

AFFECTED SYSTEM ANALYSIS OF SPP ERAS-2025-001 STUDY

MINNKOTA POWER COOPERATIVE, INC.

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Document Revisions

Date	Revision	Description	PRD	CHK	APV
08/31/26	0	Initial Draft	MR	AG	AG
09/04/26	1	Addressed MPC Comments	MR	AG	AG

1. Executive Summary

The purpose of this Affected System Analysis (ASA) is to determine the impacts of generators in the SPP ERAS-2025-001 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 SPP ERAS-2025-001 generating facilities shown in Table 1. Mentions of the ERAS-2025-001 projects throughout this report will only refer to those shown in Table 1.

Table 1: ASA of SPP ERAS-2025-001 Projects

Project	POI	Summer MW	Fuel Type	Service Type
ERAS-2025-011	Leland Olds Substation 345 kV	750	Combined Cycle	ER/NR
ERAS-2025-012	Leland Olds Substation 345 kV	750	Combined Cycle	ER/NR

1.1. Network Upgrades Identified in ASA

The steady state 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 SPP ERAS-2025-001 Projects

Constraint	Owner	Highest Loading (MVA)	Mitigation	Cost (\$)	Projects
Jamestown – Center 345 kV	MPC/OTP	1010.53	Structure Raise	\$2,100,000	ERAS-2025-011 ERAS-2025-012
MPC steady-state voltage constraints	MPC	NA	Prairie 345 kV MSC: 3 x 70 MVAR	\$7,500,000	ERAS-2025-011 ERAS-2025-012
MPC steady-state voltage constraints	MPC	NA	Prairie 345 kV Reconfiguration: Add 2x 345 kV Circuit Breakers and switches at Prairie 345 kV	\$1,500,000	ERAS-2025-011 ERAS-2025-012

Table 3 shows the steady state network upgrades that are required to mitigate the identified stability constraints in the Minnkota ASA. The costs are captured within the steady state network upgrades in Table 2 as the steady state network upgrades resolved the transient stability voltage violations.

Table 3: Minnkota Stability Network Upgrades Allocated to SPP ERAS-2025-001 Projects

Constraint	Owner	Network Upgrade to Address Stability Violations	Cost (\$)	Generators
Low transient voltage violations due to: 0822_w_otp_p12 0826_w_otp_p42	MPC	Prairie 345 kV MSC: 3 x 70 MVAR	Listed in in Table 2	ERAS-2025-011 ERAS-2025-012

Table 4 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 SPP ERAS-2025-001 Phase 2 projects.

Table 4: Minnkota Network Upgrades Allocated to Prior Queued Projects with Executed GIAs for Thermal Violations

Constraint	Owner	Highest Loading (MVA)	Mitigation	Projects
Coleman – Berg 69 kV	MPC	69.3	MPC Group 2021-1 Restudy Sensitivity #2: Line rebuild expected to resolve overload	ERAS-2025-011 ERAS-2025-012
Prairie - Berg 69 kV	MPC	70.7		
Center 345/230 kV Autotransformer 1	MPC	892.2	MPC ASA restudy of DISIS-2019: Third Center transformer expected to resolve overload	ERAS-2025-011 ERAS-2025-012
Center 345/230 kV Autotransformer 2	MPC	890.7		

Table 5 shows the contingent network upgrades allocated to higher queued projects that are required to mitigate the identified steady state constraints. If the upgrades are not built by the higher queued projects, they may be required to be built by the SPP ERAS-2025-001 Phase 2 projects.

Table 5: Minnkota Network Upgrades Allocated to Prior Queued Projects with Executed GIAs for Voltage Violations

Constraint	Owner	Highest Loading (MVA)	Mitigation	Projects
MPC steady-state voltage constraints	MPC	NA	MPC Group 2021-1 Restudy Sensitivity #2: Replace Prairie 345/230 kV Xfmr #1	ERAS-2025-011 ERAS-2025-012

Table 6 show the Minnkota constraints that are alleviated by existing MPC equipment and do not require mitigation. **Table 7** show the Minnkota constraints that are alleviated by planned MPC projects and do not require mitigation.

