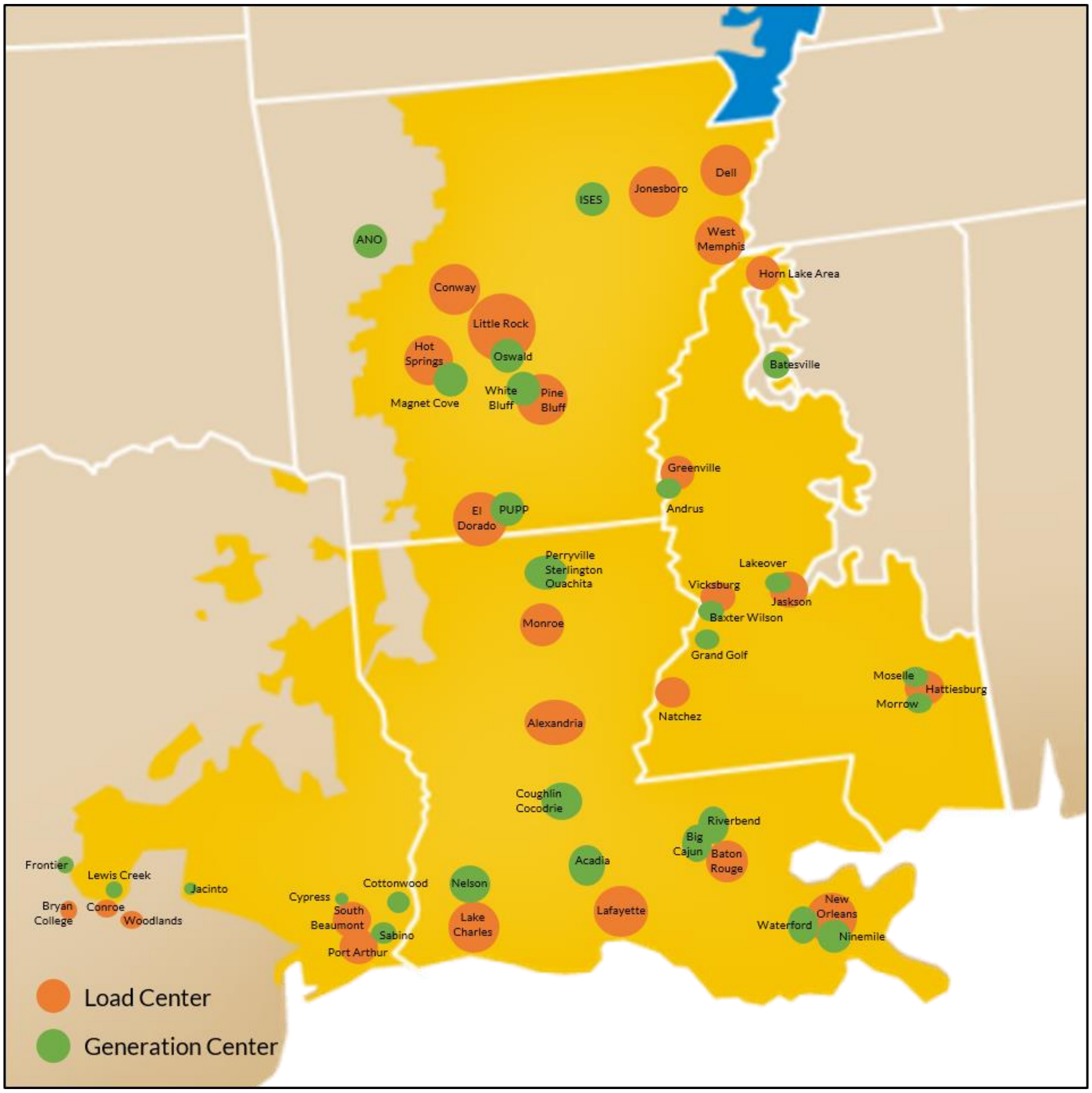


Figure 4.4-1: Generation and load centers in the South planning region

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 2021 Summer Peak planning model, the regional load is over 36.0 GW. Power generally flows from generation-rich areas to the major load centers.

In accordance with Attachment FF to 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 thirty (30) Days of the project's submittal to MISO unless a longer review period is mutually agreed upon. During the MTEP19 cycle, MISO received the following projects through the Expedited Project Review (EPR) process. The EPR for MTEP19 are listed below:

1. MTEP ID # 16604 Oak Grove DP Temp
2. MTEP ID # 16544 Riverview 138 kV: New Customer Station
3. MTEP ID # 16324 Foreman 69 kV: New Customer Station
4. MTEP ID # 17611 Star Bayou 230 kV: New Customer Substation
5. MTEP ID #17784 Pelican and Loring Substations
6. MTEP ID #17924 Huffman 161/12.47 Substation

The following project needs were identified after the submittal date of September 15, 2018 for MTEP19. They do not represent an emergent need and were not required to go through the Expedited Review Process. More information for each of these projects can be found in the project detail sections.

TO	Project ID	Project Name	Estimated Cost
AECC	16904	McDougal 161/24.9kV Substation	$3.0M
AECC	17084	Pocahontas Industrial Park Tap	$0.05M
AECC	17085	Partain to Heber Springs North 69kV line rebuild	$15.0M
AECC	17610	Moro thru path maintenance	$0.3M
AXLA	17104	Twin Bridges Auto Replacement	$4.3M
Entergy-LA	17606	Ponchatoula 230 kV: Add Breakers and Transfer Bus	$5.2M
Entergy-LA	17608	Michigan 230 kV Substation: Cut in Nelson to Manena 230 kV	$10.6M

As of October 18, 2019, 71 projects are recommended for inclusion in Appendix A at an estimated cost of $787.6 million. Of these, fifteen are Baseline Reliability Projects, and twelve are Generation Interconnection Projects. The remaining forty-three projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects.

Of these 71 projects, eleven have an estimated cost of less than $1 million, 45 have an estimated cost greater than $5 million, and fifteen are estimated to cost between $1 and $5 million (see Figure 4.4-2 for the breakdown by project type). Additionally, the majority of these projects are expected to go into service within three years (Figure 4.4-3).

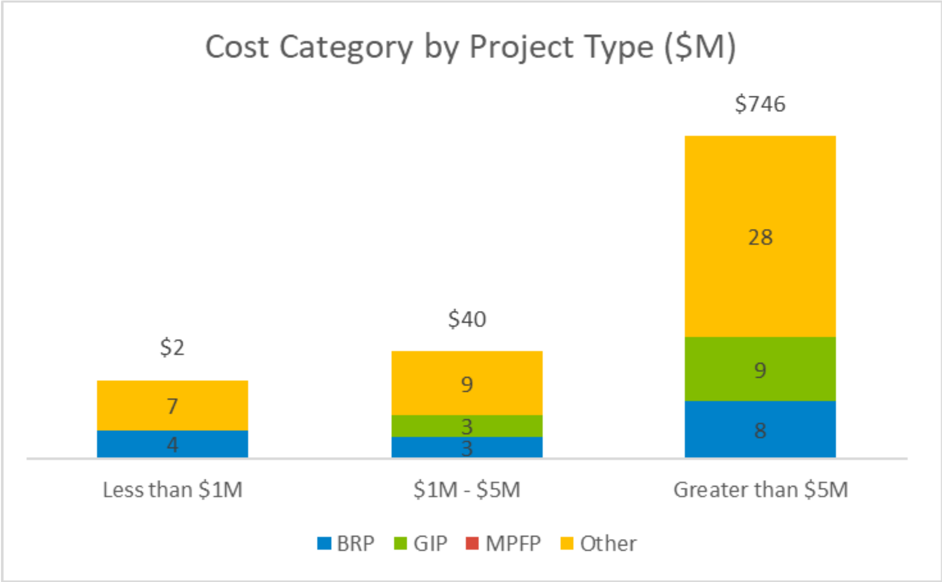


Figure 4.4-2: Project cost category by project type for South Planning Region for MTEP19. (Project data as of October 18, 2019)

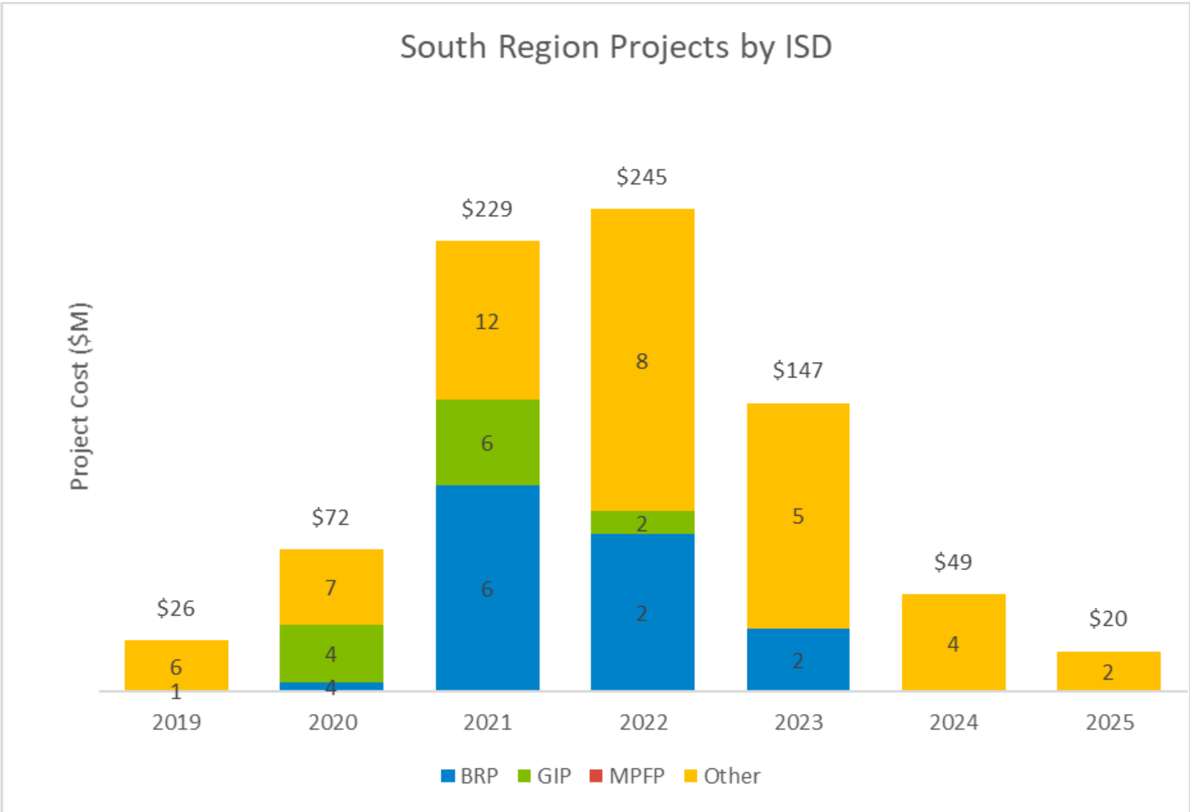


Figure 4.4-3: Project in-service date by project type for South Planning Region for MTEP19. (Project data as of October 18, 2019)

The ten most expensive projects account for $387.6 million of the $787.6 million total recommended projects for the South in MTEP19. The locations of the ten most expensive projects are shown in Figure 4.4-

4 and it is seen that they are spread throughout the South planning region. Projects that are blanket expenditures (relays, physical security, etc.) are excluded from this list.

Figure 4.4-4: The ten most expensive projects in the South Planning Region for MTEP19, excluding blanket projects.

4.4.1 Arkansas Electric Cooperative Corporation (AECC)

Based on TO submission and MISO independent assessment Arkansas Electric Cooperative Corporation (AECC) will have seven projects for inclusion in Appendix A at an estimated cost of $59 million. All of the seven projects are classified as Other Projects.

Other Projects

Other projects 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, interconnect 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. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Project 10207 – Partain-Heber Springs North 161 kV Line

Project Description

This project involves constructing a five-position ring bus at the existing AECC Heber Springs North substation and building 26 miles of 161 kV transmission lines between the existing Heber Springs North substation and the proposed Partain 161/69 kV substation. The expected in-service date for this project is February 2, 2023, and it has an estimated cost of $38.9 million.

Project Need

This project is driven by Local reliability. This project provides a means to reliably serve the Heber Springs North loads for the loss of north and south feed at Heber Springs North station, and Clinton West loads for the loss of east and west feed into Clinton West station. This project also allows a looped feed into the proposed Partain 161/69 kV substation.

Project 17085 – Partain-Heber Springs North 69 kV Lines Rebuild

Project Description

Rebuild existing 69 kV lines from the proposed Partain 161/69kV substation to the existing Heber Springs North 161/69 kV substation. This project has an estimated cost of $15.0 million and is expected to be in service by February 1, 2023. This project was submitted late since the need was identified during scoping of Project 10207.

Project Need

The 69 kV lines between Partain to Heber Springs North are over 40+ years old and are in disrepair (failing poles, cross-arms, and conductor). This is also a cost saving project since the lines are being rebuilt in parallel with the Partain to Heber Springs North 161 kV line using the same right of way and structures.

Projects driven by local reliability

The following projects are driven by local planning criteria or by operational flexibility and do not meet requirement for BRP.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
17084	Pocahontas Industrial Park Tap	This project was submitted late since the need was identified during the construction of Project 8420. Pocahontas Industrial Park Tap switch is being added to maintain the capability of the current topology (serving this line out of Pocahontas East) and to create an alternate path for the 161 kV network system between Baltz Lake Switching Station and Pocahontas East for operational flexibility.	Dec. 31, 2019	AR	$0.05M
17610	Moro thru path maintenance	This project was submitted late since the need for the project was identified during routine maintenance work. Perform maintenance on thru path changing bus conductor, switches, and MODs.	Jun. 1, 2020	AR	$0.3M

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15668	Tap EAI Hot Springs EHV - Woodward: Construct Sheridan West 115/13.2 kV substation	Construct 12 MVA, 115/13.2 kV substation under Entergy Hot Springs EHV - Woodward 115 kV transmission west of Sheridan, AR.	Jan. 1, 2022	AR	$2.0M
16904	McDougal 161/24.9kV Substation	This project was submitted late because the need was identified while scoping for the distribution substation. 161/24.9 kV 16 MVA distribution substation tapping into Entergy's Corning to Texas Eastern 161 kV line.	Dec. 1, 2020	AR	$3.0M
17924	Huffman 161/12.47 Substation	An existing industrial customer is expanding their production facilities to include 25 MW of new load. AECC will be tapping AECC 161 kV transmission line, constructing approximately 3 miles of 161 kV transmission line with 605 ACSS, and constructing the new Huffman 161/12.47 kV distribution substation to serve this load.	Sep. 1, 2021	AR	$4.0M

4.4.2 City of Alexandria (AXLA)

Based on TO submission and MISO independent assessment the City of Alexandria will have one project for inclusion in Appendix A at an estimated cost of $4.3 million. The single project is categorized as an Other project.

Other Projects

Other projects 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, interconnect 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. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by age and condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
17104	Twin Bridges Auto Replacement	This project was submitted late because of age and condition identified during recent inspection and TO was concerned about imminent failure. The project will replace the existing Twin Bridges 230/138 kV autotransformer.	Mar. 1, 2020	LA	$4.3M

4.4.3 CLECO Power LLC (CLEC)

Based on TO submission and MISO independent assessment CLECO will have four projects for inclusion in Appendix A at an estimated cost of $25 million. The four projects are classified as Baseline Reliability Projects.

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 adoptd by Regional Reliability Organizations and applicable within the Transmission Provider Region.”

Project 15914 – Plaisance – Champagne Reconductor

Project Description

This project is a joint project to between CLECO and Entergy. This project is to rebuild CLECO's portion of Plaisance to Champagne 138 kV line (9.5 miles) to 230 kV standards. The project's estimated cost is $9.4 million and the estimated in service date is December 1, 2021.

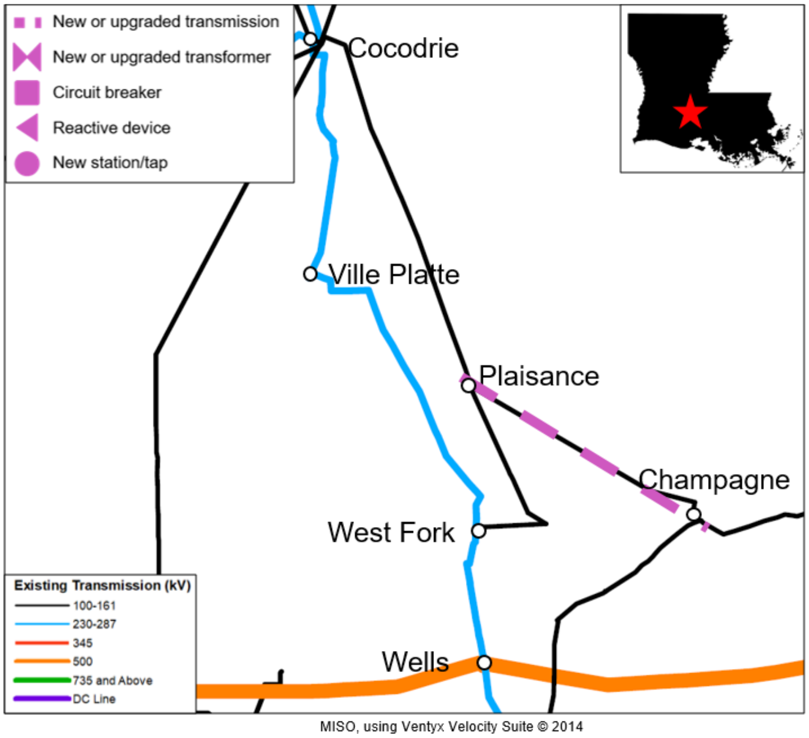


Figure 4.4-#15914-1: Geographic transmission map of project area

Project Need

This line overloads for several single initiating events involving losing any of the 230 kV path between Cocodrie and West Fork. The thermal overload increases with the loss of generation to the south. Reconductoring the line will alleviate the thermal overloads. The thermal overloading before and after the project is in service is shown in Table 4.4-#15914-1.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P1.2	Champagne - Plaisance 138 kV	278	110	75
P2.1	Champagne - Plaisance 138 kV	278	108	70
P2.3	Champagne - Plaisance 138 kV	278	109	71
P3	Champagne - Plaisance 138 kV	278	115	78

Table 4.4-#15914-1: Thermal loading drivers

Project 15918– Manuel Reactor

Project Description

This project adds a nine ohm reactor at Manuel substation in series with the Coughlin to Manuel 138 kV line. A by-pass breaker will be installed to allow for the Reactor to be by-passed under certain operational conditions. The project's estimated cost is $1.5 million and the estimated in service date is June 1, 2021.

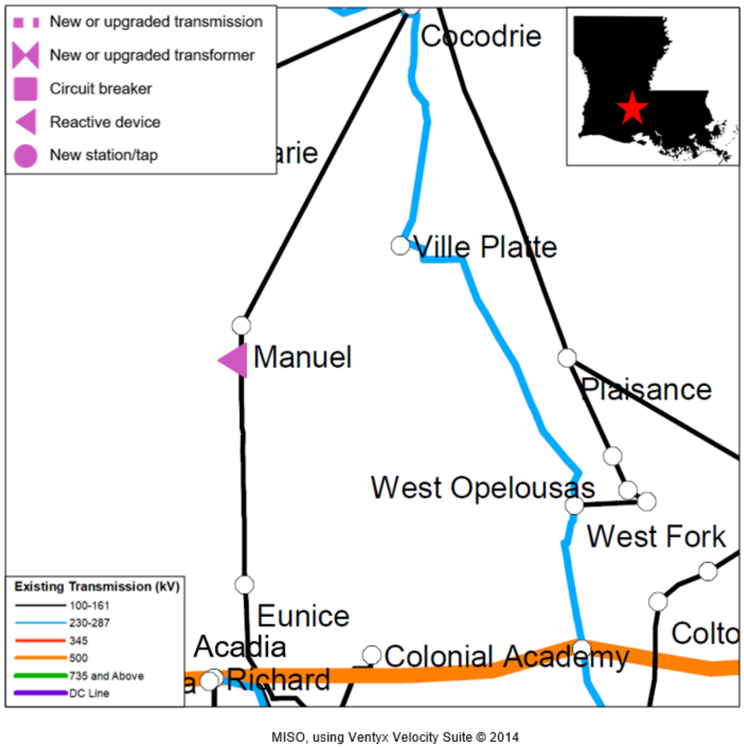


Figure 4.4-#15918-1: Geographic transmission map of project area

Project Need

During an outage of one of the Acadia combined cycle power plants near Cocodrie and the Cocodrie to Ville Platte 230 kV line, the 138 kV path between Coughlin and Richard overloads. Redispatching after one of the events would require turning off 250 MW of generation at Coughlin, assuming the second Acadia power plant is outputting 570 MW. With the Manuel reactor in service, no redispatch is required during either event.

During a double line outage of Coughlin to Plasiance 138 kV and Cocodrie to Ville Platte 230 kV, several lines along the path from Coughlin to Manual to Eunice to Richard 138 kV overload beyond 125%. Redispatching after either of the single line outages would require shutting down up to 570 MW of generation at Coughlin while assuming all Acadia generation is online for 1154 MW. If redispatch was not done in time, the lines would trip causing 70 MW of load shed. With the reactor in service, the highest overload of 166% is reduced to 105% if no action was taken. Coughlin generation would need to be lowered by 60 MW as opposed to 570 MW in order to fix this thermal overload. No load is at risk of being automatically tripped with the reactor in service.

The post contingent line flows are shown in Table 4.4-#15918-1.

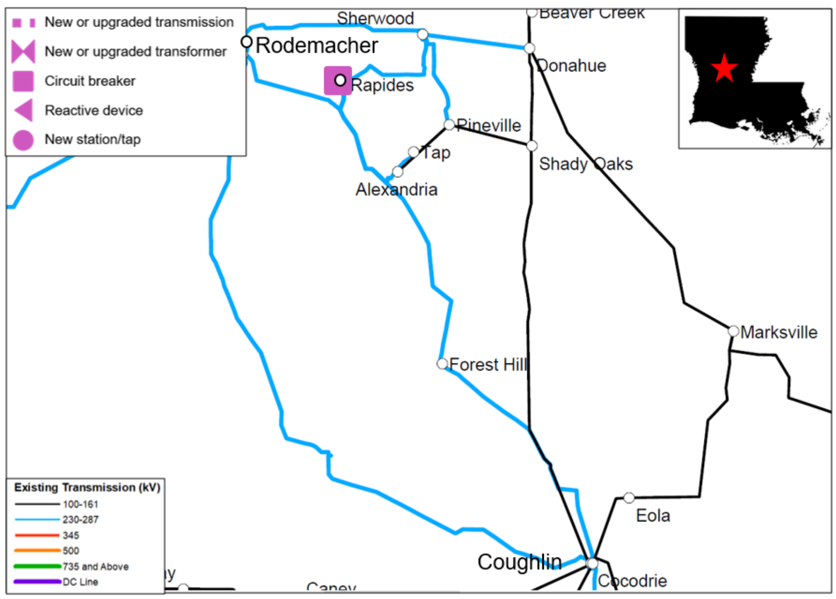
Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P3	Coughlin - Manuel 138 kV	287	121	79
P3	Eunice – Richard 138 kV	243	113	64
P3	Manuel – Eunice 138 kV	287	114	72
P6	Coughlin - Manuel 138 kV	287	166	105
P6	Eunice – Richard 138 kV	243	155	98
P6	Manuel – Eunice 138 kV	287	154	98

Table 4.4-#15918-1: Thermal loading drivers

Project 15929 – Rapides Breaker Upgrade

Project Description

This project upgrades breaker 9106 at Rapides. The project's estimated cost is $0.2 million and the estimated in service date is April 1, 2020.



MISO, using Ventyx Velocity Suite © 2014

Figure 4.4-#15929-1: Geographic transmission map of project area

Project Need

During the outage of Rodemacher to Sherwood 230 kV, Rapides to Rodemacher 230 kV line approaches 96% loading. If the Coughlin Unit 7 Generation tripped with the Rodemacher to Sherwood 230 kV line, Rapides to Rodemacher 230 kV overloads. Fixing the overload would involve decreasing generation at Rodemacher by 150 MW after one of the single events. Upgrading the breaker will increase the rating of the line so that no thermal overload occurs and no redispatch is necessary as shown in Table 4.4-#15918-1.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P1.2	Rapides – Rodemacher 230 kV	690	96	83
P3	Rapides - Rodemacher 230 kV	690	107	93

Table 4.4-#15918-1: Thermal loading drivers

Project 17045 – Sellers Road Expansion

Project Description

The Sellers Road Expansion, along with MTEP 17044, is replacing MTEP17/18 projects 12101 East ALP and 12112 North ALP. The projects changed through significant collaboration between CLECO, Entergy, Lafayette Utilities System, and MISO to develop a lower cost solution. The proposed $84 million alternative is a joint solution between CLECO and Entergy – Louisiana and will save customers $115 million compared to the original ALP projects.

CLECO's portion of the project is to Expand Sellers Road Substation to add a 4 terminal 138 kV substation tapped into and out of the Habetz to Flanders 138 kV line near Sellers Road substation. A 500 MVA 230/138 kV Auto connecting the existing 230 kV sub to the New 138 kV Sub will be added. The project's estimated cost is $14.1 million and the estimated in service date is December 1, 2021.

