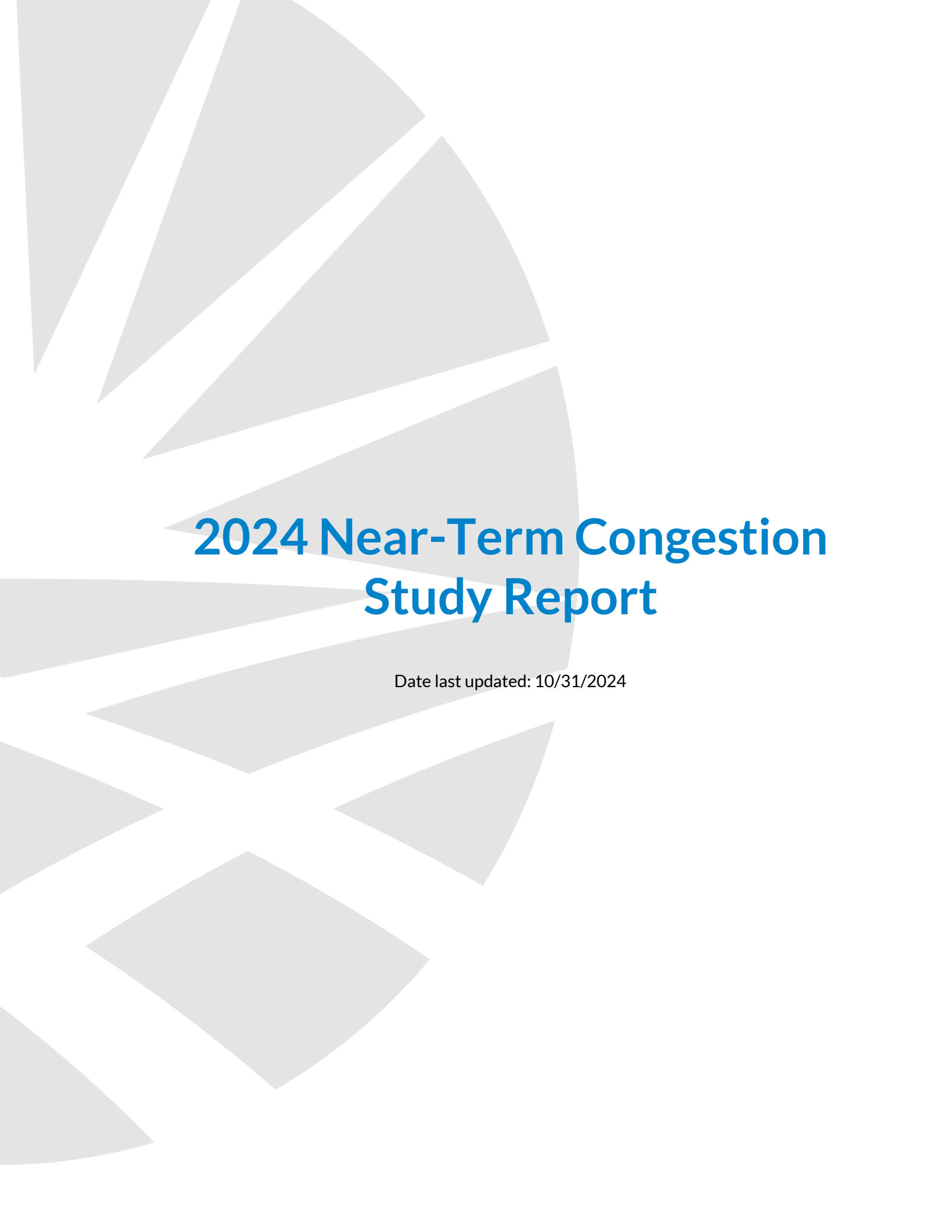




2024 Near-Term Congestion Study Report

Date last updated: 10/31/2024



Contents

	1
Introduction and Background	3
Study Objectives and Scope	3
Study	5
Initial Testing	5
Scenarios Studied	6
Results	9
Introduction to Results	9
West Region Congestion and Curtailment Results	10
Central Region Congestion and Curtailment Results	12
East Region Congestion and Curtailment Results	14
Economic Metrics	16
APC	16
Congestion Measure	18
Congested Flowgates	19
Curtailment	20
6-Month Delay	22
Worst-Case with Delay	23
Study Takeaways	24
Grid-Enhancing Technologies (GETs)	24
GETs Solutions - GRE	25
Congestion Cost Reconfigurations Process	25
Near-Term Congestion Study Appendix	26



Introduction and Background

The first Near-Term Congestion Study was completed in 2023 in response to PAC-2021-1: Address Congestion at Existing Resources. The 2023 study focused on recreating and assessing historically congested flowgates in a near-term PROMOD model. In 2024 this issue was delegated to the Planning Subcommittee (PSC) for further stakeholder technical discussion. Information on stakeholder discussions and presentations on this issue can be found on the MISO website at [PAC-2021-1 Address Congestion At Existing Resources](#).

The 2024 Near-Term Congestion Study provided stakeholders the opportunity to submit feedback on various near-term study approaches. The study options presented to stakeholders included:

- Year 5 Economic Model Refinement and Study
- LRTP Tranche 1 Construction Outages Assessment
- Year 2 Economic Model Development and Study

Based on stakeholder feedback and internal MISO interest, MISO moved forward with an LRTP Tranche 1 Construction Outages Assessment for the 2024 Near-Term Congestion Study. This study utilized the Year 5 PROMOD model from the 2023 Near-Term Congestion Study to test and analyze LRTP Tranche 1 construction outages. By partnering with Operations Planning and Competitive Transmission teams internally, and working with our Transmission Owners, outage sequence issues were identified, GETs solutions were requested, and general outage sequence recommendations were developed.

Study Objectives and Scope

The primary objective of this study was to provide insight into the impact of the LRTP Tranche 1 construction outages. Given the magnitude and siting of the LRTP Tranche 1 projects, as shown in [Figure 1](#), we anticipate temporary increases in congestion and the need for additional coordination with Transmission Owners to identify conflicting outages that could result in reliability issues. By collecting data on these construction outages early and studying them in PROMOD we can provide recommendations on outage sequences.

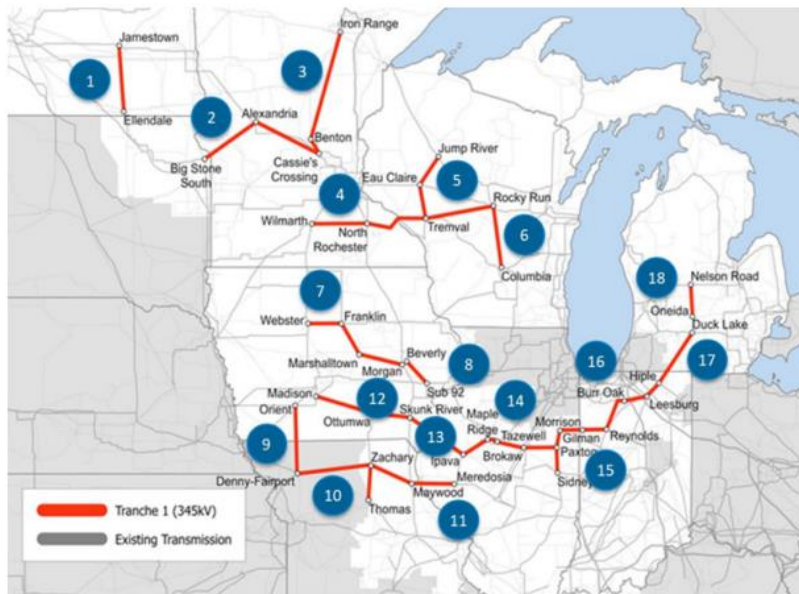


Figure 1. L RTP Tranche 1 Portfolio

The 2023 Near-Term Congestion Study model was utilized for this study with adjustments made to reflect random planned and forced, and construction outages.

Model assumptions include:

- Hitachi PROMOD¹ releases
 - Fall 2021 gen updates and economic data
 - Spring 2022 coal prices
 - PROMOD 11.5 engine
- MTEP23 No Futures Assumptions model
 - Hartburg – Sabine was removed
 - Out of cycle projects were added if in-service date was before study window
- MTEP22 Year 2027 Summer Peak TA powerflow
- Resource utilization – generators with signed GIA additions and finalized retirement studies were included.

Operations Planning and Competitive Transmission teams supported the collection of outage information from Transmission Owners required for the study. Outage data was submitted directly to MISO teams through the MTEP Quarterly Update report and CROW. Operations Planning teams provided general guidelines and helped review potential reliability issues in outage information submitted.

General guidelines that have been used to develop and assess outage sequences include:

- Evaluate outages to minimize concurrent outages likely to strand or limit generation outlets.

¹ PROMOD, Hitachi Energy owned, is a chronological security constrained unit commitment and economic dispatch tool that adheres to a wide variety of operating constraints.



- Evaluate outages to ensure that multiple outages do not impact the same interface and interchange as it would create a significant challenge to the system's reliability.
- Review and compare against historical outages that have been challenging for our system.

PROMOD studies are typically conducted with transmission system intact assumptions, excluding the contingencies included in the event file. The Near-Term Congestion Study used a similar methodology to the LRTP Tranche 2.1 Transmission Outages business case metric to create a base random planned and forced outages scenario. This allows us to compare the impact of LRTP Tranche 1 construction outages against more simulated “real-world” conditions. Approximately 2,450 random planned and forced outages were included in all runs with about 250 planned and 2,200 forced outages.

The construction outage scenarios studied include LRTP Tranche 1 construction outage sequences combined with random planned and forced outages. The scenarios studied range from currently planned sequences to worst case scenarios that would present more severe impacts on the system.

Outage sequences from Transmission Owners were incorporated in the testing and study work as they were received. For LRTP Tranche 1 projects where outages were not submitted, Economic Planning estimated outages by utilizing powerflow models and input from Operations Planning and Competitive Transmission teams. Approximately 220 Tranche 1 construction outages were submitted and estimated based on in-service date expectations with about half of those outages occurring in 2027. [Figure 2](#) outlines how outages were incorporated to build the scenarios studied.

