AFFECTED SYSTEM ANALYSIS OF SPP DISIS-2022-001 PHASE 2 STUDY

MINNKOTA POWER COOPERATIVE, INC.

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Document Revisions

Date	Revision	Description
02/14/25	0	Initial Draft
02/18/25	1	Incorporated comments from MPC

1. Executive Summary

The purpose of this Affected System Analysis (ASA) is to determine the impacts of generators in the SPP DISIS-2022-001 Phase 2 study cycle on Minnkota Power Cooperative (MPC) facilities and any Network Upgrades (NUs) required to mitigate those impacts.

Steady-state power flow, contingency analyses, and dynamic stability analysis were performed for the DISIS generating facilities shown in Table 1. Mentions of the DISIS-2022-001 Phase 2 projects throughout this report will only refer to those shown in Table 1.

Table 1: ASA DISIS-2022-001 Phase 2 Projects

Project	POI	Summer MW	Fuel Type	Service Type
GEN-2022-009	Judson Substation 345 kV	125	Thermal	ER
GEN-2022-010	Judson Substation 345 kV	250	Thermal	ER
GEN-2022-068	Chappelle Creek 345 kV	250	Wind	ER/NR
GEN-2022-083	Judson Substation 345 kV	250	Thermal	ER

1.1. Network Upgrades Identified in ASA

The network upgrades required to mitigate constraints identified in the Minnkota ASA are listed in Table 2. The costs are planning level estimates and subject to revision in the facility studies.

Table 2: Minnkota Steady State Network Upgrades Allocated to DISIS-2022-001 Phase 2 Projects

Constraint	Owner	Highest Loading (MVA)	Mitigation	Cost ($)	Generators
Jamestown – New Sub 345 kV	MPC	1196.1	Structure Raise	$3,500,000	GEN-2022-068

Table 3 shows Minnkota network upgrades allocated to higher queued projects that are required to mitigate identified thermal constraints. If the upgrades are not built by the higher queued projects, they may be required to be built by the DISIS-2022-001 Phase 2 projects.

Table 3: Minnkota Network Upgrades Allocated to Higher Queued Projects for Thermal Violations

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Jamestown – Center 345 kV	MPC	910.7	Prior queued project expected to mitigate thermal violation – Facility rating upgrade	GEN-2022-068
Bison – Buffalo 345 kV	MPC	1515.4	Prior queued project expected to mitigate thermal violation – 2nd Bison – Buffalo circuit	GEN-2022-009, GEN-2022-010, GEN-2022-068, GEN-2022-083
Coleman – Walle 69 kV	MPC	88.1	Prior queued project expected to mitigate thermal violation – Terminal upgrade and reconductor	GEN-2022-009, GEN-2022-010, GEN-2022-068, GEN-2022-083
Berge – Prairie 69 kV	MPC	94.2	Prior queued project expected to mitigate thermal violation – Terminal upgrade and reconductor	GEN-2022-009, GEN-2022-010, GEN-2022-068, GEN-2022-083
Center 345/230 kV Autotransformer 1	MPC	910.4	Prior queued project expected to mitigate thermal violation – 3rd Center transformer	GEN-2022-068
Center 345/230 kV Autotransformer 2	MPC	912.0	Prior queued project expected to mitigate thermal violation – 3rd Center transformer	GEN-2022-068

Table 4 shows the contingent network upgrades allocated to higher queued projects that are required to mitigate the identified stability constraints.

Table 4: Network Upgrades Allocated to Higher Queued Projects for Stability Violations

Constraint	Owner	Network Upgrade to Address Stability Violations (not allocated)
Transient voltage instability Redacted		Prior queued project expected to mitigate stability violation – STATCOMs from Table 30
Non-convergence Redacted		Prior queued project expected to mitigate non-convergence violation – MSCs from Table 30

Table 5 and Table 6 show the Minnkota constraints that are alleviated by existing MPC equipment and do not require mitigation.

Table 5: Minnkota Network Upgrades mitigated by existing MPC Equipment

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
MPC 3839 POI – MPC 4300 POI 345 kV	MPC	924.21	Below minimum MPC equipment rating Redacted	GEN-2022-068
Drayton – Letellier 230 kV	MPC/ MH	511.7	Below minimum MPC equipment rating Redacted MPC equipment not limiting.	GEN-2022-009, GEN-2022-010, GEN-2022-083
Buffalo – New Sub 345 kV	MPC/OTP	1494.1	Below minimum MPC equipment rating; MPC equipment not limiting.	GEN-2022-009, GEN-2022-010, GEN-2022-068, GEN-2022-083

Table 6: Minnkota Voltage Constraint Mitigated by Existing MPC Equipment

Constraint	Mitigation	Projects
Pickert 69 kV	Switch existing reactor on the low-side of the Pickert 230/69 kV transformer	GEN-2022-009, GEN-2022-010, GEN-2022-083

1.1.1. GEN-2022-009 Project Summary

No network upgrade costs assigned to request GEN-2022-009.

1.1.2. GEN-2022-010 Project Summary

No network upgrade costs assigned to request GEN-2022-010.