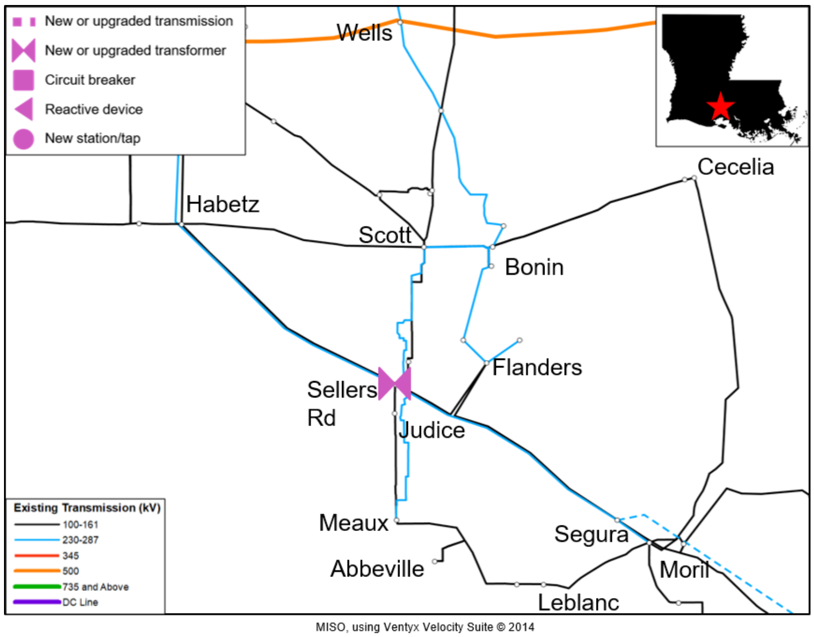


Figure 4.4-#17045-1: Geographic transmission map of project area

Project Need

In the Lafayette area of Louisiana approximately 380 MW of load is served by the Judice, Meaux, Abbeville, Leblanc, and Delcambre substations. These substations are served by well networked hubs, the Moril and Scott substations, as well as a 230/138 kV transformer at the Meaux substation. Loss of two of three of these sources caused loading up to 137 percent of the capacity of the single remaining source. Up to 150 MW of load shed is required to mitigate the excessive flows. Table 4.4-#17045-1 shows the thermal loading of various limiting elements during different events with and without this project in service.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P2.2	Cecelia – Bonin 138 kV	145	101	84
P2.4	Cecelia – Bonin 138 kV	145	111	91
P6	Scott - Judice 138 kV	241	137	83

P6	Delcambre – Moril 138 kV	251	125	60
P6	Meaux – Abberville 138 kV	233	111	64
P6	Cecelia – Bonin 138 kV	145	111	78

Table 4.4-#17045-1: Thermal loading drivers

Alternatives Considered

This project, along with MTEP 17044, is replacing MTEP17/18 projects 12101 East ALP and 12112 North ALP to save customers $115 million.

4.4.4 Cooperative Energy

Based on TO submission and MISO independent assessment Cooperative Energy will have six projects for inclusion in Appendix A at an estimated cost of $63 million. $19 million of which represents EML's estimated cost required to interconnect these new facilities to EML's existing transmission system. All of the projects are other type projects.

Other Projects

Other projects 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, interconnect 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. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Project 15849 – Evans Loop Project

Project Description

Tap the existing Schlater to Evans 115 kV line with a 115 kV GOAB and build a new 115 kV line to Half Mile Switching Station. Add a new 115 kV line bay to Entergy's Schlater substation. The project's total estimated cost is $9.76 million, with Cooperative Energy paying $3.12 million and Entergy Mississippi LLC paying $6.64 million. The estimated in service date is April 1, 2021.

Project Need

The current radial transmission system results in 115 MW-miles and violates section 6.7 of Cooperative Energy's local planning criteria, which states that 100 MW-miles cannot be exceeded for any Point of Common Coupling. This project will provide a loop from the new Half Mile delivery point to Evans and remove the MW-mile violation.

Project 15847 – Utica JC Loop Project

Project Description

Rebuild Utica to Utica JC with sufficient ACSR conductor. Tap Utica to Utica JC with a 115 kV GOAB and build a new 115 kV line to Port Gibson substation. The project's total estimated cost is $20.46 million, with Cooperative Energy paying $16.19 million and Entergy Mississippi LLC paying $4.27 million. The estimated in service date is July 1, 2024.

Project Need

The current radial transmission system results in 303 MW-miles and violates section 6.7 of Cooperative Energy's local planning criteria, which states that 100 MW-miles cannot be exceeded for any Point of Common Coupling. This project will provide a loop from Utica JC to Port Gibson and remove the MW-mile violation.

Project 15845 – Woodville Loop Project

Project Description

Tap the Centreville to Woodville 115 kV line with a switching station and build a new 115 kV line to Entergy Mississippi's Harper Switching Station. The project's total estimated cost is $14.79 million, with Cooperative Energy paying $11 million and Entergy Mississippi LLC paying $3.79 million. The estimated in service date is March 1, 2023.

Project Need

The current radial transmission system results in 166 MW-miles and violates section 6.7 of Cooperative Energy's local planning criteria, which states that 100 MW-miles cannot be exceeded for any Point of Common Coupling. This project will provide a loop from Woodville to Harper Switching Station and remove the MW-mile violation.

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15624	Half Mile 115kV Delivery Point	Build an 115kV radial transmission line from Itta Bena switching station to the new Half Mile delivery point to serve new load. Rebuild the Itta Bena 115kV switching station and add breakers.	Apr. 1, 2021	MS	$8.70M[13]
15625	East Brandon 115kV Delivery Point	Add new 115kV bay with breaker to Rankin substation and build a new 115 kV transmission line from the Rankin	Jun. 1, 2022	MS	$7.17M[14]

[13] Cooperative Energy portion will be $8.01M and Entergy Mississippi portion will $0.69M
[14] Cooperative Energy portion will be $4.26M and Entergy Mississippi portion will $3.40M

		substation to East Brandon delivery point GOAB.			
12212	Oak Grove Delivery Point	Okahola GOAB to Oak Grove will be extended to the proposed Oak Grove 161/69kV substation and the temporary 69kV GOAB will be removed.	Dec. 1, 2021	MS	$2.33M
16604	Oak Grove Delivery Point Temp	Cooperative Energy's Okahola GOAB to Oak Grove will be rebuilt with 795 ACSR conductor. A temporary 69kV GOAB will be installed near the original location. A new 69/26.4kV, 15/20/25 MVA transformer will be installed at the Oak Grove substation to accommodate the 69kV service	Dec. 1, 2019	MS	

*Cooperative Energy projects proposed in JPZ30 are subject to the EML-CE JPZ Agreement whose terms are currently under review by both parties.

4.4.5 East Texas Electric Cooperative (ETEC)

Based on TO submission and MISO independent assessment East Texas Electric Cooperative (ETEC) will have one project for inclusion in Appendix A at an estimated cost of $8 million. This project is categorized as an Other Project.

Other Projects

Other projects 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, interconnect new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plants, 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. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15734	Plum Grove substation	The project is to build a new distribution substation. The station will	Jun. 1, 2022	TX	$8.0M

		be cut into the Entergy's China-Timberland or Porter-Timberland 230 kV line (The exact cut in to be further determined contingent on the engineering for Entergy Transmission line and ETEC / Sam Houston substation project).			

4.4.6 Entergy Arkansas LLC (EAL)

Based on TO submission and MISO independent assessment Entergy Arkansas LLC will have eleven projects for inclusion in Appendix A at an estimated cost of $93 million. Of the eleven projects, one is a Baseline Reliability Project, five are Other projects and the remaining five are Generation Interconnection Projects.

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.”

Project 15564 – Hot Springs Village - Sierra 115kV Rebuild

Project Description

This project involves upgrading approximately 1 mile of 115 kV transmission line and terminal equipment between the Hot Springs Village and Sierra substations to achieve a 1300 A and 259 MVA rating. The expected in-service date for this project is December 30, 2020, and it has an estimated cost of $2.13 million. Figure 4.4-#15564-1 shows a geographic map of the project area.

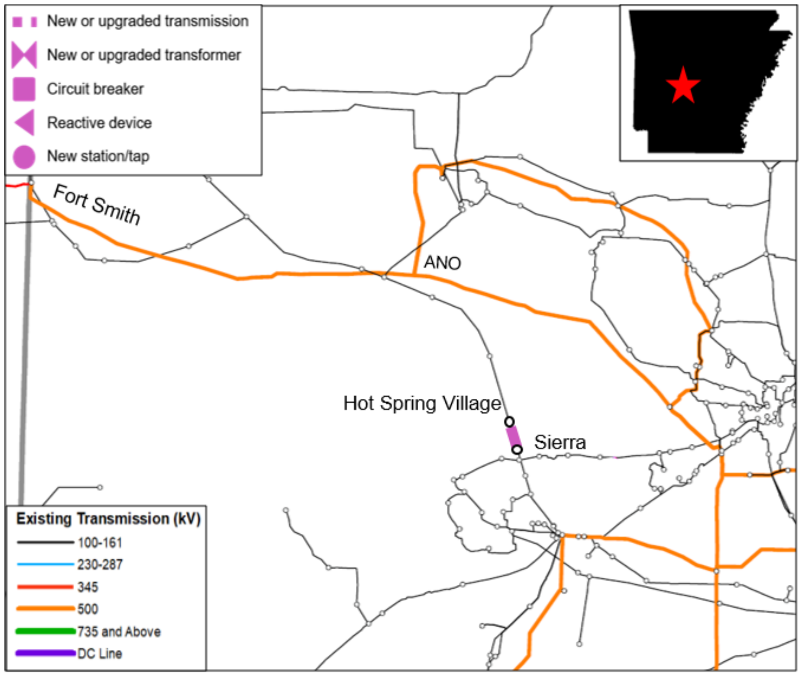


Figure 4.4-#15564-1: Geographic transmission map of project area

Project Need

In this area, thermal overloads are seen for single line outage category events. The Hot Springs Village to Sierra 115 kV transmission line experiences thermal overloads due to the loss of a single line. To justify this project Entergy 2026 Summer Peak model was used. In this model, loading on this line reaches 101 percent. Upgrading the line and the terminal equipment would reduce the line loading percentage and mitigate these issues. The models with the local peak load were posted the MTEP19 FTP site.

Table 4.4-#15564-1 summarizes the improvement in the area following the addition of this project. Note the rating listed in the table is the emergency loading level, which does not allow system adjustments to resolve.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P12	Hot Springs Village – Sierra 115kV	106	101	41

Table 4.4-#15564-1: Thermal loading drivers

Other Projects

Other projects 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, interconnect new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plants, 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. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Project 12050 – Amity Tap 115 kV: Add Transmission Breakers

Project Description

This project is proposing to build a 115 kV breaker station at the Amity 115 kV tap location. This project has an estimated cost of $9.61 million and is expected to be in service by June 1, 2023.

Project Need

Enhanced project to reduce customer interruptions due to a 78 mile-long breaker to breaker transmission line with 12,500 customers and a 28 mile radial tap with three substations on this breaker to breaker line.

Project 12053 – Batesville 161 kV: Add Transmission Breakers

Project Description

This project proposes to build a new station adjacent to Batesville 161 kV substation, which is located between ISES 161 kV and Sage 161 kV substations. This project has an estimated cost of $9.0 million and is expected to be in service by June 1, 2024.

Project Need

There is 45 miles of transmission exposure breaker to breaker, which includes a 10 mile tap line to Cave City. There are 14,000 customers on this transmission line. This project will reduce customer interruptions on the long line.

Project 13612 – Little Rock Enhanced Reliability Project Phase 2

Project Description

This project proposes to upgrade approximately 3.8 miles of the Little Rock 8th and Woodrow to Little Rock Palm Street to Little Rock West 115 kV lines to a minimum of 1950 A. This project has an estimated cost of $14.0 million, and is expected to be in service by June 1, 2025.

Project Need

LR Gaines to Little Rock West 115 kV line overloads over 180% when the Little Rock South to LR Rock Creek and LR Kanis to LR West Markham 115 kV lines are out of service. This condition would require up to 150 MW's of load shed to relieve the thermal overload on the lines. There are multiple other line and breaker outages in this area that cause 50 - 150 MW of load at risk that will also be addressed with this project.

Project 13613 – Little Rock Enhanced Reliability Project Phase 1

Project Description

This project proposes to upgrade approximately 2.2 miles of the Little Rock Gaines to Little Rock 8th and Woodrow 115 kV line to a minimum of 1950 A. This project has an estimated cost of $8.4 million and is expected to be in service by June 1, 2024.

Project Need

LR Gaines to Little Rock West 115 kV line overloads over 180% when the Little Rock South to LR Rock Creek and LR Kanis to LR West Markham 115 kV lines are out of service. This condition would require up to 150 MW's of load shed to relieve the thermal overload on the lines. There are multiple other line and breaker outages in this area that cause 50 - 150 MW of load at risk that will also be addressed with this project.

Project 15565 – Laney Road 115kV New Substation

Project Description

This project proposes to build a new 115/13.8 kV substation with a 40 MVA 115/13.8 kV transformer, install a new 2000 A main breaker and new 13.8 kV low side operating and transfer buses. This project has an estimated cost of $11.2 million and expected to be in service by June 1, 2024.

Project Need

This project will improve reliability for the town of Junction City and the surrounding area and reduce voltage dips for the Union County Lumber and Great Lakes Chemical facilities. It will also reduce the load shed at the El Dorado Upland substation for the loss of the second transformer as well as reliably serve distribution loads El Dorado Upland and El Dorado Newell Stations.

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed. These projects are funded by the interconnection customer.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16244	Bellaire 115 kV: Construct Switching Station (J620)	Construct a three breaker 115 kV ring bus on the Macon Lake – Dermott 115 kV line section to facilitate the J620 Solar facility interconnection. There will be remote relay setting changes performed as well.	Mar. 18, 2020	AR	$8.26M
16246	Crossett South 115 kV: Construct Switching Station (J680)	The existing Crossett South 115 kV switching station, on the Crossett North – Sterlington 115 kV line, will be converted to a four breaker ring bus switching station to accommodate the interconnection of J680 Solar Facility. The line trap at Crossett North 115 kV will be removed. Relay Setting will be updated at the Sterlington 115 kV substation.	Apr. 15, 2021	AR	$9.98M

16247	Crooked Lake 161 kV: Install Transmission Breaker and Line Bay (J586)	Expand the existing Crooked Lake 161 kV Substation with a new line bay and breaker	Mar. 1, 2022	AR	$3.85M
16248	Lee 115 kV: Construct Switching Station (J552)	Construct a new three breaker 115 kV ring bus station on the Brinkley East – Moro 115 kV line. New relay setting will be required at the remote end station of Brinkley East and West Helena.	Jun. 1, 2022	AR	$7.86M
16249	Ashley 115 kV: Construct Switching Station J603)	A new three breaker 115kV ring bus will be constructed on the AECC Mist – Montrose 115 kV line. New relay panels and settings will be needed at Crossett North.	Sep. 15, 2021	AR	$8.89M

4.4.7 Entergy Louisiana LLC (ELL)

Based on TO submission and MISO independent assessment, Entergy Louisiana will have twenty projects for inclusion in Appendix A at an estimated cost of $276 million. Of the twenty projects, six are classified as Baseline Reliability Projects, eleven are classified as Other Projects, and three are classified as Generation Interconnection Projects.

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."

Project 12124 – Bogalusa 230-115 kV AT2: Upgrade Auto

Project Description
This project upgrades the line bay bus, line trap and air break switch to a minimum of a 2000 A rating. The project's estimated cost is $0.1 million and the actual in service date is June 18, 2019.

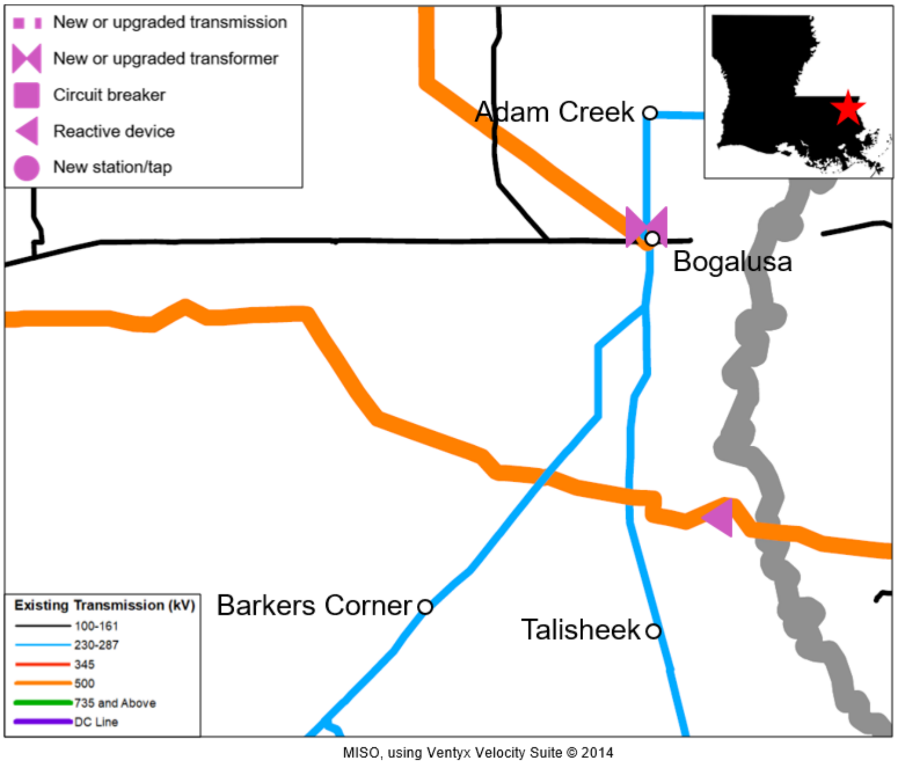


Figure 4.4-#12124-1: Geographic transmission map of project area

Project Need

A breaker failure contingency at Bogalusa 230 kV causes a thermal violation on the second Bogalusa transformer. Upgrading the station equipment will increase the thermal rating in order to alleviate the thermal violation.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P2.3	Bogalusa 230/115 kV AT2	228	135	91

Table 4.4-#12124-1: Thermal loading drivers

Project 12139 – Jefferson Parish Area Reliability Plan Phase 2

Project Description

This project will construct a new 230 kV substation named Munster located north of the existing Meraux Substation. The new substation will be configured as a 9 breaker, breaker and a half substation. The substation will be cut in to Meraux to Michoud, Meraux to Oaks, and Michoud to Arabi 230 kV lines.

Approximately, one mile of double circuit 230 kV transmission line will be installed, with a minimum through-path rating of 1608 A, from the new Munster Substation to the point at which the existing 230 kV turns north towards the Michoud Substation. The terminations at the junction point will be reconfigured to accommodate the new installation. The project's estimated cost is $53.3 million and the estimated in service date is June 1, 2022.

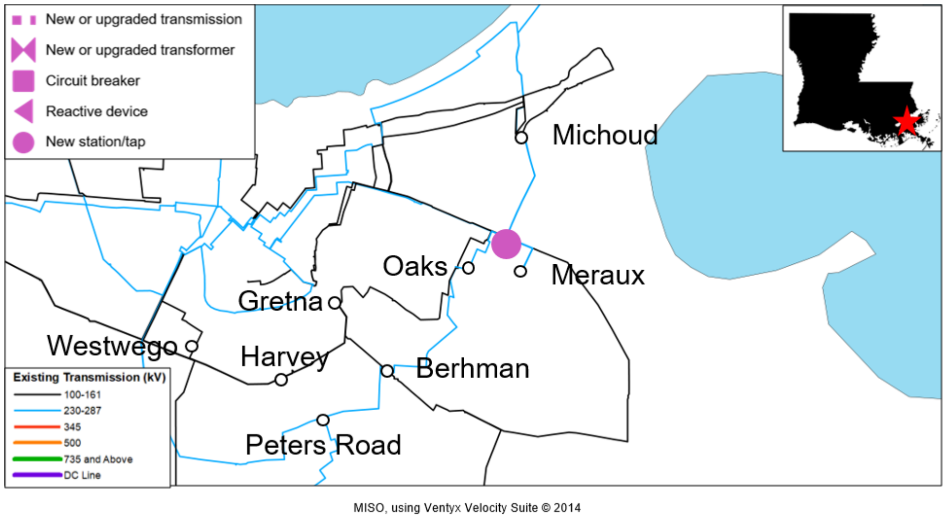


Figure 4.4-#12139-1: Geographic transmission map of project area

Project Need

The loss of two lines, Peters Road to Behrman 230 kV line along with Michoud to Meraux 230 kV line will overload multiple facilities as the 115 kV system in the area attempts to support the 230 kV system, primarily through the Behrman 230-115 kV autotransformer. There is no generation available to resolve the issue. Up to 130 MW of loadshed is required to fix the overload after one of the single events. Without loadshed, Gretna – Behrman 115 kV will trip causing a cascade of line outages losing up to 350 MW of load. The new Munster substation will provide more paths for the 230 kV to serve the load and resolves the overloads.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Westwego - Harvey 115 kV	228	101	N/A
P6	Gretna - Behrman 115 kV	176	163	N/A

Table 4.4-#12139-1: Thermal loading drivers

Project 15566 – Addis to Tiger 230 kV Series Reactor

Project Description

This project installs a five ohm reactor on the existing Addis to Tiger 230 kV line. The project's estimated cost is $16.2 million and the estimated in service date is June 1, 2023.

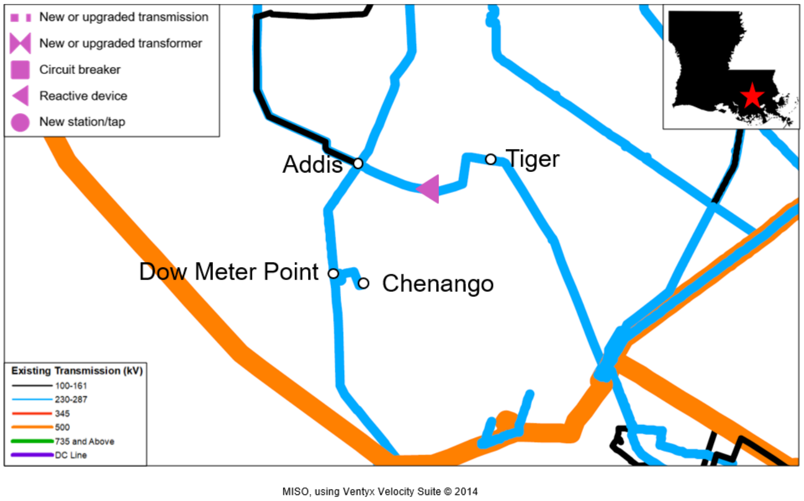


Figure 4.4-#15566-1: Geographic transmission map of project area

Project Need

The 2018 MISO Deliverability study shows an overload on the Addis to Tiger 230 kV line for the loss of the Dow Meter to Chenango 230 kV line or the Richardson to Iberville 230 kV line in 2023.

Project 15584 – Champagne to Plaisance 138 kV: Rebuild to 230 kV (operate at 138 kV)

Project Description

Rebuild Entergy's portion of Champagne to Plaisance 138kV line to 230 kV specifications and operate at 138 kV. Entergy and CLECO own portions of this line. The project's estimated cost is $9.0 million and the estimated in service date is June 1, 2021.

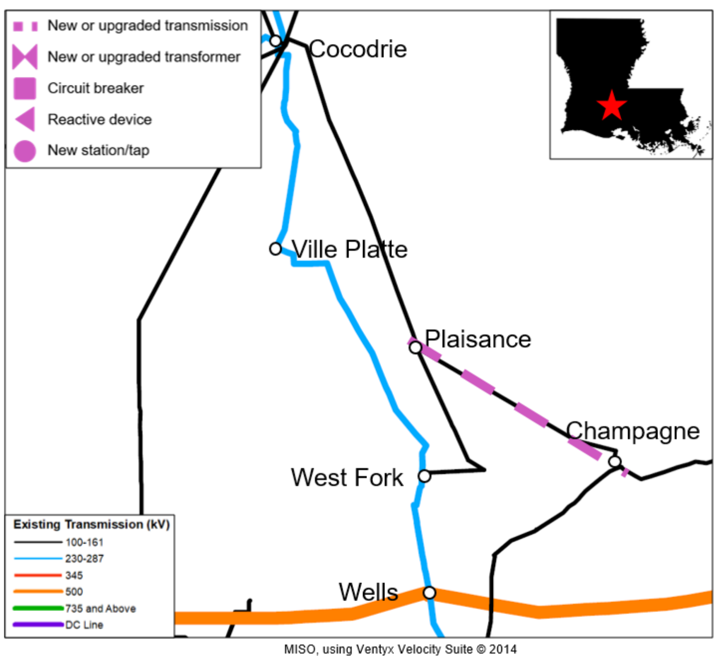


Figure 4.4-#15584-1: Geographic transmission map of project area

Project Need

This line overloads for several single initiating events involving losing any of the 230 kV path between Cocodrie and West Fork. The thermal overload increases with the loss of generation to the south. Reconductoring the line will alleviate the thermal overloads. The thermal overloading before and after the project is in service is shown in Table 4.4-#15584-1.

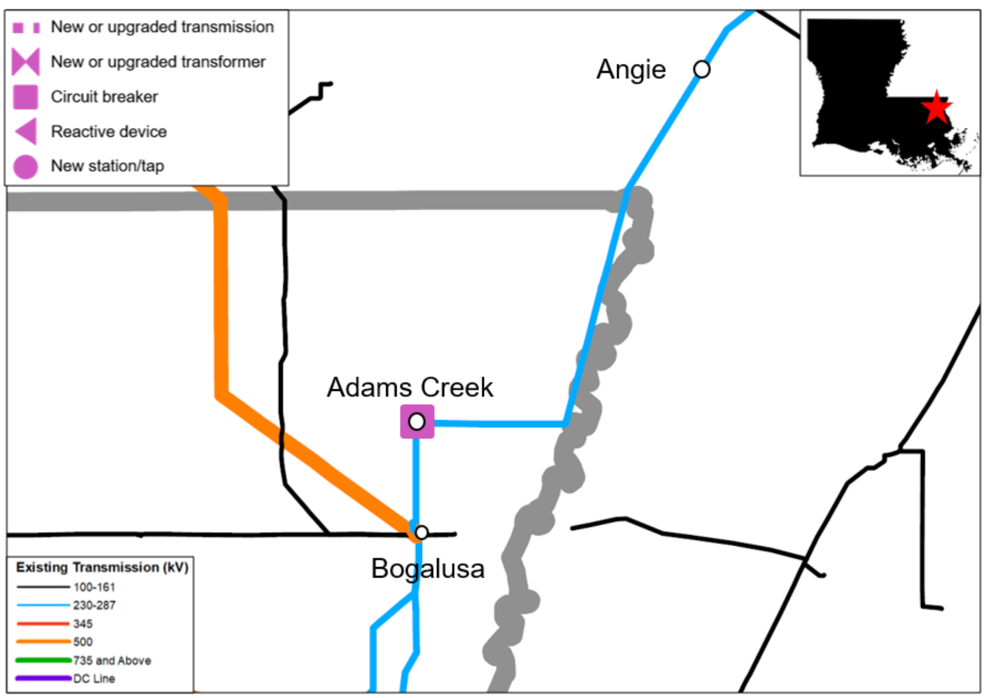
Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P1.2	Champagne - Plaisance 138 kV	278	110	75
P2.1	Champagne - Plaisance 138 kV	278	108	70
P2.3	Champagne - Plaisance 138 kV	278	109	71
P3	Champagne - Plaisance 138 kV	278	115	78

Table 4.4-#15584-1: Thermal loading drivers

Project 15587 – Adams Creek 230 kV: Add Breaker

Project Description

Add a redundant 230 kV breaker at Adams Creek 230 kV substation. The project's estimated cost is $0.9 million and the estimated in service date is June 1, 2021.