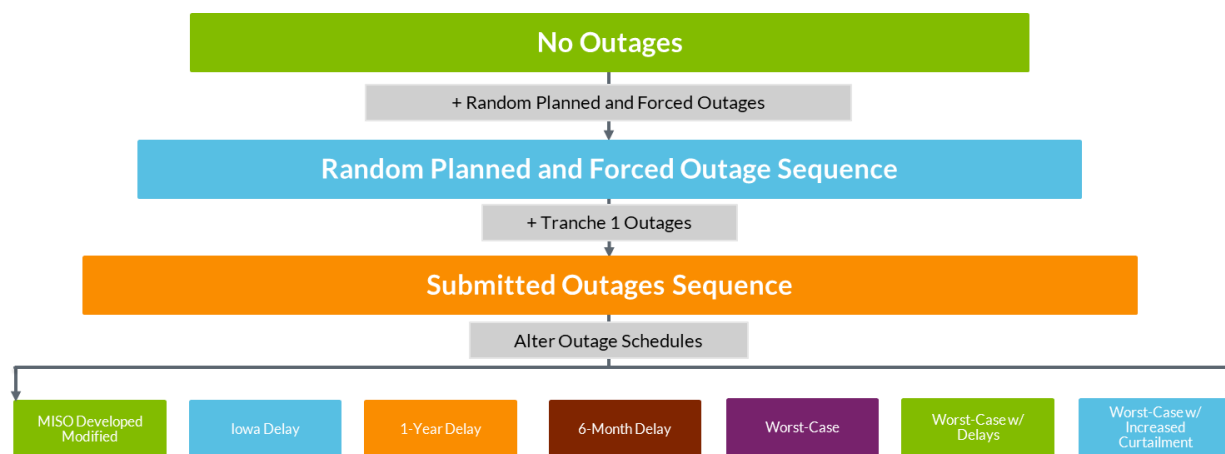


Figure 2. Process for Adding Outages and Building Scenarios

Study

Initial Testing

Testing for this study followed a path of simple to complex when it came to identifying outages and how they are included in the model. Initially, specific outages were entered into PROMOD. This worked for small amounts of outages but was not ideal for larger sequences of outages. By utilizing the PDTR (Power Dated Transmission Record) Tool in PAT (PROMOD Analysis Tool) and



incorporating the LRTP Tranche 2.1 Transmission Outage business case outage methodology, we were able to come up with a more efficient process for incorporating outages.

Additional testing included comparing runs by Local Resource Zone (LRZ) versus region, and the impact of a larger number of outages within a year timeframe. Much of this testing was done to assess any impacts on runtime. Because PROMOD can only study one year at a time, we started by putting all outages in 2027 to test its capabilities. We then sequenced them between 2025-2030, with consistent lengths, followed by the same test with more realistic lengths. We also split the MISO footprint into multiple areas for these runs to analyze outages at a more localized level. Since we did not encounter any hurdles related to PROMOD run-times or processing, our study remained focused on the full MISO footprint.

Scenarios Studied

All sequences studied included random planned and forced outages and started with the Submitted Outages sequence. Adjustments or alterations were made to specific information in the Submitted Outages sequence relative to that scenario. Scenario descriptions and assumptions are listed below:

Submitted Outages (Base Outages)

Description

- Around 77% of all construction outage data was submitted by Transmission Owners and included in the sequence. The remaining 23% was estimated by the MISO Economic Planning Team with assistance from MISO Operations Planning and Competitive Transmission teams.
- All Iowa outages are estimated due to continued discussions around project ownership.

Assumptions

- Outages not submitted by Transmission Owners were estimated based off Tranche 1 line connection points. Start and end dates for outages were estimated by using in service dates and working with Competitive Transmission group to estimate outage durations.

6-Month Delay

Description

- Construction outages in the Submitted Outages sequence were pushed out by 6 months.

Assumptions

- Start dates were moved to the closest Monday and end dates were moved to the closest Sunday for PROMOD efficiency.

1-Year Delay

Description

- Construction outages in the Submitted Outages sequence were pushed out by 1 year.

Assumptions

- Start dates were moved to the closest Monday and end dates were moved to the closest Sunday for PROMOD efficiency.

MISO Developed Modified



Description

- All submitted outage information and estimated outages that were not related to Iowa projects.
- Outages for estimated construction outages were adjusted due to various combinations of outages possible using engineering judgement.

Assumptions

- Adjustments were developed by taking the initial outage schedule and flipping it. The right pieces would still connect by making sure that certain outages followed one another while still ensuring that dates would be changed. Projects remained the same length of time.
 - For example: Outage A to B is from January to June and Outage C to D is from July to December. After making the adjustments, Project A to B is now from July to December and Project C to D is now from January to June. This ensures that outages are left in the same time frame but mixes up concurrent outages.

Iowa Delay

Description

- Outages related to Iowa projects were pushed out beyond the 2027 study year.

Assumptions

- Construction was assumed to be delayed due to ongoing discussions around Iowa project ownership. Outages were pushed out to 2028 and beyond.

Worst-Case

Description

- Outages are sourced from the Submitted Outages scenario but adjusted to all occur in 2027.

Assumptions

- Outages originally scheduled for 2027: These dates remain unchanged.
- Multi-year outages (e.g., Nov 2025–Feb 2026): These start on a comparable Monday in 2027 and conclude on the last Sunday of 2027.
- Outages originally scheduled outside of 2027: For outages scheduled in other years, we identified the same calendar date in 2027 and determined the corresponding day of the week. Based on this, we adjusted the start or end dates using the guidelines below:
 - Start date adjustments:
 - Outages that originally began on a Tuesday through Thursday were moved to the preceding Monday.
 - Outages that originally began on a Friday through Sunday were moved to the following Monday. If the Monday is a national holiday, the outage is scheduled for the following Monday.
 - End date adjustments:
 - Outages that originally ended on a Monday through Wednesday are moved to the preceding Sunday.
 - Outages that originally ended on a Thursday through Saturday are moved to the following Sunday. If the Sunday is a national holiday, the outage is scheduled for the following Sunday.

Worst-Case w/ Delays



Description

- Outages are pulled from the Submitted Outages scenario but adjusted to all occur in 2027 but with additional 1 to 2 month delays.

Assumptions

- Similar to the original Worst Case sequence, we assumed that all outages will occur in the year 2027, but with an additional 1 to 2 month delay to the original end dates. To complete this delayed scenario, the end dates for the outages were adjusted as follows:
 - Outages set to end between January and October: A 2-month delay was added to the original end date.
 - Outages set to end in November: A 1-month delay was applied.
 - Outages set to end in December: These were extended to the last Sunday of 2027.
- For the new end dates, we located the same day of the month in the adjusted period. If the corresponding day fell on a Monday through Wednesday, the outage was set to end on the preceding Sunday. If it fell on a Thursday through Saturday, the outage was set to end on the following Sunday.

Worst-Case w/ Increased Curtailment

Description

- Outages are pulled from the Submitted Outages scenario but adjusted to all occur in 2027 but with additional 1 to 2 month delays.
- Additional outages are added intended to stress the system and increase curtailment.

Assumptions

- Utilizes assumptions from the Worst Case scenario.
- Additional outages added include:
 - MN & ND:
 - Loss of HVDC lines between Square Butte - Arrowhead
 - Loss of HVDC lines between Coal Creek - Dickinson
 - Loss of MWEX Lines (King - Eau Claire 345kV, Arrowhead - Stone Lake 345kV are main two)
 - Loss of lines parallel to MWEX (North Rochester - Briggs Road 345kV or Hazelton - Hickory Creek 345kV)
 - AMEREN:
 - Sibley - Overton 345kV, Zachary - Hughes 345kV
 - Lutesville - Essex 345kV
 - Sidney - Rising 345kV
 - Sub T - Maywood 345kV
 - McCredie - Burns 345kV
 - NIPS:
 - Wilton Center - Dumont 765kV
 - Reynolds - Olive 345kV
 - Reynolds - Meadow Lake 345kV ckt 1
 - Reynolds - Meadow Lake 345kV ckt 2



Results

Introduction to Results

Results were assessed in comparison to the Random Planned and Forced Outages scenario and the Submitted Outages scenario. The Random Planned and Forced Outages scenario reflects real-time conditions while the Submitted Outages scenario reflects real-time conditions with the most likely LRTP Tranche 1 construction outage sequence included. [Figure 3](#) and [Figure 4](#) show the congested flowgates for the Random Planned and Forced Outages and Submitted Outages scenarios for MISO North.

Scenarios most aligned to the Submitted Outages scenarios saw lower APC, Congestion Measures, and Curtailment while scenarios with delays and worst-case assumptions saw variation and, in most scenarios, large increases to these metrics.

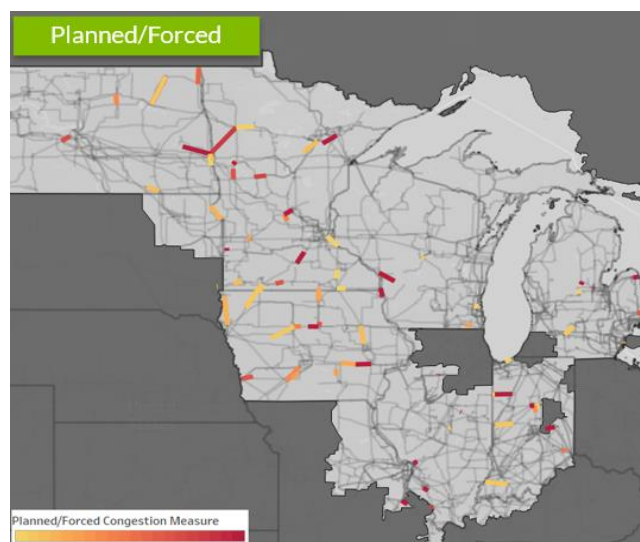


Figure 3: Congested flowgates in Random Planned and Forced Outages Scenario

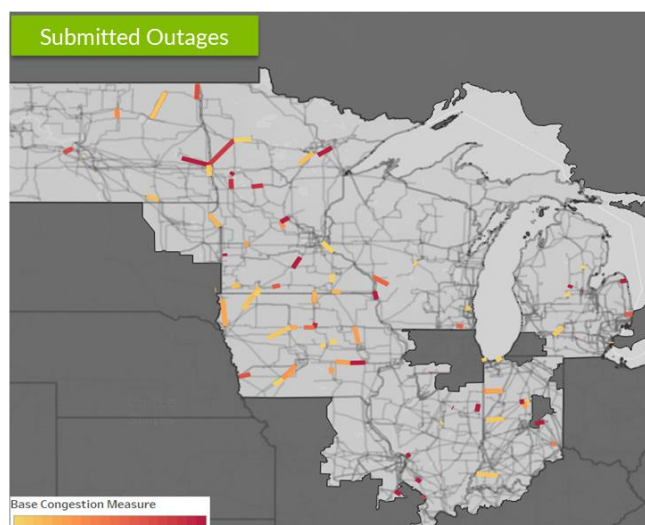


Figure 4: Congested flowgates in Submitted Outages Scenario



West Region Congestion and Curtailment Results

MISO's West Region was the most heavily impacted by various sequences. The West Region contains many flowgates with high levels of congestion as shown in [Figure 5](#). These flowgates are focused more specifically in Local Resource Zones (LRZ) 1 and 3, with larger lines being affected along the seams of states like North Dakota and Minnesota. The three worst case sequences, designed to test and stress the system, all see the largest increases in Congestion Measure. However, the 1-Year Delay scenario also resulted in a high increase in congestion when compared to the Random Planned and Forced outages sequence. The 6-Month Delay scenario resulted in a decrease in congestion by about \$179K/MW, compared to that of the Random Planned and Forced Outages.