1.1.3. GEN-2022-068 Project Summary

Table 7: Cost Allocation of Minnkota Network Upgrades to GEN-2022-068

Network Upgrade	Total Cost ($)	GEN-2022-068 Allocation
Structure Raise Jamestown – New Sub 345 kV	$3,500,000	$3,500,000

1.1.4. GEN-2022-083 Project Summary

No network upgrade costs assigned to request GEN-2022-083.

1.2. Steady State Power Flow Analysis

Power flow and contingency analyses were performed to identify and mitigate any non-converged, thermal, or voltage issues on the Minnkota system caused by the ASA project. Analyses were performed for summer peak, winter peak, and summer shoulder conditions.

1.3. Transient Stability Analysis

A transient stability analysis was performed to identify and mitigate any system instability, transient voltage, damping, or relay margin issues on the Minnkota system caused by the addition of the ASA project. The transient stability analysis was performed only for summer shoulder conditions.

1.4. Conclusion

Thermal and stability constraints were identified on the MPC system for the ASA project, and there were no identified steady-state voltage constraints. The required network upgrades allocated to the ASA project to address the identified issues are listed in Table 2, which assumed that all contingent upgrades in Table 3 and Table 4 are in-service. The total upgrade cost assigned to the ASA project is $3,500,000 in planning level estimates as identified in Table 7.

2. Steady State Power Flow Analysis

Power flow and contingency analyses were performed to identify and mitigate any non-converged, thermal, or voltage issues on the MPC system caused by the ASA project under study.

2.1. Study Methodology

Study cases representing summer peak, winter peak, and summer shoulder system conditions were created with the ASA project dispatched at the GIA output, as applicable. System performance was benchmarked using cases without the studied ASA project.

Power flow and nonlinear (AC) contingency analyses were performed on the benchmark and study cases, and the incremental impacts of the studied ASA project were evaluated by comparing the steady-state performance of the MPC system.

Steady-state analyses were performed using TARA v2402.1 and cases were created using PSS®E version 34.

2.2. Case Development

Power flow cases were created from the MPC ASA of DPP-2021 Ph2 summer peak base case (ASA_DPP21-P2_2026SUM_Study-Discharge_240306), winter peak base case (ASA_DPP21-P2_2025WIN_Study_240318), and summer shoulder base case (ASA_DPP21-P2_2026SHHW_Study-Charge_240311).

ASA summer peak (SUM), winter peak (WIN), and summer shoulder (SSH) study cases were created from the MPC DPP-2021 ASA base cases by applying the model updates listed in Table 8 and dispatching MPC generators and MISO Generator Interconnection Projects as show in Table 9 and Table 10.

The dispatch of North Dakota and South Dakota generators in the ASA study cases can be found in Appendix A.

Table 8: ASA Model Updates

Model Update	SUM (MW)	SH (MW)	WIN (MW)
Dispatched Selected MISO DPP-2021-Cycle Study Units as PQ:			
- J1888	27.3	175	175
- J1893	78	500	500
- J1990	39	250	219.5
- J2080	31.2	200	200
- J2084	45	0	45
- J2085	40	0	40
- J2086	500	0	500
- J2097	15.6	100	100
- J2101	102.6	-102.6	102.6
- J2157	15.6	100	100
- J2250	31.2	200	200
- J2276	39.5	0	39.5
Dispatched Selected MISO DPP-2020-Cycle Study Units as PQ:			
- J1575	10.92	70	70
- J1588	200	0	0
Dispatched Selected SPP DISIS-2021-001 Study Units as PQ:			
- GEN-2021-008	200	0	200
Dispatched Selected SPP DISIS-2020-001 Study Units as PQ:			
- GEN-2020-091	150	0	150
- GEN-2020-021	235	176.25	235
- GEN-2020-014	33.81	0	42.75
Dispatched Selected SPP DISIS-2019-001 Study Units as PQ:			
- GEN-2019-037	150	0	0
Dispatched Selected SPP DISIS-2018-001 Study Units as PQ:			
- GEN-2018-010 (BESS)	74.1	0	0

Table 9: Minnkota Generator Dispatch

Generator	SUM (MW)	SH (MW)	WIN (MW)
Young 1	274	274	274
Young 2	493	493	493
Oliver County	6.43	47.324	66.5
Langdon	12.0616	153.6251	133.665
Ashtabula (GRE)	2.1223	39.4006	34.17
Ashtabula (OTP)	22.9192	290.8471	252.828
MPC03600	87.26	0	0
MPC03700	65.44	0	0
MPC03800	16.99	234	156.78
MPC03900	10.194	142	95.14
MPC04000	20.38	290	194.3

Table 10: ASA Study Project Dispatch

Project	Summer (MW)	Summer Shoulder (MW)	Winter (MW)	Fuel Type	Service Type
GEN-2022-009	125	0	125	Thermal	ER
GEN-2022-010	250	0	250	Thermal	ER
GEN-2022-068	250	250	250	Wind	ER/NR
GEN-2022-083	250	0	250	Thermal	ER

The power flow cases were solved with transformer tap adjustments enabled, area interchange adjustments disabled, phase shifter adjustments enabled, and switched shunt adjustments enabled.

