CRITICAL ENERGY/ELECTRIC INFRASTRUCTURE INFORMATION

# AFFECTED SYSTEM ANALYSIS OF SPP DISIS-2020-001 PHASE 2 RESTUDY

MINNKOTA POWER COOPERATIVE, INC.

JULY 9, 2025

## Table of Contents

# Document Revisions

| Date | Revision | Description |
|---|---|---|
| 05/01/25 | 0 | Initial Draft |
| 05/07/25 | 1 | Addressed Cost Changes |
| 7/09/25 | 2 | Final Release |

# 1. Executive Summary

The purpose of this Affected System Analysis (ASA) is to determine the impacts of generators in the SPP DISIS-2020-001 study cycle on Minnkota Power Cooperative (MPC) facilities and any Network Upgrades (NUs) required to mitigate those impacts. This is a restudy for the previous ASA of DISIS-2020-001 study, triggered by the withdrawn units 2018-007, 2018-008, and 2018-039 of the 2018 study cluster.

Steady-state power flow, contingency analyses, and a dynamic stability analysis were performed for the DISIS generating facilities shown in Table 1. Mentions of the DISIS-2020-001 projects throughout this report will refer to those shown in Table 1.

**Table 1: ASA DISIS-2020-001 Projects**

| Project | POI | Summer MW | Fuel Type | Service Type |
|---|---|---|---|---|
| GEN-2020-014 | Lonesome Creek 115 kV Substation | 45 | Gas | ER/NR |
| GEN-2020-021 | Leland Olds - Fort Thompson 345 kV Line Tap | 235 | Wind | ER/NR |
| GEN-2020-091 | Patent Gate 115 kV Substation | 150 | Solar | ER/NR |

## 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-2020-001 Projects**

| Constraint | Owner | Highest Loading (MVA) | Mitigation | Cost ($) | Generators |
|---|---|---|---|---|---|
| Jamestown – Center 345 kV | MPC/OTP | 819.5 | Structure Raise | $11,500,000 | GEN-2020-014<br>GEN-2020-021<br>GEN-2020-091 |
| Bison – Buffalo 345 kV | MPC | 1124.8 | Structure Raise | $1,000,000 | GEN-2020-014<br>GEN-2020-021<br>GEN-2020-091 |
| Buffalo – New Sub 345 kV | MPC/OTP | 1234.1 | Structure Raise | $2,000,000 | GEN-2020-014<br>GEN-2020-021<br>GEN-2020-091 |

Table 3 shows Minnkota thermal network upgrades and Table 4 shows voltage network upgrades allocated to higher queued projects that are required to mitigate identified thermal and voltage constraints. If the upgrades are not built by the higher queued projects, they may be required to be built by DISIS-2020-001 projects.

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

| Constraint | Owner | Highest Loading (MVA) | Mitigation | Generators |
|---|---|---|---|---|
| MPC4300 POI – Prairie 345 kV | MPC | 1009.1 | MPC04300 SIS - terminal upgrade expected to resolve overload | GEN-2020-014<br>GEN-2020-091 |

**Table 4: Minnkota Voltage Network Upgrades Allocated to Higher Queued Projects**

| Constraint | Owner | Mitigation | Generators |
| --- | --- | --- | --- |
| Fronter 230 kV | MPC | MPC ASA of DISIS-2017 – 1 x 40 MVAR cap at WAHPETN4 | GEN-2020-014<br>GEN-2020-021 |
| MPC03637 POI 230 kV | MPC | MPC ASA of DISIS-2017 – 1 x 40 MVAR cap at WAHPETN4 | GEN-2020-014<br>GEN-2020-021 |

## 1.2. DISIS-2020-001 Project Summary

The allocation of Minnkota NUs to the ASA projects are summarized in the following tables.

