



# **INTERCONNECTION FACILITIES STUDY REPORT**

GEN-2016-050

IFS-2016-001-42

Published November 2021

By SPP Generator Interconnections Dept.

## REVISION HISTORY

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DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
07/26/2019	SPP	Initial draft report issued.
08/26/2019	SPP	Final report issued.
11/10/21	SPP	Updated final report issued. Updated wording on Pages 1 and 2 to reflect Modification Impact Study results. Updated estimated ISD for R-Plan

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## SUMMARY

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### *INTRODUCTION*

This Interconnection Facilities Study (IFS) for Interconnection Request GEN-2016-050/IFS-2016-001-42 is for a 250.7 MW generating facility located in Webster County, Nebraska. The Interconnection Request was studied in the DISIS 2016-001 Impact Study for Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The Interconnection Request was restudied in the DISIS 2016-001-1, DISIS-2016-001-2, and DISIS-2016-001-4 for ERIS only. The Interconnection Request was also studied in a Modification Impact Study in which the turbine configuration changed. The Interconnection Customer's requested in-service date is 12/31/2021.

The interconnecting Transmission Owner, Nebraska Public Power District (NPPD), 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 interconnect facilities (TOIF), non-shared network upgrades, shared network upgrades, previously allocated, 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.

### *CREDITS/COMPENSATION FOR AMOUNTS ADVANCED FOR NETWORK UPGRADE(S)*

Interconnection Customer shall be entitled to compensation in accordance with Attachment Z2 of the SPP OATT for the cost of SPP creditable-type Network Upgrades, including any tax gross-up or any other tax-related payments associated with the Network Upgrades, that are not otherwise refunded to the Interconnection Customer. Compensation shall be in the form of either revenue credits or incremental Long Term Congestion Rights (iLTCR).

### ***INTERCONNECTION CUSTOMER INTERCONNECTION FACILITIES***

The Generating Facility is proposed to consist of eighty (80) Siemens 3.0 MW + seven (7) GE 2.32 MW wind turbine generation systems for a total of 256.24 MW that will be limited to 250.7 MW by a Power Plant Controller.

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 collector circuits;
- 34.5 kV to 345 kV transformation substation with associated 34.5 kV and 345 kV switchgear;
- One (1) 345/34.5 kV, 170/220/280 MVA (ONAN/ONAF/ONAF) step-up transformer to be owned and maintained by the Interconnection Customer at the Interconnection Customer's substation;
- A six and a half (6.5) mile overhead 345 kV line to connect the Interconnection Customer's substation to the Point of Interconnection ("POI") at the 345 kV bus at existing Transmission Owner substation Axtell-Post Rock 345 kV 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 turbine 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.

The Interconnection Customer shall coordinate relay, protection, control, and communication system configurations and schemes with the Transmission Owner.

## **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** lists 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 (\$)	Estimated Lead Time
<b><u>NPPD Macon 345 kV Interconnection</u></b> <b>Substation:</b> Construct a 345 kV line terminal, line switches, dead end structure, line relaying, communications, revenue metering, line arrester, and all associated equipment and facilities necessary to accept transmission line from Interconnection Customer's Generating Facility.	\$700,000	100%	\$700,000	36 Months
<b>Total</b>	<b>\$700,000</b>	<b>100%</b>	<b>\$700,000</b>	

*Table 2: Non-Shared Network Upgrade(s)*

Non-Shared Network Upgrades Description	Z2 Type <sup>1</sup>	Total Cost Estimate (\$)	Allocated Percent (%)	Allocated Cost Estimate (\$)	Estimated Lead Time
<b><u>NPPD Macon 345 kV Interconnection</u></b> <b>Substation:</b> Construct Macon 345 kV Substation to accommodate new generation interconnection. Install continuous ampacity breakers, control panels, line relaying, acquire land, disconnect switches, structures, foundations, conductors, insulators, and all other associated work and materials.	Non-Creditable	\$15,800,000	100%	\$15,800,000	36 Months
<b>Total</b>		<b>\$15,800,000</b>	<b>100%</b>	<b>\$15,800,000</b>	

<sup>1</sup> Indicates the method used for calculating credit impacts under Attachment Z2 of the Tariff.

**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 Upgrades*

Shared Network Upgrades Description	Z2 Type	Total Cost Estimate (\$)	Allocated Percent (%)	Allocated Cost Estimate (\$)	Estimated Lead Time
<b>None</b>	N/A	\$0	N/A	\$0	N/A
<b>Total</b>		<b>\$0</b>		<b>\$0</b>	

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.