2.3. Contingencies

The study area was defined as transmission facilities rated 69 kV and above in the BEPC (areas 663 and 659), GRE (area 615), MDU (area 661), MH (area 667), MP (area 608), OTP (area 620), WAPA (area 652) and XEL (area 600) areas. The contingency set included contingencies in the study area from the MPC ASA of MISO DPP-2021-Cycle Phase 2 Study; contingency files are shown below in Table 11.

Table 11: List of Contingency Files for Steady State Analysis

Contingency File Name	Summer	Shoulder	Winter
MPC ASA of DPP-2021-Phase2_basecase.con	x	x	x
MPC ASA of DPP-2021-Phase2_Master_P1.con	x	x	x
MPC ASA of DPP-2021-Phase2_Master-P1_P2_P4_P5_P7.con	x	x	x
MPC ASA of DPP-2021-Phase2_Outlet.con	x	x	x
cons_Auto_MPC.con	x	x	x
cons_Auto_DIS2022.con	x	x	x

Post-contingent cases were solved with transformer tap adjustments enabled, area interchange adjustments disabled, phase shifter adjustments disabled, and switched shunt adjustments enabled.

2.4. Monitored Elements

Facilities in the study area were monitored for system intact and post-contingency conditions. Under NERC category P0 conditions (system intact), branches were monitored for loading above the normal (PSS®E/TARA Rate A) rating; under NERC category P1-P7 (post-contingent) conditions, branches were monitored for loading above the emergency (PSS®E/TARA Rate B) rating. Bus voltages were monitored using the limits shown in Table 12.

Facility loadings were calculated based on MVA at the actual voltage by setting both transformer and non-transformer units to "Current expressed as MVA" in TARA.

Table 12: List Monitored Elements

Area	Monitored Elements	Voltage Limits (High/Low)[1]	
		System intact	Post-Contingency
BEPC (659)	69 kV and above	1.05/0.95	1.1/0.90
GRE (615)	Load buses 69 kV and above	1.05/0.95	1.1/0.92
	No load buses 69 kV and above	1.05/0.95	1.1/0.90
MDU (661)	100 kV and above	1.05/0.95	1.1/0.90
MH (667)	100 kV and 119 kV	1.1/0.99	1.15/0.94
	120 kV and 129 kV	1.1/0.95	1.1/0.90
	130 kV and 199 kV	1.05/0.96	1.1/0.90
	200 kV and 228 kV	1.12/0.97	1.15/0.94
	229 kV and 499 kV	1.05/0.97	1.1/0.90
	500 kV and 800 kV	1.07/1.04	1.1/0.90
MPC (owner 657)	69 kV and above	1.07/0.97	1.1/0.92
MP (owner 608)	69 kV and above	1.05/1.00	1.1/0.95
MRES (owner 608)	69 kV and above	1.05/1.00	1.1/0.95
OTP (owner 620)	69 kV and above	1.07/0.97	1.1/0.92
	200 kV and 800 kV	1.05/0.97	1.1/0.92
WAPA (652)	100 kV and above	1.05/0.95	1.1/0.92
XEL (owner 600)	69 kV and above	1.05/0.95	1.05/0.92

Notes:

1. Default voltage limits are shown in the table; some buses were monitored using specific limits provided in Transmission Owner Planning Criteria.

2.5. Performance Criteria

MPC Significantly Affected Facilities (SAF), ERIS constraints, and NRIS constraints were identified in accordance with the MPC Transmission Planning BPM and MPC Planning Criteria.

2.5.1. Significantly Affected Facilities

SAF are identified as any transmission facility, 69 kV and above, for which all the following conditions exist:

- In the post-project case, the facility exceeds its applicable thermal or voltage rating.

- The increase in the loading of the facility from the pre-project to the post-project case is greater than 1 MVA.
- Thermal: Distribution Factor (DF) greater than 3%.
- Voltage: impact greater than 0.01 p.u. (applies to all types of voltage analysis).

2.5.2. ERIS Maximum Impact Criteria

ERIS constraints are SAFs that meet the following criteria:

- Non-Converged
  - The study project has a larger than five percent (5%) distribution factor on the contingent elements pre-contingency.
- Thermal
  - The study project has a larger than twenty percent (20%) distribution factor on the overloaded facilities under post-contingent conditions or five percent (5%) distribution factor under system intact conditions, or
  - The overloaded facility or the overload-causing contingency is at the study project's POI, or
  - The impact due to the new facility is greater than or equal to twenty percent (20%) of the applicable facility rating of the overloaded facility.
  - The cumulative impact of the group of study generators is greater than twenty percent (20%) of the rating of the facility and the impact of the study generator is greater than five percent (5%) of the rating of the facility.
- Voltage
  - The voltage change due to the study project is greater than 0.01 per unit of the nominal system voltage.
  - The cumulative impact of the group of study generators is greater than 0.01 per unit of the nominal system voltage and the impact of the study generator is greater than 0.003 per unit.