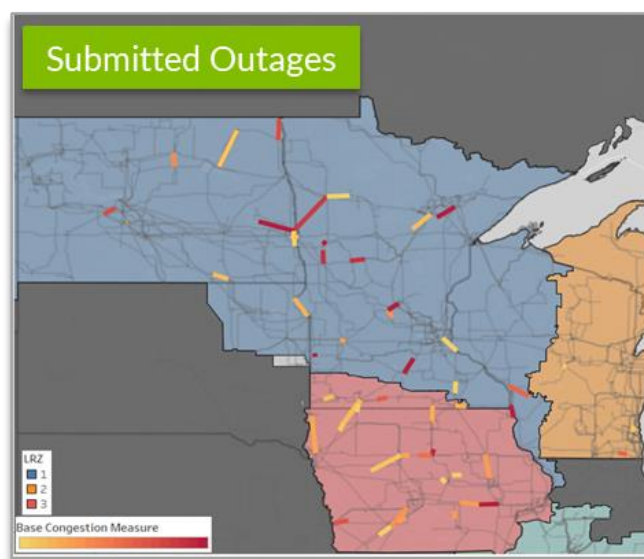


Figure 5. Congested flowgates in West Region

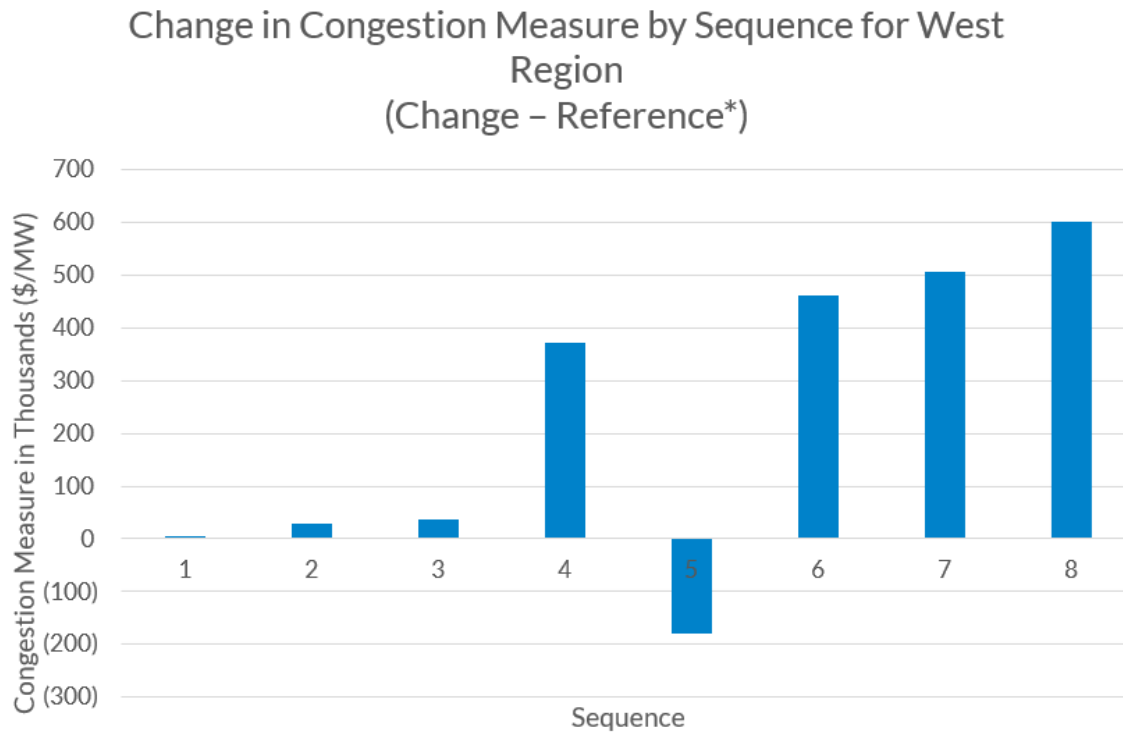


Figure 6. Congestion Measure for West Region by sequence.

*Reference case is Random Planned and Forced outages. *Sequence Names (Change Case):* 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

The West Region sees increases in Curtailment across scenarios. As expected, each of the Worst-Case sequences resulted in a high amount of Curtailment. The 1-Year Delay sequence sees the smallest increase in Curtailment against the Random Planned and Forced Outages sequence when compared to the other scenarios. The 6-Month Delay sees the largest increase in Curtailment outside of the worst-case scenarios.

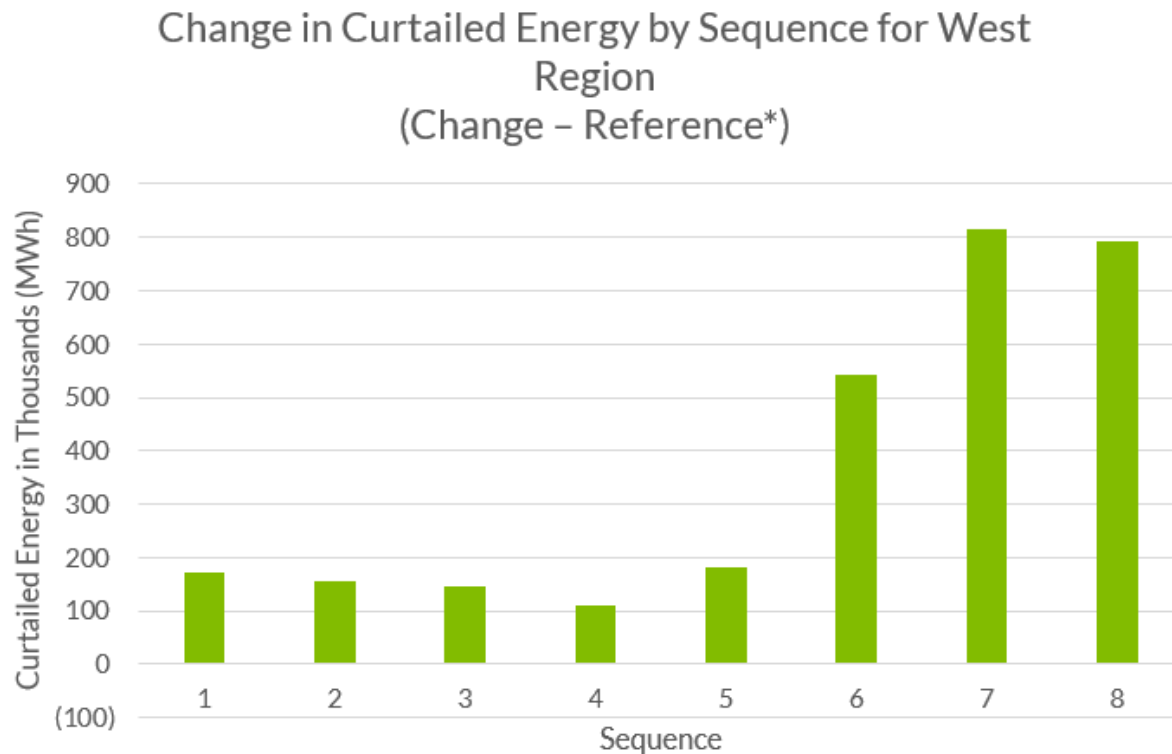


Figure 7. Curtailment Energy for West Region by sequence.

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

Central Region Congestion and Curtailment Results

The various outage sequences resulted in minimal change in Congestion Measure for the Central Region (Figure 8). The only sequence that had a notable change when compared to the Random Planned and Forced Outages scenario was the 6-Month Delay, which decreased as shown in Figure 9.

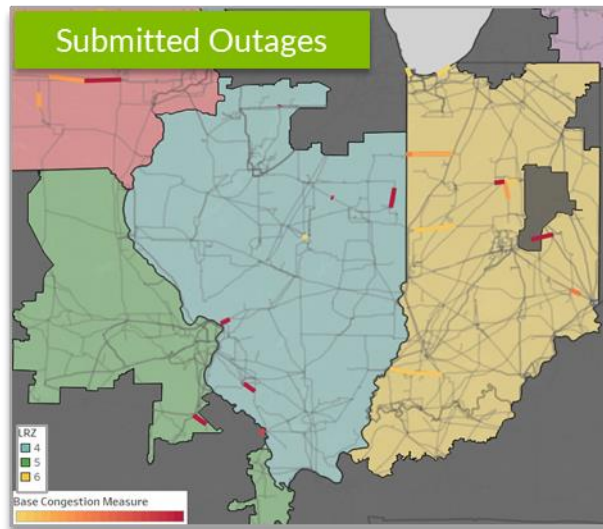


Figure 8. Congested flowgates in Central Region

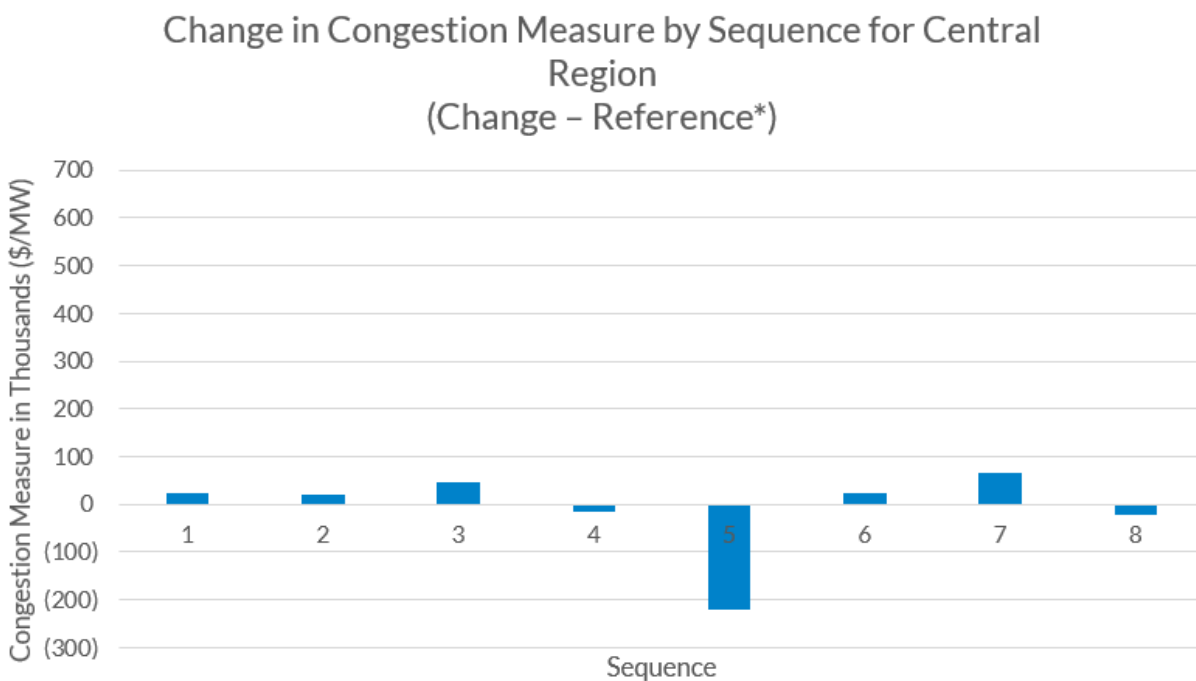


Figure 9. Congestion measure in Central Region by sequence.