Table 6: Minnkota Network Upgrades Mitigated by Existing MPC Equipment

Constraint	Owner	Highest Loading (MVA)	Mitigation	Projects
Coleman – Walle 69 kV	MPC	65.8	Below minimum MPC equipment rating Redacted	ERAS-2025-011 ERAS-2025-012

Table 7: Minnkota Network Upgrades Mitigated by MPC Planned Projects

Constraint	Owner	Highest Loading (MVA)	Mitigation	Projects
Fargo – Delvo 69 kV	MPC	86.9	MPC planned project expected to mitigate	ERAS-2025-011 ERAS-2025-012
Maple River – Delvo kV	MPC	84.5	MPC planned project expected to mitigate	ERAS-2025-011 ERAS-2025-012

1.2. ERAS-2025-001 Project Summary

The allocation of Minnkota NUs to the ASA project(s) are summarized in the following tables.

1.2.1. ERAS-2025-011 Project Summary

Table 8: Cost Allocation of Minnkota Network Upgrades to ERAS-2025-011

Network Upgrade	Total Cost (\$)	ERAS-2025-011 Allocation
Structure Raise Jamestown – Center 345 kV	\$2,100,000	\$1,050,000
Prairie 345 kV MSC: 3 x 70 MVAR	\$7,500,000	\$3,750,000
Prairie 345 kV Reconfiguration: Add 2x 345 kV Circuit Breakers and switches at Prairie 345 kV	\$1,500,000	\$750,000

1.2.2. ERAS-2025-012 Project Summary

Table 9: Cost Allocation of Minnkota Network Upgrades to ERAS-2025-012

Network Upgrade	Total Cost (\$)	ERAS-2025-012 Allocation
Structure Raise Jamestown – Center 345 kV	\$2,100,000	\$1,050,000
Prairie 345 kV MSC: 3 x 70 MVAR	\$7,500,000	\$3,750,000
Prairie 345 kV Reconfiguration: Add 2x 345 kV Circuit Breakers and switches at Prairie 345 kV	\$1,500,000	\$750,000

1.3. 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(s). Analyses were performed for summer peak, summer shoulder, and winter peak conditions.

1.4. Transient Stability Analysis

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

1.5. Conclusion

Steady-state thermal, steady-state voltage, and transient stability voltage constraints were identified on the MPC system for the ASA project(s). There were no steady-state or transient stability non-convergence constraints. The required network upgrades allocated to the ASA project(s) to address the identified issues are listed in **Table 2**, which assumed that all contingent upgrades in **Table 4**, **Table 5**, and **Table 7** are in-service. The total upgrade costs assigned to the ERAS-2025-001 projects are \$11,100,000 in planning level estimates.

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(s) under study.

2.1. Study Methodology

Study cases representing summer peak and summer shoulder system conditions were created with the ASA project(s) dispatched at the generation interconnection request output, as applicable. System performance was benchmarked using cases without the studied ASA project(s).

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

Steady-state analyses were performed using TARA v2206.1 and cases were created using PSS®E v 35.

2.2. Case Development

Power flow cases were created from the MPC ASA of MISO ERAS summer peak base case (ASA_ERAS 2025 SUM-E0027-study_260226), summer shoulder case (ASA_ERAS 2025 SH_D-E0027-study_260226), and winter base case ASA_ERAS 2025 WINNF-E0027-study_260226).

ASA summer peak (SUM), summer shoulder (SSH), and winter peak (WIN) study cases were created from the MPC ASA of MISO ERAS Phase 2 cases by applying the model updates listed in **Table 10** and dispatching MPC generators and MISO Generator Interconnection Projects as shown in **Table 11** and **Table 12**. Regional transmission projects updates are included in **Table 13**.