MISO, using Ventyx Velocity Suite © 2014

Figure 4.4-#15587-1: Geographic transmission map of project area

Project Need

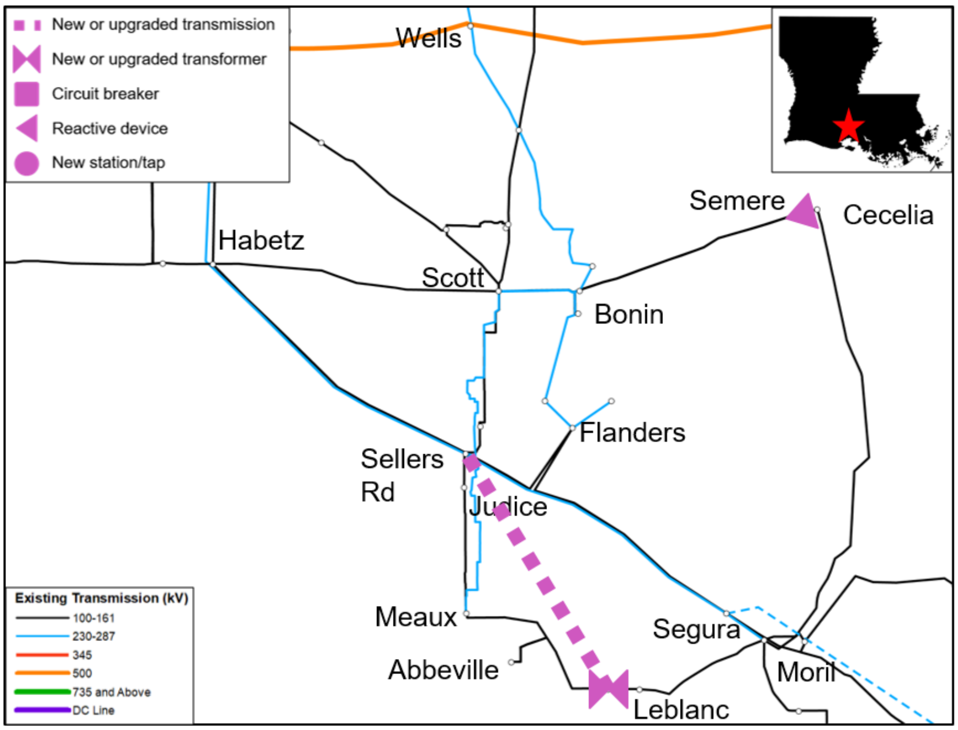
An internal breaker fault will overload the Adams Creek to Bogalusa 230 kV line circuit 2. Adding the additional breaker will eliminate the contingency that causes the overload.

Project 17044 – Sellers Leblanc Project (SLP)

Project Description

The Sellers Leblanc Project, along with MTEP 17045, is replacing MTEP17/18 projects 12101 East ALP and 12112 North ALP. The projects changed through significant collaboration between CLECO, Entergy, Lafayette Utilities System, and MISO to develop a lower cost solution. The proposed $84M alternative is a joint solution between CLECO and Entergy – Louisiana and will save customers $115M compared to the original ALP projects.

The Sellers Leblanc Project will construct a new Sellers Road to Conrad 230 kV line (operate at 138 kV); which is approximately 19.2 miles based on preliminary routing. Add a 138 kV line breaker, switches, bus, etc. at the Conrad Substation. Add a 138 kV series reactor at the Cecelia 138 kV Substation on the line to Bonin. Reroute the existing Gecko to Cecelia 69 kV line (to facilitate the 230 kV line construction). The project's estimated cost is $69.9 million and the estimated in service date is December 1, 2021.



MISO, using Ventyx Velocity Suite © 2014

Figure 4.4-#17044-1: Geographic transmission map of project area

Project Need

In the Lafayette area of Louisiana approximately 380 MW of load is served by the Judice, Meaux, Abbeville, Leblanc and Delcambre substations. These substations are served by well-networked hubs, the Moril and Scott substations, as well as a 230/138 kV transformer at the Meaux substation. Loss of two of three of these sources caused loading up to 137 percent of the capacity of the single remaining source. Up to 150 MW of load shed is required to mitigate the excessive flows. Table 4.4-#17044-1 shows the thermal loading of various limiting elements during different events with and without this project in service.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P2.2	Cecelia – Bonin 138 kV	145	101	84
P2.4	Cecelia – Bonin 138 kV	145	111	91
P6	Scott - Judice 138 kV	241	137	83
P6	Delcambre – Moril 138 kV	251	125	60
P6	Meaux – Abberville 138 kV	233	111	64
P6	Cecelia – Bonin 138 kV	145	111	78

Table 4.4-#17044-1: Thermal loading drivers

Alternatives Considered

This project, along with MTEP 17045, is replacing MTEP17/18 projects 12101 East ALP and 12112 North ALP to save customers $115M.

Other Projects

Other projects 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, interconnect new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plants, 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. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Project 17606 – Ponchatoula 230 kV: Add Breakers and Transfer Bus

Project Description

This project was submitted late due to Entergy's Operating Company realizing the work could be completed and considered a transmission upgrade for this cycle to enhance local reliability. Entergy is proposing to add line breakers and a transfer bus at the existing Ponchatoula 230 kV substation in South Louisiana. Ponchatoula 230 kV station currently does not contain transmission breakers or a transfer bus. The estimated in service date is December 1, 2021 and the estimated cost is $5.2 million.

Project Need

This project will reduce exposure to the large amount of customers served from the Ponchatoula 230 kV station to a line fault. This project also addresses operational concerns and provides flexibility during planned and unplanned outages.

Project 17608 – Michigan 230 kV Substation: Cut in Nelson to Manena 230 kV

Project Description

This project was submitted late due to Entergy's Operating Company realizing the work could be completed and considered a transmission upgrade for this cycle to enhance local reliability. Entergy is proposing to cut the new Nelson to Manena 230 kV line, project ID# 10008, in and out of the Michigan 230 kV station. The estimated in service date is December 1, 2020 and the estimated cost is $10.6 million.

Project Need

This project will reduce exposure to customers served in the area on the 230 kV system. This project also addresses operational concerns and provides flexibility during planned and unplanned outages.

Projects driven by local reliability

The following projects are driven by local planning criteria or by operational flexibility and do not meet requirement for BRP.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15569	Port Hudson to Blount 69 kV: Upgrade Switches	Upgrade substation equipment which is currently de-rating the conductor on this circuit.	Jun. 1, 2021	LA	$3.9M
15586	Ninemile S2015: Close Normally Open Breaker	Return breaker S2015 to its normally closed operating condition.	Jun. 1, 2020	LA	$0.0M
15602	Move Nesser Normally Open Point	Create a new normally open point by closing Switch 20647 and opening Switch 20648. Nesser will be served from a Tap on the Tiger to East line rather than the Harelson to Jonescreek line.	Jun. 1, 2021	LA	$1.72M
15603	Coly to DEMCO Coly 69 kV Upgrade	Upgrade Coly to DEMCO Coly 69 kV through path ratings for circuit 1 and circuit 2.	Jun. 1, 2021	LA	$1.84M

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
12744	Cotton 230 kV: Construct New Substation	Construct new distribution substation in southwest Ouachita Parish to serve area load.	Jun. 1, 2021	LA	$16.9M
13956	Goos Ferry 230 kV: New Substation	Goos Ferry substation with high side breakers will cut in on the Gillis to Chalkley 230 kV line section.	Jun. 1, 2022	LA	$21.2M
13985	Henry 69 kV: New Line and Substation	Henry 69 kV substation will cut in and out of the Five Points to Line 281 Tap 69 kV line section. There will be additional 69 kV line built from the cut in point to the new station depending on its location.	Jun. 1, 2022	LA	$21.9M
15626	Colyell Creek 230 kV: New Substation	Construct a new 230 kV distribution station on the French Settlement to Springfield 230 kV line section. The new station will be near the French Settlement 230 kV station.	Dec. 1, 2021	LA	$26.1M

16544	Riverview 138 kV: New Customer Station	Construct a new 138 kV substation which will serve an existing customer's ~5 MW load. The industrial load is currently being served on distribution facilities sourcing from the Cohen 230 kV station. The interconnection will cut in and out of the existing 138 kV line between Wilbert and Louisiana Station.	Apr. 9, 2019	LA	TBD

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed. The interconnection customer funds these projects.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16566	J683 Interconnection: Construct 138 kV Switching Substation	Construct a 138 kV 3 breaker ring bus on the Wilbert to Livonia 138 kV line.	Oct. 30, 2020	LA	$2.3M
16570	J581 Interconnection: Construct 115 kV Switching Station	Construct a 115kV 3 breaker ring bus on the Sterlington - Bastrop 115kV line section.	Dec. 31, 2021	LA	$8.13M
16571	Galion 115 kV: Install Transmission Line Bay and Breakers (J544 Interconnection)	Install transmission circuit breakers at the Galion 115kV substation.	Sep. 15, 2021	LA	$6.47M

4.4.8 Entergy Mississippi LLC (EML)

Based on TO submission and MISO independent assessment, Entergy Mississippi LLC will have eleven projects for inclusion in Appendix A at an estimated cost of $130 million. Of the eleven projects, three are Baseline Reliability Projects, six are Other Projects, and two are Generation Interconnection Projects.

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."

Project 9823 – Franklin 500kV Reconfigure

Project Description

Reconfigure the Franklin 500kV EHV substation so that the Franklin – Bogalusa and Franklin – McKnight 500 kV lines do not share a common breaker. This project's estimated cost is $26.3 million and has an estimated in service date of December 1, 2022.

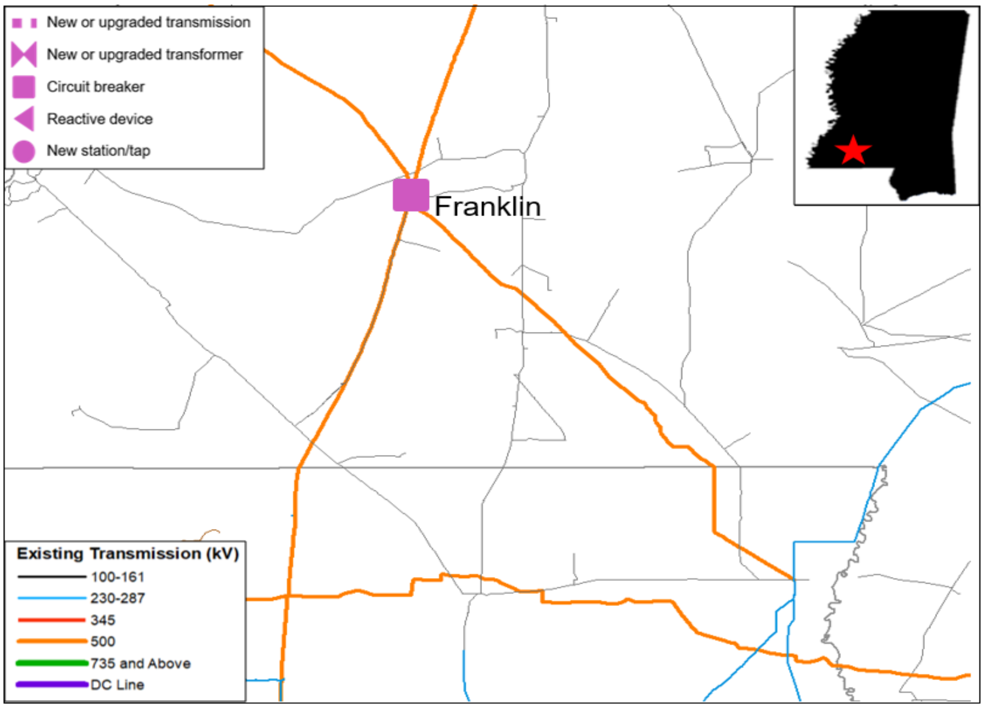


Figure 4.4-#9823-1: Geographic transmission map of project area

Project Need

An internal breaker fault at the Franklin 500kV substation causes a thermal overload on Liberty to Amite 115 kV and McComb to Fernwood 115 kV. Reconfiguring the Franklin 500 kV substation so that the Franklin – Bogalusa and Franklin – McKnight 500 kV lines do not share a common breaker invalidates the contingency and mitigates the overloads.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P23	Liberty – Gillsburg - Amite 115 kV	112	134	NA[15]
P23	McComb – Oakdale– Ferwood 115 kV	199	110	NA[15]

Table 4.4-#9823-1: Thermal loading drivers

[15] Contingency is no longer valid due to project.

Project 13955 Northpark: Install 230/115 kV Autotransformer

Project Description

Install 3-phase, 400 MVA, 230/115 kV autotransformer at Northpark Substation. Rebuild the Northpark to Country Club 115 kV line section. This project's estimated cost is $15.6 million with an estimated in service date of June 1, 2023.

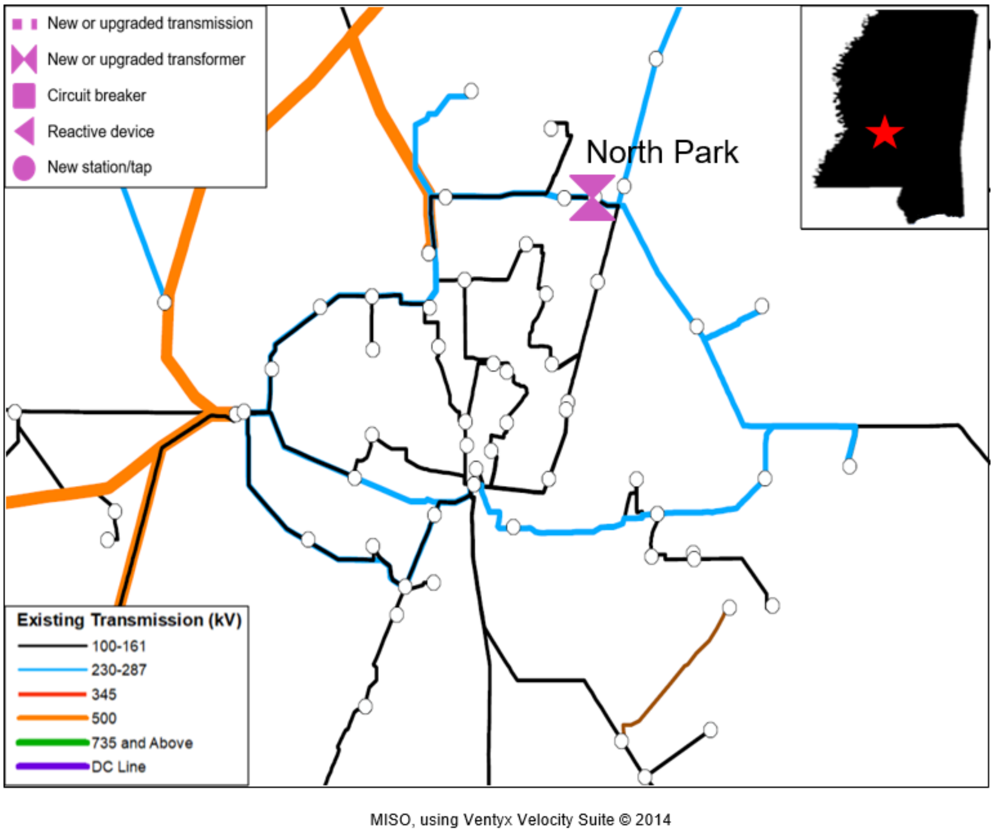


Figure 4.4-#13955-1: Geographic transmission map of project area

Project Need

An internal breaker fault causes a thermal overload on the Rex Brown 230/115 kV autotransformer. Installing a new 230/115 kV autotransformer at Northpark allows for another feed to the underlying 115 kV network and alleviates the loading on the Rex Brown 230/115 kV autotransformer. An internal breaker fault at Rex Brown 115kV substation causes thermal overloads on the Northpark - Country Club 115 kV line section.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P23	Rex-Brown 230/115 kV autotransformer	392	112	97

Table 4.4-#13955 -1: Thermal loading drivers

Project 15729 Centreville 115kV: Install Cap Bank

Project Description

Install 10.8 MVAR capacitor bank at Centreville 115 kV substation. This project's estimated cost is $1.9M with an estimated in service date of December 1, 2020.

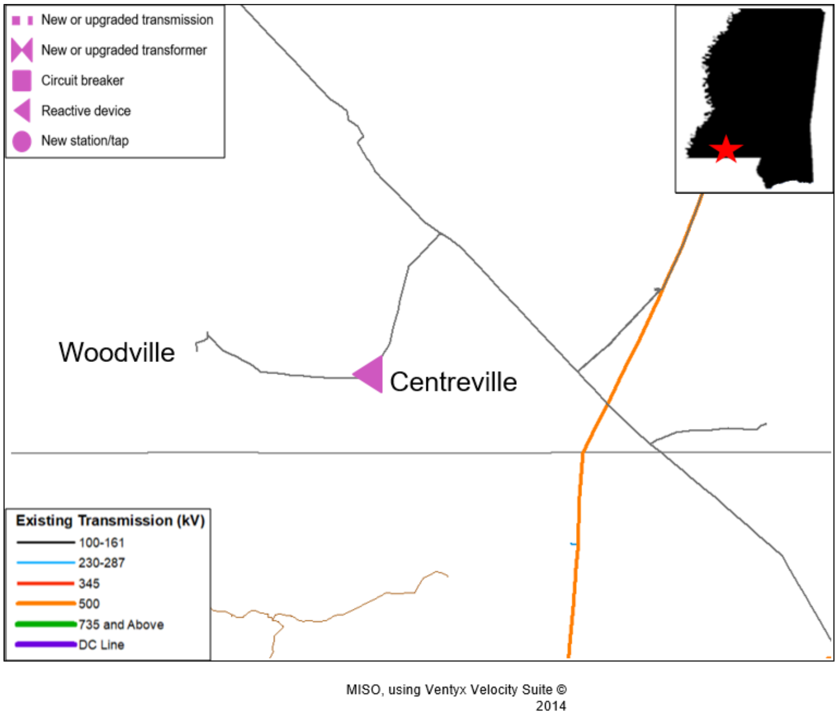


Figure 4.4-#15729-1: Geographic transmission map of project area

Project Need

The loss of a shunt device and a bus section fault cause low voltage at Centreville and Woodville. Installing a new capacitor bank at the Centreville 115 kV substation raises the voltage and mitigates the violations.

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P14	Woodville 115kV	0.92	0.90	0.94
P22	Woodville 115kV	0.92	0.88	0.93
P14	Centreville 115kV	0.92	0.91	0.95
P22	Centreville 115kV	0.92	0.89	0.94

Table 4.4-#15729-1: Voltage performance drivers

Other Projects

Other projects 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, interconnect new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plants, 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. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Project 13932 – Catlett Road – South Canton 230kV: New Line

Project Description

Tap the Bozeman to Tinnin 230kV line and build a new breaker station called Catlett Road. Build 5 miles of 230kV line from Catlett Road to South Canton. The project's total estimated cost is $58.9 million and the estimated in service date is December 1, 2022.

Project Need

This project is needed for enhanced transmission reliability. For the loss of McAdams to Pickens 230kV and South Canton to Yandell Road 230kV there is approximately 50MW of load at risk. This project will allow for another feed and increase reliability of service.

Project 13959 – Fernwood 115kV: Install Transmission Breakers

Project Description

Install transmission breakers at Fernwood 115kV substation. The project's total estimated cost is $5.2 million and the estimated in service date is December 15, 2019.

Project Need

This project is needed for enhanced transmission reliability. Installation of transmission breakers on the Kentwood – McComb 115kV circuit will improve customer performance along this transmission circuit which serves a large amount of customers. Scope of the project allows for a short lead time.

Project 15710 – Cleveland 115kV: Install Transmission Breakers

Project Description

Install transmission breakers at Cleveland 115kV substation. The project's total estimated cost is $5.7 million and the estimated in service date is December 15, 2019.

Project Need

This project is needed for enhanced transmission reliability. Installation of transmission breakers on the Delta SES Switchyard – Indianola 115kV circuit will improve customer performance along this transmission circuit which serves a large amount of customers. Scope of the project allows for a short lead time.

Project 15709 – Clinton 115kV: Install Circuit Breakers

Project Description

Install transmission breakers at Clinton 115kV substation. The project's total estimated cost is $6.15 million and the estimated in service date is December 31, 2025.

Project Need

This project is needed for enhanced transmission reliability. Installation of transmission breakers on the Ray Braswell EHV – Rex Brown SES Switchyard 115kV circuit will improve customer performance along this transmission circuit which serves a large amount of customers.

Projects driven by local reliability

The following projects are driven by local planning criteria or by operational flexibility and do not meet requirements for Baseline Reliability Project.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
13958	Horn Lake 230/161 kV: Energize autotransformer	Energize the existing 230/161 kV auto at Horn Lake.	Dec. 31, 2022	MS	$0.20M
15712	South Jackson – Florence 115 kV: Terminal Equipment	Upgrade a 115 kV switch at the Florence substation in order to increase the rating of the South Jackson – Florence 115 kV line to 260 MVA	Jun. 1, 2020	MS	TBD

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed. The projects are funded by the interconnection customer.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16565	J679 Interconnection: Construct a 115kV Switching Station	Construct an 115kV 3 breaker ring bus on the Greenwood – Winona 115kV line.	Apr. 15, 2021	MS	$2.7M
16568	Ruleville 115kV: Install Transmission Line Bay and Breakers (J604 Interconnection)	Install breakers at the Ruleville 115kV substation.	Mar. 15, 2021	MS	$7.4M

4.4.9 Entergy New Orleans LLC (ENO)

Based on TO submission and MISO independent assessment, Entergy New Orleans will have two projects for inclusion in Appendix A at an estimated cost of $17 million. Of the two projects, one is categorized as Other project, and one is categorized as a Generation Interconnection project.

Other Projects

Other projects 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, interconnect new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plants, 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. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by local reliability

The following projects are driven by local planning criteria or by operational flexibility and do not meet requirement for BRP.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15600	Lower Coast 230kV : Add Breaker	Install transmission breakers at the existing Lower Coast 230 kV substation	Jun. 20, 2021	LA	$2.1M

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16045	New Orleans Power Station Interconnection Project	Install breakers, jumpers, and all other station work at Michoud 115 kV to accommodate the interconnection of the New Orleans Power Station.	Feb. 28, 2020	LA	$9.35M

4.4.10 Entergy Texas Inc. (ETI)

Based on TO submission and MISO independent assessment, Entergy Texas Inc. (ETI) will have seven projects for inclusion in Appendix A at an estimated cost of $113 million. Of these seven projects, six of these projects are classified as Other Projects and one project is classified as a Generation Interconnection Project.

Other Projects

Other projects 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, interconnect new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plants, 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. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by local reliability

The following projects are driven by local planning criteria or by operational flexibility and do not meet requirement for BRP.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15647	Dayton Series Capacitor Bank: Operate Normally Open	Operate the Dayton series capacitor bank normally open. Some station and relay work is required to accomplish this.	Jun. 1, 2021	TX	$0.4M

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
13941	Veteran 230 kV: New Substation	Construct a new Veteran 230 kV substation and cut in and out of Lewis Creek - Rocky Creek 230 kV line.	Jun. 1, 2022	TX	$34.5M
13944	Colony 230 kV: Construct New Substation	Construct a new 230 kV substation on the Porter to Timberland 230 kV line near Colony Rd.	Jun. 30, 2023	TX	$36.5M
15650	ONTF 138 kV: New Station	Construct a 138 kV station between the Union and Stonegate 138 kV stations.	Jun. 1, 2020	TX	$8.1M
16324	Foreman 69 kV: New Customer Station	Entergy is proposing to construct a new 69 kV substation (Foreman 69	Dec. 31, 2019	TX	$12.1M

		kV Substation) which will serve an existing industrial customer's ~22 MW of load in Orange County, TX.			
17611	Star Bayou 230 kV: New Customer Substation	Entergy is proposing to construct a new 230 kV substation (Star Bayou 230 kV Substation) which will serve an industrial customer's 3.8 MW of existing load in addition to 14 MW of new load in Orange County, TX.	Jun. 1, 2020	TX	$11.9M

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed. The interconnection customer funds the project.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16572	J483 Interconnection: Construct 138 kV Switching Substation	Construct a 138 kV 3 breaker ring bus cut into the Stilson to Gordon 138 kV line.	Sep. 1, 2020	TX	$9.5M

4.4.11 Lafayette Utilities System (LAFA)

Lafayette Utilities Systems submitted no projects for MTEP19.

4.5 Project Justifications – West Region

West Region Overview

The MISO West Planning Region consists of nineteen 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. It contains approximately 31,000 miles of transmission ranging from 57 kV to 500 kV.

