INTERCONNECTION FACILITIES STUDY REPORT

GEN-2020-014

Published May 2025

By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
May 20, 2025	SPP	Initial draft report issued.
May 29, 2025	SPP	Final report issued.

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SUMMARY

INTRODUCTION

This Interconnection Facilities Study (IFS) for Interconnection Request GEN-2020-014 is for a 45 MW generating facility located in Alexander, ND. The Interconnection Request was studied in the DISIS-2020-001 Impact Study for NRIS. The Interconnection Customer's requested in-service date is 10/18/2021.

The interconnecting Transmission Owner, Basin Electric Power Cooperative (BEPC), performed a detailed IFS at the request of SPP. The full report is included in Appendix A. SPP has determined that full Interconnection Service will be available after the assigned Transmission Owner Interconnection Facilities (TOIF), Non-Shared Network Upgrades, Shared Network Upgrades, Contingent Network Upgrades, and Affected System Upgrades that are required for full interconnection service are completed.

The primary objective of the IFS is to identify necessary Transmission Owner Interconnection Facilities, Network Upgrades, other direct assigned upgrades, cost estimates, and associated upgrade lead times needed to grant the requested Interconnection Service.

PHASE(S) OF INTERCONNECTION SERVICE

It is not expected that Interconnection Service will occur in phases. However, full Interconnection Service will not be available until all Interconnection Facilities and Network Upgrade(s) can be placed in service.

COMPENSATION FOR AMOUNTS ADVANCED FOR NETWORK UPGRADE(S)

FERC Order ER20-1687-000 eliminated the use of Attachment Z2 revenue crediting as an option for compensation. The Incremental Long Term Congestion Right (ILTCR) process will be the sole process to compensate upgrade sponsors as of July 1st, 2020.

INTERCONNECTION CUSTOMER INTERCONNECTION FACILITIES

The Generating Facility is proposed to consist of One (1) 38.7 MW gas turbine for a total generating nameplate capacity of 45 MW.

The Interconnection Customer's Interconnection Facilities to be designed, procured, constructed, installed, maintained, and owned by the Interconnection Customer at its sole expense include:

- 34.5 kV underground cable collection circuits;
- 34.5 kV to 115kV transformation substation with associated 34.5 kV and 115kV switchgear;
- One 115kV/34.5 kV 45/60/75 MVA (ONAN/ONAF/ONAF) step-up transformer to be owned and maintained by the Interconnection Customer at the Interconnection Customer's substation;
- An Approximately 400 foot overhead 115kV line to connect the Interconnection Customer's substation to the Point of Interconnection ("POI") at the 115kV bus at existing Transmission Owner substation ("Lonesome Creek 115kV") that is owned and maintained by Transmission Owner;
- All transmission facilities required to connect the Interconnection Customer's substation to the POI;
- Equipment at the Interconnection Customer's substation necessary to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 95% lagging and 95% leading in accordance with Federal Energy Regulatory Commission (FERC) Order 827. The Interconnection Customer may use inverter manufacturing options for providing reactive power under no/reduced generation conditions. The Interconnection Customer will be required to provide documentation and design specifications demonstrating how the requirements are met; and,
- All necessary relay, protection, control and communication systems required to protect Interconnection Customer's Interconnection Facilities and Generating Facilities and coordinate with Transmission Owner's relay, protection, control and communication systems.

TRANSMISSION OWNER INTERCONNECTION FACILITIES AND NON-SHARED NETWORK UPGRADE(S)

To facilitate interconnection, the interconnecting Transmission Owner will perform work as shown below necessary for the acceptance of the Interconnection Customer's Interconnection Facilities.

Table 1 and **Table 2** list the Interconnection Customer's estimated cost responsibility for Transmission Owner Interconnection Facilities (TOIF) and Non-Shared Network Upgrade(s) and provides an estimated lead time for completion of construction. The estimated lead time begins when the Generator Interconnection Agreement has been fully executed.