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

The amount of curtailed energy shown in [Figure 10](#) was consistently larger than the Random Planned and Forced Outages sequence for most scenarios within the Central Region. The exception is the 1-Year Delay scenario which resulted in a negligible change in curtailment when



compared to the Random Planned and Forced Outage scenario.

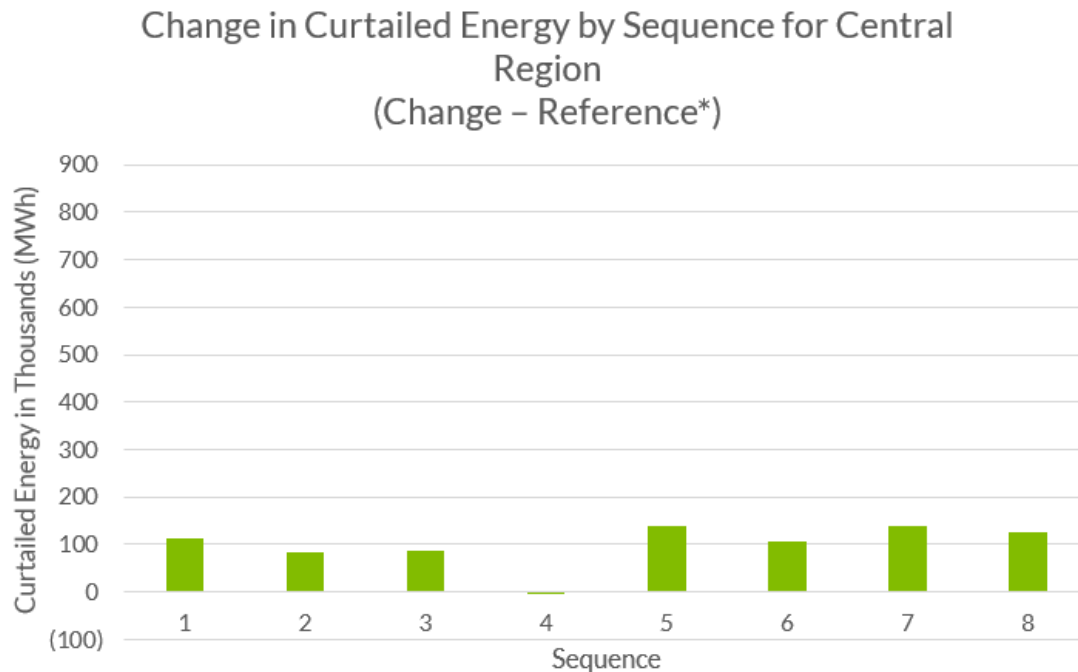


Figure 10. Curtailed Energy for Central Region by sequence.

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

East Region Congestion and Curtailment Results

MISO's East Region was the least impacted by the various outage sequences. The East Region only had a handful of flowgates with low to relatively high congestion as shown in [Figure 11](#). The only notable changes were the implementation of the 6-Month Delay sequence, which shows a minimal decrease in congestion (Figure 12).

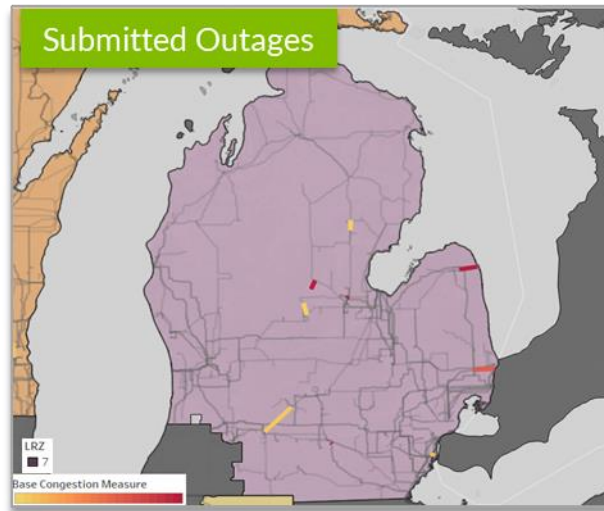


Figure 11. Congested flowgates in East Region

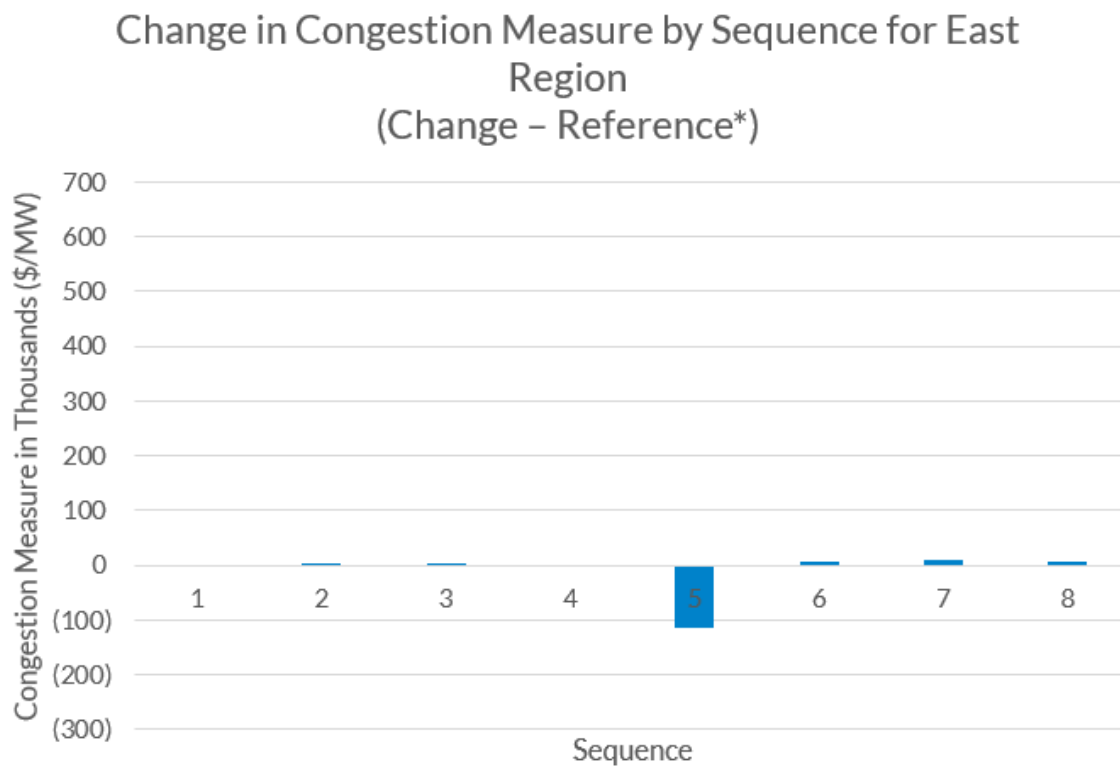


Figure 12. Congestion measure in East Region by sequence

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment



In [Figure 13](#), the first four sequences are shown to have no change in curtailment energy compared to the Random Planned and Forced Outages sequence within the East region. However, sequences 5-8 are shown to have a very slight change in curtailment when compared to the Random Planned and Forced Outages sequence.

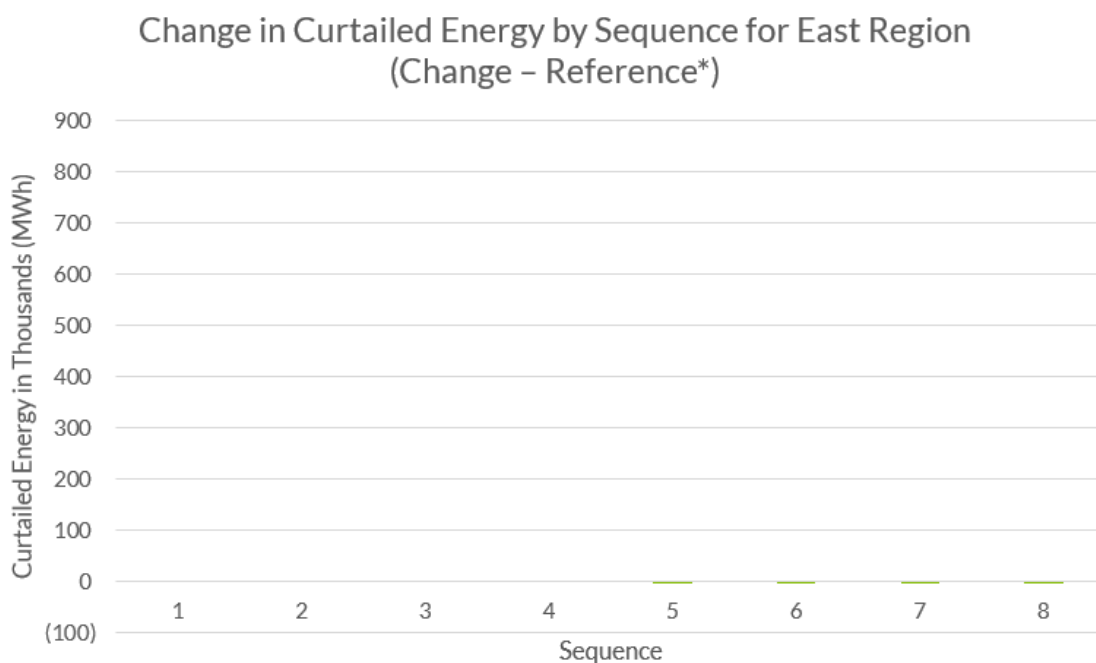


Figure 13. Curtailment Energy for East Region by sequence

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

Economic Metrics

MISO Economic Planning utilizes several economic metrics to assess the impacts of portfolios, projects, outages, and other study elements. Details on these metrics can be found in the [MISO Economic Planning Whitepaper](#). This study focused on Adjusted Production Cost (APC), Congestion Measure, and Curtailment to observe the impacts that different outage sequences have across the footprint.