**PREVIOUS NETWORK UPGRADE(S)**

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

*Table 4: Interconnection Customer Previous Network Upgrade(s)*

Previous Network Upgrade(s) Description	Current Cost Assignment	Estimated In-Service Date
<b>SPP-NTC-200220 - R-Plan:</b> Build new 222 mile, 345 kV line from Gentleman - Cherry Co - Holt Co. Build new 345 kV substations at Cherry Co and Holt Co. Terminal upgrades at Gentleman.	\$412,074,343	4/1/2024

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 Previous 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 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 Share (%)	Allocated Cost Estimate (\$)
<b>None</b>	\$0	N/A	\$0
<b>Total</b>	<b>\$0</b>		<b>\$0</b>

### ***CONCLUSION***

After all Interconnection Facilities and Network Upgrades have been placed into service, Interconnection Service for 250.7 MW can be granted. Full Interconnection Service will be delayed until the transmission owner interconnect facilities (TOIF), non-shared network upgrades, shared network upgrades, previously allocated, and affected system upgrades that are required for full interconnection service are completed. The Interconnection Customer's estimated cost responsibility is summarized in the table below.

*Table 6: Cost Summary*

Description	Allocated Cost Estimate
Transmission Owner Interconnection Facilities	\$700,000
Network Upgrades	\$15,800,000
<b>Total</b>	<b>\$16,500,000</b>

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

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## **A: TRANSMISSION OWNER'S INTERCONNECTION FACILITIES STUDY REPORT**

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See next page for the Transmission Owner's Interconnection Facilities Study Report.

# **DISIS-2016-001-1 GENERATION INTERCONNECTION FACILITY STUDY**

## **NPPD**

**SPP GEN-2016-021 300.0 MW at Hoskins 345 kV Substation**

**SPP GEN-2016-043 230.0 MW at Hoskins 345 kV Substation**

**SPP GEN-2016-050 250.7 MW at Macon 345 kV Substation**

## **WAPA**

**SPP GEN-2015-089 200.00 MW at Utica Junction 230kV**

**SPP GEN-2016-023 150.50 MW at Banner County 345kV**

**SPP GEN-2016-029 150.00 MW at Banner County 345kV**

**SPP GEN-2016-075 50.00 MW at Grand Prairie 345kV**

**MAY 2018**

**PREPARED FOR:  
SOUTHWEST POWER POOL**

**PREPARED BY:  
NEBRASKA PUBLIC POWER DISTRICT OPERATIONS  
TRANSMISSION ASSET PLANNING  
T&D ASSET MANAGEMENT  
T&D ENGINEERING**



**Nebraska Public Power District**  
*"Always there when you need us"*



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## Executive Summary

The *NPPD DISIS-2016-001-1 Facility Study* was performed to document the reliability impacts of generation projects that are proposed to interconnect to the NPPD transmission system. These projects have developed through the SPP Definitive Interconnection System Impact Study process and have advanced to the facility study stage. SPP has requested that NPPD perform the Facility Study associated with the generation interconnection projects listed below:

<u>Project</u>	<u>MW</u>	<u>Type</u>	<u>Point-of-Interconnection</u>
GEN-2015-089	200.00	Wind	WAPA Utica Junction 230kV
GEN-2016-021	300.00	Wind	NPPD Hoskins 345kV
GEN-2016-023	150.50	Wind	WAPA Interconnect Laramie River – Sidney (Banner Co) 345kV
GEN-2016-029	150.00	Wind	WAPA Interconnect Laramie River – Sidney (Banner Co) 345kV
GEN-2016-043	230.00	Wind	NPPD Hoskins 345kV
GEN-2016-050	250.70	Wind	NPPD Interconnect Axtell- Post Rock (Macon) 345kV
GEN-2016-075	<u>50.00</u>	Wind	WAPA Grand Prairie 345kV
	1331.2		

SPP entered into a facility study agreement with each of the generation interconnection customers and subsequently requested that NPPD perform the Facility Study for each request. This facility study focused on the impacts of the generation interconnection projects which included a detailed loadflow analysis, short circuit analysis and stability analysis. The Facility Study also includes detailed cost estimates and estimated project schedules for the interconnection and network upgrades identified in the System Impact and Facility Study.

The DISIS-2016-001-1 Facility Study includes a loadflow analysis, short circuit analysis and stability analysis.

The Loadflow Analysis documents the steady-state performance of the network following the generation interconnection projects. The loadflow analysis was split into three phases.