2.5.3. NRIS Maximum Impact Criteria

When performing affected system analysis to determine the impacts of neighboring providers' queued generation interconnection requests on the Minnkota system, standard transmission service impact criteria are applied for NRIS requests. NRIS thermal constraints are SAF that meet the following criteria:

- Non-Converged
  - The study project has a larger than five percent (5%) distribution factor on the contingent elements pre-contingency.
- Thermal
  - System Intact (PTDF) greater than 5%.
  - Under Contingency (OTDF) greater than 3%.
- Voltage
  - The voltage change due to the study project is greater than 0.01 per unit of the nominal system voltage.
  - The cumulative impact of the group of study generators is greater than 0.01 per unit of the nominal system voltage and the impact of the study generator is greater than 0.003 per unit.

2.6. Thermal Constraints

MPC thermal constraints for the summer peak and summer shoulder cases are summarized in Table 13.

Thermal constraint details for NERC P0, P1, P2, P4, P5, and P7 (post-contingent) conditions are provided in Appendix B.

Table 13: Minnkota Worst Thermal Constraints

Facility	Owner	Rating MVA	Pre-Project Loading		Post-Project Loading		Contingency	Type	ERIS Constraint	NRIS Constraint
			MVA	%	MVA	%				
							Redacted			

2.7. Voltage Significantly Affected Facilities

The Minnkota non-converged voltage constraints identified for the summer shoulder study case are summarized in Table 14. There were no Minnkota non-converged voltage constraints in the summer peak or winter peak case. Prior-queued network upgrades were utilized to mitigate the non-convergence.

Table 14: Minnkota Non-Converged Constraints

Case	Contingency	Type	Bench Status	Study Status
Redacted				

2.8. Mitigation of Steady State Constraints

Network upgrades required to mitigate MPC NRIS thermal constraints are shown below in Table 15.

Table 15: Minnkota Thermal Constraint Mitigation

Facility	Owner	Rating MVA	Post-Project Loading		Mitigation	Cost	ERIS Constraint	NRIS Constraint
			MVA	%				
Redacted								

3. Transient Stability Analysis

A transient stability analysis was performed to identify and mitigate any system instability, transient voltage, damping, or relay margin issues on the MPC system caused by the ASA project under study.

3.1. Study Methodology

Transient stability analysis was performed using the MPC ASA of MISO DPP 2021-Ph2 summer shoulder stability case with network upgrades (ASA_DPP21-P2_2026SHHW_Study-Discharge_240403_ST_20241204_Drayton_STATCOM_Bison_Buff_2nd_line.pfb) and making modifications as described in Table 16 and Table 17.

Table 16: Stability Model Updates – Modifications to Reactive Devices

Bus	Removed Equipment	Reactive Devices after Modifications
Alexandria 345 Redacted	MSC: 1x75 MVAR	MSC: 12x75 MVAR
Alexandria 345 STATCOM Redacted	±100 MVAR STATCOM	None
Audubon 230 STATCOM Redacted	±150 MVAR STATCOM Redacted	±150 MVAR STATCOM
Bison 345 Redacted	MSC: 2x75 MVAR	MSC: 2x75 MVAR
Buffalo 115 Redacted	MSC: 1x30 MVAR	None
Buffalo 345 Redacted	MSC: 1x75 MVAR	None
Fort Ridgley Redacted	MSC: 1x20 MVAR	None
Toronto N 115 Redacted	MSC: 1x5.4 MVAR	None
Wahpeton 230 STATCOM Redacted	±150 MVAR STATCOM Redacted	±150 MVAR STATCOM
Winger 230 Redacted	MSC: 2x30 MVAR	None
Winger 230 STATCOM Redacted	±250 MVAR STATCOM	None
Drayton 230 STATCOM Redacted	±100 MVAR STATCOM	None

Redacted

Table 17: Stability Model Updates – Dispatch Modifications to PSAT Model

Model Update	Fuel Type	Benchmark case	Study Case
Dispatched Selected MISO DPP-2020-Cycle Study Units as PQ:			
- J2084	Solar	Offline	Offline
- J2085	Solar	Offline	Offline
- J2086	Solar	Offline	Offline
- J2101	Storage	-98 MW	-98 MW
- J2276	Solar	Offline	Offline
Dispatched Selected SPP DISIS-2021-001 Study Units:			
- GEN-2021-024 (withdrawn)	Wind	Offline	Offline
Dispatched Selected SPP DISIS-2022-001 Study Units as CQ:			
- GEN-2022-009	Thermal	Offline	Offline
- GEN-2022-010	Thermal	Offline	Offline
- GEN-2022-068	Wind	Offline	253 MW
- GEN-2022-083	Thermal	Offline	Offline

Table 18 lists the contingent upgrades from the PSSE steady-state analysis that were modified to ensure consistency with the PSAT load flow case for the stability study.

Table 18: Stability Model Updates – Contingent Upgrades from Steady-State Analysis

Bus	Modifications	Reactive Devices after Modifications
Alexandria 345 Redacted		12x 75 MVAR MSC
Cedar Mountain 345 Redacted	Removed 2x 75 MVAR MSC banks to match PSSE steady-state case	2x 75 MVAR MSC
Horner 115 Redacted		1x 20 MVAR MSC
Hubbard 230 Redacted		2x 50 MVAR MSC
Inman 230 Redacted		2x 40 MVAR MSC
Maple River 230 Redacted	Removed 2x 40 MVAR MSC banks to match PSSE steady-state case	2x 50 MVAR MSC
McLeod 230 Redacted	Removed 1x 50 MVAR MSC banks to match PSSE steady-state case	4x 40 MVAR MSC
Panther 230 Redacted		4x 40 MVAR MSC
Paynesville 230 Redacted	Added 2x 40 MVAR MSC banks to match PSSE steady-state case	4x 40 MVAR MSC

The contingent upgrades listed in Table 29 were also included in the stability study.