APC

Adjusted Production Cost (APC)² was used to assess the overall impacts of the construction outage scenarios. In Figure 14 the Random Planned and Forced Outages and Submitted Outages Scenarios are used as the reference cases to assess change in APC in the other scenarios.

² Adjusted Production Cost is a measure of the cost to serve load by company and is utilized to capture the differences in production cost between two models.



Scenario	Change in APC (Scenario - P+F) (Million)	Change in APC (Scenario - Submitted Outages) (Million)
Submitted Outages	+ \$10.50	--
MISO Developed Modified	+ \$9.16	- \$1.34
Iowa Delay	+ \$9.22	- \$1.28
6-Month Delay	+ \$17.99	+ \$7.49
1-Year Delay	+ \$14.07	+ \$3.57
Worst-Case	+ \$37.95	+ \$27.45
Worst-Case w/ Delay	+ \$51.01	+ \$40.51
Worst-Case w/ Delay & Curtailment	+ \$68.47	+ \$57.97

Figure 14. Adjusted Production Cost Comparison

The Random Planned and Forced Outages scenario was the foundation for comparative sequence development and was used as a reference for assessing changes to APC. The Submitted Outages scenario was used to develop, analyze, and evaluate other potential outage sequences and also serves as a reference case in [Figure 14](#). The Submitted Outages scenario had an APC of \$10.5M more than the Random Planned and Forced Outages scenario.

The MISO Developed Modified scenario focused on rearranging the MISO estimated outages that were not submitted by TOs. The adjustment to estimated outages resulted in an APC \$1.34M less than the Submitted Outages scenario. The Iowa Delay scenario was a similar adjustment in MISO estimated outages that pushed all Iowa project construction outages out past 2027. This scenario resulted in an APC reduction of \$1.28M. These are the only scenarios where adjustments were only made to MISO estimated outages.

The 6-Month Delay scenario utilized the Submitted Outages sequence, but delayed start and end dates by six months. This resulted in outages starting in July of 2026 and beyond to be moved into the study year 2027 and outages starting in July of 2027 and beyond to be moved out to 2028. These changes in schedules led to a \$7.49M increase in APC compared to the Submitted Outages scenario. A similar process was used to create the 1-Year Delay scenario, resulting in a \$3.57M increase in APC compared to the Submitted Outage scenario.

MISO also took the opportunity to create three “worst case” sequences where more stress was placed on the system for the year 2027. The original Worst-Case scenario simulated all outages occurring in the 2027 study year which caused APC to increase by \$27.45M. The Worst Case with Delays scenario utilized the same outage schedule as the Worst Case but also extended the length of some outages, resulting in a \$40.51M increase to APC. This result was \$13.06M more than the



original Worst Case scenario. This Worst Case with Increased Curtailment scenario built on the Worst Case with Delays scenario by incorporating additional outages with the intent to curtail more energy. This sequence resulted in an APC \$57.97M greater than the Submitted Outages scenario.

Congestion Measure

The change to Congestion Measure³ was assessed by region and by Local Resource Zone (LRZ). In all comparisons the Random Planned and Forced Outage scenario was used as a Reference case and all other scenarios were included as Change cases. Details on these results can be found in the West Region, Central Region, East Region and Near-Term Congestion Study Appendix sections of this report.

The most significant impacts to Congestion Measure occurred in LRZ 1 as shown in Figure 15. The Congestion Measure for LRZ 1 fluctuates for different outages, with a 6-Month Delay resulting in a decrease to Congestion Measure and the Worst-Case w/ Increased Curtailment scenario having the highest increase to Congestion Measure. As expected, all Worst-Case sequences have the highest Congestion Measure. However, the 1-Year Delay caused the change from Random Planned and Forced Outages in LRZ 1 to increase by approximately \$350,000/MW, which is a greater change than all other sequences.

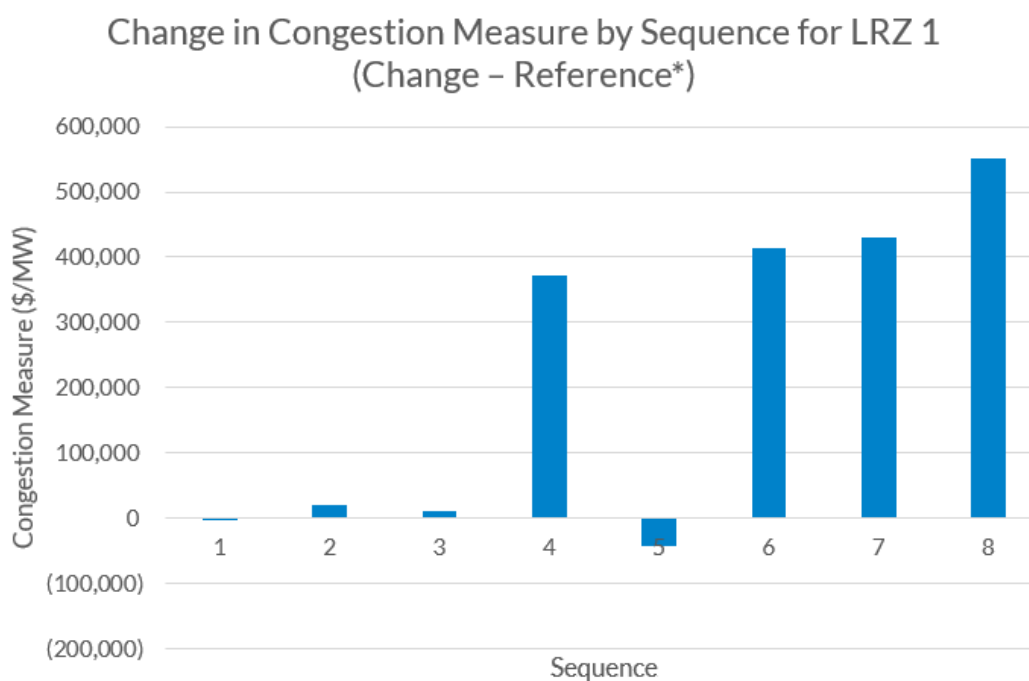


Figure 15. Change in Congestion Measure for LRZ 1

³ Congestion Measure is calculated by multiplying the Average Annual Shadow Price (\$/MW/hr) of a transmission constraint by the number of annual Binding Hours (hr/yr).



*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

Congested Flowgates

Many of the top congested flowgates saw significant changes in the scenarios studied. Details on the impacts to notable flowgates can be seen in [Figure 16](#). Below MISO provides additional details on these flowgates and their contingencies.

Notable Flowgates	Contingency	SO Shadow Price (\$/MWh)	SO Binding Hours	SO Congestion (\$/MW)
(NIPS) Goodland – (NIPS) Reynolds 138 kV	(AMIL) Gilman South – (AMIL) Watseka 138 kV	35**	123**	4,287**
(AMIL) Rossville – (AMIL) Vermilion 138 kV	(AMIL) Paxton E – (AMIL) Gifford 138 kV	34**	900**	30,455**
(GRE) Inman – (GRE) Wing River 230 kV	(MP) Long Prairie – (GRE) Little Sauk 115 kV	136	127	17,268
(NSP) St. Augusta Tap – (NSP) Wakefield 115 kV	(NSP) Wakefield – (NSP) Stockade Tap 115 kV	280	162	45,377
(ALTW) Woody – (ALTW) Apanose 161 kV	(AMMO) Adair – (AMMO) Zachary 161 kV	20	2	39
(GRE) Chub Lake Transformer 345 kV/115 kV	(NSP) Spring Creek – (NSP) Prairie Island 161 kV	194**	56**	10,849**
(NIPS) Goodland – (NIPS) Morrison Ditch 138 kV	(AMIL) Paxton E – (AMIL) Gifford 138 kV	25	350	8,731
(MEC) Franklin – (MEC) Wall Lake 161 kV	(ALTW) Nuthatch – (MEC) Franklin 161 kV	22	498**	10,983

Legend	
■	Large Decrease from Submitted Outages
■	Large Increase from Submitted Outages
■	Large Change from P/F to Submitted Outages
**	New from P/F

Figure 16. Notable flowgates

- (NIPS) Goodland – (NIPS) Reynolds 138 kV FLO (AMIL) Gilman South – (AMIL) Watseka 138 kV
 - Was observed with a Congestion Measure of \$4,287/MW and binding 123 hours once the Submitted Outages sequence was applied
- (AMIL) Rossville – (AMIL) Vermilion 138 kV FLO (AMIL) Paxton E – (AMIL) Gifford 138 kV



- Was not observed in the Random Planned and Forced Outage scenario but increased to a Congestion Measure of \$30,455/MW in the Submitted Outages sequence with 900 binding hours
- (GRE) Inman – (GRE) Wing River 230 kV FLO (MP) Long Prairie – (GRE) Little Sauk 115 kV
 - Was congested at \$17,268/MW in the Submitted Outages sequence, increased to \$92,175/MW in the 1-Year Delay sequence, and maxed out at \$123,847/MW in the Worst Case w/ Increased Curtailment sequence
- (NSP) St. Augusta Tap – (NSP) Wakefield 115 kV FLO (NSP) Wakefield – (NSP) Stockade Tap 115 kV
 - A Congestion Measure of \$45,377/MW was seen in the Submitted Outages sequence and increased to \$275,299/MW with the 1-Year Delay sequence
- (ALTW) Woody – (ALTW) Appanoose 161 kV FLO (AMMO) Adair – (AMMO) Zachary 161 kV
 - Had a shadow price of \$153/MWh in the Random Planned and Forced sequence; however, the shadow price decreased to \$20/MWh in the Submitted Outage sequence. The shadow price does increase to \$62/MWh in the Worst Case w/ Increase Curtailment sequence
- (GRE) Chub Lake Transformer 345 kV/115 kV FLO (NSP) Spring Creek – (NSP) Prairie Island 161 kV
 - Was not observed in our Random Planned and Forced sequence but appeared in our Submitted Outages sequence with a congestion measure of \$10,849/MW while binding 1 hour.
 - In the test sequences the shadow price and Congestion Measure decrease hitting its lowest price in the 6 Month Delay sequence with \$51/MWh and binding 15 hours resulting in a decrease in congestion measure to \$769/MW.
- (NIPS) Goodland – (NIPS) Morrison Ditch 138 kV FLO (AMIL) Paxton E – (AMIL) Gifford 138 kV
 - Congestion Measure increased from \$280/MW to \$8,731/MW from our Random Planned and Forced sequence to our Submitted Outage sequence.
 - Both binding hours and Congestion Measure decreased in all of our test sequences hitting a low in Worst Case w/ Delays at 3 binding hours and a Congestion Measure of \$4/MW
- (MEC) Franklin – (MEC) Wall Lake 161 kV FLO (ALTW) Nuthatch – (MEC) Franklin 161 kV
 - Had a Congestion Measure of \$19,129/MW and binding 1182 hours in our Random Planned and Forced sequence but saw a significant decrease in both once the Submitted Outages sequence was applied resulting in a congestion measure of \$10,983/MW and binding 498 hours