### 1.2.1. GEN-2020-014

| Network Upgrade | Total Cost ($) | GEN-2020-014 Allocation |
| --- | --- | --- |
| Structure Raise Jamestown - Center 345 kV | $11,500,000 | $1,638,556 |
| Structure Raise Bison - Buffalo 345 kV | $1,000,000 | $138,638 |
| Structure Raise Buffalo - New Sub 345 kV | $2,000,000 | $277,470 |
| **Total** | **$14,500,000** | **$2,054,664** |

### 1.2.2. GEN-2020-021

| Network Upgrade | Total Cost ($) | GEN-2020-021 Allocation |
| --- | --- | --- |
| Structure Raise Jamestown - Center 345 kV | $11,500,000 | $4,394,660 |
| Structure Raise Bison - Buffalo 345 kV | $1,000,000 | $399,097 |
| Structure Raise Buffalo - New Sub 345 kV | $2,000,000 | $797,359 |
| **Total** | **$14,500,000** | **$5,591,115** |

### 1.2.3. GEN-2020-091

| Network Upgrade | Total Cost ($) | GEN-2020-091 Allocation |
| --- | --- | --- |
| Structure Raise Jamestown - Center 345 kV | $11,500,000 | $5,466,784 |
| Structure Raise Bison - Buffalo 345 kV | $1,000,000 | $462,266 |
| Structure Raise Buffalo - New Sub 345 kV | $2,000,000 | $925,171 |
| **Total** | **$14,500,000** | **$6,854,221** |

## 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 projects. Analyses were performed for summer peak and summer shoulder 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 projects. The transient stability analysis was performed for summer shoulder conditions.

## 1.5. Conclusion

Thermal and voltage constraints were identified on the MPC system for the ASA projects. No transient stability constraints were identified. The required thermal network upgrades to address the identified thermal issues are listed in Table 2, which assumed that all contingent upgrades in Table 3 are in-service. The required voltage network upgrade to address the identified voltage issue is listed in Table 4 and has been allocated to higher queued Projects. The total upgrade costs assigned to the DISIS-2020-001 projects are $14,500,000 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 projects under study.

## 2.1. Study Methodology

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

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

Steady-state analyses were performed using TARA v2202.2 and cases were created using PSS®E version 34.

## 2.2. Case Development

Power flow cases were created from the MPC 4300 summer peak base case (MPC04300_SUM_Bench_230504), winter peak base case (MPC04300_WIN_Bench_230504), and summer shoulder base case (MPC04300_SH90_Bench_BC03_230515).

ASA summer peak (SUM), winter peak (WIN), and summer shoulder (SSH) study cases were created from the MPC 4300 base cases by applying the model updates listed in Table 5 and dispatching MPC generators and MISO Generator Interconnection Projects as shown in Table 6 and Table 7.

The cases included both upgrades from MISO LRTP-01 and LRTP-02 upgrades. Additionally, the cases included the new line from MPC04300 POI to a tap on the Buffalo – Jamestown 345 kV line. The descriptions are shown in Table 8.

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

**Table 5: ASA Model Updates**

| Model Update | SUM (MW) | SH (MW) | WIN (MW) |
|---|---|---|---|
| Dispatched Selected MISO DPP-2018-Cycle Study Units as PQ:<br>- J1040 | 39.2 | 250 | 250 |
| Dispatched Selected MISO DPP-2020-Cycle Study Units as PQ:<br>- J1575<br>- J1588 | 10.98<br>203 | 70.8<br>0 | 70.8<br>203 |
| Dispatched Selected SPP DISIS-2018-001 Study Units as PQ:<br>- GEN-2018-010 | 74.1 | 0 | 74.1 |
| Dispatched Selected SPP DISIS-2019-001 Study Units as PQ:<br>- GEN-2019-037 | 152.1 | 0 | 152.1 |

**Table 6: Minnkota Generator Dispatch**

| Generator | SUM (MW) | SH (MW) | WIN (MW) |
|---|---|---|---|
| Young 1 | 274 | 274 | 274 |
| Young 2 | 493 | 493 | 493 |
| Oliver County | 99.3 | 99.3 | 99.3 |
| Langdon | 199.5 | 199.5 | 199.5 |
| Ashtabula (GRE) | 51 | 51 | 51 |
| Ashtabula (OTP) | 377.4 | 377.4 | 377.4 |
| MPC03600 | 170 | 170 | 0 |
| MPC03700 | 130 | 130 | 0 |
| MPC03800 | 234 | 234 | 234 |
| MPC03900 | 142 | 142 | 142 |
| MPC04000 | 290 | 290 | 290 |
| MPC04300 | 400 | 400 | 400 |

**Table 7: ASA Study Project Dispatch**

| Project | Summer (MW) | Summer Shoulder (MW) | Winter (MW) | Fuel Type | Service Type |
|---|---|---|---|---|---|
| GEN-2020-014 | 45 | 0 | 45 | Gas | ER/NR |
| GEN-2020-021 | 235 | 235 | 235 | Wind | ER/NR |
| GEN-2020-091 | 150 | 150 | 0 | Solar | ER/NR |

**Table 8: Upgrade Descriptions**

| Upgrade Name | Description |
|---|---|
| LRTP-01 | The Jamestown – Ellendale transmission line. |
| LRTP-02 | The Cassie's crossing substation and the Big Stone South – Alexandria – Cassie's Crossing transmission line. |
| MPC4300-Jamestown-Buffalo 345 kV Tap | A new line from MPC04300 POI to a tap on the Buffalo – Jamestown 345 kV line |

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 4300 study; contingency files are shown below in Table 9.