3.1.1. Stability Study Scenarios

Figure 1 and Table 19 describe the high-level study scenarios used in the stability analysis. Table 20 identifies the specific network upgrades included in each scenario.

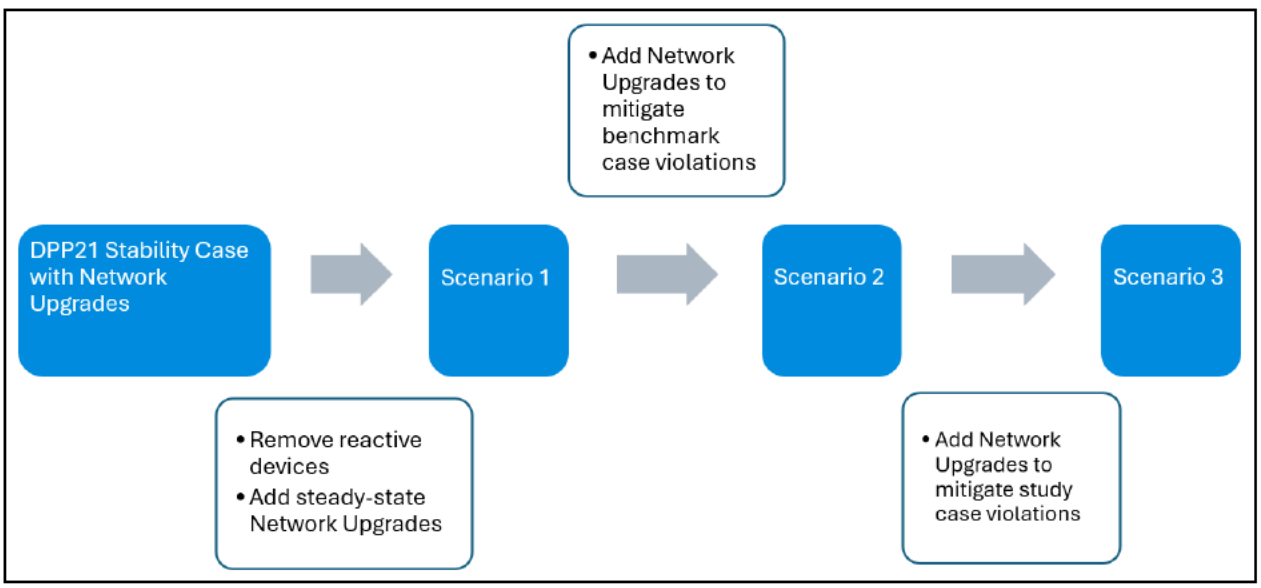

Figure 1: Network Modifications used to Create Stability Scenarios

Table 19: Stability Study Scenarios Description

Scenario	Description
Scenario 1	The MPC ASA of DPP 2021 Phase 2 summer shoulder case modeled with reactive devices modifications from Table 16 as well as the steady-state network upgrades from Table 18 and Table 29. Only the benchmark case was simulated in TSAT.
Scenario 2	Scenario 1 modeled with the network upgrades to mitigate all stability concerns in Scenario 1's benchmark case. Both the benchmark and study cases were simulated in TSAT.
Scenario 3	Scenario 2 modeled with the network upgrades to mitigate all stability concerns in Scenario 2's study case. Both the benchmark and study cases were simulated in TSAT.

Table 20: Stability Study Scenarios with Detailed Upgrades

<table>
<tr><th>Scenario</th><th>Starting Case</th><th>Drayton STATCOM</th><th>Alexandria STATCOM</th><th>Audubon STATCOM</th><th>Wahpeton STATCOM</th></tr>
<tr><td>Scenario 1</td><td rowspan="3">DPP 2021-Ph2 with Network Upgrades and Modifications in Table 16, Table 18 and Table 29</td><td>None</td><td>None</td><td>±150 MVAR</td><td>±150 MVAR</td></tr>
<tr><td>Scenario 2</td><td rowspan="2">±50 MVAR</td><td rowspan="2">±650 MVAR</td><td rowspan="2">±300 MVAR</td><td>±150 MVAR</td></tr>
<tr><td>Scenario 3</td><td>±300 MVAR</td></tr>
</table>

3.2. Dynamic Data

The transient stability analysis was performed using the MPC summer shoulder stability package. The stability package was updated by applying the model updates listed in Appendix A. The study project was represented with the following dynamic model:

- **GEN 2022-009 (Offline)**: Model consistent with DISIS 2022-001 representation
- **GEN 2022-010 (Offline)**: Model consistent with DISIS 2022-001 representation
- **GEN 2022-068**: Model consistent with DISIS 2022-001 representation
- **GEN 2022-083 (Offline)**: Model consistent with DISIS 2022-001 representation

3.3. Contingency Criteria

The stability simulations performed as part of this study considered the MPC regional and local contingencies listed in Table 21. Simulations were performed with a 0.5-second steady-state run followed by the disturbance. Simulations were run for a 15-second duration.