In the 2021 Summer Peak planning model, the region contains more than 55.8 GW of generation. Installed generation capacity in the region consists mostly of coal, gas and wind. Approximately 32.5 percent (18.1 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).

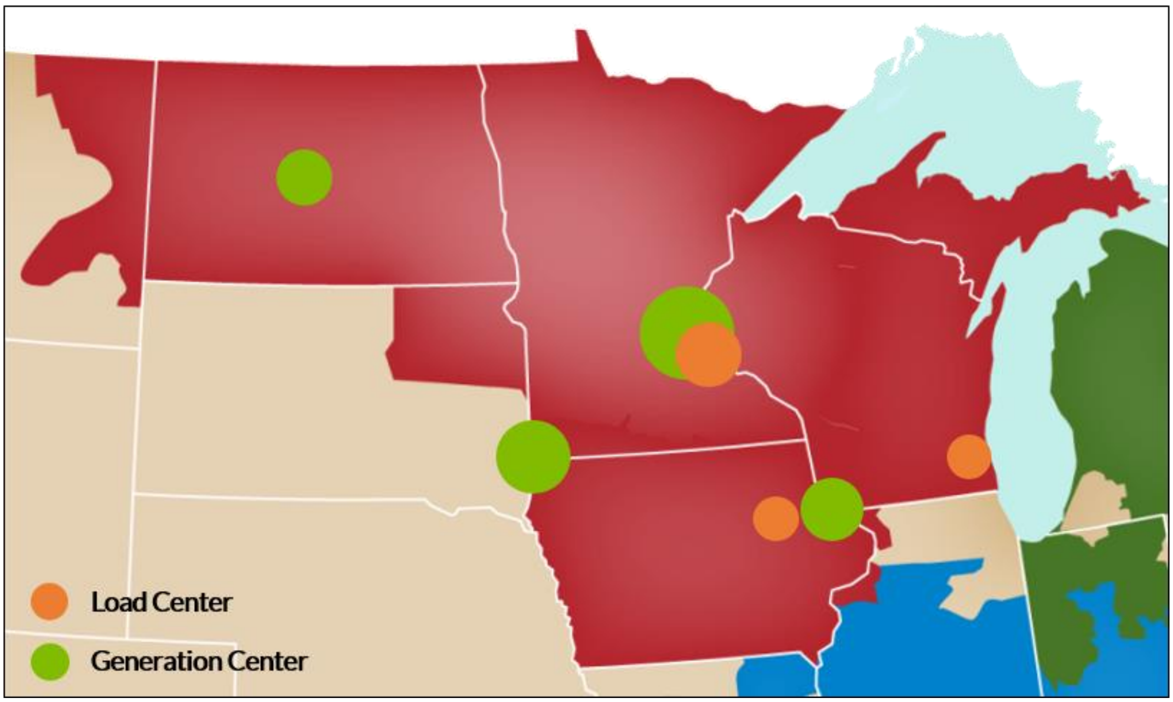


Figure 4.5-1: Generation and load centers in the West Planning Region

Major load centers are typically found around larger cities in the region: Minneapolis/Saint Paul, Milwaukee and Des Moines. According to the 2021 Summer Peak planning model, the regional load exceeds 35.3 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.

During the MTEP19 cycle, MISO received the following projects through the Expedited Project Review (EPR) process. The construction schedule for these projects was driven by new customers requesting to connect to the grid on an expedited basis:

1. MTEP ID #14364 GRE Swenoda 115 kV Distribution Substation
2. MTEP ID #16065 SMMPA West Owatonna Substation – 161 kV Load Interconnection
3. MTEP ID #16685 ITC Midwest Nevada 19th St Expansion
4. MTEP ID #16686 ITC Midwest Garner Galls Creek 161 kV Interconnection
5. MTEP ID #16687 ITC Midwest Clinton 2nd Ave – Clinton North 6-mile 69 kV Rebuild

As of October 18, 2019, 142 projects are recommended for inclusion in Appendix A at an estimated cost of $789.5 million. Of these, thirteen are Baseline Reliability Projects, twenty-one are Generation Interconnection Projects, and one is a Market Participant Funded Project. The remaining 107 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 these 142 projects, 34 have an estimated cost of less than $1 million, 50 have an estimated cost greater than $5 million, and 58 are estimated to cost between $1 and $5 million (see Figure 4.5-2 for the breakdown by project type). Additionally, most projects are expected to go into service within three years (Figure 4.5-3).

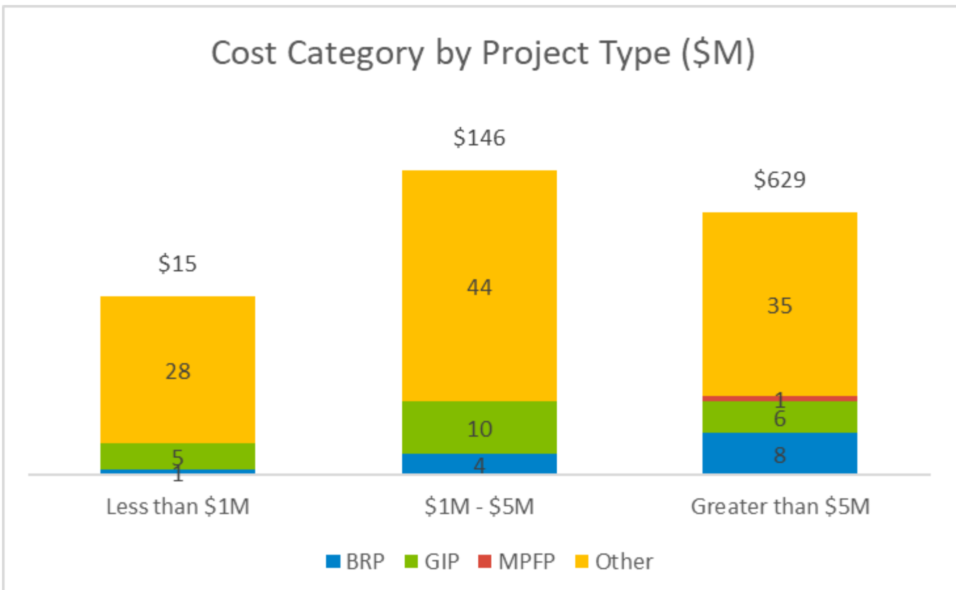


Figure 4.5-2: Project cost category by project type for MTEP19 West projects. (Project data as of October 18, 2019)

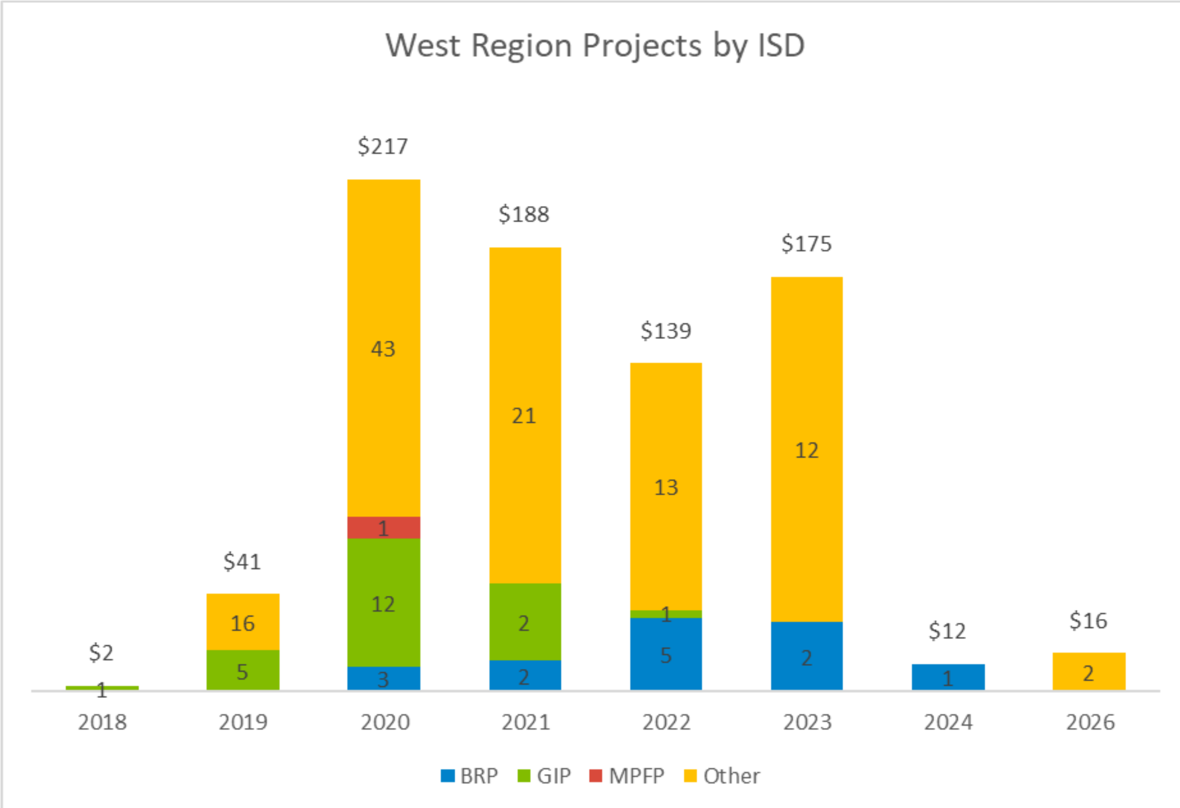


Figure 4.5-3: Project in-service date by project type for MTEP19 West projects. (Project data as of October 18, 2019)

The ten most expensive projects represent $263 million of the $789.5 million total recommended projects for the West in MTEP19. 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.

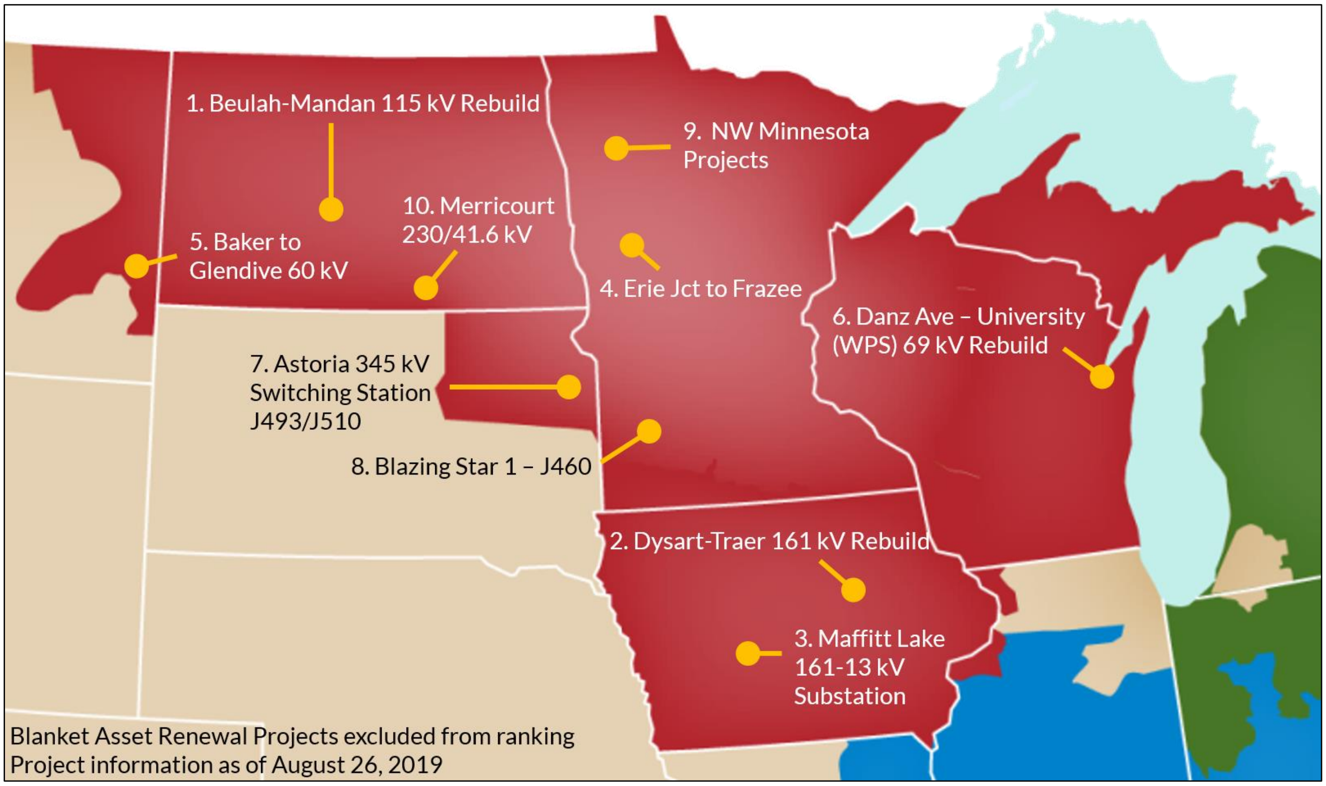


Figure 4.5-4: The ten most expensive projects in the West Planning Region for MTEP19

4.5.1 American Transmission Company (ATC)

For American Transmission Company, 22 projects are recommended for MISO Board of Directors' approval in the MTEP19 planning cycle. Two are baseline reliability, four are generator interconnection requests, and 16 are classified as Other projects related to age and condition, load growth, local reliability, and other local needs (physical security and communications).

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."

Project 15345– Presque Isle – Tilden 138 kV, loop and uprate

Project Description

Reconfigure the existing Presque Isle - Tilden 138kV line to loop into the existing National substation, uprate the National - Tilden portion of the 138kV line, and relay and circuit breaker replacements driven by asset renewal at the National SS control house. The estimated in service date is December 31, 2022 with an estimated total cost of $12M.

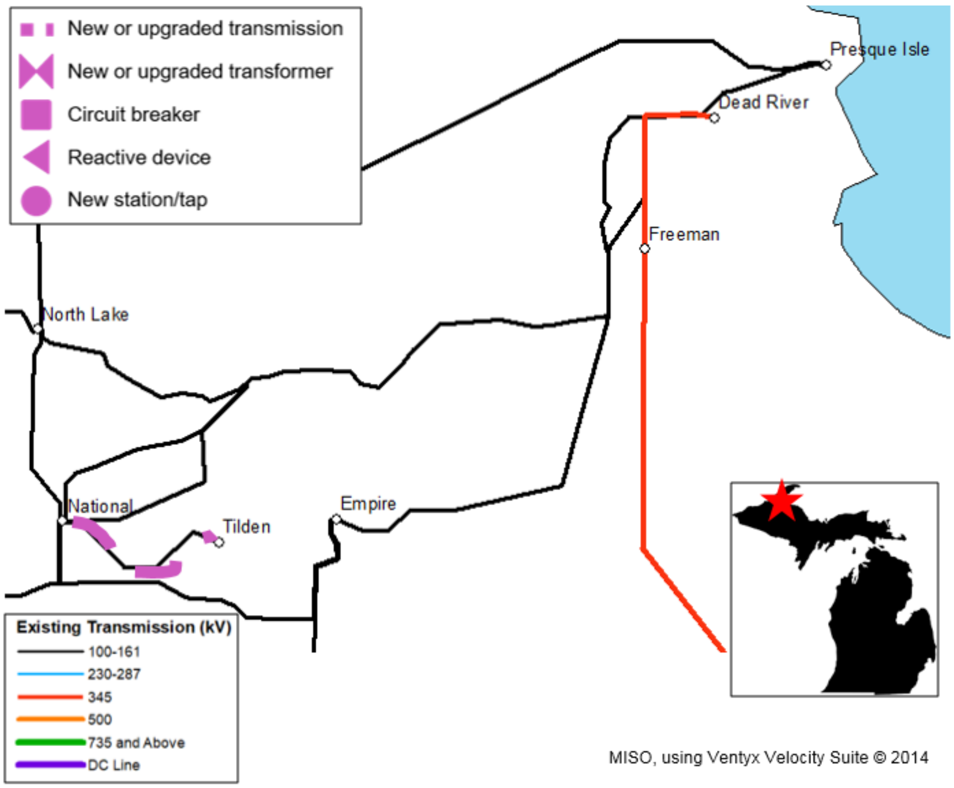


Figure 4.5.1-#15345-1: Geographic transmission map of project area

Project Need

There are three existing lines connecting the Tilden 138 kV substation to the existing transmission system: two from National and one from Presque Isle. Studies have shown that during contingencies, such as a P6 or maintenance plus P1.2 which remove both National-Tilden lines, large overloads (exceeding 170% of emergency rating) will occur on the existing Presque Isle-Tilden 138kV line and low voltages (<90% of nominal) at Tilden are observed.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P22	Tilden – Presque Isle 138 kV	104	179	Proposed project eliminates this contingency
P23	Tilden – Presque Isle 138 kV	104	179	Proposed project eliminates this contingency

Table 4.5.1-#15345-1: Thermal loading drivers

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P22	Tilden 1,2,3,4 138 kV	0.90	0.89	Proposed project eliminates this contingency
P23	Tilden 1,2,3,4 138 kV	0.90	0.89	Proposed project eliminates this contingency

Table 4.5.1-#15345-2: Voltage performance drivers

Project 4730– Portage – Columbia 138 kV (X-13/X-20), rebuild existing double circuit

Project Description

This project is to resolve thermal overloads under contingency conditions on either the X-13 or X-20 lines between Portage and Columbia. Lines X-13 and X-20 are double circuit 138kV system elements approximately 5.7 miles long from Portage Substation to Columbia Substation. This project will uprate the circuit rating of these lines to 1300/1800 A Normal/Emergency for all seasons. The estimated in service date is June 1, 2024 with an estimated total cost of $11.5M.

Project Need

MISO ‘s analysis of the 5 and 10 year MTEP19 models have shown that P6 events that remove one of the two 138 kV circuits between Columbia and Portage will cause high thermal loadings on the remaining in-service circuit. The increased normal and emergency ratings for this project reduce all the thermal loadings associated with the outage of X-13 or X-20 in the MISO MTEP models.

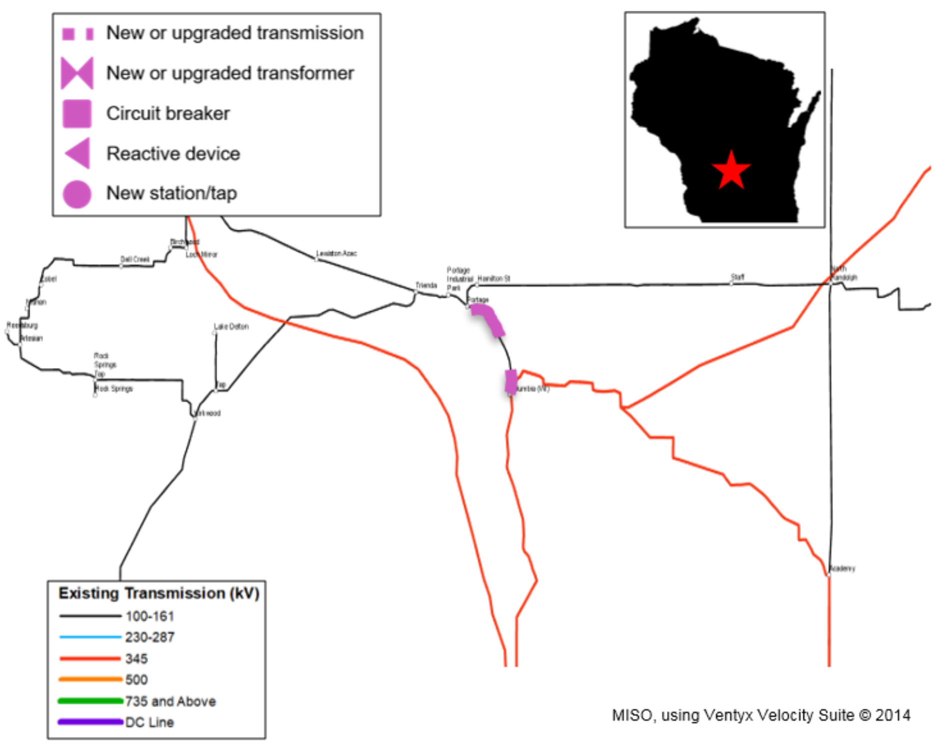


Figure 4.5.1-#4730-1: Geographic transmission map of project area

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Portage – Columbia ckt 1,2 138 kV	403	114	89

Table 4.5.1-#4730-1: Thermal loading drivers

Other Projects

Project 15947 – Waupaca Area Energy Storage as Transmission Only Asset (SATOA) Project

Project Description

This project is proposed to install a total of 5 MWh of energy storage batteries in the Waupaca area. The proposed battery location will be at Harrison North substation, which will consist of 2.5 MW of batteries with 5 MWh of energy, as illustrated in Figure 4.5.1-#15947-1. Additionally, an 8 MVAR 138 kV capacitor bank will be installed at the Arnott substation and a 6 MVAR 138 kV capacitor bank will be installed at the Harrison North substation. A bus upgrade will also be completed on the 69 kV Wautoma substation. Communication equipment will be installed for control. The battery will be installed to help address multiple outage issues (maintenance outage + NERC Category P1 or NERC category P6) during certain system load conditions and will provide operational flexibility to address these limitations. The estimated cost is $8.1 Million in 2019 dollars and the expected in-service date of the project is December 2021.

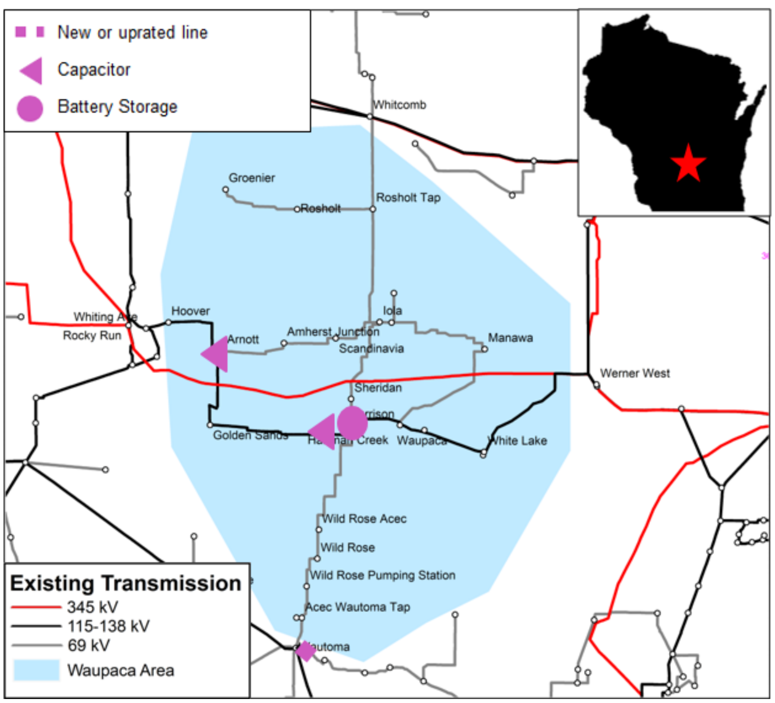


Figure 4.5.1-#15947-1: Geographic transmission map of project area

Project Need

The Waupaca area involves a local 69 kV system supported by nearby multi-segment 115 and138 kV transmission lines. When both ends of the 115 and138 kV supply lines are out of service (planned or forced) the local loads cannot be sustained. The existing solution is to utilize an operating guide at certain load levels (ATC Reference Guide) after the first outage to sectionalize the 69 kV system, creating radially served loads. This allows the loads to be served within applicable loading and voltage ratings after the first contingency, but places many radial loads at risk for consequential load loss, should another outage occur. This condition would persist for the duration of the initial planned or forced outage. The proposed project will eliminate the need for the operating step reducing the risk of load loss for area load levels covering over 90% of load levels historically experienced in this area, and allow for additional operational flexibility to plan maintenance outages

SATOA Modeling and Operation

The SATOA is modeled as offline, except for specific N-1-1 conditions, and is operated as a post contingency automatic action as prescribed in an operating guide that will be jointly developed by ATC and MISO. The operating guide will establish conditions for which the device should be discharged and/or charged to meet the anticipated needs. For the base case (system intact) the SATOA is offline and provides no real or reactive support. After the first N-1 event in the Waupaca area, system adjustments can be made to the local capacitors and transformers in preparation for the next N-1 event. The automatic operation of the SATOA will allow it to monitor voltages, line loadings, and line statuses in the area such that after the second N-1 event the SATOA will be automatically dispatched to control voltage and thermal violations, as defined in the operating guide. The extremely fast discharge capability of the storage device makes it uniquely positioned to provide this post contingency solution greatly reducing the hours at risk for load loss.

System performance of the SATOA and wires solution alternative

MISO evaluated system performance of the proposed SATOA compared to a traditional wire solution alternative. The wires alternative would rebuild the existing Hoover – Whiting Avenue 115 kV single circuit structures to double circuit and install a parallel second circuit, install a 10 MVAR capacitor at Arnott 138 kV, and upgrade the Wautoma 69 kV bus.

The analysis concluded that both the proposed SATOA and traditional wires solution provide comparable reduction in risk of load loss for the full 10 year planning horizon. All thermal loadings in the Waupaca area are reduced to less than or equal to their emergency ratings for various P6 events without the use of the existing ATC reference guide, as illustrated in Table 4.5.1-#15947-1.

Monitored Facility	Event Type	No Project	SATOA	Transmission Rebuild Alternative
		Max loading %	Max loading %	Max loading %
Wautoma - ACEC Wautoma Tap 69 kV	P6	143%	<100%	< 100%
Wild Rose Tap - Harrison Tap 69 kV	P6	115%	<100%	< 100%

Harrison - Harrison Tap 69 kV	P6	114%	<100%	< 100%

Table 4.5.1-#15947-1: Maximum thermal loading comparison of the proposed and alternative solutions

Similarly, both the SATOA and the wires alternative mitigate the voltage collapse and all facilities in the Waupaca area are within the emergency voltage range (0.9 to 1.1 pu), as illustrated in Table 4.5.1-#15947-2.