**Table 9: List of Contingency Files for Steady State Analysis**

| Contingency File Name | Summer | Shoulder | Winter |
|---|---|---|---|
| MISO20_2025_SUM__TA_P1_MINN-DAKS.con | x | x | |
| MISO20_2025_SUM__TA_P1_MINN-DAKS_SPK.con | x | x | |
| MISO20_2025_SUM__TA_P1_P2_P4_P5_NoLoadLoss.con | x | x | |
| MISO20_2025_SUM__TA_P1_P2_P4_P5_NoLoadLoss_SPK.con | x | x | |
| MISO20_2025_SUM__TA_P2_P4_P5_P6_P7_LoadLoss.con | x | x | |
| Monopole_Bipole_Update_220125.con | x | x | x |
| MPC_contingencies.con | x | x | x |
| MPC04300 Ph3_basecase.con | x | x | |
| MPC04300 Ph3_HVDC_SH.con | x | x | |
| MPC04300 Ph3_HVDC_SPK.con | x | x | |
| MPC04300 Ph3_Noloadloss.con | x | x | |
| MPC04300 Ph3_Noloadloss_SPK.con | x | x | |
| MPC04300 Ph3_P1.con | x | x | |
| MPC04300_outlet_contingency.con | x | x | x |
| NewSub_contingencies.con | x | x | |
| MPC20ASA_BaseCase.con | | | x |
| MPC20ASA_Ph3_HVDC_WIN.con | | | x |
| MPC20ASA_Ph3_Loadloss.con | | | x |
| MPC20ASA_Ph3_Noloadloss.con | | | x |
| MPC20ASA_Ph3_P1.con | | | x |
| WIN_MISO20_2025_TA_P1_MINN-DAKS.con | | | x |
| WIN_MISO20_2025_TA_P1_P2_P4_P5_NoLoadLoss.con | | | x |
| WIN_MISO20_2025_TA_P2_P4_P5_P6_P7_LoadLoss.con | | | 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 10.

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 10: 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 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 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.

## 2.6. Thermal Constraints

MPC thermal constraints for the summer peak and summer shoulder cases are summarized in Table 11.

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

**Table 11: Minnkota Worst Thermal Constraints**

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

## 2.7. Voltage Constraints

MPC voltage constraints for the summer peak, winter peak, and summer shoulder cases are summarized in Table 12.

**Table 12: Minnkota Voltage Constraints**

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

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

## 2.8. Mitigation of Steady State Constraints

Network upgrades required to mitigate MPC thermal constraints are shown in Table 13.

**Table 13: Minnkota Thermal Constraint Mitigation**

| Constraint | Owner | Rating MVA | Post-Project Loading | | Mitigation | Cost ($) | ERIS/NRIS Constraint |
|---|---|---|---|---|---|---|---|
| | | | MVA | % | | | |
| | | | | | | | 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 projects under study.

## 3.1. Study Methodology

Transient stability cases were created from the MPC 4300 summer shoulder base case (MPC04300 stability 230922) and making modifications as described in Table 14.

The cases included both upgrades from MISO LRTP-1 and LRTP-2 upgrades. Additionally, the cases included the new line from MPC04300 POI to a tap on the Buffalo – Jamestown 345 kV line.

The cases also removed Network Upgrades Allocated to Higher Queued Projects including MISO DPP2020, MPC Group 2021-1, MISO ASA MPC Group 2021-1 and MPC4300.