Flow on the North Dakota Export Interface (NDEX) were captured for all three seasons as summarized in **Table 14**.

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

Table 10: ASA Model Updates

Model Update					SUM (MW)	SSH (MW)	WIN (MW)
Dispatched	Selected	MPC	Base	Load			
Generation:							
-	Center1G				274	274	274
-	Center2G				493	493	493
-	Coyote1G				452	452	452

Table 11: Minnkota Generator Dispatch

Generator	SUM (MW)	SSH (MW)	WIN (MW)
Young 1	274.0	274.0	274.0
Young 2	493.0	493.0	493.0
Oliver County	26.4	70.7	65.9
Langdon	43.7	142.1	132.4

Generator	SUM (MW)	SSH (MW)	WIN (MW)
Ashtabula (GRE)	8.9	36.3	33.9
Ashtabula (OTP/MPC)	70.9	268.9	250.5
MPC03600	84.8	79.4	0.0
MPC03700	64.8	60.7	0.0
MPC03800	45.2	180.3	167.3
MPC03900	27.3	108.8	100.9
MPC04000	52.1	207.5	192.5

Table 12: ASA Study Project Dispatch

Project	Summer (MW)	Shoulder (MW)	Winter (MW)	Fuel Type	Service Type
ERAS-2025-011	750	750	750	Thermal	ER/NR
ERAS-2025-012	750	750	750	Thermal	ER/NR

Table 13: Regional Transmission Projects Updates Included

Project	Project Name	SUM	SSH	WIN
LRTP	LRTP 19: Bison-Alexandria 345 #2	x	x	x
	LRTP 20: Maple River – Cuyuna 345	x	x	x
	LRTP 21: Iron Range – St Louis Co-Arrowhead 345	x	x	x
	LRTP 22: Big Stone South – Brookings Co-Lakefield Jct 765	x	x	x
	LRTP 23: Lakefield Jct – East Adair 765	x	x	x
	LRTP 24: Lakefield Jct – Pleasant Valley – North Rochester 765	x	x	x
	LRTP 26: North Rochester – Columbia 765	x	x	x
JTIQ	JTIQ: Bison – Hankinson – Big Stone South 345	x	x	x
ITP	Belfield-Maurine-New Underwood-Laramie River 345			

Table 14: NDEX Flow

Season	Benchmark (MW)	Study (MW)
SUM	474.65	1815.57
SSH	2691.92	4012.14
WIN	909.33	2240.57

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 files are shown below in Table 15.

Table 15: List of Contingency Files for Steady State Analysis

Contingency File Name	Summer	Shoulder	Winter
ASA_ERAS-2025_260225_SPSH.con	x	x	
ASA_ERAS-2025_260225_WIN.con			x
ERAS-2025_POI_Cons.con	x	x	x
Prairie_345_breaker_NU.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 16.

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 16: 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 ² /0.97 ²	1.07 ² /0.97 ²
	200 kV and 800 kV	1.05 ² /0.97 ²	1.05 ² /0.97 ²

Area	Monitored Elements	Voltage Limits (High/Low) ¹	
		System intact	Post-Contingency
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. OTP voltage limits are shown in the table reflect the most stringent Continuous Low/High voltage planning criteria; see OTP Transmission Planning Criteria for specific HV and EHV Contingency Category exceptions and 30-minute Emergency Low/High voltage 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 and NRIS Maximum Impact Criteria

ERIS and NRIS 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 five percent (5%) 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.

2.6. Thermal Constraints

MPC thermal constraints for the summer peak, summer shoulder, and winter cases are summarized in Table 17.

Table 17: Minnkota Worst Thermal Constraints

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

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

2.7. Voltage Constraints

MPC voltage constraints for the summer peak, summer shoulder, and winter cases are summarized in Table 18.