Curtailment

The change to Curtailment⁴ was assessed by region and by Local Resource Zone (LRZ). In all comparisons the Random Planned and Forced Outage scenario was used as a Reference case and

⁴ Curtailment is a measure of the amount of energy (MWh) which is available from non-thermal generators (generally Wind, Solar, and Hydro), but cannot be dispatched and delivered economically.



all other scenarios were included as Change cases. Details on these results can be found in the West Region, Central Region, East Region and Near-Term Congestion Study Appendix sections of this report.

Economic Planning identified that two LRZs face the most impact regarding curtailed megawatt hours. LRZs 1 and 3 see much larger increases in curtailed energy between the Random Planned and Forced Outages sequence and other tested scenarios than all other LRZs. With LRTP Tranche 1 projects aiming to enable renewable generation, much of which comes from the West region of the MISO footprint, and with many Tranche 1 projects being built as double circuits on existing right of way, it is expected that construction outages would result in a temporary increase in curtailment. While most of the other LRZs do see some increases in curtailment, these increases in curtailed energy are 100,000 MWh or less.

Figure 17 and Figure 18 show the Curtailment results for LRZ 1 and LRZ 3. LRZ 3 sees the highest increases in changes in curtailed energy between each sequence. Outside of Worst-Case sequences, Submitted Outages, MISO Developed Modified, and Iowa Delay all see increases in curtailed energy by about 175,000 MWh. These sequences have minimal changes in LRZ 1. The 1-Year Delay sequence causes curtailed energy to decrease for LRZ 3 while it increases by about 150,000 MWh for LRZ 1.

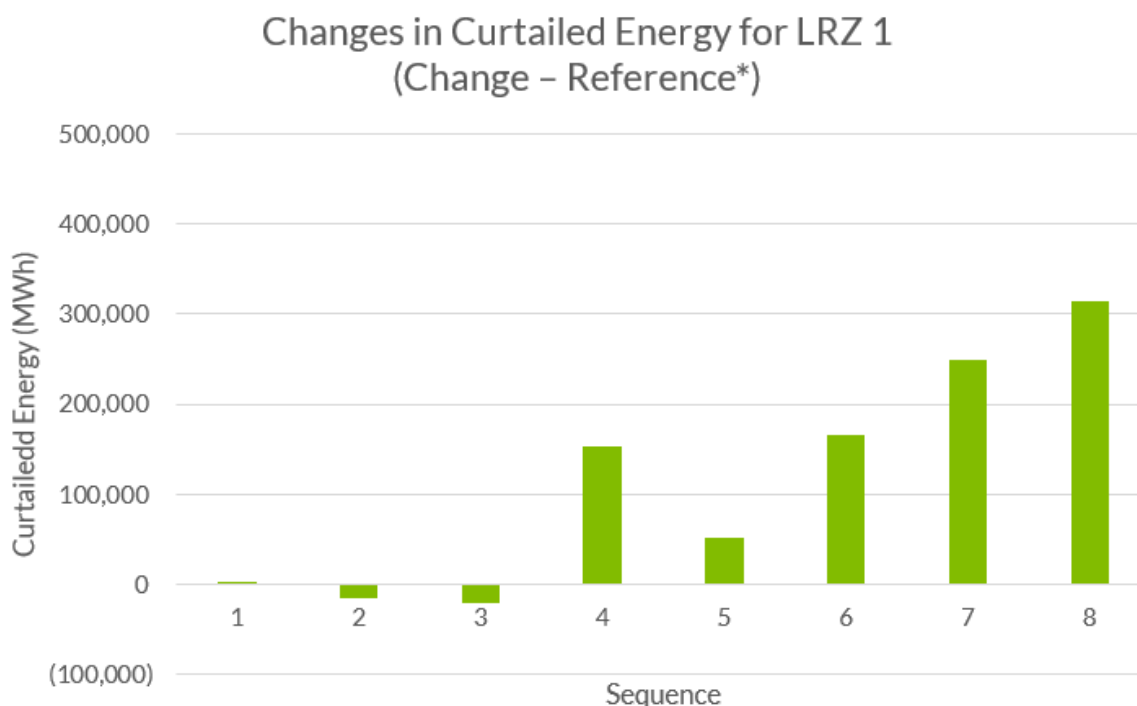


Figure 17. Change in Curtailed Energy for LRZ 1

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

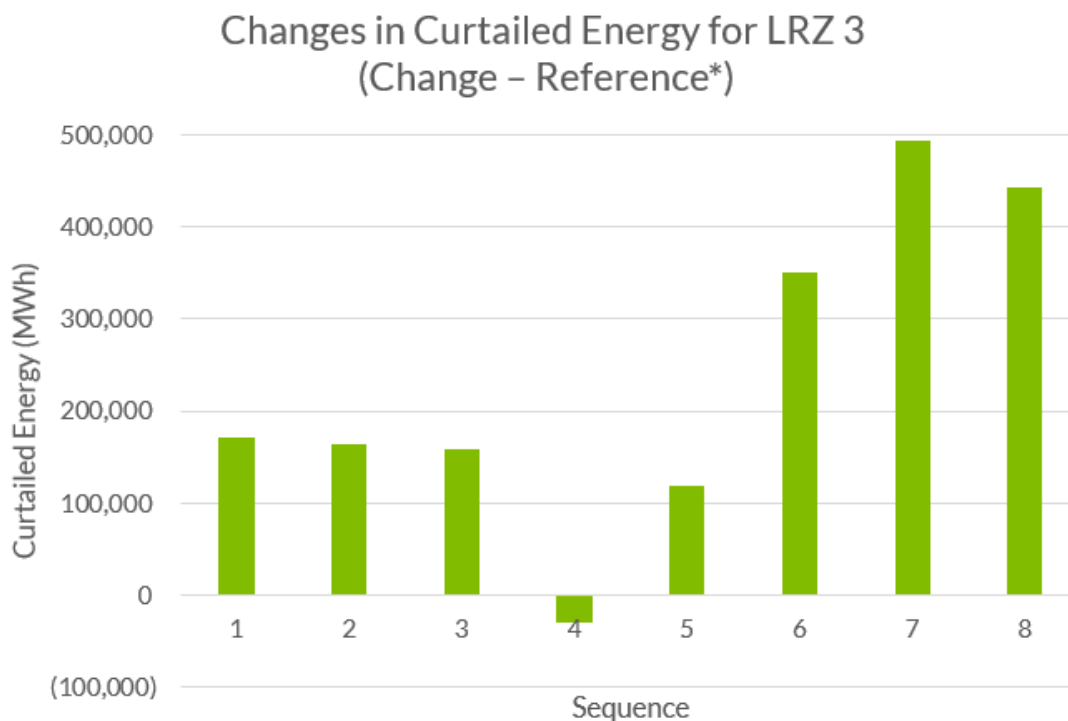


Figure 18. Change in Curtailed Energy for LRZ 3

**Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment*

6-Month Delay

The 6-Month Delay scenario resulted in increases in APC and in Curtailment, but large decreases in Congestion Measure when compared to the Submitted Outages scenario (Figure 19). The 6-Month Delay scenario took the Submitted Outages sequence and pushed construction outage dates out 6 months. This created an unusual sequence of outages where outages intended for lower load periods were exchanged with outages intended for higher load periods.

Changes in import and export dispatches between neighboring RTOs and increased dispatch in thermal generation were the key drivers to creating the inverse relationship between Congestion Measure and APC in the 6-Month Delay scenario. Additional generation, in particular thermal generation, shifted to the MISO pool resulting in a reduction to Congestion Measure but an overall increase in the cost of dispatching the system as reflected in the higher APC.

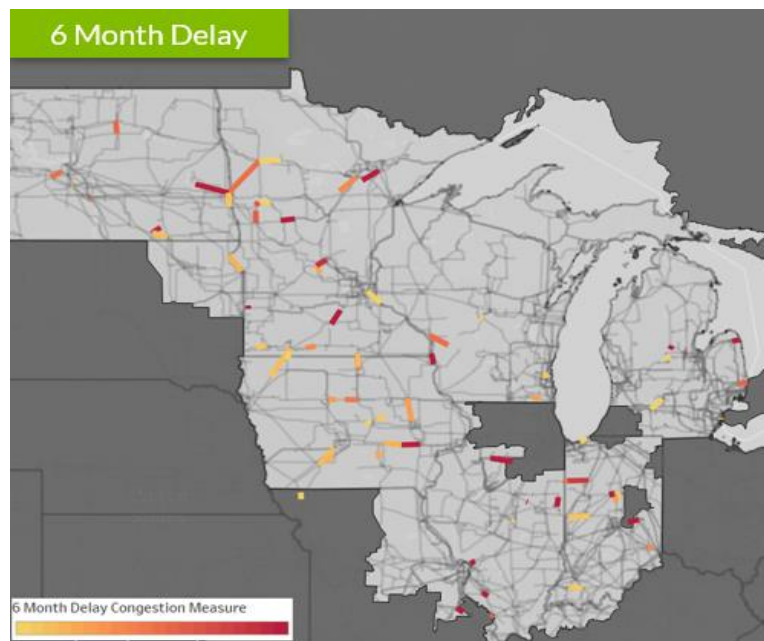


Figure 19. Congestion Flowgates across MISO's footprint W/ 6 Month Delay

Worst-Case with Delay

The Worst-Case with Delay scenario was designed by moving all outages to the 2027 study year. Each outage was then extended by adding one to two months onto the end dates. Each outage was adjusted to start on a Monday and end on a Sunday in order to help PROMOD complete faster. The intent of this sequence and other worst-case scenarios was to push the capabilities of the system. With this scenario we were able to establish an extreme result PROMOD could solve that would also provide a bookend on the range of likely Congestion Measure, APC, and Curtailment impacts when these construction outages go into effect.