Table 1: Transmission Owner Interconnection Facilities (TOIF)

Transmission Owner Interconnection Facilities (TOIF)	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)
Transmission Owner's Lonesome Creek 115kV GEN-2020-014 Interconnection (TOIF) (UID144258): Interconnection upgrades and cost estimates needed to interconnect the following Interconnection Customer facility, GEN-2020-014 (60.5/Thermal), into the Point of Interconnection (POI) at Lonesome Creek 115kV. Estimated Lead Time: 0 Months	$0	0.00%	$0
Total	**$0**		**$0**

Table 2: Non-Shared Network Upgrade(s)

Non-Shared Network Upgrades Description	ILTCR	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)
Transmission Owner's Lonesome Creek 115kV GEN-2020-014 Interconnection (UID144259): Interconnection upgrades and cost estimates needed to interconnect the following Interconnection Customer facility, GEN-2020-014 (60.5/Thermal), into the Point of Interconnection (POI) at Lonesome Creek 115kV. Estimated Lead Time: 0 Months	Ineligible	$0	0.00%	$0
Total		**$0**		**$0**

SHARED NETWORK UPGRADE(S)

The Interconnection Customer's share of costs for Shared Network Upgrades is estimated in **Table 3** below.

Table 3: Interconnection Customer Shared Network Upgrade(s)

Shared Network Upgrades Description	ILTCR	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)
NA				
Total		**$0**		**$0**

All studies have been conducted assuming that higher-queued Interconnection Request(s) and the associated Network Upgrade(s) will be placed into service. If higher-queued Interconnection Request(s) withdraw from the queue, suspend or terminate service, the Interconnection Customer's share of costs may be revised. Restudies, conducted at the customer's expense, will determine the Interconnection Customer's revised allocation of Shared Network Upgrades.

CONTINGENT NETWORK UPGRADE(S)

Certain Contingent Network Upgrades are **currently not the cost responsibility** of the Interconnection Customer but will be required for full Interconnection Service.

Table 4: Interconnection Customer Contingent Network Upgrade(s)

Contingent Network Upgrade(s) Description	Current Cost Assignment	Estimated In-Service Date
NA	**$0**	

Depending upon the status of higher- or equally-queued customers, the Interconnection Request's in-service date is at risk of being delayed or Interconnection Service is at risk of being reduced until the in-service date of these Contingent Network Upgrades.

AFFECTED SYSTEM UPGRADE(S)

To facilitate interconnection, the Affected System Transmission Owner will be required to perform the facilities study work as shown below necessary for the acceptance of the Interconnection Customer's Interconnection Facilities. **Table 5** displays the current impact study costs provided by either MISO or AECI as part of the Affected System Impact review. The Affected System facilities study could provide revised costs and will provide each Interconnection Customer's allocation responsibilities for the upgrades.

Table 5: Interconnection Customer Affected System Upgrade(s)

Affected System Upgrades Description	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)
MPC ASA DISIS-2020-001: Structure Raise Jamestown - Center 345 kV	$11,500,000	14.25%	$1,638,556
MPC ASA DISIS-2020-001: Structure Raise Bison - Buffalo 345 kV	$1,000,000	13.86%	$138,638
MPC ASA DISIS-2020-001: Structure Raise Buffalo - New Sub 345 kV	$2,000,000	13.87%	$277,470
Total	**$14,500,000**		**$2,054,664**

CONCLUSION

After all Interconnection Facilities and Network Upgrades have been placed into service, Interconnection Service for 45 MW can be granted. Full Interconnection Service will be delayed until the TOIF, Non-Shared NU, Shared NU, Contingent NU, Affected System Upgrades that are required for full interconnection service are completed. The Interconnection Customer's estimated cost responsibility for full interconnection service is summarized in the table below.