Table 18: Minnkota Voltage Constraints

Facility	Owner	Vlow	Vhigh	Bench Volt	Study Volt	Impact	Contingency	Type
Redacted								

Table 19: Minnkota Thermal Constraint Mitigation

Constraint	Owner	Rating MVA	Post-Project Loading		Mitigation	Cost (\$)	ERIS/NRIS Constraint
			MVA	%			
					Redacted		

In accordance with the ERAS-2025 study assumptions, MPC first attempted to use SPP's NU of a 300 MVAR cap bank at Kummer Ridge 345 kV to resolve MPC voltage constraints; however, this NU was too far away to affect the MPC low bus voltages.

Network upgrades required to mitigate MPC voltage constraints are shown in **Table 20**. Minnkota network upgrades allocated to higher queued projects that are required to mitigate remaining voltage constraints are listed in **Section 4.1** as required contingent facilities. If the upgrades are not built by the higher queued projects, they may be required to be built by the SPP ERAS-2025 project(s). See **Section 4.1** for required contingent facilities.

Redacted

Table 20: Minnkota Voltage Constraint Mitigation

Constraint	Owner	Vlow	Vhigh	Benchmark Vcont	Study Case Vcont	Impact	Mitigation	Cost (\$)	ERIS/NRIS Constraint
							Redacted		

Redacted

3. Transient Stability Analysis

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

3.1. Study Methodology

Transient stability cases were created from the MPC ASA of MISO ERAS Phase 2 study summer shoulder bench case and making modifications as described in **Table 21**.

Table 21: Stability Model Updates

Model Update					Benchmark case	Study Case
Dispatched	Selected	MPC	Base	Load		
Generation:						
-	Center1G				274 MW	274 MW
-	Center2G				493 MW	493 MW
-	Coyote1G				452 MW	452 MW

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. Redacted**

3.3. Contingency Criteria

The stability simulations performed as part of this study considered the MPC regional and local contingencies listed in **Table 22**. Simulations were performed with a 0.5-second steady-state run followed by the disturbance. Simulations were run for a 15-second duration.

Table 22: Disturbance Descriptions

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
Regional_1	Flat Run	Redacted	P0	-
Regional_2	0690_w_gre_p23		P2-3	GRE
Regional_3	0800_w_mp_p12		P1-2	GRE
Regional_4	0819_w_otp_p11		P1-1	OTP
Regional_5	0822_w_otp_p12		P1-2	OTP
Regional_6	0823_w_otp_p12		P1-2	OTP
Regional_7	0824_w_otp_p12		P1-2	OTP

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
Regional_8	0826_w_otp_p42	Redacted	P4-2	OTP
Regional_9	0830_w_otp_p42		P4-2	OTP
Regional_10	0831_w_otp_p42		P4-2	OTP
Regional_11	0832_w_otp_p42		P4-2	GRE
Regional_12	1677_w_otp_p12		P1-2	GRE
Regional_13	1681_w_otp_p42		P4-2	OTP
Regional_14	1684_w_xel_p12.idv		P1-2	XEL
Regional_15	P15_GRE_CCK_MONOPOLE_U1TRIP		P1-5	GRE
Regional_16	P7_GRE_CCK_BIPOLE_U1U2TRIP		P7	GRE
Regional_18	J1588_p42_bison_buffalo_mapleriv		P4-2	XEL
POI_3PH_P1_1	3PH-LELAND_O-BE3-ANTELOPE-BE3-Ck1		P1-2	WAPA
POI_3PH_P1_2	3PH-LELAND_O-BE3-ANTELOPE-BE3-Ck2		P1-2	WAPA
POI_3PH_P1_3	3PH-LELAND_O-BE3-CRANECRK-BE3		P1-2	WAPA
POI_3PH_P1_4	3PH-LELAND_O-BE3-LO.LS-GR-BE3		P1-2	WAPA
POI_3PH_P1_5	3PH-LELAND_O-BE3-LO.LS-CC-BE3		P1-2	WAPA
POI_3PH_P1_6	3PH-LELAND_O-BE3-OLIVR4.H-UA3		P1-1	WAPA
POI_3PH_P1_7	3PH-LELAND_O-BE3-GEN-2019-037		P1-1	WAPA
POI_3PH_P1_8	3PH-LELAND_O-BE3-ERA-11		P1-1	WAPA