Table 21: TSAT Contingency Descriptions

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
-	Flat Run	No fault	P0	-
Regional_1	0690_w_gre_p23	Redacted	P2-3	GRE

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
Regional_2	0800_w_mp_p12	Redacted	P1-2	GRE
Regional_3	0819_w_otp_p11		P1-1	OTP
Regional_4	0822_w_otp_p12		P1-2	OTP
Regional_5	0823_w_otp_p12		P1-2	OTP
Regional_6	0824_w_otp_p12		P1-2	OTP
Regional_7	0826_w_otp_p42		P4-2	OTP
Regional_8	0830_w_otp_p42_MISO		P4-2	OTP
Regional_9	0831_w_otp_p42		P4-2	OTP
Regional_10	0832_w_otp_p42		P4-2	GRE
Regional_11	1677_w_otp_p12		P1-2	GRE
Regional_12	1681_w_otp_p42		P4-2	OTP
Regional_13	1684_w_xel_p12.idv		P1-2	XEL
Regional_14	P7_GRE_CCK_BIPOLE_U1U2TRIP		P7	GRE
Regional_15	P15_GRE_CCK_MONOPOLE_U1TRIP		P1-5	GRE
Regional_16	J1588_p42_bison_buffalo_mapleriv		P4-2	J1588 / XEL
Regional_17	J1588_3ph_poi_alxlnrctrt_p12_fault		P1-2	J1588 / XEL
Regional_18	J1588_p42_bison_buffalo_alex		P4-2	J1588 / XEL
Regional_19	p12_mpc4300poi-prairie		P1-2	MPC04300
Regional_20	SQBUTTE_BIPOLE_FAULT		P7-2	MP
G22-068_2	3PH-CHAPELLE-FTTHOM-LNX		P1-2	G22-068
G22-068_3	3PH-CHAPELLE-TRIPLEH		P1-2	G22-068
G22-068_4	3PH-CHAPELLE-CC.LS-LO-BE		P1-2	G22-068
G22-068_5	P4_3PH-CHAPELLE-FTTHOM-LNX_AND_CHAPELLE-TRIPLEH		P4-2	G22-068
G22-068_6	P4_3PH-CHAPELLE-FTTHOM-LNX_AND_CHAPELLE-CC.LS-LO-BE		P4-2	G22-068

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
G22-068_7	P4_3PH-CHAPELLE-TRIPLEH_AND_CHAPELLE-CC.LS-LO-BE	Redacted	P4-2	G22-068

3.4. Performance Criteria

Regional and local disturbances were simulated using TSAT version 24.0.0. The results were screened to identify any violations of MPC transmission reliability criteria.

3.4.1. Transient Stability Period Voltage Limitations

MPC buses were monitored using the transient voltage limits summarized in Table 22. The voltage must return within applicable post-contingency voltage limits within ten seconds of fault clearing. The bus voltage on the MPC System is allowed to increase to 1.3 per unit for a duration of up to 200 milliseconds.

Table 22: Minnkota Transient Stability Period Voltage Limitations

Facility	Maximum Voltage (p.u.)	Minimum Voltage (p.u.)
All buses	1.2	0.7
Drayton 230 kV	1.15	0.8

3.4.2. Transient-Period Damping Criteria

Machine rotor-angle oscillations were monitored using the criteria below, which does not apply to bus voltages.

- For disturbances (with faults): SPPR (maximum) = 0.95; Damping Factor (minimum) = 5%
- For line trips: SPPR (maximum) = 0.90; Damping Factor (minimum) = 10%

The Damping Factor is calculated from the Successive Positive Peak Ratio (SPPR) of the peak-to-peak amplitude of the rotor oscillation. SPPR and the associated Damping Factor will be calculated as:

- SPPR = Successive swing amplitude / previous swing amplitude, and
- Damping Factor = (1 - SPPR) * 100 (in %)

3.4.3. Distance Relaying – Apparent Impedance Transient Criteria

Apparent impedance swings on all lines were monitored, after fault clearing, against a three-zone ohm (or offset impedance) circle characteristic. Apparent impedance transient swings into the inner zones (Circles A or B) are considered unacceptable unless documentation is provided showing the actual relays will not trip for the event.

3.5. Transient Stability Analysis Results

The detailed transient stability results on the MPC facilities are found in Appendix C.

3.5.1. Scenario 1 Results

Several contingencies in Scenario 1's benchmark case caused voltage instability, as shown in Table 23. The voltage instability must first be mitigated before assessing the other stability violations on MPC transmission reliability criteria.

Table 23: Scenario 1 – Summary of Violations for Benchmark Case

Scenario	Cont. No.	Contingency Description	Status
	Redacted		

To mitigate the voltage instability in Scenario 1's benchmark case, Table 24 shows the required network upgrades.