The Worst-Case with Delay sequence increased APC by \$51 million compared to the Random Planned and Forced outage case and \$40.5 million compared to the Submitted Outage sequence. Curtailments for the Worst-Case with Delay was seen the most in LRZs 1 and 3. Total curtailment increased by 952,000 MWh and Congestion Measure increased by \$600,000/MW when compared to the Random Planned and Forced sequence. In addition to worsening congestion, additional flowgates were binding under this scenario compared to the Submitted Outages scenario as shown in [Figure 20](#).

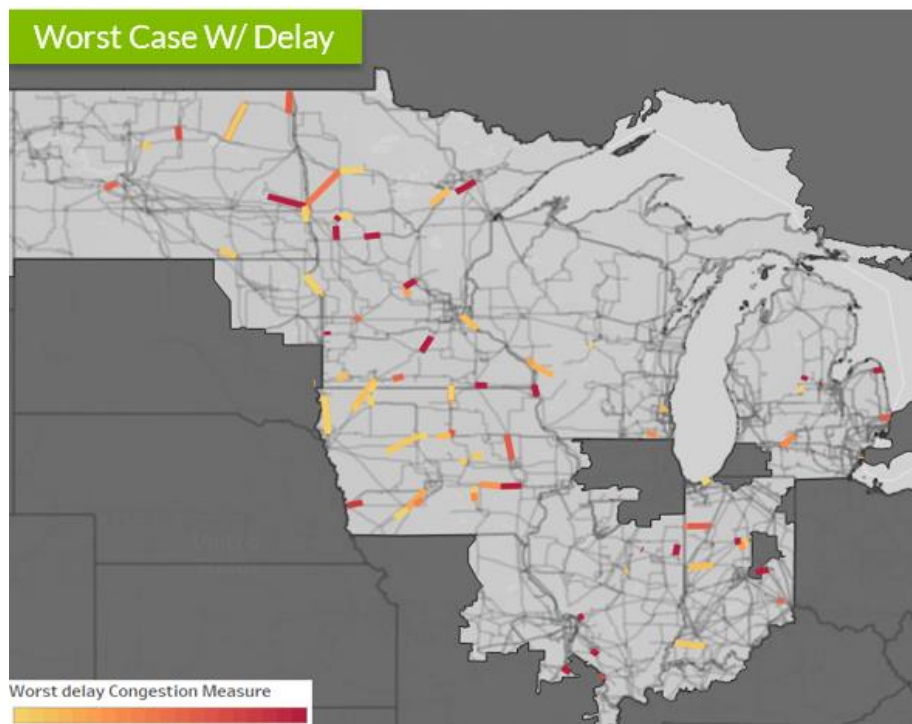


Figure 20. Worst Case w/ Delay Congestion Map

Study Takeaways

The study has provided opportunities to assess and prepare for the upcoming LRTP Tranche 1 construction outages. It has been observed that increasing outage durations due to delays leads to higher APC, Congestion Measures, and Curtailments. Receiving information sooner will give our Operations Planning teams more time to effectively prepare for these Tranche 1 outages. Notable flowgates have already been shared with internal operations partners for close monitoring as these construction outages commence. Results have also been shared with stakeholders to provide an opportunity to consider Market Participant Funded Projects (MPFP).

Grid-Enhancing Technologies (GETs)

MISO asked stakeholders for feedback regarding any potential GETs solutions that could help with near term congestion as a result of installation of Long-Range Transmission Planning (LRTP) Tranche 1 lines.

While MISO will share potential solutions from stakeholders, MISO does not plan to recommend projects for approval based on the results of this informational study. Voluntary pursuit of any project proposals by stakeholders based on the study results should be performed in accordance with the planning processes and timelines outlined in the MISO Transmission Planning Business Practice Manual (BPM-020). Cost allocation outside of market participant funding for any specific upgrades are not in scope for this effort.



GETs Solutions - GRE

MON: EDGETAP7 115kV - PEL RPD7115 kV CON: AUDUBON4 230kV - LAKE PARK T4230 kV

MON: GRE-TAMARAC7 115kV - GRE-CORMRNT7115 kV CON: AUDUBON4 230kV - LAKE PARK T4230 kV

MON: GRE-TAMARAC7 115kV - GRE-CORMRNT7115 kV CON: HOOT LK7 115kV - FERGSFL7115 kV

Dynamic Line Ratings DLR on Edgetown-Pelican Rapids-Tamarac-Cormorant-Audubon 115 kV (GRE/MRES)

- Dynamic Line Ratings (DLR) are a recommended solution for MISO to study for these facilities. GRE's internal study work indicates that the entire path from Edgetown to Audubon would need the DLR to be effective, otherwise congestion would shift to segments adjacent to those identified in the NTCS report. These are joint-owned facilities so utility coordination is required. Some jumpers and other minor equipment upgrades may be needed to utilize the conductor rating gains from the DLR. There is little wind generation in the immediate area so there is not a strong correlation between the high wind conditions that cause this issue and local wind conditions that impact line ratings. In the long term, this line's conductor should be upgraded.

MON: GRE-INMAN 4 230kV - GRE-WINGRIV4230 kV CON: LONG PR7 115kV - GRE-LTLSKTP7115 kV

Dynamic Line Ratings (DLR) on Henning-Inman-Wing River-Riverton 230 kV (GRE/MP)

- Dynamic Line Ratings (DLR) are a recommended solution for MISO to study for these facilities. GRE's internal study work indicates that the entire path from Henning to Riverton would need the DLR to be effective, otherwise congestion would shift to segments adjacent to those identified in the NTCS report. Some jumpers and other minor equipment upgrades may be needed to utilize the conductor rating gains from the DLR.

Congestion Cost Reconfigurations Process

It is likely that adjustments will occur to the Submitted Outage sequence as timelines for LRTP Tranche 1 projects are refined. To help manage the impacts of delays and extensions, MISO recommends stakeholders utilize the [MISO Congestion Cost Reconfiguration Process](#) to help address economic reconfiguration needs as they arise.