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
POI_3PH_P1_9	3PH-LELAND_O-BE3-ERA-12	Redacted	P1-1	WAPA
POI_3PH_P1_10	3PH-LELAND_O-BE3-LELAND_2-BEG		P1-1	WAPA
POI_3PH_P1_11	3PH-LELAND_O-BE3-XFMR-T1		P1-3	WAPA
POI_3PH_P1_12	3PH-LELAND_O-BE3-XFMR-T2		P1-3	WAPA
POI_SLG_P4_1	LOSNEW_p42_Brkr2096_slg		P4-2	WAPA
POI_SLG_P4_2	LOSNEW_p42_Brkr2196_slg		P4-2	WAPA
POI_SLG_P4_3	LOSNEW_p42_Brkr2296_slg		P4-2	WAPA
POI_SLG_P4_4	LOSNEW_p42_Brkr2696_slg		P4-2	WAPA
POI_SLG_P4_5	LOSNEW_p42_Brkr2896_slg		P4-2	WAPA
POI_SLG_P4_6	LOSNEW_p42_Brkr3096_slg		P4-2	WAPA

3.4. Performance Criteria

Regional and local disturbances were simulated using TSAT version 25.1.11. 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 23**. The voltage must return within applicable post-contingency voltage limits within ten seconds of fault clearing. The bus voltages on the MPC System are allowed to decrease below their stated minimum voltage limitations for a duration of five (5) cycles following fault clearing. The bus voltages on the MPC System are allowed to increase to 1.3 per unit for a duration of up to 200 milliseconds, unless otherwise noted.

Table 23: 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:

- $SPPR = \text{Successive swing amplitude} / \text{previous swing amplitude}$, and
- $\text{Damping Factor} = (1 - SPPR) * 100$ (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 are summarized in **Appendix C**.

3.5.1. Bench Case Results

There were no transient voltage instability, transient stability voltage violations, damping, or valid relay margin violations.

3.5.2. Study Case Results with no Network Upgrades

There were no damping or valid relay margin violations; however, two faults resulted in transient voltage violations in the study case with no steady state network upgrades as shown in **Table 24**. Because the entirety of the transient voltage violation was not captured within a 15 second simulation, the simulations of the 0822_W_OTP_P12 and 0826_W_OTP_P42 faults were ran to an extended time of 30 seconds as shown in **Table 25**.

Table 24: Study Case with no Network Upgrades Low Voltage Violations

Fault	Bus Number	Bus Name	Minimum Voltage (VPU)	Start Time	End Time	Duration	Comment
Redacted							

Fault	Bus Number	Bus Name	Minimum Voltage (VPU)	Start Time	End Time	Duration	Comment
Redacted							

Table 25: Extended Study Case run with no Network Upgrades Low Voltage Violations

Fault	Bus Number	Bus Name	Minimum Voltage (VPU)	Start Time	End Time	Duration	Comment
Redacted							

3.5.3. Study Case Results with Network Upgrades

The study case was updated with the steady state Network Upgrades (NUs) provided in Table 26 to mitigate the ASA project(s) attributable low voltages without any stability NUs.

Table 26: Network Upgrades required to Mitigate Study Stability Violations

Constraint	Network Upgrade
Transient voltage instability	Add MSC: 3x70 MVAR at Prairie 345 kV
Transient voltage instability	Replace Prairie 345/230 kV Xfmr #1

There were no damping, valid relay margin violations, or voltage violations with the allocated NUs included.