Monitored facility	Event Type	No Project Violation Count (worst voltage < 0.9)	Proposed SATOA Violation Count (worst voltage)	Wires Alt Violation Count (worst voltage)
Arnott 138 kV	P6	12	N/A	N/A
Arnott 69 kV	P6	13	N/A	N/A
Golden Sands 138 kV	P6	10	N/A	N/A
Harrison 138 kV	P6	10	N/A	N/A
Harrison 69 kV	P6	10	N/A	N/A
Hoover 115 kV	P6	10	N/A	N/A
Hoover 138 kV	P6	19	N/A	N/A
Harrison North 69 kV	P6	10	N/A	N/A
Harrison Tap 69 kV	P6	8	N/A	N/A
Hartman Creek 138 kV	P6	10	N/A	N/A
Waupaca 138 kV	P6	8	N/A	N/A
White Lake 138 kV	P6	8	N/A	N/A
Wild Rose 69 kV	P6	2	N/A	N/A
Wild Rose Tap 69 kV	P6	3	N/A	N/A

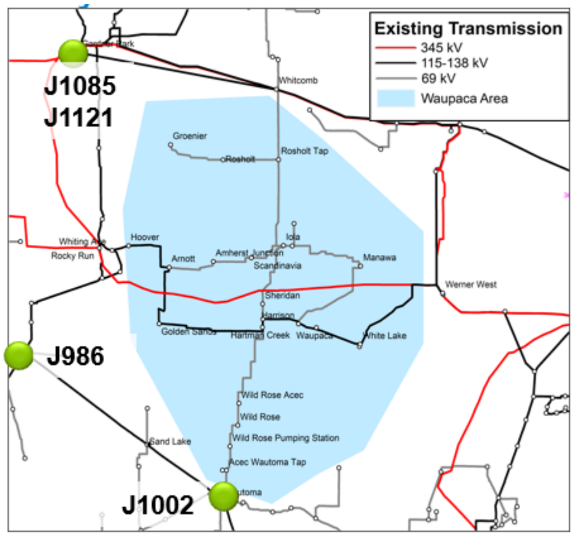
Table 4.5.1-#15947-2: Most severe voltage violations for the Waupaca Area

Life Cycle Cost Comparison

Recognizing different useful life of proposed SATOA and wires solutions, a 40 year life cycle cost analysis was conducted to compare the cost of the SATOA to the wires alternative by calculating the present value of the revenue requirements. The SATOA's battery technology estimates a 20 year useful life with a replacement cost of 50% of a new system to reach the 40 year expected life of a conventional wire solution. Augmentation is assumed to occur in year 4 and year 10 in each 20 year span of the battery's life. The operations and maintenance expenses include the anticipated contracted services and warranty costs, battery degradation, and argumentation, inverter replacements, station power, energy costs, and other general operating and routine maintenance costs, based on available vendor information. MISO and ATC collaboratively developed a financial analysis tool which compared the Present Value of the Revenue Requirements (PVRR) for the traditional wire alternative and the SATOA battery storage project. Life cycle cost comparison showed that the SATOA is a more cost effective solution compared to the traditional wires solution.

Generation Interconnection Impact Assessment

Generation resources currently in the generator interconnection queue were assessed to determine potential impacts from the operation of the SATOA battery storage device. Four resources in the interconnection queue have been sited near the Waupaca study area which were included in the assessment to compare loading impacts with and without the SATOA in the necessary operating mode prescribed to address reliability issues identified.



Project	Fuel Type	MW Size	DPP Cycle
J1085	Wind	300	2018-APR
J1121	Solar	200	2018-APR
J986	Solar	149.76	2018-APR
J1002	Solar	99	2018-APR

Figure 4.5.1-#15947-2: Location of interconnection requests

The interconnection requests were dispatched using the appropriate MTEP methodology and LBA tier order for ATC units. The targeted assessment evaluated the incremental impact of the SATOA on specific P6 and maintenance (prior outage + P1.2) events in the Waupaca area. As demonstrated in table 4.5.1-#15947-3, the SATOA does not negatively impact any of the identified generators in this area seeking interconnections in the MISO DPP process.

% of line flow changes			
Monitored Facility	Voltage Level (kV)	Contingency Category	Impact of SATOA (%)
Wautoma transformer	138/69	P6	-8%
Wild Rose Tap – Harrison Tap	69	P6	-15%
Harrison Tap - Harrison	69	P6	-15%
Wautoma – Wautoma Tap	69	P6	-49%

Table 4.5.1-#15947-3: percent of line flow changes with and without SATOA project

Based on the review of system performance and life cycle cost comparison between the SATOA and wires solution alternative as summarized in Table 4.5-#15947-4, MISO recommends the SATOA project as the preferred solution subject to outcome of pending FERC SATOA filing in the near future. For this reason the

Waupaca Energy Storage project is listed in Appendix B and MISO intends to move it into Appendix A after FERC's order on the SATOA filing without further analysis.

	Wire Solution	Non-Wire Solutions (proposed SATOA)
Solution Considered	Rebuild Whiting Avenue – Hoover 115kV as double circuit, install 10MVAR capacitor at Arnott 138kV substation and upgrade Wautoma 69kV bus	Install a 2.5MW/5MWh battery at Harrison North 138kV substation, and a 8 MVAR capacitor at Arnott 138kV and a 6 MVAR capacitor at Harrison North 138kV substation, and upgrade Wautoma 69kV bus
Reliability Performance	Address identified needs comparable load serving risk reduction	Address identified needs Comparable load serving risk reduction
Estimated Capital Cost ($2019)	$11.3M	$8.1M
Present Value of Revenue Requirements (PVRR) for 40 year Life cycle Costs	$13.07M	$12.24M
Overall Comparison	Comparable performance More expensive Need for expanded ROW No online time restrictions	Comparable performance Less expensive No public impacts on ROW 2-hour discharge period

Table 4.5.1-#15947-4: Comparison table of the proposed project and the wires solution alternative

Projects driven by local reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
7586	Atlantic SS, 138/69 kV Transformer Replacement and Bus Reconfiguration	Install a new 138/69 kV transformer Reconfigure the Atlantic substations 138 kV and 69 kV bus work	Dec. 31, 2022	MI	$6.60M
14912	Line Clearance Mitigation Projects 2020	Projects are driven by the ongoing assessment and analysis of field line clearances using Light Detection and Ranging (LiDAR) technology. Initial capital spend for this program expected in 2020.	June 30, 2023	WI, MI	$12.06M
15933	NLKG31 Tap - Greenstone SS 138 kV new T-line	ATC to create new 138kV tap from NLKG31 to UMERC's Greenstone substation.	June 1, 2022	MI	$5.20M

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
14906	Load Interconnection 2020	Load Interconnection Project life cycles are customer need driven and typically have shorter project life cycles. Initial capital spend for this program expected in 2020.	June 30, 2023	WI,MI	$26.77 M

Projects driven by age and condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
14908	Small Capital Project and Asset Renewal 2020	Structures, Cross-arm, Insulator, Surge-arrester, and Pole hardware replacements. Relays, Circuit breakers, Switches, Instrument Transformers (CTs & PTs etc.), Batteries, RTUs, and IT/OT/Communications hardware replacements. Initial capital spend for this program expected in 2020.	June 30, 2023	WI,MI	$35.91M
15457	Summit - Cooney 138kV (6431), rebuild	Rebuild Summit Cooney 138kV (6431) due to wood pole deterioration	Dec. 31, 2023	WI	$4.10M
15924	Danz Ave - University (WPS), 69kV (O-15), underground rebuild & OPGW	*Replace the existing O-15 underground cable and install OPGW	Dec. 31, 2023	WI	$15.85M
15925	Edgewater - Lodestar, 138/69kV, (X-48/Y-31), underground rebuild	Replace the existing X-48/Y-31 underground cable section	Dec. 31, 2022	WI	$11.40M
15928	Range Line Switchyard, Control House Replacement and Asset Renewal	Install a new control house, replace relays, and replace circuit breakers	Oct. 31, 2022	WI	$7.10M
15931	Erdman SS, Transformer and Circuit Breaker Replacements	Replace 138/69kV transformer including high side circuit switcher and circuits breaker	Dec. 1, 2021	WI	$7.00M
15932	Bain SS, Control House and Relay Replacement	Construct a new control house with new relay panels, relays, and circuit breakers	Dec. 1, 2021	WI	$8.50M

Projects driven by other local needs

The following projects do not appear to be driven by local reliability concerns, growing load, or the replacement of aging equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
14910	Communication Reliability Upgrades 2020	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. Initial capital spend for this program expected in 2020.	June 30, 2023	WI,MI	$11.34M
14914	Physical Security 2020	The Physical Security Program is guided by the NERC Standard CIP-014 and is designed to harden substation infrastructure. Initial capital spend for this program expected in 2020.	June 30, 2023	WI,MI	$21.60M
15935	Wautoma to Port Edwards, OPGW Installation	Install OPGW between Madison and the Appleton-Wausau area	Dec. 31, 2023	WI	$7.30M
15936	Stiles - West Marinette, OPGW Installation	Install OPGW between the Marinette - Menominee area	Dec. 31, 2023	WI	$5.60M

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16492	J849, Chandler SS, Interconnection Facilities and Network Upgrades	J849 Interconnection request is for a new 125 MW solar farm to be connected to the open 138 kV bus position at Chandler.	Jan. 27, 2022	MI	$3.04M
16493	J584 GIC Jordan SS, Generator Interconnection Facilities and Network Upgrades Information	Construct a new 69-kV substation and loop in the existing Blacksmith Tap - Spring Grove Tap 69-kV line (Y-33)	May 15, 2021	WI	$6.20M

16494	J928 - Garden Corner SS GIC Network Upgrades	This will be an expansion of the wind farm that is already at Garden Corners.	June 28, 2020	WI	$0.30M
17064	J928/J849 Indian Lake Common Use Upgrades	The ground grid upgrades at Indian Lake SS are split between the J928 and J849 interconnections.	Oct. 13, 2019	MI	$0.17M

4.5.2 Cedar Falls Utilities (CFU)

No projects are recommended from Cedar Falls Utilities for MTEP19 approval.

4.5.3 Central Minnesota Municipal Power Agency (CMMPA)

No projects are recommended from CMMPA for MTEP19 Appendix A.

4.5.4 City of Ames, IA

No projects are recommended from the City of Ames for MTEP19 Appendix A.

4.5.5 Dairyland Power Cooperative (DPC)

For MTEP19, Dairyland Power Cooperative has a joint Other project with Xcel Energy on Project 15724, Twin Town Substation, which is driven by local reliability. The details of this project are included in the Xcel Energy (Northern States Power) section of this chapter.

4.5.6 Great River Energy (GRE)

One baseline reliability project and ten other projects from GRE are recommended for the MTEP19 Appendix A.

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."

Project 15344 – Erie Jct to Frazee

Project Description

This project will construct the new Erie Junction substation, tapping the 230 kV line between Audubon and Hubbard. A new 115 kV line will be built from Erie Junction to the existing Frazee Substation. At Frazee substation, a new 30 MVAR cap bank will be added. Figure 4.5.6-#15344-1 shows a geographic map of the project area. Project 15344 is expected to cost $16.95 million and have an in-service date of November 30, 2023.

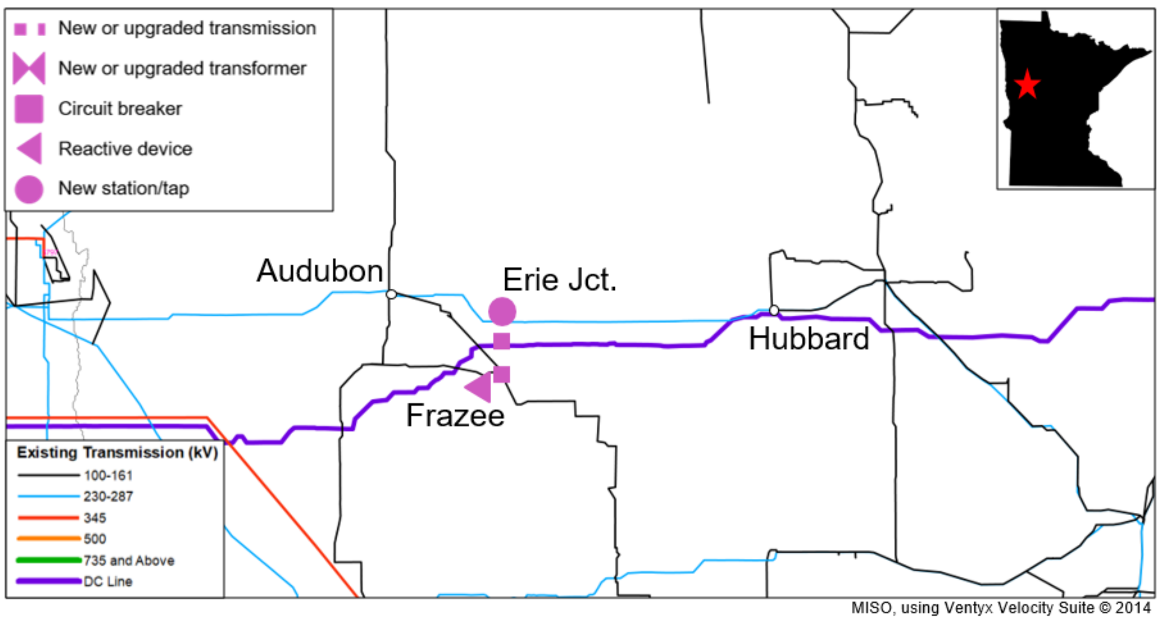


Figure 4.5.6-#15344-1: Geographic transmission map of Erie Junction to Frazee project area

Project Need

In this area, thermal overloads are seen for P12 and P21 category events and low voltages are seen for P21-P24 category events. This area has its local load peak in the winter. To justify this project, TO-supplied local peak levels were used and models with the local peak load were posted to the MTEP19 FTP site.

Tables 4.5.6-#15344-1 and 4.5.6-#15344-2 summarize the improvement in the area following the addition of this project. Note that the ratings listed in Table 4.5.6-#15344-1 are the emergency loading levels, which do not allow system adjustments to resolve. The voltage limit listed in Table 4.5.6-#15344-2 is the normal voltage limit, as the planning criteria require that the voltage return to this level using system adjustments following a contingency. However, in the area of this project, there are few options for system adjustments to raise the voltage, requiring the addition of the capacitor bank for support.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P12	Hoot Lake – Edgetown Tap 115 kV	132	101.2	98.0
P21	Pelican Rapids – Edgetown Tap 115 kV	88	115.3	99.4
P21	Pel. Turk Tap – Pelican Rapids 115 kV	88	104.9	89.7
P21	Hoot Lake – Edgetown Tap 115 kV	132	102.2	90.7

Table 4.5.6-#15344-1: Thermal loading drivers

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P21	Quadrant 115 kV	0.97	0.9421	1.0001
P22	DL OTP 115 kV	0.97	0.9362	1.0103
P23	DL OTP 115 kV	0.97	0.9385	1.0133
P24	Edgetown Tap 115 kV	0.97	0.9381	0.9746

Table 4.5.6-#15344-2: Voltage performance drivers

Alternatives Considered

Project 15344 was submitted after a targeted study involving the affected Transmission Owners. This study, called the Western Minnesota Load Serving Study, involved MRES, GRE, OTP, and MPC. Three broad alternatives were evaluated in that study, which was supplied to MISO through the MTEP Project Portal. Specific alternatives included upgrading the Audubon substation, upgrading Audubon plus adding a 115 kV line, and adding two new 115 kV lines in the area. The option submitted to MTEP was one of four that generally tapped the 230 kV line and added a new 115 kV line.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by local reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15745	Lake Eunice 115 kV Conversion	Convert the Lake Region Electric Cooperative (LREC)-owned Lake	Oct. 30, 2020	MN	$1.7M

		Eunice substation from 41.6 kV service to 115 kV service			
15775	Arrowhead Reliability Upgrades	Motor operators added to existing disconnect switches at Schroeder SS2558, Lutsen SS2877 and Taconite Harbor 42NS2. Reactive support added to the Arrowhead 69 kV system.	Apr. 03, 2020	MN	$2.2M

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
14364	Swenoda 115 kV Substation	Install a 3-way, 115 kV switch on GRE's AG-BK line and construct 3 mile of 115 kV line from the new 3-way switch to Agralite Electric Cooperative (AEC) Swenoda distribution substation	Feb. 19, 2019	MN	$1.6M
14365	Dublin 115 kV Substation	Install a 3-way 115 kV switch on GRE's AG-BK line and construct one span of 115 kV line from the new 3-way switch to Agralite Electric Cooperative (AEC) Dublin distribution substation	Feb. 28, 2020	MN	$0.6M
15764	Lismore 115 kV Interconnection	Move the Nobles Cooperative Electric's Lismore substation load from the 24 kV line between Fulda and Magnolia to the Fenton-Nobles 115 kV line and provide support to remaining 24 kV system with 115 kV interconnection	Oct. 30, 2020	MN	$1.6M
15773	Blaine II Substation	Add a second transformer to serve the Blaine II substation	Nov. 29, 2019	MN	$0.9M

Projects driven by age and condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15744	PD Line Rebuild	Rebuild 5.18 miles of the GRE PD 69 kV line from Harry Maser to the GRE EC-PAX line	Jun. 1, 2020	MN	$2.5M
15778	Dickinson breaker 62JB3 & JB4	Replace breakers 62JB3 & JB4 at Dickinson 345 kV	Jul. 1, 2020	MN	$1.3M
15781	Small Capital Projects and Asset Renewal - 2019	Breaker replacements for $730,048 Meter replacements for $1,050,000 RTU replacements for $499,000 Relay replacements for $1,558,451 Switch replacements for $496,893	Dec. 31, 2019	MN	$4.3M

Projects driven by other local needs

The following project does not appear to be driven by local reliability concerns, growing load, or the replacement of aging equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15782	Frog Creek 69 kV Bypass Switch	Install a one-way manually operated 69 kV switch at the intersection of Dahlberg Light and Power's 69 kV line and Great River Energy's BW line	Jun.5, 2019	MN	$0.4M

4.5.7 ITC Midwest (ITCM)

For ITC Midwest, one baseline reliability project and 21 other projects are recommended for MISO Board of Directors' approval.

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."

Project 10785 – Beaver Channel-Rock Creek 161kV Reconductor

Project Description

ITC will reconductor the Beaver Channel-Rock Creek 161 kV 3.68 mile line to 366 MVA capacity and upgrade the Beaver Channel 161 kV terminal 140 and the Rock Creek 161kV terminal 171. The will also require modifying the 69 kV circuit that is on the same structures. This project is expected to cost $3.3M and be in-service December of 2022.

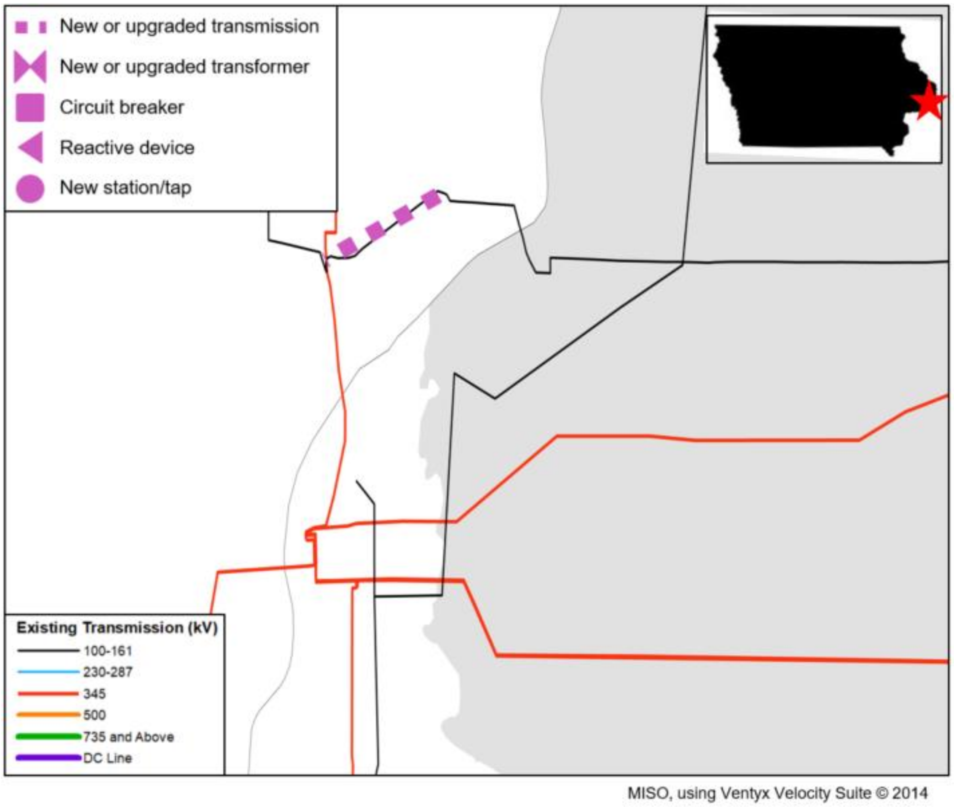


Figure 4.5.7-#10785-1: Geographic transmission map of project area

Project Need

The Beaver Channel to Rock Creek 161 kV line overloads during P6 events in the Quad Cities area. Loading on this line exceeds its thermal capabilities and ITCM does not permit load shedding as a corrective action plan.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
Base case	Beaver Channel – Rock Creek 161 kV	219	113.7	68.8

Table 4.5.7-#10785-1: Thermal loading drivers

Alternatives Considered

Connections between the Iowa side of the quad cities and the eastern 161 kV north/south run were considered. Each option would require new right-of-way and cost would far exceed the replacement of existing conductor.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by local reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15485	Asbury 161kV Breaker Additions	Add two 161kV line breakers, and a 161kV bus tiebreaker, a new control enclosure at the Asbury substation and Install OPGW on the 2.95 mile Lore-Asbury 161kV line section.	Dec. 31, 2021	IA	$4.3M
15486	South Grandview 161kV Breaker Additions	Add two 161kV line breakers, a bus tie breaker, and a new control enclosure	Dec. 31, 2020	IA	$2.9M

Projects driven by load growth

For the following projects, growing load is the primary driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15445	ITCM Customer Interconnects with short lead time 2022	Interconnection bucket for MTEP19	Dec. 31, 2022	IA	$2.4M
15446	Toledo Central 69kV Substation Interconnection	Two 69kV breakers will be installed at the Toledo Central Substation to accommodate a new IPL transformer	Dec. 30, 2023	IA	$1.4M
15449	Ottumwa Heights 161kV Substation Interconnection	Transmission in support of a new Ottumwa area 161 kV load serving substation	Dec. 31, 2021	IA	$9.8M
15450	Beaver Rock 69kV Terminal Addition	Construct a new line terminal at the Beaver Rock substation	Dec. 31, 2021	IA	$0.3M
15452	Anamosa White Fawn Substation 69kV Interconnection	In and out 69 kV transmission tap with associated high side buswork to support IPL dist. Interconnection	Dec. 31, 2019	IA	$1.5M
15453	Clarence South 69kV Substation Interconnection	69 kV transmission tap with associated high side buswork to support IPL dist. Interconnection	Dec. 31, 2022	IA	$2.1M
15454	Walford Terry 69kV Substation Interconnection	69 kV transmission work to support IPL dist. Interconnection	Dec. 30, 2022	IA	$2.7M
15484	Solon Big Grove 69kV Interconnection	69 kV transmission work to support IPL dist. Interconnection. A 34.5 kV connection will be extended to CIPCO	Dec. 31, 2020	IA	$2.4M
16685	Nevada 19th Street Expansion	Improve the Nevada 19th St substation for an Alliant expansion	Apr. 1, 2020	IA	$2.3M
16686	Garner Galls Creek 161kV Interconnection	ITC will construct a 4 position ring bus with a 36 MVAR rated (27.6 MVAR effective) capacitor bank that shares a position with one of IPL's transformers	Sept. 30, 2020	IA	$5.3M

Projects driven by age and condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15004	New London Tap 69kV Rebuild	Rebuild the existing 69kV New London tap to current 69kV standards using T2(2-4/0) conductor	Dec. 31, 2022	IA	$6.1M
15444	ITCM Asset Replacement Program 2022	ITCM Replacement program	Dec. 31, 2022	IA,MN,IL	$37.1M
15447	Belle Plaine North 69kV Substation Interconnection	ITC Midwest will build the 69kV portion of the new Belle Plaine North 69kV substation	Dec. 31, 2023	IA	$3.9M
15448	Williamsburg West 161kV Substation	The Williamsburg West Substation will be a 161kV Five (5) Position Ring Bus	Dec. 30, 2022	IA	$4.4M
15451	Mt Vernon 161-69kV Transformer Addition	At Mount Vernon substation a 100 MVA 161/69 kV transformer will be installed	June 1, 2022	IA	$6.7M
15455	Dysart-Traer 161kV Rebuild	ITC Midwest will rebuild the existing 15.93 mile 161kV circuit with T2 Hawk conductor	Dec. 31, 2021	IA	$26.5M
15456	Brooklyn-Malcom 69kV line & Grinnell 69kV Terminal	ITC Midwest will construct a new ~9 mile 69kV line from Brooklyn to the Malcom Tap	Dec. 31, 2026	IA	$10.7M

Projects driven by other local needs

The following projects do not appear to be driven by local reliability concerns, growing load, or the replacement of aging equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15024	Huntwoods-Sawyer IAAP 69kV Rebuild	Re-route the line segment requiring maintenance by constructing approximately 4.4 new miles of T2(2-4/0) 69kV line for accessibility	Dec. 31, 2020	IA	$6.5M
16687	Clinton 2nd Ave-Clinton North 6 mile 69kV Rebuild	Rebuild ~6.1 miles of old 4/0 ACSR line from the Clinton 2nd Ave sub to the Clinton North sub and retire the Clinton 2nd Street-Clinton South 69kV line.	Dec. 31, 2026	IA	$5.4M

4.5.8 MidAmerican Energy Company (MEC)

For MidAmerican Energy Company, two baseline reliability projects, three generation interconnection projects, one market participant funded project, and eighteen other projects are recommended for MISO Board of Directors' approval.