Near-Term Congestion Study Appendix

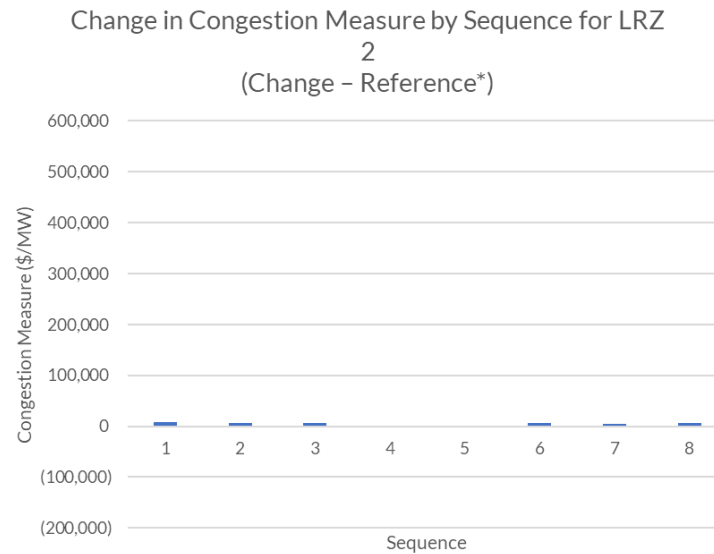


Figure 21. Congestion measure in LRZ 2 by sequence

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

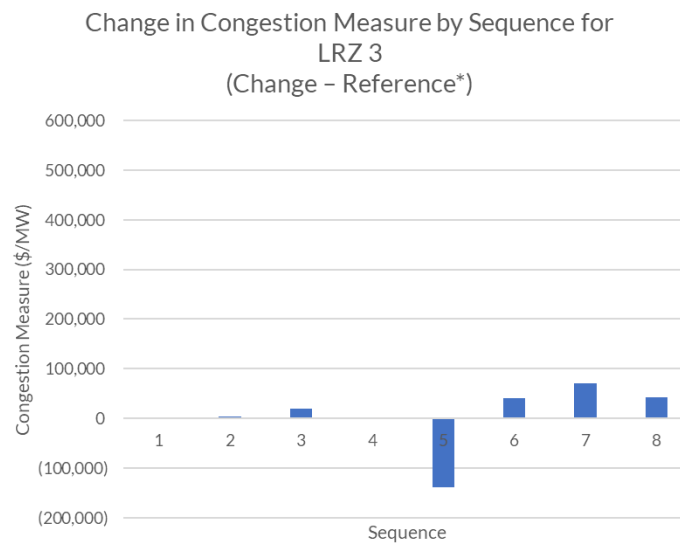


Figure 22. Congestion measure in LRZ 3 by sequence

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

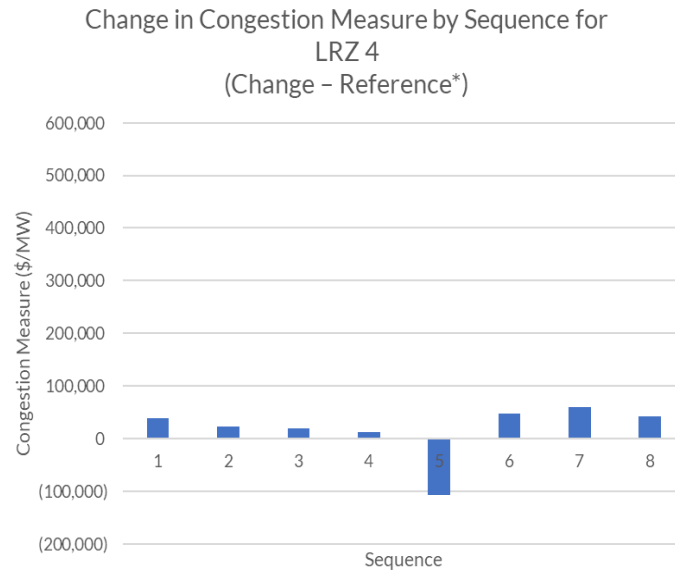


Figure 23. Congestion measure in LRZ 4 by sequence

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

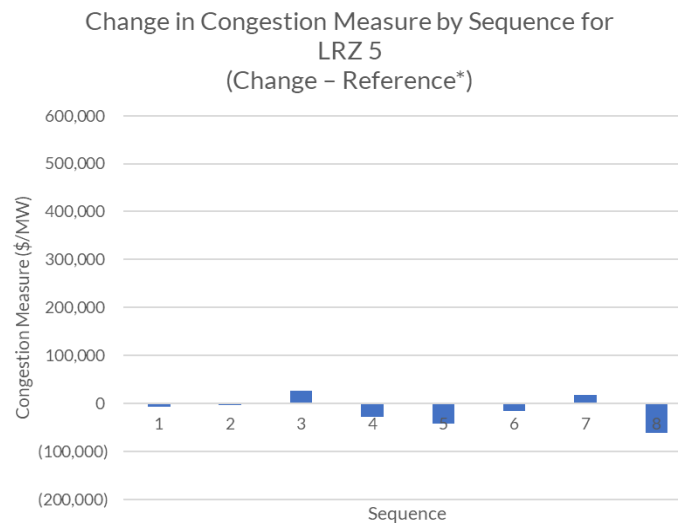


Figure 24. Congestion measure in LRZ 5 by sequence

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

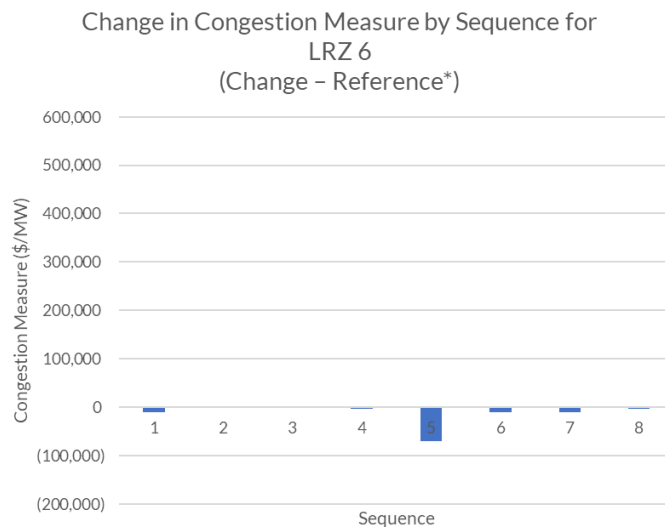


Figure 25. Congestion measure in LRZ 6 by sequence

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

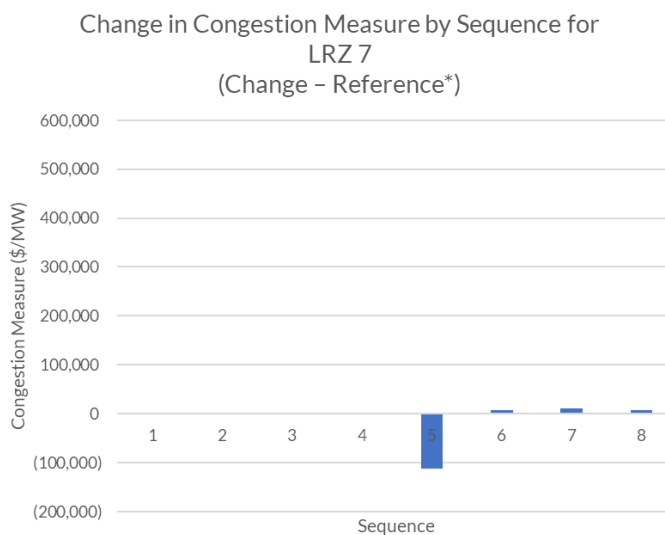


Figure 26. Congestion measure in LRZ 7 by sequence

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

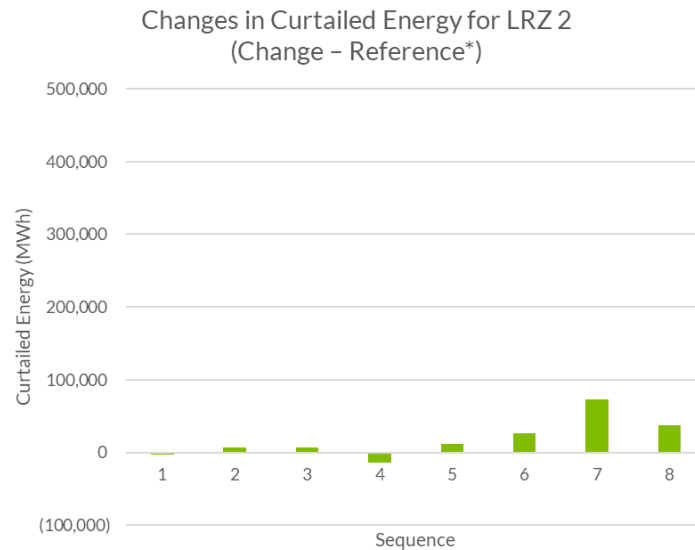


Figure 27. Change in Curtailed Energy for LRZ 2

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

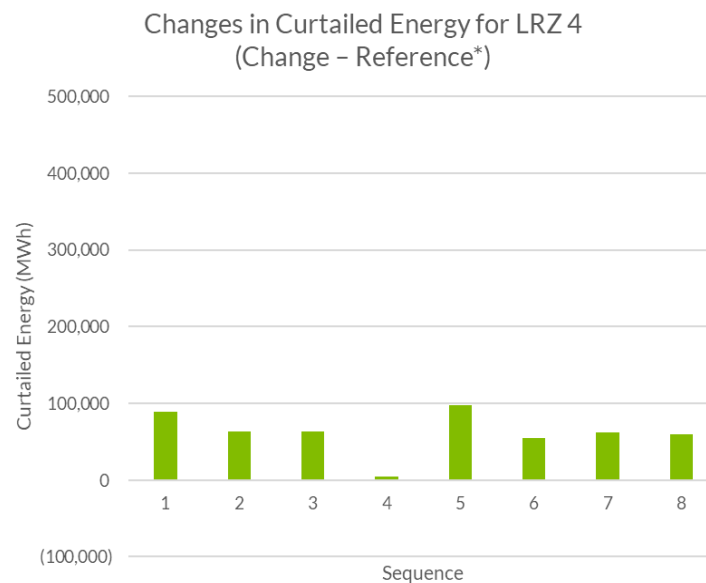


Figure 28. Change in Curtailed Energy for LRZ 4

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

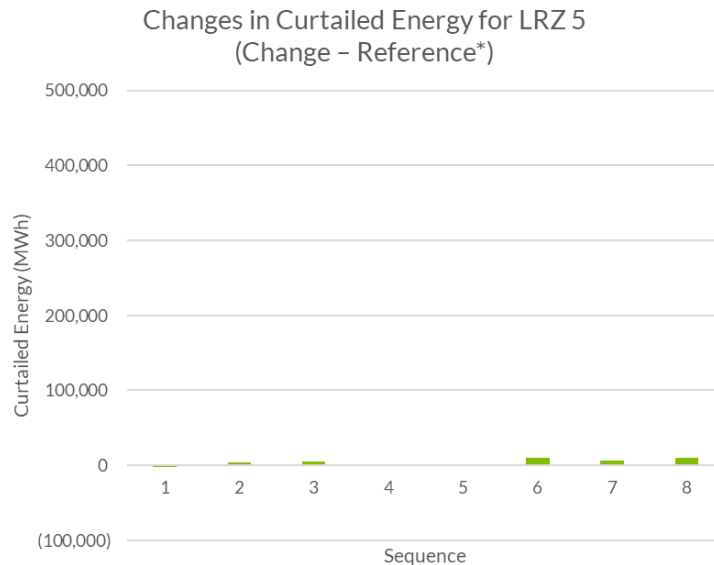


Figure 29. Change in Curtailed Energy for LRZ 5

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

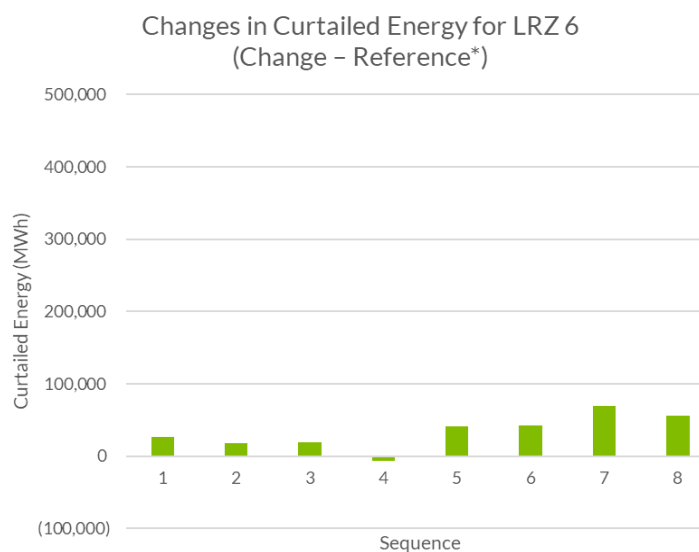


Figure 30. Change in Curtailed Energy for LRZ 6

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment

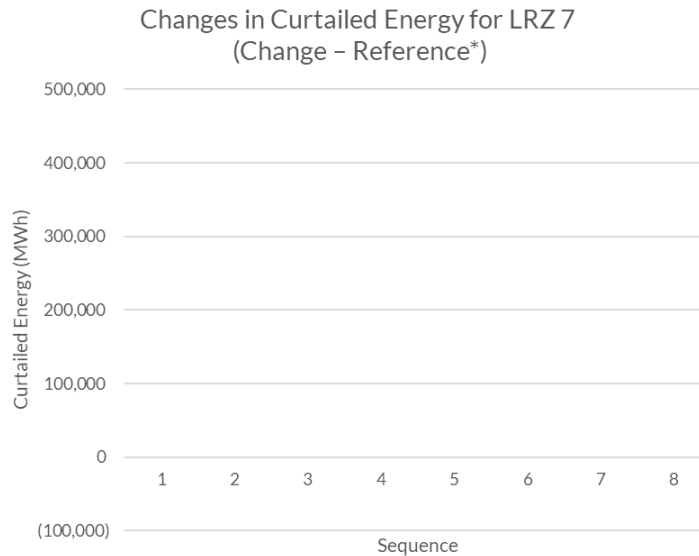


Figure 31. Change in Curtailed Energy for LRZ 7

*Reference case is Random Planned and Forced outages. Sequence Names (Change Case): 1. Submitted Outages 2. MISO Developed Modified 3. Iowa Delay 4. 1-Year Delay 5. 6-Month Delay 6. Worst-Case 7. Worst-Case w/ Delays 8. Worst-Case w/ Increased Curtailment



Revision History

Revision Level	Description	Revised By	Issued Date
01	Added revision page, Removed Foreman 3 xfmr from pg 19, added submitted GETs solutions to pg 25	Bobby Klene (MISO)	11/26/2024