Table 6: Cost Summary

Description	Allocated Cost Estimate
Transmission Owner Interconnection Facilities Upgrade(s)	$0
Non-Shared Network Upgrade(s)	$0
Shared Network Upgrade(s)	$0
Affected System Upgrade(s)	**$2,054,664**
Total	**$2,054,664**

Use the following link for Quarterly Updates on upgrades from this report: https://spp.org/spp-documents-filings/?id=18641

A draft Generator Interconnection Agreement will be provided to the Interconnection Customer consistent with the final results of this IFS report. The Transmission Owner and Interconnection Customer will have 60 days to negotiate the terms of the GIA consistent with the SPP Open Access Transmission Tariff (OATT).

APPENDICES

A: TRANSMISSION OWNER'S INTERCONNECTION FACILITIES STUDY REPORT AND NETWORK UPGRADES REPORT(S)

See next page for the Transmission Owner's Interconnection Facilities Study Report and Network Upgrades Report(s).

CRITICAL ENERGY/ELECTRIC INFRASTRUCTURE INFORMATION

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

MINNKOTA POWER COOPERATIVE, INC.

MAY 7, 2025

Electric Power Engineers, LLC is a Texas Registered Engineering Firm F-3386

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DOCUMENT REVISIONS

Date	Revision	Description
05/01/25	0	Initial Draft
05/07/25	1	Addressed Cost Changes

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

Constraint	Owner	Highest Loading (MVA)	Mitigation	Cost ($)	Generators
					GEN-2020-021 GEN-2020-091
Bison – Buffalo 345 kV	MPC	1124.8	Structure Raise	$1,000,000	GEN-2020-014 GEN-2020-021 GEN-2020-091
Buffalo – New Sub 345 kV	MPC/OTP	1234.1	Structure Raise	$2,000,000	GEN-2020-014 GEN-2020-021 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 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 GEN-2020-021
MPC03637 POI 230 kV	MPC	MPC ASA of DISIS-2017 – 1 x 40 MVAR cap at WAHPETN4	GEN-2020-014 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

Network Upgrade	Total Cost ($)	GEN-2020-021 Allocation
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: - J1040	39.2	250	250
Dispatched Selected MISO DPP-2020-Cycle Study Units as PQ: - J1575 - J1588	10.98 203	70.8 0	70.8 203
Dispatched Selected SPP DISIS-2018-001 Study Units as PQ: - GEN-2018-010	74.1	0	74.1
Dispatched Selected SPP DISIS-2019-001 Study Units as PQ: - 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	

Contingency File Name	Summer	Shoulder	Winter
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	%			
Bison – Buffalo 345 kV	MPC	1041.6	1089.5	104.6	1124.8	107.99	P12:345:OTP:PRAIRIE3:CNTSHNT3:1_Dup3	P12	GEN-2020-014 GEN-2020-021 GEN-2020-091
Buffalo – New Sub 345 kV	MPC/OTP	1041.6	1197.2	114.94	1234.1	118.48	P12:345:OTP:PRAIRIE3:CNTSHNT3:1_Dup3	P12	GEN-2020-014 GEN-2020-021 GEN-2020-091
Jamestown – Center 345 kV	MPC/OTP	704.5	175.09	110.02	819.47	116.32	67020 MPC03839POI 345 657110 MPC4300 POI 345 1	P12	GEN-2020-014 GEN-2020-021 GEN-2020-091
MPC4300 POI – Prairie 345 kV	MPC	900	996.48	110.72	1009.08	112.12	620358 BUFFALO3 345 657120 NEW SUB 345 1	P12	GEN-2020-014 GEN-2020-091

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
FRONTER4 230 kV	MPC	0.92	1.1	0.9139	0.9031	0.0108	P23:230:MPC: FRONTER4:77	P23
MPC03637POI 230 kV	MPC	0.92	1.1	0.9289	0.9184	0.0105	P23:230:MPC: FRONTER4:77	P23

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	%			
Jamestown – Center 345 kV	MPC/OTP	704.5	819.47	116.32	Structure Raise	$11,500,000	GEN-2020-014 GEN-2020-021 GEN-2020-091
Bison – Buffalo 345 kV	MPC	1041.6	1124.82	107.99	Structure Raise	$1,000,000	GEN-2020-014 GEN-2020-021 GEN-2020-091
Buffalo – New Sub 345 kV	MPC/OTP	1041.6	1234.09	118.48	Structure Raise	$2,000,000	GEN-2020-014