3.6. Conclusion

The transient stability study assessed regional and local contingencies across the study case with and without network upgrades. Stability analysis showed low voltage violations on MPC buses for select faults. Table 27 shows the required mitigation to resolve the MPC low voltage violations. Minnkota network upgrades allocated to higher queued projects that are required to mitigate remaining voltage stability constraints are listed in Section 4.1 as required contingent facilities. If the upgrades are not built by the higher queued projects, they may be required to be built by the SPP ERAS-2025 project(s). See Section 4.1 for required contingent facilities.

Table 27: Minnkota Stability Constraint Mitigation

Constraint	Network Upgrade	Cost	ERIS/NRIS Constraint
Transient voltage instability	Add MSC: 3x70 MVAR at Prairie 345 kV	Listed in Table 20	ERAS-2025-011 ERAS-2025-012

The detailed transient stability results are summarized in Appendix C.

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 28 through Table 31.

This section is separated into network upgrades allocated to higher queued projects (contingent upgrades) and network upgrades allocated to the SPP ERAS-2025 project(s).

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

Table 28 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 SPP ERAS-2025 project(s).

Table 28: Minnkota Thermal Network Upgrades Allocated to Higher Queued Projects

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Coleman – Berg 69 kV	MPC	69.3	MPC Group 2021-1 Restudy Sensitivity #2: Line rebuild expected to resolve overload	ERAS-2025-011 ERAS-2025-012
Prairie - Berg 69 kV	MPC	70.7		
Center 345/230 kV Autotransformer 1	MPC	892.2	MPC ASA restudy of DISIS-2019: Third Center transformer expected to resolve overload	ERAS-2025-011 ERAS-2025-012
Center 345/230 kV Autotransformer 2	MPC	890.7		

Table 29 shows the Minnkota network upgrades allocated to higher queued projects that are required to mitigate identified steady state and transient stability voltage constraints. If the upgrades are not built by the higher queued projects, they may be required to be built by the SPP ERAS-2025 project(s).

Table 29: Minnkota Voltage Network Upgrades Allocated to Higher Queued Projects

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
MPC steady-state voltage constraints MPC stability voltage constraints	MPC	NA	MPC Group 2021-1 Restudy Sensitivity #2: Replace Prairie 345/230 kV Xfmr #1	ERAS-2025-011 ERAS-2025-012

Table 30 shows the Minnkota network upgrades that are alleviated by existing MPC equipment that do not require mitigation.

Table 30: Minnkota Network Upgrades Mitigated by Existing MPC Equipment

Constraint	Owner	Highest Loading (MVA)	Mitigation	Generators
Coleman – Walle 69 kV	MPC	65.8	Below minimum MPC equipment rating Redacted	ERAS-2025-011 ERAS-2025-012

4.2. Required Network Upgrades Allocated to SPP ERAS-2025-001 Projects

Table 31 shows Minnkota network upgrades allocated to the SPP ERAS-2025-011 ASA project(s). Costs are planning level estimates and subject to revision in the facility studies.

Table 31: Minnkota Network Upgrades Allocated to ERAS-2025-011 Phase 2 Project

Constraint	Owner	Highest Loading (MVA)	Mitigation	Cost (\$)	Generators
Jamestown – Center 345 kV	MPC	735.6	Structure Raise	\$2,100,000	ERAS-2025-011 ERAS-2025-012
MPC steady-state voltage constraints	MPC	NA	Add MSC: 2x75 MVAR at Prairie 345 kV	\$7,500,000	ERAS-2025-011 ERAS-2025-012
MPC steady-state voltage constraints	MPC	NA	Prairie 345 kV Reconfiguration: Add 2x 345 kV Circuit Breakers and switches at Prairie 345 kV	\$1,500,000	ERAS-2025-011 ERAS-2025-012
Total Cost				\$11,100,000	

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 contingency¹. 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 32**.

Table 32: Summary of NU Costs Allocated to each Generation Project

Project	Cost of NUs (\$)
ERAS-2025-011	\$5,550,000
ERAS-2025-012	\$5,550,000
Total Cost	\$11,100,000

¹In 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.

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