Table 24: Network Upgrade to Mitigate Scenario 1's Stability Violations

Constraint	Network Upgrade	Comment
Transient voltage instability	Add ±50 MVAR STATCOM at Drayton 230 kV	Allocated to higher queued projects
	Increase Alexandria 345 kV STATCOM from ±100 MVAR to ±650 MVAR	
	Increase Audubon 230 kV STATCOM from ±150 MVAR to ±300 MVAR	

3.5.2. Scenario 2 Results

After applying the contingent network upgrades in Table 24, there were no voltage instability in Scenario 2's benchmark case. However in Scenario 2's study case, Redacted caused voltage instability, as shown in Table 25.

Table 25: Scenario 2 – Summary of Violations for Study Case

Scenario	Cont. No.	Contingency Description	Status
Redacted			

To mitigate the voltage instability in Scenario 2's study case, Table 26 shows the required network upgrades.

Table 26: Network Upgrade to Mitigate Scenario 2's Stability Violations

Constraint	Network Upgrade	Comment
Transient voltage instability	Increase Wahpeton 230 kV STATCOM from ±150 MVAR to ±300 MVAR	Allocated to higher queued projects

3.5.3. Scenario 3 Results

With the network upgrades in Table 26 applied to Scenario 2, the voltage instability is mitigated in both benchmark and study cases.

Additionally, there were no damping or relay margin violations in Scenario 3. Redacted resulted in transient high voltages that exceeded 1.30 pu on some MPC busses, Redacted

Redacted

The transient high voltage violation occurred in both the benchmark and study cases. Table 27 shows that the DISIS 2022 ASA project reduced the maximum voltage for this contingency, which demonstrates that the ASA project does not exacerbate the transient high voltage violation and is not responsible for mitigation.

Table 27: Scenario 3 – Comparison of Maximum Voltage between Bench and Study Cases Redacte

Bus Number	Bus Name	Maximum Voltage in (PU)		Duration of Violation (Sec)	Comment
		Benchmark Case	Study Case		
Redacted					

This high voltage violation was originally observed in the MPC ASA of MISO DPP 2021-Phase 2 report, which is consistent with this violation being present in the benchmark case. As per the recommendation from the ASA of MISO DPP 2021-Phase 2 report, these transient high voltage violations will be evaluated later in the MISO DPP 2021-Phase 3 study.

3.6. Conclusion

The transient stability study assessed regional and local contingencies across three scenarios. A few contingencies resulted in voltage instability, which required additional STATCOM network upgrades to mitigate and is summarized in Table 28.

Table 28: Summary of Stability Network Upgrades

Network Upgrade Description	Reason for Network Upgrade	Comment
Add ±50 MVAR STATCOM at Drayton 230 kV	Mitigate voltage instability in the benchmark case	Allocated to higher queued projects
Increase Alexandria 345 kV STATCOM from ±100 MVAR to ±650 MVAR		
Increase Audubon 230 kV STATCOM from ±150 MVAR to ±300 MVAR		
Increase Wahpeton 230 kV STATCOM from ±150 MVAR to ±300 MVAR	Mitigate voltage instability in the study case	

With all network upgrades in Table 28 in-service, there were no damping or relay margin violations. However, one contingency resulted in transient high voltage violations, Redacted This is an existing issue from the previous MPC ASA of MISO DPP 2021-Phase 2 study and is not exacerbated by the ASA project studied in this report.

4. Cost Allocation

The cost allocation of Network Upgrades reflects responsibilities for mitigating system impacts. The network upgrades required to mitigate constraints identified in Minnkota ASA are listed in Table 29 through Table 32.

This section is separated into network upgrades allocated to higher queued projects (contingent upgrades) and network allocates to be allocated to the MPC DISIS 2022 ASA projects.

4.1. Network Upgrades Allocated to Higher Queued Projects (Contingent Upgrades)

Table 29 shows the Minnkota network upgrades allocated to higher queued projects that are required to mitigate identified thermal constraints. If the upgrades are not built by the higher queued projects, they may be required to be built by the ASA project.

Table 29: Minnkota Network Upgrades Allocated to Higher Queued Projects

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Jamestown – Center 345 kV	MPC	910.7	MPC Group 2021-1 SIS - Structure Raise	GEN-2022-068
Bison – Buffalo 345 kV	MPC	1515.4	MPC ASA of DPP-2021 Ph2 – New Bison – Buffalo second circuit	GEN-2022-009, GEN-2022-010, GEN-2022-068, GEN-2022-083
Coleman – Walle 69 kV	MPC	88.1	MPC ASA of DISIS-2021-001 Ph2 – Terminal Upgrade, Reconductor	GEN-2022-009, GEN-2022-010, GEN-2022-068, GEN-2022-083
Berg – Prairie 69 kV	MPC	94.2	MPC ASA of DISIS-2021-001 Ph2 – Terminal Upgrade, Reconductor	GEN-2022-009, GEN-2022-010, GEN-2022-068, GEN-2022-083
Center 345/230 kV Autotransformer 1	MPC	910.4	MPC ASA DISIS-2019-001 – Third Center 345/230 kV autotransformer and terminal upgrades	GEN-2022-068
Center 345/230 kV Autotransformer 2	MPC	912.0	MPC ASA DISIS-2019-001 – Third Center 345/230 kV autotransformer and terminal upgrades	GEN-2022-068

Table 30 shows the MISO contingent network upgrades allocated to higher queued projects that are required to mitigate the identified stability constraints.