**Table 14: Stability Model Updates**

| Model Update | Benchmark case | Study Case |
|---|---|---|
| Dispatched Selected MPC Study Unit:<br>- MPC04300 | 400 MW | 400 MW |
| Dispatched Selected MISO DPP-2020-Cycle Study Units as PQ:<br>- J1575<br>- J1588 | 70 MW<br>0 MW | 70 MW<br>0 MW |
| Dispatched Selected SPP DISIS-2018-001 Study Units as PQ:<br>- GEN-2018-010 | 0 MW | 0 MW |
| Dispatched Added Selected SPP DISIS-2019-001 Study Units as PQ:<br>- GEN-2019-037 | 0 MW | 0 MW |
| Added Selected SPP DISIS-2020-001 Study Units:<br>- GEN-2020-014<br>- GEN-2020-021<br>- GEN-2020-091 | N/A | 0 MW<br>235 MW<br>150 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. The study project was represented with the following dynamic model:

- **GEN-2020-014**: WECC Generic Models consistent with DISIS 2001 P2 Restudy representation
  Redacted
- **GEN-2020-021**: WECC Generic Models consistent with DISIS 2001 P2 Restudy representation
  Redacted
- **GEN-2020-091**: WECC Generic Models consistent with DISIS 2001 P2 Restudy representation
  Redacted

## 3.3. Contingency Criteria

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

**Table 15: 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 |
| Regional_8 | 0826_w_otp_p42 | | 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 |
| G20-014_P1_1 | P1_G20-014_POI_LC_SWY.S-BE7_115_G20-014 | | P1-1 | G20-014 |
| G20-014_P1_2 | P1_G20-014_POI_LC_SWY.S-BE7_115_LC_CT4-5-BE7 | | P1-2 | G20-014 |

| Cont. ID. | Disturbance Name | Description | NERC Cat. | Area |
|---|---|---|---|---|
| | | Redacted | | |
| G20-014_P1_3 | P1_G20-014_POI_LC_SWY.S-BE7_115_ARNEGARD-MK7 | | P1-2 | G20-014 |
| G20-021_P1_1 | P1_G20-021_POI_G20-021-TAP_345_G20-021 | | P1-1 | G20-021 |
| G20-021_P1_2 | P1_G20-021_POI_G20-021-TAP_345_G16-017-TAP | | P1-2 | G20-021 |
| G20-021_P1_3 | P1_G20-021_POI_G20-021-TAP_345_LO.LS-FT-BE3345. | | P1-2 | G20-021 |
| G20-091_P1_1 | P1_G20-091_POI_PATENTGT-BE3_345_GEN-2020-091 | | P1-1 | G20-091 |
| G20-091_P1_2 | P1_G20-091_POI_PATENTGT-BE3_345_PG.KU19A-BE7_Auto_1 | | P1-3 | G20-091 |
| G20-091_P1_3 | P1_G20-091_POI_PATENTGT-BE3_345_PG.KU19A-BE7_Auto_2 | | P1-3 | G20-091 |
| G20-091_P1_4 | P1_G20-091_POI_PATENTGT-BE3_345_JUDSON__-BE3 | | P1-2 | G20-091 |
| G20-091_P1_5 | P1_G20-091_POI_PATENTGT-BE3_345_CHARL_CK-BE3 | | P1-2 | G20-091 |
| G20-014_P4_1 | P4_G20-014_POI_LC_SWY.S-BE7_115_G20-014_LC_CT4-5-BE7 | | P4 | G20-014 |
| G20-014_P4_2 | P4_G20-014_POI_LC_SWY.S-BE7_115_G20-014_ARNEGARD-MK7 | | P4 | G20-014 |
| G20-021_P4_1 | P4_G20-021_POI_G20-021-TAP_345_G20-021_G16-017-TAP | | P4 | G20-021 |
| G20-021_P4_2 | P4_G20-021_POI_G20-021-TAP_345_G20-021_LO.LS-FT-BE3 | | P4 | G20-021 |
| G20-091_P4_1 | P4_G20-091_POI_PATENTGT-BE3_345_GEN-2020-091_PG.KU19A-BE7_Auto_1 | | P4 | G20-091 |
| G20-091_P4_2 | P4_G20-091_POI_PATENTGT-BE3_345_GEN-2020-091_PG.KU19A-BE7_Auto_2 | | P4 | G20-091 |

| Cont. ID. | Disturbance Name | Description | NERC Cat. | Area |
|---|---|---|---|---|
| | | Redacted | | |
| G20-091_P4_3 | P4_G20-091_POI_PATENTGT-BE3_345_GEN-2020-091_JUDSON__-BE3 | | P4 | G20-091 |
| G20-091_P4_4 | P4_G20-091_POI_PATENTGT-BE3_345_GEN-2020-091_CHARL_CK-BE3 | | P4 | G20-091 |
| G20-091_P4_5 | P4_G20-091_POI_PATENTGT-BE3_345_PG.KU19A-BE7_Auto_1_PG.KU19A-BE7_Auto_2 | | P4 | G20-091 |
| G20-091_P4_6 | P4_G20-091_POI_PATENTGT-BE3_345_PG.KU19A-BE7_Auto_1_JUDSON__-BE3 | | P4 | G20-091 |
| G20-091_P4_7 | P4_G20-091_POI_PATENTGT-BE3_345_PG.KU19A-BE7_Auto_1_CHARL_CK-BE3 | | P4 | G20-091 |