Constraint	Owner	Rating MVA	Post-Project Loading		Mitigation	Cost ($)	ERIS/NRIS Constraint
			MVA	%			
							GEN-2020-021 GEN-2020-091

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: - MPC04300	400 MW	400 MW
Dispatched Selected MISO DPP-2020-Cycle Study Units as PQ: - J1575 - J1588	70 MW 0 MW	70 MW 0 MW
Dispatched Selected SPP DISIS-2018-001 Study Units as PQ: - GEN-2018-010	0 MW	0 MW

Dispatched Added Selected SPP DISIS-2019-001 Study Units as PQ: - GEN-2019-037	0 MW	0 MW
Added Selected SPP DISIS-2020-001 Study Units: - GEN-2020-014 - GEN-2020-021 - GEN-2020-091	N/A	0 MW 235 MW 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 (Conventional machine)
- **GEN-2020-021**: WECC Generic Models consistent with DISIS 2001 P2 Restudy representation (REGCA1 inverter)
- **GEN-2020-091**: WECC Generic Models consistent with DISIS 2001 P2 Restudy representation (REGCA1 inverter)

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	No fault	P0	-

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
Regional_2	0690_w_gre_p23	SLG fault at GRE-STANTON4 with delayed clearing; clear by tripping GRE-COAL TP4 bus	P2-3	GRE
Regional_3	0800_w_mp_p12	3PH fault at SQBUTTE4 with normal clearing on SQBUTTE4 to GRE-STANTON4 line; clear SQBUTTE4 end at 6 cycles, GRE-STANTON4 end at 7 cycles	P1-2	GRE
Regional_4	0819_w_otp_p11	3ph fault at COYOTE1G with normal clearing; clear by tripping COYOTE1G gen	P1-1	OTP
Regional_5	0822_w_otp_p12	3PH fault at CENTER 3 with normal clearing on CENTER3-JAMESTN3 line	P1-2	OTP
Regional_6	0823_w_otp_p12	3PH fault at CENTER 4 with normal clearing on CENTER 4-ROUGHRIDER4 line	P1-2	OTP
Regional_7	0824_w_otp_p12	3PH fault at CENTER 4 with normal clearing on CENTER 4-SQBUTTE4 line	P1-2	OTP
Regional_8	0826_w_otp_p42	SLG fault at CENTER 3 with delayed clearing; clear by tripping CENTER 3-JAMESTN3 line and CENTER 3-SQBUTTE4 transformer	P4-2	OTP
Regional_9	0830_w_otp_p42	SLG fault at SQBUTTE4 with delayed clearing; clear by tripping SQBUTTE4-GRE-STANTON4 line at 12 cycles, both dc poles restart at 17 cycles	P4-2	OTP
Regional_10	0831_w_otp_p42	SLG fault at CENTER 4 with delayed clearing; clear by tripping CENTER4-ROUGHRIDER line at 12 cycles, both dc poles restart at 17 cycles	P4-2	OTP
Regional_11	0832_w_otp_p42	SLG fault at GRE-COAL CR4 with delayed clearing; clear by tripping GRE-COAL CR4-UNDERWD4 and GRE-STANTON4-GRE-COAL CR4 lines at 12 cycles	P4-2	GRE
Regional_12	1677_w_otp_p12	3PH fault at SQBUTTE4 with normal clearing; clear by tripping SQBUTTE4-GRE-STANTON line at 4 cycles	P1-2	GRE
Regional_13	1681_w_otp_p42	SLG fault at SQBUTTE4 with delayed clearing; clear by tripping SQBUTTE4-CENTER 4 lines at 12 cycles, ramp SQBUTTE4 DC to pre-disturbance schedule at 17 cycles	P4-2	OTP
Regional_14	1684_w_xel_p12.idv	3PH fault at BISON 3 with normal clearing; clear by tripping BISON 3 - ALXLNCRTRT line	P1-2	XEL