Table 30: MISO Network Upgrades Allocated to Higher Queued Projects for Stability Violations

Constraint	Owner	Mitigation
Transient voltage instability	MPC	Add ±50 MVAR STATCOM at Drayton 230 kV
	MRES	Increase Alexandria 345 kV STATCOM from ±100 MVAR to ±650 MVAR
	OTP	Increase Audubon 230 kV STATCOM from ±150 MVAR to ±300 MVAR
	OTP	Increase Wahpeton 230 kV STATCOM from ±150 MVAR to ±300 MVAR

Constraint	Owner	Mitigation
Steady-State Non-Convergence	MPC	MPC ASA of DPP-2021 Phase 2: Alexandria 345 kV 12x75 MVAR MSC, Cedar Mountain 345 kV 2x75 MVAR MSC, Horner 115 kV 1x20 MVAR MSC, Hubbard 230 kV 2x50 MVAR MSC, Inman 230 kV 2x40 MVAR MSC, Maple River 230 kV 2x50 MVAR MSC, McLeod 230 kV 4x40 MVAR MSC, Panther 230 kV 4x40 MVAR MSC, Paynesville 230 kV 4x40 MVAR MSC

Table 31 shows the Minnkota network upgrades that are alleviated by existing MPC equipment that do not require mitigation.

Table 31: Minnkota Network Upgrades Mitigated by Existing MPC Equipment

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
MPC 3839 POI – MPC 4300 POI 345 kV	MPC	924.21	Below minimum MPC equipment rating Redacted	GEN-2022-068
Drayton – Leteler 230 kV	MPC/ MH	511.7	Below minimum MPC equipment rating Redacted MPC equipment not limiting.	GEN-2022-009, GEN-2022-010, GEN-2022-083
Buffalo – New Sub 345 kV	MPC/ OTP	1494.1	Below minimum MPC equipment rating; MPC equipment not limiting.	GEN-2022-009, GEN-2022-010, GEN-2022-068, GEN-2022-083

4.2. Required Network Upgrades Allocated to MPC DISIS 2022 ASA Projects

Table 32 shows Minnkota network upgrades allocated to the ASA project. Costs are planning level estimates and subject to revision in the facility studies.

Table 32: Minnkota Network Upgrades Allocated to DISIS-2022-001 Phase 2 Project

Constraint	Owner	Highest Loading (MVA)	Mitigation	Cost ($)	Generators
Jamestown – New Sub 345 kV	MPC	1196.1	Structure Raise	$3,500,000	GEN-2022-068
				Total Cost	$3,500,000

4.3. Cost Allocation Methodology

A generator in the DISIS-2022-001 ASA will participate in mitigating a thermal constraint if the constrained facility is identified as an ERIS or NRIS constraint for that generator. Costs are allocated based on a pro-rata share of the MW impact of each impacting generator.

The MW impact of each ASA study generator is calculated using the distribution factor of each generator. The cost of each NU is allocated based on the pro rata share of the MW contribution from each generating facility on the constraints mitigated by the NU. The methodology to determine the cost allocation of NU is:

$$Project\ A\ Cost\ Portion\ of\ NU = Cost\ of\ NU \times \frac{Max(Project\ A\ MW\ Contribution\ on\ Constraint)}{\sum_i Max(Project\ i\ MW\ Contribution\ on\ Constraint)}$$

A generator will participate in mitigating a voltage constraint if the generator has an impact greater than 0.003 per unit of the nominal bus voltage. Costs are allocated based on a pro-rata share of the voltage impact of each impacting generator.

4.3.1. Cost Allocation

The Distribution Factor (DF) from each generating facility was calculated on the thermal constraints identified in the steady-state analysis. For each thermal constraint, the maximum MW contribution (increasing flow) from each generating facility was calculated. The MW contribution of a generating facility was set as zero if the constraint is not categorized as a constraint for that specific generating facility. The maximum MW contribution on each constraint is provided in Appendix D.

Cost allocation of a steady-state or a transient stability voltage constraint driven NUs was determined from the voltage impact each project has on the most constrained bus under the most constraining contingency[1]. The voltage impact of each project was calculated by locking all voltage-regulating equipment in the model and backing out each project one at a time to identify each project's impact on the constraint. The impact of each project on each voltage constraint is provided in Appendix D.

Cost allocation of voltage constraint driven NUs was determined from the voltage impact each project has on the most constrained bus under the most constraining contingency. The voltage impact of each project was calculated by locking all voltage-regulating equipment in the model and backing out each project one at a time to identify each project's impact on the constraint. The impact of each project on each voltage constraint is provided in Appendix D.

The cost allocation for each NU is calculated based on the MW or voltage impact of each generating facility. Details are provided in Appendix D.

A summary of the costs allocated to each generating facility is shown in Table 33.

Table 33: Summary of NU Costs Allocated to each Generation Project

Project	Cost of NUs ($)
GEN-2022-009	$0
GEN-2022-010	$0
GEN-2022-068	$ 3,500,000
GEN-2022-083	$0
Total Cost	**$ 3,500,000**

[1]In the stability analysis, for contingencies that resulted in non-convergence in power flow, the voltage impact was taken from the stability models at system intact condition.

Redacted

Redacted

Redacted

Redacted