## 3.4. Performance Criteria

Regional and local disturbances were simulated using TSAT version 22.2.22. 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 16. 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 16: 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 are summarized in Appendix C.

Redacted

These violations were considered pre-existing and not due to the addition of the DISIS-2020-001 projects. No additional mitigations are required to address the violations.

**Table 17: Benchmark Case Violations**

| Cont. No. | Contingency Description | MPC Violations | Violation Type | Damping Index (%) | Volt. Drop Duration Index (Sec) | Volt. Rise Duration Index (Sec) | Zone 1 Relay Margin Index (%) | Zone 2 Relay Margin Index (%) | Status |
|---|---|---|---|---|---|---|---|---|---|
| Redacted | | | | | | | | | |
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**Table 18: Study Case Violations**

| Cont. No. | Contingency Description | MPC Violations | Violation Type | Damping Index (%) | Volt. Drop Duration Index (Sec) | Volt. Rise Duration Index (Sec) | Zone 1 Relay Margin Index (%) | Zone 2 Relay Margin Index (%) | Status |
|---|---|---|---|---|---|---|---|---|---|
| Redacted | | | | | | | | | |
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## 3.6. Conclusion

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These violations were considered pre-existing and not due to the addition of the DISIS-2020-001 projects. No additional mitigations are required to address the violations.

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.

### 4.1. Required Network Upgrades

The network upgrades required to mitigate constraints identified in Minnkota ASA are listed in Table 19 through Table 20. Costs are planning level estimates and subject to revision in the facility studies.

Table 19 shows Minnkota network upgrades allocated to the ASA projects.

**Table 19: Minnkota Network Upgrades Allocated to Current Queued Projects**

| Constraint | Owner | Highest Loading (MVA) | Mitigation | Cost ($) | Generators |
|---|---|---|---|---|---|
| Jamestown – Center 345 kV | MPC/OTP | 819.5 | Structure Raise | $11,500,000 | GEN-2020-014<br>GEN-2020-021<br>GEN-2020-091 |
| Bison – Buffalo 345 kV | MPC | 1124.8 | Structure Raise | $1,000,000 | GEN-2020-014<br>GEN-2020-021<br>GEN-2020-091 |
| Buffalo – New Sub 345 kV | MPC/OTP | 1234.1 | Structure Raise | $2,000,000 | GEN-2020-014<br>GEN-2020-021<br>GEN-2020-091 |

Table 20 shows Minnkota network upgrades allocated to higher queued projects that are required to mitigate identified thermal and voltage constraints. If the upgrades are not built by the higher queued projects, they may be required to be built by the ASA projects.

**Table 20: Minnkota Network Upgrades Allocated to Higher Queued Projects**

| Constraint | Owner | Highest Loading (MVA) | Bus Voltage (V.p.u.) | Mitigation | Generators |
|---|---|---|---|---|---|
| MPC4300 POI – Prairie 345 kV | MPC | 1029.4 | | Prior queued project expected to mitigate thermal violation | GEN-2020-014<br>GEN-2020-091 |
| Fronter 230 kV | MPC | | 0.9031 | Prior queued project expected to mitigate voltage violation | GEN-2020-014<br>GEN-2020-021 |
| MPC03637 POI 230 kV | MCC | | 0.9184 | Prior queued project expected to mitigate voltage violation | GEN-2020-014<br>GEN-2020-021 |

### 4.2. Cost Allocation Methodology

A generator in the DISIS-2020-001 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.

#### 4.2.1. 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 21.

**Table 21: Summary of NU Costs Allocated to each Generation Project**

| Project | Cost of NUs ($) |
|---|---|
| GEN-2020-014 | $2,054,664 |
| GEN-2020-021 | $5,591,115 |
| GEN-2020-091 | $6,854,221 |
| **Total Cost** | **$14,500,000** |

[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.

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