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."

Project 15678– Sub 17: New 161 kV Capacitors

Project Description

Install two 25 MVar capacitor banks at the existing Sub 17 location. This installation is expected to cost $1.5 M and be in service June 1, 2020.

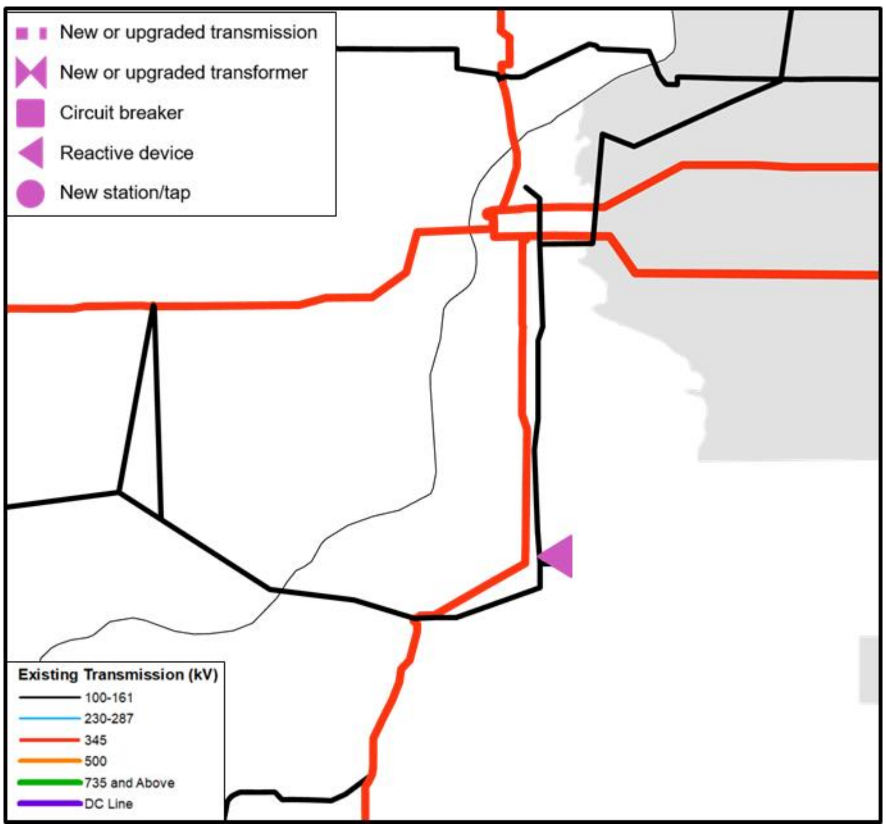


Figure 4.5.8-#15678-1: Geographic transmission map of project area

Project Need

P6 events in the Quad Cities drop voltage below criteria along the 161 kV path running through Illinois. No generation redispatch was found to alleviate these low voltages.

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	Sub 31 161 kV	0.93	0.90	0.964
P6	Sub 17 161 kV	0.93	0.906	0.97
P6	Sub 28 161 kV	0.93	0.901	0.965

Table 4.5.8-#15678-1: Voltage performance drivers

Alternatives Considered

Connections from the 161 kV system to the west of the Illinois were considered as an alternative to reactive support in Illinois. In addition to a line supplying the area, a 345/161 kV connection as considered at Cordova.

Project 15682– Neal South 161 kV Tap Lines

Project Description

Bring the Neal North – Salix Junction 161 kV line in and out to the Neal South substation. The Neal South substation will need to be expanded to accommodate the two new line terminations. This installation is expected to cost $6.5 M and be in service June 1, 2020.

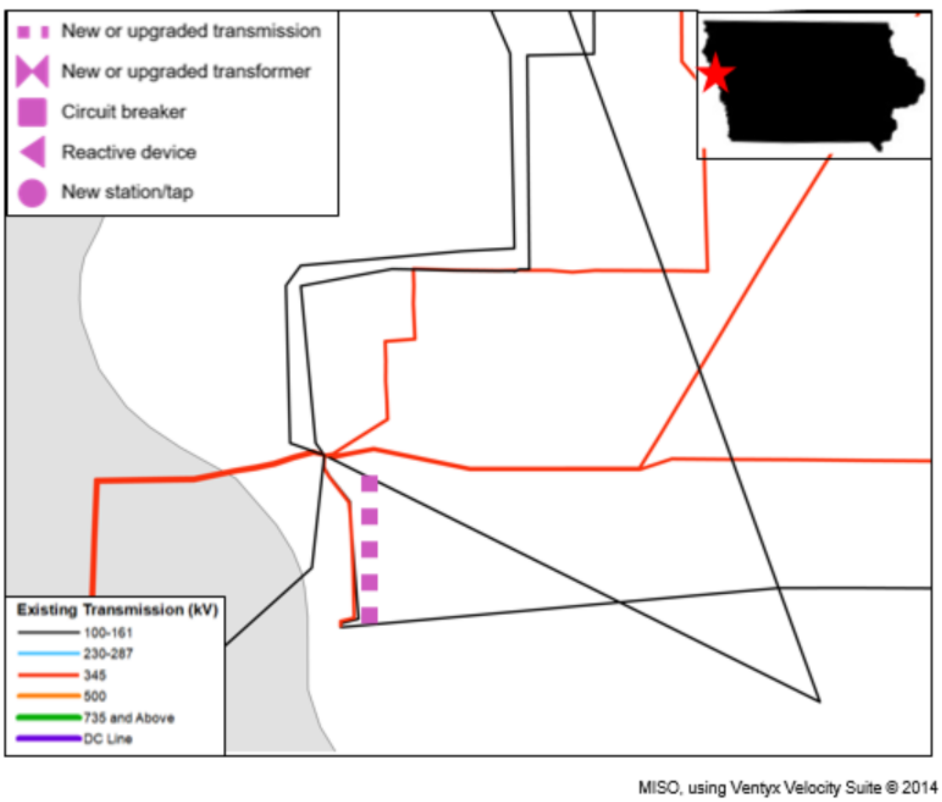


Figure 4.5.8-#15682-1: Geographic transmission map of project area

Project Need

Loss of two 161 kV lines in the area of the Neal substations can cause Neal South substation to become isolated to the high side of a 161/69 kV substation. This results in low voltages at the Neal South substation.

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	Neal South 161kV	0.93	Voltage Collapse	1.024

Table 4.5.8-#15682-1: Voltage performance drivers

Alternatives Considered

Installing reverse power relaying on the transformer feeding the Neal South substation was considered. It was preferred to continue to serve load in this area instead of relying on load shedding.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by local reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15669	Sub 701: Install 2nd 161-69 kV Transformer	Install a second 161-69 kV transformer and complete the 161 kV ring bus at Sub 701. Install two new 161 kV circuit breakers	June 1, 2021	IA	$4.2M
15674	John Deere West 69-13 kV Substation	Construct a new John Deere West 69-13 kV distribution substation adjacent to the existing John Deere Substation and retire the existing John Deere Substation	June 1, 2020	IA	$4.9M
15675	Dakota City 69 kV Switching Station	New Dakota City four-terminal 69 kV Switching Station tapping the MidAmerican Energy Humboldt East-Thor 69 kV line and the Corn Belt Power Cooperative Galbraith to Hope 69 kV line	June 1, 2020	IA	$4.9M
15679	Sub 56: New 161 kV Line Terminal	Add a new 161 kV line terminal at Sub 56 for a new CIPCO/MPW 161 kV line to Muscatine, Iowa	June 1, 2021	IA	$0.9M

15680	Sub A-Sub 84-Sub 55 69 kV Line Uprate	Replace structures to increase the allowable operating temperature of the line conductor on the Sub A-Sub 84 and Sub 84-Sub 55 69 kV lines	Nov. 1, 2019	IA	$0.6M
15684	Kellogg-Plymouth 69 kV Line Uprate	Replace structures on the Plymouth-Kellogg 69 kV line to increase the line rating	Dec. 31, 2020	IA	$0.25M

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
14784	50th Avenue NW Substation	New 161 kV distribution substation and associated 161 kV line reconfiguration and construction	Aug. 15, 2020	IA	$21.0M
15664	Indian Creek East 161 kV Substation Expansion	Expand the 161 kV ring bus and install two 161 kV circuit breakers and one transformer terminal	Nov. 1, 2019	IA	$2.0M
15667	Southland 345 kV Substation Expansion	Add two new 345 kV circuit breakers and two transformer terminals	Dec. 1, 2019	IA	$3.8M
15672	Maffitt Lake 161-13 kV Substation	Interconnect a new 161-13 kV substation and 9.5 miles of associated 161 kV line taps	June 1, 2020	IA	$23.7M
15673	SE Magazine Road 161-13 kV Substation	Interconnect a new SE Magazine Road 161-13 kV distribution substation tapping the Ankeny to NE Ankeny 161 kV line	June 1, 2020	IA	$1.1M
15677	Foster Road 161-13 kV Substation	Interconnect a new Foster Road 161-13 kV distribution substation bisecting the Sub P-Northgate 161 kV line	June 1, 2020	IA	$1.9M
16545	Ponderosa 161-13 kV Substation	Interconnect a new Ponderosa 161-13 kV Substation	June 1, 2021	IA	$2.8M
16605	Gilbertville 161-13 kV Substation	Interconnect a new Gilbertville 161-13 kV distribution substation on the Washburn-Hazleton 161 kV line.	June 1, 2020	IA	$1.3M

Project 16605 was submitted after the September 15th deadline on January 23, 2019.

Projects driven by age and condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15670	Glenwood: Rebuild 69 kV Substation	Rebuild the Glenwood 69-13.2 kV Substation	Dec. 1, 2020	IA	$0.4M
15683	Merrill North Substation Transformer and Line	Expand the Merrill North Substation 69 kV bus to install a second 69-12.47	Dec. 1, 2020	IA	$0.9

		kV transformer and second 69 kV line. Install two 69 kV line breakers and construct second 69 kV line into Merrill North Substation. Retire the existing Merrill Substation.			

Projects driven by other local needs

The following projects do not appear to be driven by local reliability concerns, growing load, or the replacement of aging equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15681	Raun Substation: Retire Reactor and Install Reactor Switchers	Retire one 13 kV reactor connected to the tertiary of Raun 345-161 kV transformer AC and install new reactor switchers on the two remaining 13 kV reactors	Dec. 31, 2019	IA	$0.6M
15690	Buena Vista: Replace CT on Wisdom 161 kV Line Terminal	Replace a CT (current transformer) on the Wisdom 161 kV line terminal at Buena Vista Substation	Dec. 31, 2020	IA	$0.02M

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15676	Webster-Hayes 161 kV Structure Replacements	Replace structures on the Webster to Hayes 161 kV line to increase conductor clearances	June 1, 2020	IA	$0.2M
15822	New Sharon-Poweshiek 69 kV Reconductor and Replace Structures	Reconductor and replace structures, as appropriate, on the New Sharon-Poweshiek 69 kV line	Dec. 31, 2018	IA	$2.4M
15824	M Avenue-New Sharon 69 kV Reconductor and Replace Structures	Reconductor and replace structures, as appropriate, on the M Avenue to New Sharon 69 kV line	Apr. 1, 2019	IA	$2.1M

Market Participant Funded Projects

According to Attachment FF of the MISO Tariff, "Market Participant funded projects (MPFPs) are defined as Network Upgrades fully funded by one or more market participants but owned and operated by an incumbent Transmission Owner."

Project 15665 – Overland Trail – Bunge 161 kV line

Project Description

Project 15665 constructs a new 161 kV line between the Overland Trail and Bunge substations. This distributes power from locally interconnected wind away from the existing 161 kV line. This installation is expected to cost $9.3 M and be in service June 1, 2020.

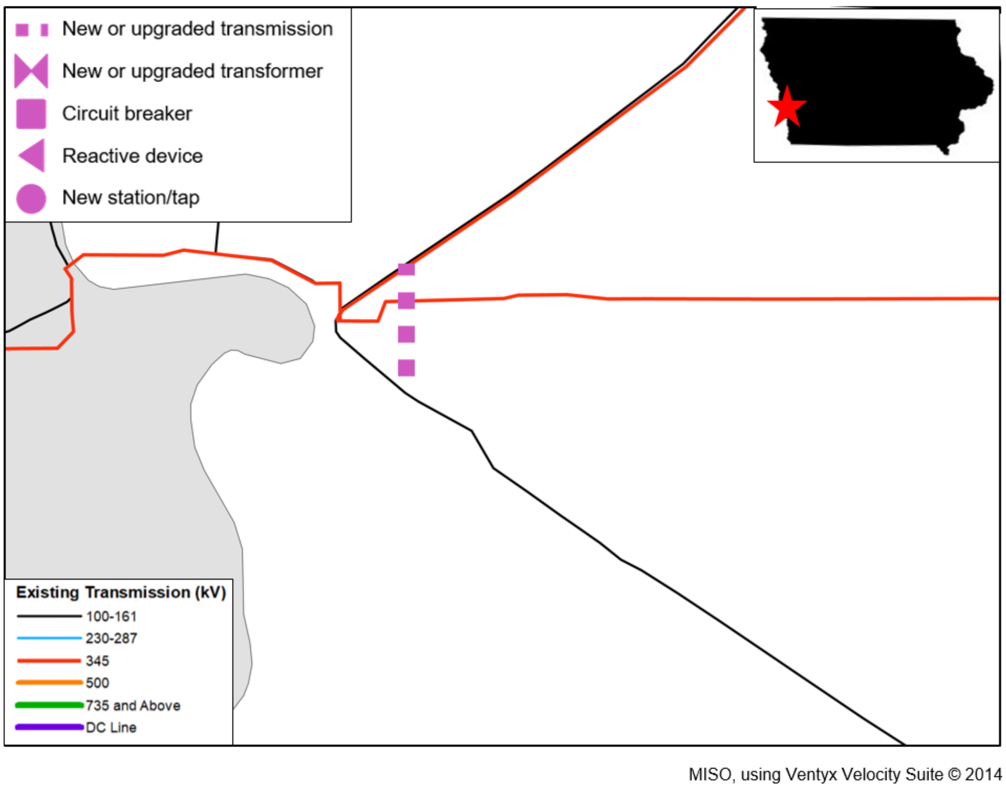


Figure 4.5.8-#15665-1: Geographic transmission map of project area

Project Need

A P6 in South West Iowa isolates more than 500 MW of wind generation to the 161 kV line between Council Bluffs and the Overland Trail substations. This line loads to more than 140% during high wind conditions. This project balances flows back to the Council Bluffs 345/161 kV substation for movement across Iowa.

4.5.9 Minnesota Municipal Power Agency (MMPA)

One Other project from MMPA is recommended for MTEP19 Appendix A.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Project 17584 – MN River Breaker Install (position 5M421)

Project Description

This project will install a breaker in the ring bus at Minnesota River Substation, at position 5M421. The estimated cost is $0.3M and the expected in-service date is March 31, 2020. Project 17584 was submitted on July 26, 2019, after the September 15th submission deadline.

Project Need

Without this breaker, a fault on the generator bus can result in partial loss of load. The main driver for this project is improved local reliability for the customers served from Minnesota River substation.

4.5.10 Minnesota Power (MP)

Minnesota Power, whose service territory covers most of Northeastern Minnesota and parts of North Central Minnesota, proposes eight projects for inclusion in Appendix A in MTEP19. Of these projects, five projects are Baseline Reliability Projects, and three projects fulfill other local needs. All eight of these projects are expected to be in service by the end of 2022. The total estimated cost of these eight projects is $28 million, which is similar to the total investment approved in the previous MTEP cycle.

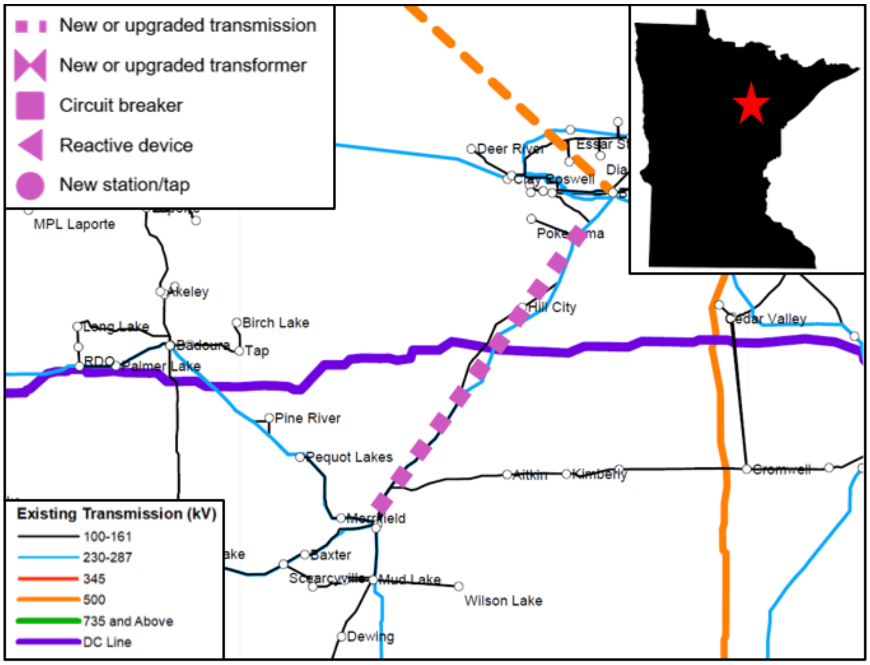
Baseline Reliability Projects

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."

Project 15590 – 11 Line Upgrade

Project Description

Minnesota Power's 11 Line is a 115 kV circuit from Riverton to Grand Rapids with taps at Pokegama and Hill City. This project will increase the operating temperature of the line from 50˚C to 70˚C by raising and replacing existing structures. The total cost of this project will be $3.0M, with an in service date of May 1, 2021.



MISO, using Arc GIS

Figure 4.5.10-#15590-1: Geographic transmission map of project area

Project Need

This aging line can be overloaded for a variety of P1 and P2 category events which result in the loss of a parallel line or lines. Violations are seen as early as the summer of 2021 and could reach 144% of the normal rating for a P1 event in 2029. The loading is strongly impacted by the magnitude of flows into MISO from Manitoba, which increase when the Great Northern Transmission Line is completed early in 2021. This project increases the rating on all portions of the affected line, increases which are sufficient to prevent overloads throughout the planning horizon. Table W-15590-1 describes the project's performance under the most severe events in 2029.

Cont. Type	Limiting Element	Existing Rating / New Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P12	Hills City Tap - Riverton 115 kV	55 / 84	134.3%	87.9%
P12	Grand Rapids –Hills City Tap 115 kV	55 / 182	144.3%	43.6%

Table 4.5.10-#15590-1: Thermal loading drivers

Project 15591 – Forbes – 37 Line Tap Upgrade

Project Description

Minnesota Power's 37 Line is a three terminal 115 kV line with terminals at Forbes, Virginia, and Laskin. The leg from Forbes to the three-way junction is tapped at Iron Mountain Tap and Thunderbird South. This project will increase the operating temperature of the leg from Forbes 70 ˚C to 100 ˚C by replacing or raising structures, increasing its rating. The total cost of this project will be $0.94M, with an in service date of March 31, 2022.

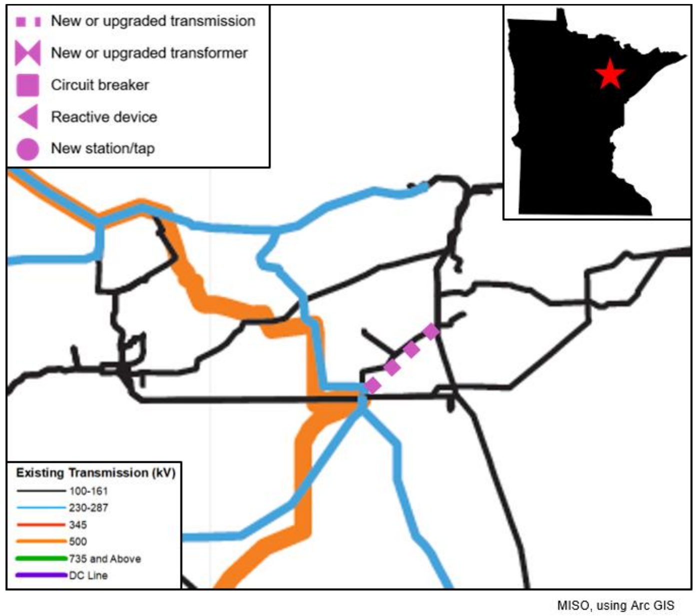


Figure 4.5.10-#15591-1: Geographic transmission map of project area

Project Need

A variety of P6 events can disconnect a major local source in this industrial load center, shifting power onto the underlying 115 kV lines and heavily loading the Forbes – 37 Line Tap 115 kV circuit. Parts of this line are loaded above the Normal rating (135 MVA) in the 2021 and 2024 Summer cases and the 2024 Shoulder and Light Load cases, and above the Emergency rating (148 MVA) in the 2029 Summer case. P6 events allow for operator actions to be taken after the first outage in preparation for the second, but there are no effective redispatch options available and no viable reconfiguration options to mitigate this loading. Prior to 2029, post-contingent load-shedding could be used to return to the Normal rating, but by 2029 these events exceed even the short term Emergency rating. Replacing and raising structures along the line will increase its ratings to 182 MVA Normal and 200 MVA Emergency, which is sufficient to prevent this overload. Table 4.5.10-#15591-1 describes the worst loading on this line, relative to the Normal rating, in the 2029 Summer cases.

Cont. Type	Limiting Element	Existing Rating / New Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Forbes – Iron Tap 115 kV	135 / 182	112.7%	83.6%
P6	Iron Tap – Thunderbird S 115 kV	135 / 182	110.7%	82.1%
P6	Thunderbird S – 37L Tap 115 kV	135 / 182	108.7%	80.7%

Table 4.5.10-#15591-1: Thermal loading drivers

Project 16804 – 38 Line Upgrade

Project Description

The 38 Line is a 115 kV circuit from Forbes to Hoyt Lakes. This project will re-conductor the line to increase the rating to 178 MVA Normal 196 MVA Emergency. The total cost of this project will be $9.9M, with an in service date of March 30, 2021. This project was submitted after the September 15th deadline on April 4, 2019.

Project Need

For a couple of P6 events, this line becomes the main source for all load on the North Shore loop, a long loop of line that serves all load Northeast of Duluth and generally East of Hoyt Lakes. There is a single generating plant on this loop, at Taconite Harbor, which is publicly scheduled to cease operation in 2020, and cannot be quickly dispatched. For all MTEP19 Summer, Shoulder, and Light Load models, if Taconite Harbor is not in service, the P6 events cause overloads above the Emergency rating on Forbes – 38 Line Tap – Hoyt Lakes 115 kV. With the re-conductoring, post-contingent loading is below the new rating. Table 4.5-#16804-1 describes the loading on segments of this line relative to the Emergency rating for the worst P6 event, in the 2029 Summer case with Taconite Harbor out of service.

Cont. Type	Limiting Element	Existing Rating / New Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Forbes – 38 Line Tap 115 kV	124 / 196	152.3%	83.6%
P6	38 Line Tap – Hoyt Lake 115 kV	158 / 196	113.7%	96.3%

Table 4.5-#16804-1: Thermal loading drivers

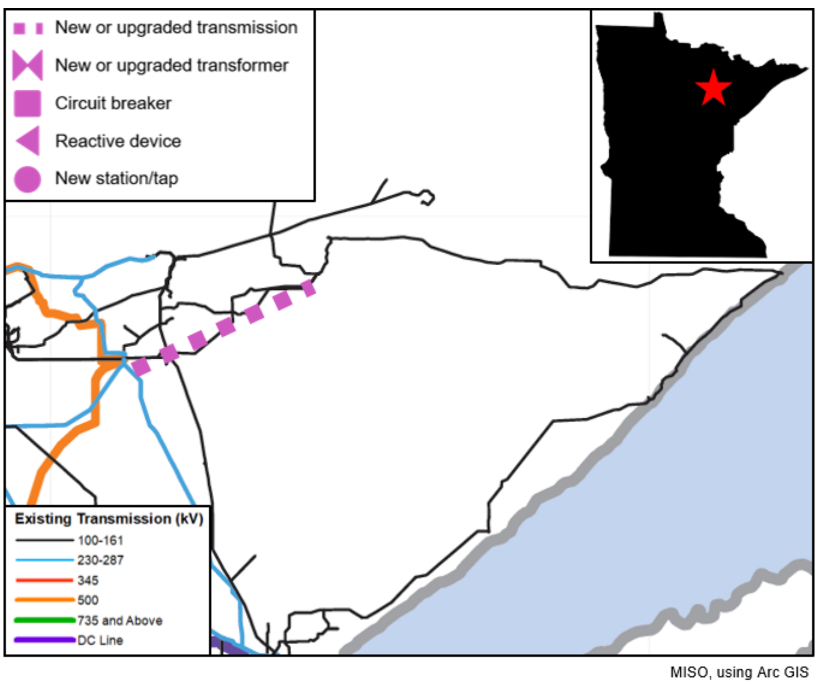


Figure 4.5-#16804-1: Geographic transmission map of project area

Project 7913 – 868 Line Upgrade

Project Description

The 868 Line is a 115 kV circuit from Little Falls South to St. Stephens Tap, after which portions of the line down to West St Cloud are owned by Great River Energy. This project will increase the rating of Minnesota Power's portion of the line by replacing limiting terminal equipment at Little Falls and re-conductoring the line. The total cost of this project will be $6.9M, with a final in service date of March 1, 2022.

Project Need

In 2024 Light Load and Winter models, the P6 outage of nearby higher voltage circuits results in strong South to North flow on this path which exceeds the Emergency rating of portions of this line. There are no viable reconfiguration or re-dispatch options. Uprating these segments prevents overloading. A summary of the worst loadings for the 2024 Light Load and 2024 Winter cases relative to the Emergency ratings is given in Table 4.5.10-#7913-1.