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
Regional_15	P15_GRE_CCK_MONOPOLE_U1TRIP	Monopole fault on the CUDC line; trip Coal Creek Unit 1	P1-5	GRE
Regional_16	P7_GRE_CCK_BIPOLE_U1U2TRIP	Permanent bipole fault on the CUDC line; trip Coal Creek Units 1 and 2	P7	GRE
G20-014_P1_1	P1_G20-014_POI_LC_SWY.S-BE7_115_G20-014	3PH fault at LC_SWY.S-BE7(G20-014 POI) with normal clearing; clear by tripping G20-014 gen in 6 cycles	P1-1	G20-014
G20-014_P1_2	P1_G20-014_POI_LC_SWY.S-BE7_115_LC_CT4-5-BE7	3PH fault at LC_SWY.S-BE7(G20-014 POI) with normal clearing; clear by tripping LC_SWY.S-BE7-LC_CT4-5-BE7 line at 6 cycles; resulting in additional loss of LONESM_4-BEG Unit 4 and LONESM_5-BEG Unit 5	P1-2	G20-014
G20-014_P1_3	P1_G20-014_POI_LC_SWY.S-BE7_115_ARNEGARD-MK7	3PH fault at LC_SWY.S-BE7(G20-014 POI) with normal clearing; clear by tripping LC_SWY.S-BE7- ARNEGARD-MK7 line at 6 cycles; resulting in additional loss of LONESM_4-BEG Unit 4, LONESM_5-BEG Unit 5 and G20-014 gen	P1-2	G20-014
G20-021_P1_1	P1_G20-021_POI_G20-021-TAP_345_G20-021	3PH fault at G20-021-TAP with normal clearing; clear by tripping G20-021 gen in 6 cycles	P1-1	G20-021
G20-021_P1_2	P1_G20-021_POI_G20-021-TAP_345_G16-017-TAP	3PH fault at G20-021-TAP with normal clearing; clear by tripping G20-021-TAP - G16-017-TAP line at 6 cycles	P1-2	G20-021
G20-021_P1_3	P1_G20-021_POI_G20-021-TAP_345_LO.LS-FT-BE3345.	3PH fault at G20-021-TAP with normal clearing; clear by tripping G20-021-TAP - LO.LS-FT-BE3 line at 6 cycles	P1-2	G20-021
G20-091_P1_1	P1_G20-091_POI_PATENTGT-BE3_345_GEN-2020-091	3PH fault at PATENTGT-BE3 (G20-091_POI) with normal clearing; clear by tripping G20-021 gen in 6 cycles	P1-1	G20-091
G20-091_P1_2	P1_G20-091_POI_PATENTGT-BE3_345_PG.KU19A-BE7_Auto_1	3PH fault at PATENTGT-BE3 (G20-091_POI) with normal clearing; clear by tripping PG.KU19A-BE7 transformer 1 in 6 cycles	P1-3	G20-091
G20-091_P1_3	P1_G20-091_POI_PATENTGT-BE3_345_PG.KU19A-BE7_Auto_2	3PH fault at PATENTGT-BE3 (G20-091_POI) with normal clearing; clear by tripping PG.KU19A-BE7 transformer 2 in 6 cycles	P1-3	G20-091
G20-091_P1_4	P1_G20-091_POI_PATENTGT-BE3_345_JUDSON__-BE3	3PH fault at PATENTGT-BE3 (G20-091_POI) with normal clearing; clear by tripping PATENTGT-BE3 - JUDSON__-BE3 line in 6 cycles	P1-2	G20-091
G20-091_P1_5	P1_G20-091_POI_PATENTGT-BE3_345_CHARL_CK-BE3	3PH fault at PATENTGT-BE3 (G20-091_POI) with normal clearing; clear by	P1-2	G20-091