Cont. Type	Limiting Element	Existing Rating / New Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	Little Falls – Langola Tap 115 kV	107.8 / 200	103.8%	56.0%
P6	Little Falls – Langola Tap 115 kV	126 / 235	124.4%	66.7%
P6	Langola Tap – St. Stephens Tap 115 kV	162.6 / 235	101.3%	70.1%

Table 4.5.10-#7913-1: Thermal loading drivers

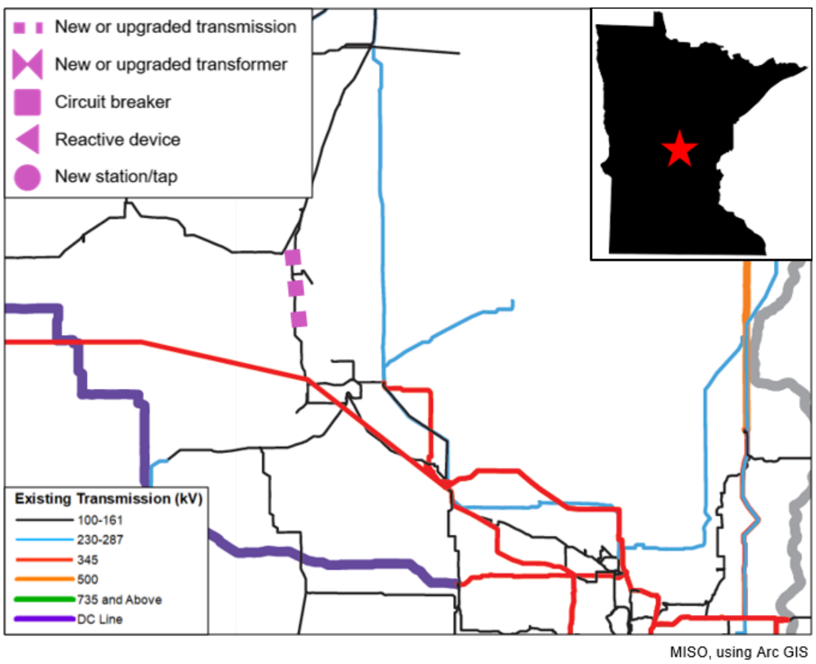


Figure 4.5.10-#7913-1: Geographic transmission map of project area

Project 10285 – Forbes Tie Breaker Addition

Project Description

The 115 kV yard at the Forbes substation is configured as a two straight buses joined by a bus tie breaker. This project would reconfigure the 115 kV yard and add a 2nd bus tie breaker in series with the existing bus tie breaker. The total cost of this project will be $2.2M, with an in service date of December 31, 2020.

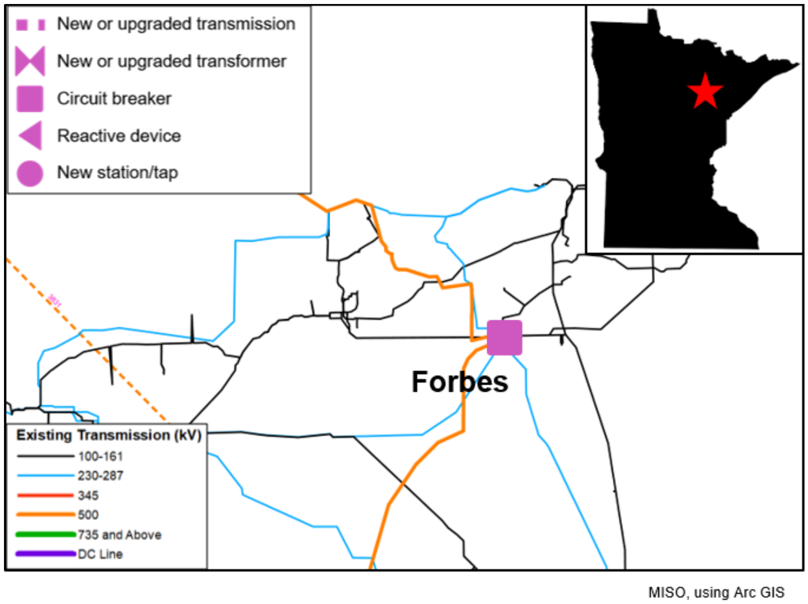


Figure 4.5.10-#10285-1: Geographic transmission map of project area

Project Need

A P24 or P46 fault at Forbes 115 kV, when cleared, disconnects all equipment at two important straight buses and reroutes the flows on many of the 115 kV lines in this area, resulting in overloads on MinTac-Maturi-KewauneeTap-Hibbing 115 kV in the 2024 Shoulder and Light Load models. This project adds a redundant breaker in series with the existing bus tie breaker which is responsible for this event. With the second breaker, the equivalent event responsible for this violation causes only one or the other of those straight buses to be disconnected, but never both at the same time. All bus tie breaker faults at the station become equivalent to the existing P22 faults at this station, none of which causes any known violations on its own. The thermal violations prevented by this project are listed in Table W-10285, which tabulates the loading in the 2024 Shoulder 40% wind case, relative to the Emergency rating of the affected elements.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)
P24, P46	Hibbing – Kewatin Tap 115 kV	60	105.1%
P24, P46	Kewatin Tap – Maturi 115 kV	60	102.5%
P24, P46	Maturi – Mintact 115 kV	60	100.2%

Table 4.5.10-#10285-1: Thermal loading drivers

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as “Other Projects,” according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by local reliability

The following project is driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15596	Long Prairie Transformer Replacement	Replace existing Long Prairie 115/34.5 kV 1TR and 2-3TR with higher-capacity LTC transformers	Dec. 31, 2021	MN	$1.7M

Projects driven by age and condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15597	Savanna Transformer	Install new 115/13.8 kV transformer and breaker at existing Savanna Switching Station, retire 90 year Floodwood transformer. Replace existing Meadowlands transformer with new larger 115/13.8 kV transformer.	Dec. 31, 2020	MN	$2.5M
15601	Midway Substation Retirement	Retire and remove Midway Substation, the load from which will be served from other nearby substations	Dec. 31, 2019	MN	$1.2M

4.5.11 Missouri River Energy Services (MRES)

One Other project from MRES is recommended for MTEP19 Appendix A.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as “Other Projects,” according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by age and condition

The following project is proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15818	Willmar Sub Strain Bus Replacement	Willmar Municipal Utilities is replacing strain bus, jumpers, and switches at the Willmar Substation on the 69 kV bus	Dec. 1, 2019	MN	$0.16M

4.5.12 Montana-Dakota Utilities Co. (MDU)

Ten Other projects from MDU are recommended for MTEP19 Appendix A.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by local reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15771	Plentywood Loop	Build a 60 kV loop line around Plentywood, MT	Dec. 31, 2020	MT	$2M
15747	Merricourt 230/41.6	Add 230/41.6 kV transformer and 41.6 ring bus at Merricourt Substation. Build Merricourt-Ashley 41.6 kV line and Merricourt-Fredonia 41.6 kV line.	Dec. 31, 2022	ND	$12.1M

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16125	Keystone XL PS #14	A new tap on the Baker-Cabin Creek 115 kV line and radial line to distribution substation	Jun. 30, 2020	MT	$3M

16124	Dickinson Refinery	New 115 kV substation with distribution transformer on the Dickinson North-Dickinson West 115 kV line	Mar. 31, 2020	ND	$7M

Projects 16124 and 16125 were submitted after the September 15th submission deadline, on October 11, 2018.

Projects driven by age and condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15746	Beulah-Mandan 115 Rebuild	Rebuild Beulah-Mandan 115 kV and build a new 115 segment to terminate at Coyote	Dec. 31, 2021	ND	$26.9M
15748	Baker-Glendive 60 kV	Line needs to be rebuild due to age & condition	Dec. 31, 2021	MT	$16.9M
15777	Rosebud-Forsyth 60 kV	Rebuild Rosebud-Forsyth 60 kV line	Oct. 15, 2020	MT	$2M
15780	Lignite-Kincaid 60 kV	Build new Lignite-Kincaid 60 kV line	Mar. 31, 2021	ND	$3.1M

Projects driven by other local needs

The following projects do not appear to be driven by local reliability concerns, growing load, or the replacement of aging equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
14684	Miles City	A new 115 kV transmission line from WAPA's Miles City 115 kV Substation to a new Miles City SW 115/60 kV Substation. The new Miles City SW substation will connect to the existing Miles City-Rosebud 60 kV line.	Dec. 31, 2020	MT	$6.6M
15772	Cabin Creek Breaker	Add 60 kV breaker and bay to split the Cabin Creek-Plevna and the Cabin Creek-North Baker 60 kV line onto separate breakers	Mar. 31, 2021	MT	$0.6M

4.5.13 Muscatine Power and Water (MPW)

One project from MPW is recommended for MTEP19 Appendix A at an estimated cost of $8.3M. This project is a joint effort between MPW, Central Iowa Power Cooperative and MidAmerican Energy. Only costs allocated to MISO members are represented in the MTEP report.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Project 15495 – MPW West - CIPCO Muscatine Switch - MEC Sub 56 161 kV Line

Project Description

In a joint project between Central Iowa Power Cooperative, MidAmerican Energy and Muscatine Power and Water, a new line will be constructed between MPW's West Substation and MEC's Sub 56, shown in Figure 4.5.13-#15495-1. A midpoint interconnection will be made into the CPICO Muscatine Switching substation. This installation is expected to cost $8.3 M and in service in September of 2021.

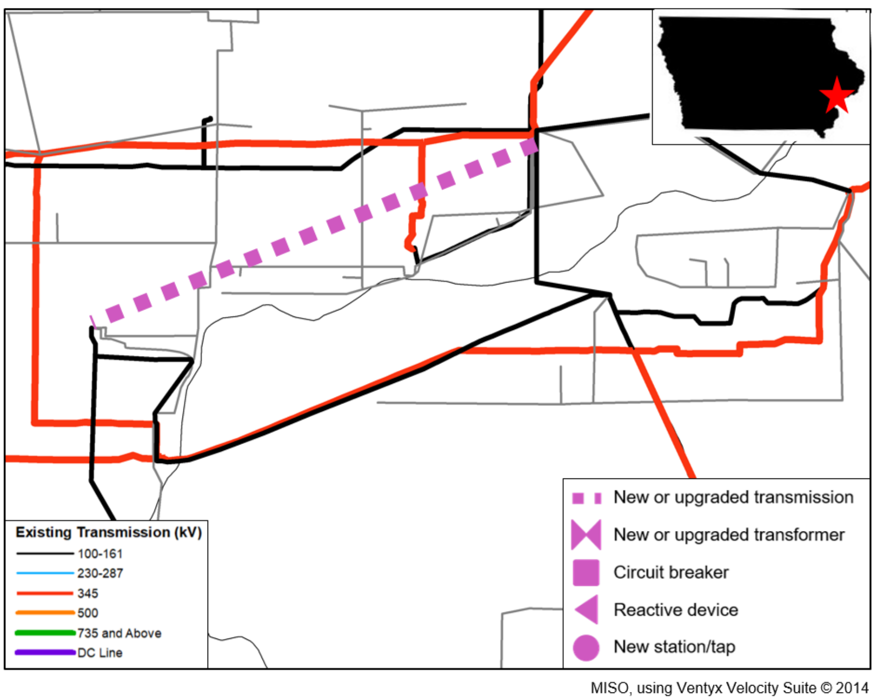


Figure 4.5.13-#15495-1: Geographic transmission map of project area

Project Need

During P6 outages of the existing 161 kV lines serving the MPW service territory, the 69 kV system is inadequate to serve load and meet the local transmission planning criteria during certain generation dispatch scenarios. Post-contingent voltages as low as 0.7 pu were observed during simulation. This extra source to the area will allow flexibility and increase reliability to the local system.

Alternatives Considered

Targeted rebuilds and capacitor installations were considered, but do not provide any additional redundancy.

4.5.14 Northwestern Wisconsin Electric (NWEC)

Six projects from NWEC are recommended for approval in the MTEP19 planning cycle. All six are classified as Other projects related to age and condition and local reliability.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by local reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15920	Lake 26-Tower Road 69kV CCC Road	Rebuild the 69kV line with 477 ASCR and horizontal post construction.	Dec. 1, 2022	WI	$0.44M
15921	Lake 26-Tower Road 69kV Lake 26 Road	Rebuild the 69kV line with 477 ASCR and horizontal post construction.	Dec. 1, 2023	WI	$0.26M
15922	Frederic-Coffee Cup 69kV Hwy 35 to Frederic	Rebuild the Dbl Ckt 69kV line with 477ACSR	June 1, 2020	WI	$0.45M

Projects driven by age and condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15915	Frederic-Falun 69kV Old 35 from 350th to 330th	Rebuild the 69kV line with 477 ASCR and horizontal post construction	Dec. 1, 2020	WI	$0.35M

15916	Frederic-Falun 69kV Old 35 from Elbow Lake Road to 350th	Rebuild the 69kV line with 477 ASCR and horizontal post construction	June 1, 2021	WI	$0.35M
15919	Frederic-Falun 69kV Elbow Lake Road from County W to Old 35	Rebuild the 69kV line with 477 ASCR and horizontal post construction	Dec. 1, 2021	WI	$0.53M

4.5.15 Otter Tail Power Company (OTP)

Otter Tail Power, whose service territory covers portions of Western Minnesota and Eastern North and South Dakota, proposes 18 projects for approval in MTEP19 Appendix A. Of these projects, one is a Baseline Reliability Project, five projects are required to meet other local planning needs, and 12 projects are associated with approved Generation Interconnection Agreements. The total investment associated with these proposed Appendix A projects is $87.8 Million, of which the Baseline Reliability Project accounts for $12.4 Million and the Generation Interconnection Projects account for $51.7 Million.

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."

Project 4232 – Northwest Minnesota Projects

Project Description

Install a 2nd 230/115 kV transformer at Winger, add breakers and relays to implement Under Voltage Load Shedding (UVLS) at Donaldson, Thief River Falls, Crookston, and Plummer, and replace a jumper and switch to increase the rating on the Winger – Plummer 115 kV circuit. This project was derived through a joint study between Otter Tail Power and Minnkota Power Cooperative (MPC) in collaboration with MISO, and selected as the necessary first phase of a suite of projects which were identified as preferred solutions to meet long term reliability needs in the Northwest corner of Minnesota. Depending on the evolution of load levels in this region, two additional projects – currently being added to Appendix B – may also be necessary to meet long-term reliability needs in this area. The upgrades proposed for MTEP19 Appendix A under this project have a total cost of $12.4 Million and are expected in service by November 30, 2021.

Project Need

The Northwest Minnesota area, for the purposes of this project and two other related projects, includes facilities East of the Drayton and Grand Forks substations and North of the Winger substation. Approximately 300 MW of Winter peaking load is served from the 115 kV system in this area. This area is distant from any strong generation sources and has historically had weak voltage support. The traditional load in this area has stayed fairly constant over the past decade, but several pipeline pumping stations constitute a significant portion of the load. The future of this pipeline has been uncertain for several years, with plans to expand its capabilities only haltingly progressing. Recognizing the timing and magnitude of long-term load level in this area is uncertain, the two incumbent utilities – Otter Tail Power, and Minnkota Power – have worked to develop a set of projects that can build on each other and will meet both near term needs and projected long-term reliability needs.

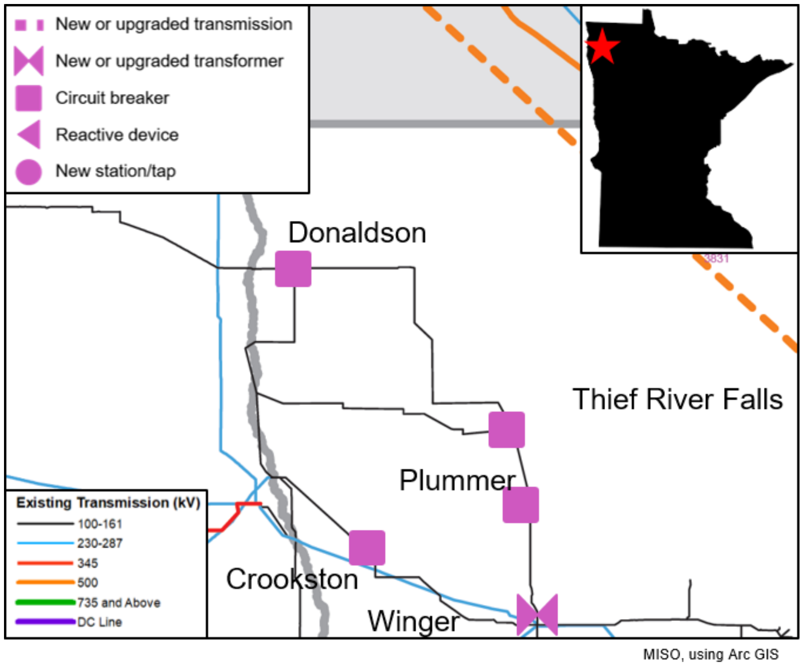


Figure 4.5.15-#4232-1: Geographic transmission map of project area

Project 4232 is the first phase of this series of projects. It resolves reliability concerns which are expected under all future scenarios, regardless of load level. Specifically, it resolves overloading on Winger – Plummer 115 kV and the Winger 230 / 115 kV transformer, and it allows for controlled automatic shedding of load for the more severe outages which can occur.

The other two projects, listed in MTEP19 Appendix B, are Lake Ardoch 230/115 kV (Project 17424) and a Winger – Plummer 115 kV second line (Project 17444). Lake Ardoch would tap the existing Prairie – Drayton 230 kV line near the Oslo 115 kV substation just West of the border in North Dakota, adding a 230/115 kV step down transformer and a short line which would connect into the Oslo 115 kV substation. This project would be built by MPC. This project would provide a new source from the stronger 230 kV system which, in combination with reconfiguration at Oslo 115 kV, could prevent some severe outages from causing voltage collapse. At the highest end of potential local load levels, the second 115 kV circuit from Winger to Plummer would also be needed to prevent some severe contingencies from causing voltage collapse or thermal violations. This project would be built by OTP. Figure 4.5.15-#17424/17444 below illustrates the location of these potential projects.

Table W-4232-1 shows the loading relative to the Normal rating on the most heavily affected facilities in the area, for the worst P21 outages in the 2024 Winter peak case. P21 outages are the most restrictive thermal issues in this area, since they do not allow firm load to be shed. As demonstrated in this table, project 4232 mitigates the most severe and immediate thermal issues.

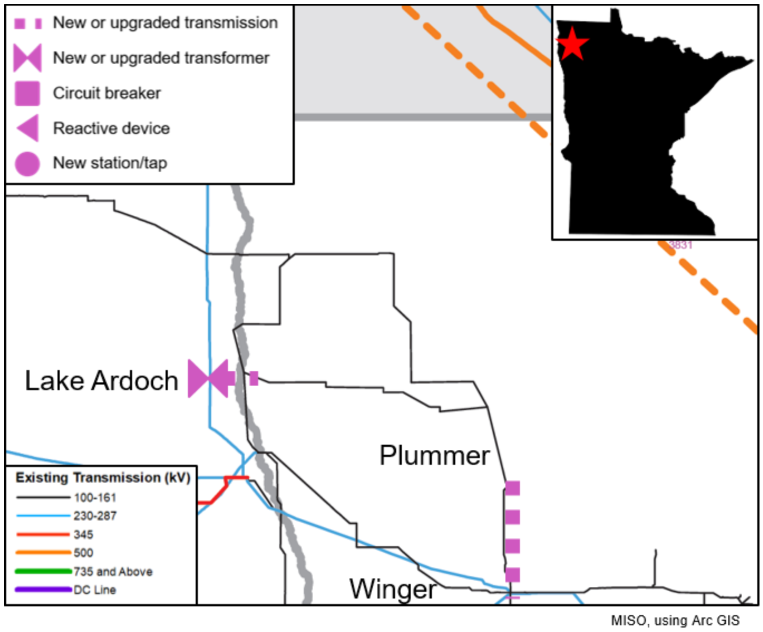


Figure 4.5.15-#17424/17444: Geographic transmission map illustrating location of Appendix B projects

Cont. Type	Limiting Element	Existing Rating / New Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P21	Winger 230/115 kV Transformer	166	130.2%	73.9%
P21	Winger - Plummer Tap 115 kV	120 / 169	108.7%	80.1%

Table 4.5.15-#4232-1: Thermal loading drivers

Table 4.5.15-#4232-2 shows the voltage performance of the Northwest Minnesota projects in the Winter Peak models, as well as performance when the two Appendix B projects are included. The firm load level in the MTEP19 2024 Winter peak models are at the high end of what expected local load levels may be, and at those load levels, some P21 events still cause voltage collapse, so one or both of the prescribed Appendix B projects would also be needed to meet criteria without resorting to load shedding.

Cont. Type	Short Term LV Limit (pu)	Voltage (pu) No Project	Voltage (pu) w/ 4232	Voltage (pu) w/ 4232 & Both App B
P12	0.92	0.8857	0.8885	0.9451
P21	0.92	Non-Converged	Non-Converged	0.9478
P23	0.92	Non-Converged	Non-Converged	0.8645

Table 4.5.15-#4232-2: Voltage performance drivers

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by local reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16146	Jamestown NW Substation 115 kV	New Substation delivery to the 41.6 kV on the West side of Jamestown. The project will consist of - One 115kV Circuit Breaker and one 41.6 kV Circuit Breaker and a 25 MVA transformer.	Nov. 30, 2021	ND	$3.0M

Project 16146 was submitted after the September 15th deadline on October 16, 2018.

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15727	New Effington 230/41.6 kV Substation	New 230/41.6 kV Substation that taps OTP's portion of the Brown's Valley to Hankinson 230 kV line near New Effington, SD. Substation will consist of a three breaker ring bus and a 230/41.6 kV transformer.	Nov. 30, 2020	SD	$5.8M
17225	Norcross 115/41.6 kV Substation and 115 kV Line	Build 7 miles of 115 kV lines west from MRES's Grant County substation to where it intersects with OTP's 41.6 kV system. Near the intersection, build a 115/41.6 kV substation with a single high side breaker. This is a joint project with MRES, of the $11.8M total cost, $4.9M is attributed to MRES.	Dec. 15, 2020	MN	$11.8M

Project 17225 was submitted after the September 15th deadline on June 20, 2019.

Projects driven by age and condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15725	Hoot Lake 115 kV Cap Banks	Install two stages of 25 MVAr cap banks on the Hoot Lake 115 kV bus to	May 1, 2021	MN	$2.0M

		accommodate the retirement of local generation			
16484	OTP Blair 230kV Substation Upgrade	Due to age and condition it is necessary to replace existing 2 single phase Oil Breakers with SF6 Breakers, replace the old Westinghouse Relay Panel with new SEL Relay Panel, replace Digital Relays with Electromechanical relays, new control house, new relaying and associated equipment (CTs, PTs, etc...), metering and new telecommunications equipment.	June 1, 2019	SD	$1.2M

Project 16484 was submitted after the September 15th deadline on November 28, 2018.

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15304	OTP Twin Brooks 345kV Switching Station - J436/J437	Construct a new Twin Brooks switching station, approximately 30 line miles west of the Big Stone South Substation on the Big Stone South to Ellendale 345 kV line	July 6, 2020	SD	$11.4M
16485	OTP Hankinson to Ellendale 230kV Network Upgrades – J436/J437	Replace structures along Hankinson to Foreman, Foreman to Oakes, and Oakes to Ellendale 230 kV lines to increase summer ratings to 311 MVA, 362 MVA, and 363 MVA respectively. Adjust CTs and replace relays at Oakes 230 kV substation, and replace the wave trap at Foreman on Foreman to Oakes with a 2000A rated wave trap.	Nov. 1, 2019	ND	$1.4M
16805	OTP Deuel Switching Station - J526	Construct a new Deuel 345 kV switching station, tapped in and out of the Big Stone South to Brooking County 345 kV transmission line	June 29, 2020	SD	$11.9M
16825	OTP Twin Brooks 345 kV Switching Station Expansion-J488	Expand the planned Twin Brooks switching station to accommodate the interconnection of J488	June 1, 2020	SD	$1.9M
16924	OTP Hankinson to Ellendale 230kV	Replace more structures along Hankinson to Foreman, Foreman to Oakes, and Oakes to Ellendale 230 kV	July 23, 2020	ND	$2.6M

	Network Upgrades - J488	lines to further increase summer ratings to 374 MVA, 448 MVA, and 452 MVA respectively. Adjust CTs and replace relays at Oakes 230 kV substation, and replace the wave trap at Foreman on Foreman to Oakes with a 2000A rated wave trap.			
16964	OTP Astoria 345kV Switching Station - J493/J510	Construct a new Astoria switching station, approximately 16 miles North of the Brookings County substation on the Big Stone South to Brookings County 345 kV line	Apr. 30, 2020	SD	$15.2M
16965	OTP Big Stone Plant 230/115 kV Transformer - J488/J493/J526	Install a new 336 MVA 230/115 kV transformer and associated terminal equipment at the Big Stone Plant 230 kV substation. Disconnect the 115 kV side of the existing 230/115/13.8 transformer, leaving the 13.8 kV winding in service to serve existing load.	Oct. 1, 2020	SD	$3.4M
16991	OTP Big Stone to Blair 230 kV - J488/J493/J526	Install a new 230 kV Switch with operating hardware, remove existing wave trap, and new jumpers and perform CT adjustments, to increase the rating of the Big Stone to Blair 230 kV line to 563 MVA.	Oct. 1, 2020	SD	$0.04M
17005	OTP Hankinson to Wahpeton 230 kV Network Upgrades - J460/J488/J493/J526	Replace structures along the existing Hankinson to Wahpeton 230 kV transmission line to further increase its summer rating to 494 MVA.	Aug. 13, 2020	ND	$1.6M
17006	OTP Ortonville to Morris 115 kV Network Upgrades - J493/J526	Rebuild portions of OTP's Ortonville to Johnson Junction and Johnson Junction to Morris 115 kV lines, and replace 115 kV terminal equipment at Ortonville including a breaker, three switches, and a CCVT.	Dec. 1, 2021	MN	$26.7M
17007	OTP Hankinson to Oakes 230 kV & Big Stone to Blair 230 kV Network Upgrades - G359R	Replace more structures along the Hankinson to Foreman, Foreman to Oakes, and Big Stone to Blair 230 kV lines to further increase their summer ratings to 414 MVA, 497 MVA, and 583 MVA respectively.	Aug. 31, 2020	SD	$1.4M
17024	OTP Blair 230 kV Substation Switches - J488/J493/J526	Upgrade two 230 kV breaker disconnect switches in the Blair Substation	July 1, 2019	ND	$0.07M

4.5.16 Rochester Public Utilities

One Other project from Rochester Public Utilities is recommended for MTEP19 MISO Board of Directors approval.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by load growth

For the following project, growing load is the primary driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15951	Marion Load Serving Substation	New 161/13.8 kV local load serving substation built into existing RPU 161 kV transmission line	June 1, 2021	MN	$8.0M

4.5.17 Southern Minnesota Municipal Power Agency (SMMPA)

SMMPA has two projects recommended for approval in the MTEP19 planning cycle. One age and condition project is to replace breakers in the Byron substation. An Expedited Project Review was conducted on the load interconnect at West Owatonna.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16065	West Owatonna Substation - 161kV Load Interconnection	Re-configure the existing 161 kV yard to a ring and interconnect a new distribution transformer West Owatonna Substation	Dec. 2, 2019	MN	$1.5M

Projects driven by age and condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
17465	Breaker Replacement - Byron	(3) 345kV breakers are being replaced at the Byron substation due to age. As a part of this replacement the CTs on the 345kV breakers will be upgraded to 2000A to match the ratings of the lines connected to the 345kV ring bus.	Dec. 31, 2019	MN	$1.5M

Project 17465 was submitted after the September 15th deadline on July 3, 2019.