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
		tripping PATENTGT-BE3 - CHARL_CK-BE3 line in 6 cycles		
G20-014_P4_1	P4_G20-014_POI_LC_SWY.S-BE7_115_G20-014_LC_CT4-5-BE7	3PH fault on LC_SWY.S-BE7(G20-014 POI) - G20-014 115 kV line; breaker failure at LC_SWY.S-BE7; trip LC_SWY.S-BE7- LC_CT4-5-BE7 115 kV line in 20 cycles; resulting in loss of LONESM_4-BEG Unit 4, LONESM_5-BEG Unit 5 and G20-014 gen	P4	G20-014
G20-014_P4_2	P4_G20-014_POI_LC_SWY.S-BE7_115_G20-014_ARNEGARD-MK7	3PH fault on LC_SWY.S-BE7(G20-014 POI) - G20-014 115 kV line; breaker failure at LC_SWY.S-BE7; trip LC_SWY.S-BE7- ARNEGARD-MK7 115 kV line in 20 cycles; resulting in loss of LC_SWY.S-BE7-LC_CT4-5-BE7 115 , LONESM_4-BEG Unit 4, LONESM_5-BEG Unit 5 and G20-014 gen	P4	G20-014
G20-021_P4_1	P4_G20-021_POI_G20-021-TAP_345_G20-021_G16-017-TAP	3PH fault on G20-021-TAP - G20-021 345 kV line; breaker failure at G20-021-TAP; trip G20-021-TAP - G16-017-TAP 345 kV line in 20 cycles	P4	G20-021
G20-021_P4_2	P4_G20-021_POI_G20-021-TAP_345_G20-021_LO.LS-FT-BE3	3PH fault on G20-021-TAP - G20-021 345 kV line; breaker failure at G20-021-TAP; trip G20-021-TAP - LO.LS-FT-BE3 345 kV line in 20 cycles	P4	G20-021
G20-091_P4_1	P4_G20-091_POI_PATENTGT-BE3_345_GEN-2020-091_PG.KU19A-BE7_Auto_1	3PH fault on PATENTGT-BE3 (G20-091_POI) - G20-091 345 kV line; breaker failure at PATENTGT-BE3; trip PG.KU19A-BE7 transformer 1 in 20 cycles	P4	G20-091
G20-091_P4_2	P4_G20-091_POI_PATENTGT-BE3_345_GEN-2020-091_PG.KU19A-BE7_Auto_2	3PH fault on PATENTGT-BE3 (G20-091_POI) - G20-091 345 kV line; breaker failure at PATENTGT-BE3; trip FT-PG.KU19A-BE7 transformer 2 in 20 cycles	P4	G20-091
G20-091_P4_3	P4_G20-091_POI_PATENTGT-BE3_345_GEN-2020-091_JUDSON__-BE3	3PH fault on PATENTGT-BE3 (G20-091_POI) - G20-091 345 kV line; breaker failure at PATENTGT-BE3; trip PATENTGT-BE3 - JUDSON__-BE3 345 kV in 20 cycles	P4	G20-091
G20-091_P4_4	P4_G20-091_POI_PATENTGT-BE3_345_GEN-2020-091_CHARL_CK-BE3	3PH fault on PATENTGT-BE3 (G20-091_POI) - G20-091 345 kV line; breaker failure at PATENTGT-BE3; trip PATENTGT-BE3 - CHARL_CK-BE3 345 kV in 20 cycles	P4	G20-091
G20-091_P4_5	P4_G20-091_POI_PATENTGT-BE3_345_PG.KU19A-BE7_Auto_1_PG.KU19A-BE7_Auto_2	3PH fault on PATENTGT-BE3 (G20-091_POI) - PG.KU19A-BE7 transformer 1; breaker failure at PATENTGT-BE3; trip PG.KU19A-BE7 transformer 2 in 20 cycles	P4	G20-091