4.5.18 WPPI Energy

No projects from WPPI are recommended for MTEP19 Appendix A.

4.5.19 Xcel Energy (Northern States Power)

Xcel Energy (Northern States Power) has facilities in Minnesota, Wisconsin, North Dakota, and South Dakota. In MTEP19, one Baseline Reliability Project, twelve Other projects, and two Generation Interconnection Projects are recommended for MISO Board of Directors' approval.

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."

Project 15743 – Project Name from Planning Portal

Project Description

This project will construct a new 115 kV line from Hurley to Norrie. It is expected to cost $8.0M and has an in-service date of January 31, 2022. Figure 4.5.18-#15473-1 shows the geographic area where this project will be located.

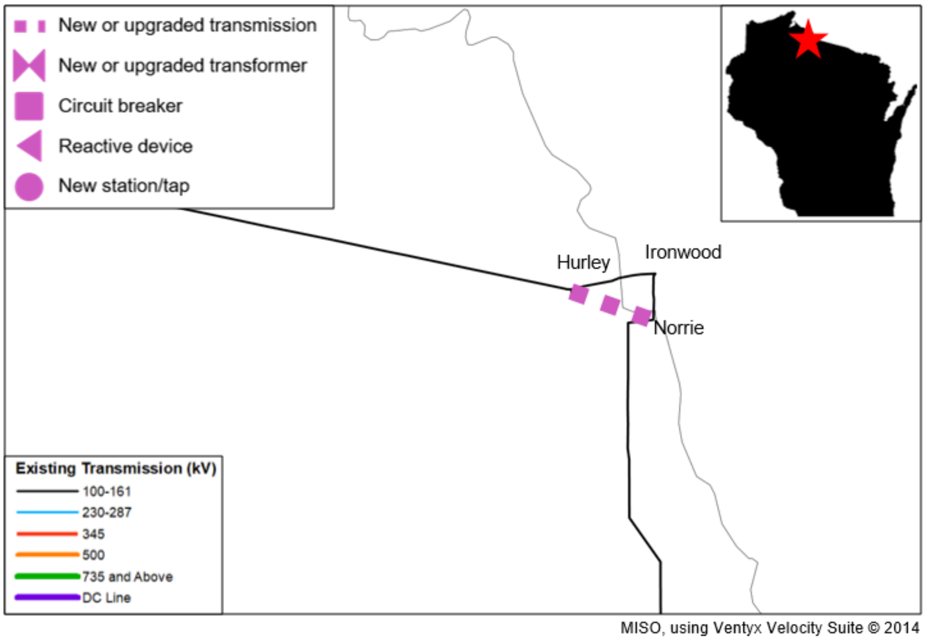
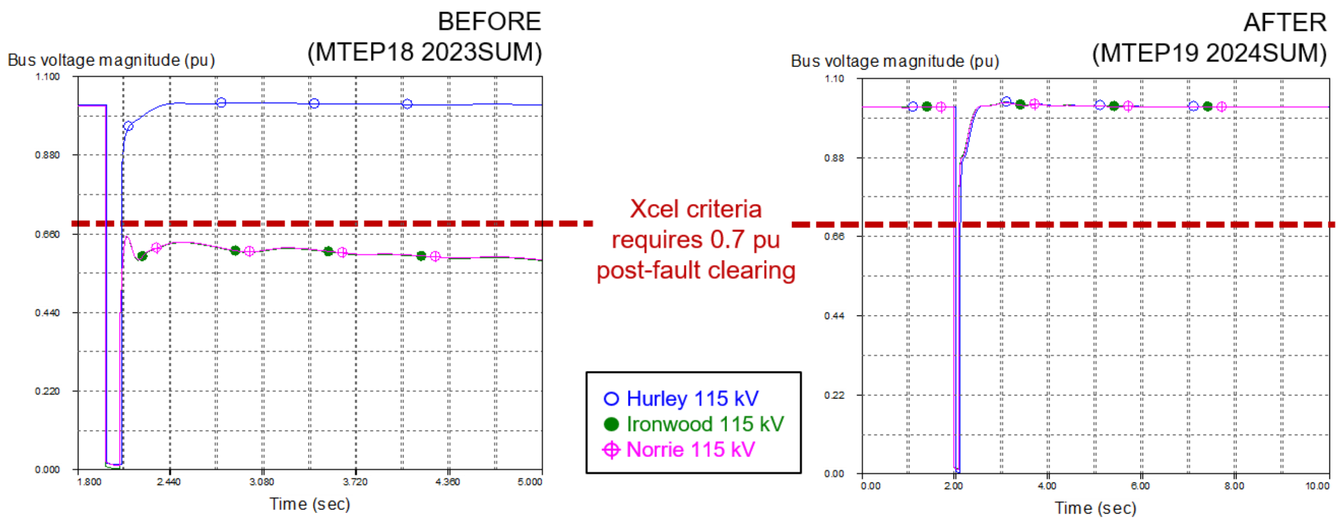


Figure 4.5.18-#15743-1: Geographic transmission map of project area

Project Need

This project is driven by transient stability recovery for P6 events. In the MTEP18 dynamic model for Summer 2023, it can clearly be seen in Figure 4.5.18-#15743-2(a) that Ironwood 115 kV and Norrie 115 kV do not recover to Xcel's limit of 0.7 pu after the contingency. The project effectively solves this issue (see Figure 4.5.18-#15743-2(b)) for the performance with the project in MTEP19 dynamic model for Summer 2024) by connecting Norrie to the existing synchronous condensers at Hurley.



(a) *(b)*

Figure 4.5.18-#15743-2: Adding a transmission line between Hurley and Norrie substations improves the post-contingent transient stability voltage performance.

Alternatives Considered

One alternative to constructing a transmission line would be to look into an SVC for the area. However, the line cost is cheap enough that the added cost of an SVC would not be justified.

Other Projects

The following projects do not meet the criteria to be considered as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects, or Multi-Value Projects. These projects are classified as "Other Projects," according to Attachment FF of the MISO Tariff. For the convenience of the reader, tables of project information are broken down by four general categories of project drivers, but note that these four drivers are not defined in the MISO Tariff.

Projects driven by local reliability

The following projects are driven by local planning criteria without Electric Reliability Organization (ERO) standard applicability or by operational flexibility.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15724	Twin Town Substation	Joint project with DPC to construct a new 69 kV line from structure 240 on line W3429 to the new Twin Town substation, retiring the section north from structure 240 to the DPC Barron to Apple River line. A 10 MVAR capacitor bank will be installed at Turtle Lake substation. A double	Jan. 1, 2021	WI	$6.4M

		circuit line will be built north from Twin Town to the new Almena DPC substation. One line will connect to the Xcel/NSP substation Twin Town. The second line will be owned by DPC and connected to the circuit going south to the DPC Clayton substation.			
15732	North Menomonie Substation	Install one 69 kV feeder and breaker in new Wakanda substation on the north side of Menomonie	Jun. 1, 2020	WI	$0.3M
15733	Rebuild Elmwood Sub	Expand and rebuild existing Elmwood breaker station including three 69 kV breakers and 69 kV feeders	Dec. 15, 2020	WI	$3.2M

Projects driven by load growth

For the following projects, growing load is the principle driver.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15715	Upgrade Waterville TR2	Split 69 kV bus by adding a new breaker	Jun. 15, 2019	MN	$1M
15726	Rebuild Clear Lake Sub	Install two 69 kV feeders to a new Clear Lake Substation across the street from existing Clear Lake Substation	Sept. 15, 2020	WI	$4.0M
15730	South Afton Substation	Install feeders from 115 kV line from Red Rock to Crystal Cave to new South Afton Substation. Install new 115 kV breakers and bus work at new South Afton Substation.	Oct. 15, 2020	MN	$1.1M

Projects driven by age and condition

The following projects are proposed to replace aging or degraded equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15731	Rebuild Wissota Beach Sub	Install one 69 kV feeder and breaker into new Bateman substation on same site as existing Wissota Beach Substation	May 15, 2020	WI	$0.4M
15735	North Ironwood Sub	Install new 115 kV breaker and 115 kV feeder into new Penokee Range Substation near existing Ironwood	Oct. 15, 2020	MI	$0.4M

Projects driven by other local needs

The following projects do not appear to be driven by local reliability concerns, growing load, or the replacement of aging equipment.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
15544	Forbes Capacitor Reconfiguration	Project being performed as part of Forbes SVC retirement. Will replace two 300 MVAR fixed capacitors at Forbes 500 kV with two 160 MVAR switched capacitors at Forbes 500 kV	Jun. 1, 2020	MN	$0.0M
15723*	Prairie Cap Bank Removal	Remove 6 of the 12, 40 MVAR fast switched cap banks at Prairie. Remove 5 of 6 fast switch controls from remaining 40 MVAR cap banks	Jun. 15, 2020	ND	$0.7M
16145	Running Capacitor Retirement	One of the six 30.5 MVAR capacitor banks at Running has failed and will be retired instead of repaired. The remaining five are sufficient for providing voltage support in the area.	Jan. 1, 2019	MN	$0.0M
17125	Eau Claire Breaker Addition	Adds a new breaker at Eau Claire in place of switch 8E2. This removes a common position between the King - Eau Claire 345 kV line and TR 9	Mar. 15, 2020	WI	$0.9M

Projects 16145 and 17125 were submitted after the September 15th submission deadline, on September 28, 2018 and May 13, 2019, respectively.

Generation Interconnection Projects

According to Attachment FF of the MISO Tariff, "Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation." The following Generation Interconnection Projects (GIPs) have been evaluated through the generation interconnection queue and the associated Generation Interconnection Agreements have been signed.

Project ID	Project Name	Project Description	In-Service Date	State	Estimated Cost
16445	Blazing Star 1 - J460	Build new 345kV - 34.5kV substation, tapping the 345kV between Brookings County 345kV and Hawks Nest 345kV to support interconnection of 200 MW of wind from Blazing Star 1 - J460.	Dec. 15, 2019	SD	$13.6M
16724	Hazel Creek Transformer Upgrade	This project will upgrade 230kV/345kV Hazel Creek TR9 to accommodate J460 Blazing Star 1 generation interconnection.	Sept. 1, 2020	MN	$4.4M

Project 16724 was submitted on February 15, 2019, after the September 15th submission deadline.

misoenergy.org

Big Rivers Electric Corporation
Case No. 2020-00064
Brandenburg Steel Mill Substation Equipment Costs

Quantity	Construction Unit Description	Estimated Installed Cost
[redacted]	[redacted]	[redacted]
	Total Part b Equipment	[redacted]
Metering, communications, relaying, control circuits, and associated equipment		
[redacted]	[redacted]	[redacted]
	Total Part c Equipment	[redacted]
	[redacted]	[redacted]
	Total Estimate for Substation	[redacted]

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR APPROVAL TO MODIFY ITS MRSM TARIFF,
CEASE DEFERRING DEPRECIATION EXPENSES,
ESTABLISH REGULATORY ASSETS,
AMORTIZE REGULATORY ASSETS, AND
OTHER APPROPRIATE RELIEF
CASE NO. 2020-00064**

**Response to the Office of the Attorney General's
Supplemental Data Requests
dated April 15, 2020**

April 24, 2020

Item 4) ***Regarding BREC response to AG 1-25 and AG 1-42, please provide the following information:***

a. ***Detailed list of expenditures surrounding Station two retirement***

b. ***Explain how these add up to the $90.4 million Station Two retirement cost assets discussed in paragraph 63 of the application.***

c. ***Explain what issues are outstanding between Big Rivers and the City of Henderson related to the decommissioning of Station Two.***

d. ***Explain how Station 2 decommissioning affects Reid 1 decommissioning costs.***

e. ***Can it be assumed that Reid 1 decommissioning costs will not exceed retirement in place?***

f. ***Can Reid 1 decommissioning, demolish and salvage be accomplished without affecting operation of Green station?***

g. ***Will complete decommissioning, demolition and salvage of Reid 1 be more costly due to other operating units at the Sebree station? How***

much? Please describe any additional work accommodating operating units will require in demolition and salvage?

Response) Big Rivers objects to this request to the extent it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. Specifically, the creation of the Station Two Regulatory Asset, including expenditures to be included in the Station Two Regulatory Asset, was approved by the Commission in Case No. 2018-00164 pursuant to the Settlement Agreement filed in that proceeding. Further, the outstanding issues between the City of Henderson and Big Rivers are being addressed by the Commission in Case No. 2019-00269, and are not subject to collateral litigation in this proceeding. Notwithstanding these objections, and without waiving them, Big Rivers responds as follows:

a. Station Two retirement costs as of December 31, 2019, relate to the unrecovered net book investment as of the date the station was retired. Please also see Big Rivers' response to subpart (b).

b. The Station Two retirement costs are described in the Settlement Agreement approved by the Commission in Case No. 2018-00146.[1]

c. The outstanding issues between Big Rivers and the City of Henderson related to the decommissioning of Station Two are at issue in PSC Case No. 2019-00269.[2] At issue is Henderson's refusal to pay its share of the decommissioning costs as required under Section 8 of the 1993 Amendments, Application Exhibit 12 in Case No. 2019-00269. Please refer to the Application in that case at page 12 beginning with paragraph 29.

d. The Station Two units and the Reid 1 unit are located adjacent to, and in very close proximity to, each other. At the time that Station Two was retired, there was electrical cabling and station piping interconnected

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[1] See *In the Matter of: Application of Big Rivers Electric Corporation for Termination of Contracts and a Declaratory Order and for Authority to Establish a Regulatory Asset* – Case No. 2018-00146 [Filed May 1, 2018].

[2] See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Enforcement of Rate and Service Standards* – Case No. 2019-00269 [Filed July 31, 2019].

between the two stations. Since retirement of Station Two, most of those facilities have been disconnected as part of the initial work to make Station Two "dry, dark, and safe." Furthermore, the first, second, and basement levels of the structure between Reid 1 and Station Two are open and connected to the corresponding levels of Station Two. The units share a common administration building and other plant equipment such as the 84-inch circulating water line and pump, jockey pump for fire protection, and coal feed system. Because of the common use and interconnection of this equipment, Big Rivers determined it would be unnecessarily difficult and expensive to demolish Reid 1 while Station Two was operating. However, that restriction does not exist today because Station Two is retired.

e. Yes, demolition of a coal generating unit is the lower long-term cost for a utility as compared to retirement-in-place. Please see Big Rivers' response to Item 3a of Commission Staff's Second Request for Information in which Big Rivers explains the reasoning behind the decision to demolish Coleman

Station and Station Two instead of retiring in place. The reasoning discussed in that data response applies to Reid 1 as well.

f. Reid 1 decommissioning, demolition, and salvage does not affect the operation of Green station.

g. The costs would be somewhat higher than if there were no nearby operating units. There are costs to relocate electrical feeds and controls for the Reid 69 kV and the Reid 161 kV Substations, Reid combustion turbine, and barge unloader and coal conveyors. This equipment is needed in order to continue operating the bulk electric system equipment at the Sebree facility, to operate the Reid combustion turbine, and Green Station. The Reid combustion turbine controls were relocated to Green Station in 2019 at an approximate cost of $75,000. Big Rivers does not have an estimate for the other work at this time.

Witnesses) Paul G. Smith (*a. and b. only*) and
Michael T. Pullen (*c., d., e., f., and g. only*)

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
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CEASE DEFERRING DEPRECIATION EXPENSES,
ESTABLISH REGULATORY ASSETS,
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Item 5) ***Regarding the response to AG 1-27b please provide the following details of the calculations used to provide estimated*** [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Response)

a. through c.

Please see Big Rivers' response to Item 29 of the Attorney General's First Set of Data Requests.

d. Yes.

e. These items are separate components in Big Rivers' current MRSM Tariff.

Witness: Paul G. Smith

BIG RIVERS ELECTRIC CORPORATION

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Item 6) ***Regarding the response to AG 1-15 please provide the annual data for 2017 through 2019 for Rural and Large Industrial Class Customers:***

a. The value and billing determinates for each rate component and rider for each class;

b. The overall class contribution to revenues for each rate class and a calculation showing how each rate component and rider added up to the overall class contribution to revenues.

Response) Big Rivers objects to this request to the extent that it seeks to require Big Rivers to prepare documents that do not exist. Notwithstanding these objections, and without waiving them, for 2019 please see the attachment specifically prepared in response to this request. Also, please see Big Rivers' **CONFIDENTIAL** responses to Item Nos. 7 and 14 of the Kentucky Industrial Utility Customers, Inc.'s First Set of Data Requests in this case.

BIG RIVERS ELECTRIC CORPORATION

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Witness) Paul G. Smith

Big Rivers Electric Corporation
Case No. 2020-00064
Member Revenue Charges - 2019

	Demand Revenue (a)	Energy Revenue (b)	Billing Adjustment (c)	Subtotal (d) = ∑ (a) thru (c)
Kenergy - Large Industrials	18,916,004.21	35,983,129.94	(1,067,535.95)	53,831,598.20
Kenergy - Rurals	36,755,881.56	52,052,986.24	0.00	88,808,867.80
Kenergy Total	55,671,885.77	88,036,116.18	(1,067,535.95)	142,640,466.00
JPEC - Large Industrials	47,746.05	14,848.85	0.00	62,594.90
JPEC - Rurals	19,735,158.66	28,385,405.94	0.00	48,120,564.60
JPEC Total	19,782,904.71	28,400,254.79	0.00	48,183,159.50
Meade Co. - Large Industrials	0.00	0.00	0.00	0.00
Meade Co. - Rurals	15,902,379.88	21,309,718.75	0.00	37,212,098.63
Kenergy Total	15,902,379.88	21,309,718.75	0.00	37,212,098.63
Member Total-Large Industrials	18,963,750.26	35,997,978.79	(1,067,535.95)	53,894,193.10
Member Total-Rurals	72,393,420.10	101,748,110.93	0.00	174,141,531.03
	91,357,170.36	137,746,089.72	(1,067,535.95)	228,035,724.13

Big Rivers Electric Corporation
Case No. 2020-00064
Member Revenue Charges - 2019

	Fuel Adjustment Clause (e)	Environmental Surcharge (f)	NSNFPPA (g)	Green Power (h)	Power Factor Penalty (i)	Subtotal (j) = ∑ (e) thru (i)
Kenergy - Large Industrials	821,400.05	4,600,260.93	1,749,638.73	0.00	68,554.71	7,239,854.42
Kenergy - Rurals	1,012,763.47	7,548,975.72	2,146,730.25	0.00	0.00	10,708,469.44
Kenergy Total	1,834,163.52	12,149,236.65	3,896,368.98	0.00	68,554.71	17,948,323.86
JPEC - Large Industrials	519.21	4,502.45	877.47	0.00	0.00	5,899.13
JPEC - Rurals	552,563.11	4,087,153.82	1,171,699.64	82.00	0.00	5,811,498.57
JPEC Total	553,082.32	4,091,656.27	1,172,577.11	82.00	0.00	5,817,397.70
Meade Co. - Large Industrials	0.00	0.00	0.00	0.00	0.00	0.00
Meade Co. - Rurals	432,113.22	3,166,370.45	879,903.76	0.00	0.00	4,478,387.43
Kenergy Total	432,113.22	3,166,370.45	879,903.76	0.00	0.00	4,478,387.43
Member Total-Large Industrials	821,919.26	4,604,763.38	1,750,516.20	0.00	68,554.71	7,245,753.55
Member Total-Rurals	1,997,439.80	14,802,499.99	4,198,333.65	82.00	0.00	20,998,355.44
	2,819,359.06	19,407,263.37	5,948,849.85	82.00	68,554.71	28,244,108.99

Big Rivers Electric Corporation
Case No. 2020-00064
Member Revenue Charges - 2019

	Total Revenue (k) = (d) + (j)	MRSM (l)	Total Billed (m) = (k) = (l)
Kenergy - Large Industrials	61,071,452.62	(3,609,993.87)	57,461,458.75
Kenergy - Rurals	99,517,337.24	(6,066,974.01)	93,450,363.23
Kenergy Total	160,588,789.86	(9,676,967.88)	150,911,821.98
JPEC - Large Industrials	68,494.03	(1,769.26)	66,724.77
JPEC - Rurals	53,932,063.17	(3,310,018.88)	50,622,044.29
JPEC Total	54,000,557.20	(3,311,788.14)	50,688,769.06
Meade Co. - Large Industrials	0.00	0.00	0.00
Meade Co. - Rurals	41,690,486.06	(2,478,645.34)	39,211,840.72
Kenergy Total	41,690,486.06	(2,478,645.34)	39,211,840.72
Member Total-Large Industrials	61,139,946.65	(3,611,763.13)	57,528,183.52
Member Total-Rurals	195,139,886.47	(11,855,638.23)	183,284,248.24
	256,279,833.12	(15,467,401.36)	240,812,431.76

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Item 7) ***Regarding the response to AG 1-10 please provide the following excel spreadsheets related to Big Rivers MISO Attachment O formula rate (as posted on webSmartOASIS):***

a. BREC Attachment O 2019

b. BREC Attachment O Work Papers 2019

c. BREC Schedule 1 2019

Response) Please find the following Excel files on the electronic media accompanying these responses.

a. BREC Attachment O 2019,

b. BREC Attachment O Work Papers 2019, and

c. BREC Schedule 1 2019.

Witness Michael W. Chambliss

BIG RIVERS ELECTRIC CORPORATION

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Item 8) ***Refer to BREC's response to AG 1-7 (b). Provide a quantification of all sums spent for 2018, 2019, and 2020 to date.***

Response) The annual maintenance expenses associated with keeping the Coleman Station idled for years 2018, 2019, 2020 to date are:

	2018	**2019**	**2020 (as of 3/31/2020)**
Non-Labor	$ 292,884	$ 344,133	$ 133,718
Labor	543,913	413,077	0
Total	$ 836,797	$ 757,210	$ 133,718

Witness) Michael T. Pullen

**ELECTRONIC APPLICATION OF
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Item 9) ***Reference BREC's response to AG 1-8. Does BREC commit to filing into the record of the instant case a copy of the RFP that it eventually issues? If not, explain why not.***

Response) Big Rivers believes the RFP is very likely to be issued after a final order has been entered in this proceeding. As a result, Big Rivers agrees to file a copy of the RFP in the record as a subsequent reporting requirement.

Witness) Michael T. Pullen

**ELECTRONIC APPLICATION OF
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April 24, 2020

Item 10) ***Reference the responses to AG 1-10, and to AG 1-28 (a)(Nucor Contracts), the draft LICX tariff.***

a. ***Explain when the LICX tariff will be filed with BREC's other publicly-accessible tariffs.***

b. ***With regard to the [redacted], explain whether the LICX tariff will provide [redacted] power. If so:***

i. ***Explain whether members, and ultimately the system's retail ratepayers will be paying for any portion of the costs to provide service of any type or sort to Nucor, and if so, explain how much.***

c. ***Reference the confidential response to AG 1-17. Confirm that BREC will be the entity procuring all [redacted] under the proposed Nucor tariff. Confirm also that Nucor will remain a customer of Meade County RECC and BREC for all of its power needs.***

d. ***Reference the confidential response to AG 1-28 (a)(Nucor Contracts),*** [redacted] ***Explain whether BREC and Meade County RECC in this agreement*** [redacted].

Response) Big Rivers objects to this request on the grounds that it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. More specifically, issues related to the contract with Nucor Corporation are pending before the Commission in Case No. 2019-00365, and are not subject to collateral litigation in this proceeding. Notwithstanding these objections, without waiving them, and with specific objection to collateral litigation of issues pending in Case No. 2019-00365 in this proceeding, Big Rivers responds as follows:

a. If the Commission approves the Nucor retail electric service agreement and related wholesale letter agreement, Big Rivers will file the LICX tariff after that approval is received.

b. Under Exhibit C, Section C.2 of the agreement between Nucor and Meade County RECC, [redacted]

   i. Existing Members will not be paying for any portion of the costs to provide service of any type or sort to Nucor.

c. Big Rivers will be the entity [redacted] needed for Meade County RECC to serve Nucor. Yes, Nucor will remain a member of Meade County RECC.

d. Big Rivers and Meade County RECC in this agreement are not granting to Nucor the right to become a MISO market participant.

Witness) Mark J. Eacret