Cont. ID.	Disturbance Name	Description	NERC Cat.	Area
G20-091_P4_6	P4_G20-091_POI_PATENTGT-BE3_345_PG.KU19A-BE7_Auto_1_JUDSON__-BE3	3PH fault on PATENTGT-BE3 (G20-091_POI) - PG.KU19A-BE7 transformer 1; breaker failure at PATENTGT-BE3; trip PATENTGT-BE3 - JUDSON__-BE3 345 kV in 20 cycles	P4	G20-091
G20-091_P4_7	P4_G20-091_POI_PATENTGT-BE3_345_PG.KU19A-BE7_Auto_1_CHARL_CK-BE3	3PH fault on PATENTGT-BE3 (G20-091_POI) - PG.KU19A-BE7 transformer 1; breaker failure at PATENTGT-BE3; trip PATENTGT-BE3 - CHARL_CK-BE3 345 kV in 20 cycles	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.

Voltage and Relay violations were found in the contingencies listed in Table 17 for the benchmark case, and in Table 18 for the study case for MPC facilities. 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
3	0800_w_mp_p12	Yes	Relay	99.000	0.175	0.212	6.300	-17.200	Insecure
5	0822_w_otp_p12	Yes	Volt/Relay	99.000	0.075	0.000	-99.900	-99.900	Insecure
6	0823_w_otp_p12	Yes	Volt/Relay	65.420	0.075	0.004	-99.900	-99.900	Insecure
7	0824_w_otp_p12	Yes	Relay	99.000	0.062	0.054	-99.900	-99.900	Insecure

12	1677_w_otp_p12	Yes	Relay	99.000	0.062	0.025	6.500	-16.900	Insecure
14	1684_w_xel_p12	Yes	Volt/Relay	99.000	0.058	0.079	-98.700	-98.700	Insecure

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
3	0800_w_mp_p12	Yes	Relay	99.000	0.192	0.200	6.300	-17.200	Insecure
5	0822_w_otp_p12	Yes	Relay	99.000	0.088	0.063	-99.900	-99.900	Insecure
6	0823_w_otp_p12	Yes	Volt/Relay	99.000	0.092	0.000	-99.900	-99.900	Insecure
7	0824_w_otp_p12	Yes	Relay	99.000	0.062	0.054	-99.900	-99.900	Insecure
12	1677_w_otp_p12	Yes	Relay	99.000	0.063	0.025	6.400	-16.900	Insecure
14	1684_w_xel_p12	Yes	Volt/Relay	99.000	0.062	0.075	-98.600	-98.600	Insecure

3.6. CONCLUSION

Voltage and Relay violations were found in some contingencies for MPC facilities. 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 GEN-2020-021 GEN-2020-091
Bison – Buffalo 345 kV	MPC	1124.8	Structure Raise	$1,000,000	GEN-2020-014 GEN-2020-021 GEN-2020-091
Buffalo – New Sub 345 kV	MPC/OTP	1234.1	Structure Raise	$2,000,000	GEN-2020-014 GEN-2020-021 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 GEN-2020-091
Fronter 230 kV	MPC		0.9031	Prior queued project expected to mitigate voltage violation	GEN-2020-014 GEN-2020-021
MPC03637 POI 230 kV	MCC		0.9184	Prior queued project expected to mitigate voltage violation	GEN-2020-014 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

[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.

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

APPENDIX A

Case Development

ND and SD Generator Dispatch

Appendix A - ND
and SD Generator D

APPENDIX B

ACCC Analysis Results

Non-Converged Contingencies

Appendix B -
Non-Converged Cor

Thermal Constraints

Appendix B -
Thermal Constraints

Voltage Constraints

Appendix B -
Voltage Constraints

APPENDIX C

Transient Stability Results

Benchmark Case – Transient Stability Analysis Results

Appendix C - TSAT_Binary_Result_

Study Case – Transient Stability Analysis Results

Appendix C - TSAT_Binary_Result_

APPENDIX D

Cost Allocation

Maximum MW Impacts

Appendix D - Maximum MW Impa

MW Contribution to Constraints

Appendix D - MW Contribution to Cor

Network Upgrades Cost Allocation

Appendix D - Network Upgrades (