Phase 1 of the loadflow analysis was a system intact and N-1 contingency analysis of the Nebraska transmission system in accordance with NERC Standard TPL-001-4. The Phase 1 screening did not identify any significantly impacted NPPD facilities for system intact conditions. Four facilities were found to overload for N-1 conditions:

- NPPD Twin Church – Sioux City\* 230 kV Line \*(WAPA Owns Sioux City terminal)
- NPPD Columbus East 230/115 kV Transformer
- NPPD Ogallala – Ogallala TSGT\*\* 115 kV Substation Tie \*\* (TSGT Owns Ogallala TSGT terminal)
- TSGT Ogallala – Grant 115 kV Line #1 (TSGT Owned Facility)

The Phase 1 screening did not discover any impacted bus voltages outside of limits for system intact or N-1 conditions.

Phase 2 of the loadflow analysis involved a comprehensive multiple element contingency analysis of the Nebraska transmission system in accordance with NERC Standard TPL-001-4. The Phase 2 screening identified several facilities that were loaded in excess of facility ratings for multiple element contingencies. Each of the contingencies and overloaded facilities may require curtailment of firm transmission and/or load shed to mitigate these issues. The Phase 2 screening did not discover any impacted bus voltages outside of limits for multiple element contingency conditions.

Phase 3 of the loadflow analysis evaluated the impacts of worst case independent N-2 double contingency conditions for the local area transmission outlet paths associated with the generation interconnection projects. This phase did identify several independent N-2 contingencies that would require prior outage generation limitations of the proposed generation interconnection projects. These prior outage limitations would be developed through an operational study and/or operational guides if all the projects continue to be developed. The limiting prior outages are listed below:

#### Limiting Prior Outage Facilities

1.	POSTROCK7	345.00-G16-050-TAP	345.00	38.	HOSKINS4	230.00-HOSK.T89	34.500
2.	NOB HL3	115.00-STEELEC7	115.00	39.	HOSKINS7	115.00-NORFK.N7	115.00
3.	G15087_T	115.00-FAIRBRY7	115.00	40.	HOSKINS7	115.00-NORFOLK7	115.00
4.	G15087_T	115.00-HEBRN N7	115.00	41.	HOSKINS7	115.00-STNTN.N7	115.00
5.	G15088_T	345.00-MOORE 3	345.00	42.	KEYSTON3	345.00-SIDNEY1-LNX3	345.00
6.	G15088_T	345.00-PAULINE3	345.00	43.	MCCOOL 3	345.00-MOORE 3	345.00
7.	G1623&1629-T345.00-KEYSTON3	345.00		44.	NELIGH 7	115.00-PETERSBRG.N7	115.00
8.	G1623&1629-T345.00-LARAMIE3	345.00		45.	NELIGH 7	115.00-ANTELOPE	7115.00
9.	G1623&1629-T345.00-SIDNEY2-LNX3	345.00		46.	NORFK.N7	115.00-NORFOLK7	115.00
10.	G16-050-TAP 345.00-AXTELL 3	345.00		47.	PETRSBG7	115.00-PETERSBRG.N7	115.00
11.	G10-51T	230.00-HOSKINS4	230.00	48.	TWIN CH7	115.00-S.SIOUXCITY7	115.00
12.	G10-51T	230.00-TWIN CH4	230.00	49.	VICTRYH4	230.00-STEGALL4	230.00
13.	ALBION 7	115.00-FULERTN7	115.00	50.	WAYSIDE4	230.00-NUNDRWD4	230.00
14.	ALBION 7	115.00-GENOA 7	115.00	51.	THEDFRD3	345.00-HOLT.CO3	345.00
15.	ALBION 7	115.00-PETRSBG7	115.00	52.	HOLT.CO3	345.00-GR ISLD-LNX	3345.00
16.	ALBION 7	115.00-SPALDNG7	115.00	53.	STEGALL4	230.00-STEGALL-LNX	3230.00
17.	AXTELL 3	345.00-PAULINE3	345.00	54.	LARAMIE3	345.00-STEGALL3	345.00
18.	AXTELL 3	345.00-SWEET W3	345.00	55.	HARBINE7	115.00-STEELEC7	115.00
19.	BATTLCCR7	115.00-CO.LINE7	115.00	56.	HEBRN N7	115.00-HEBRON 7	115.00
20.	BATTLCCR7	115.00-NORFK.N7	115.00	57.	MOORE 3	345.00-SHELDON7	115.00
21.	BEATRCE7	115.00-HARBINE7	115.00	58.	MOORE 3	345.00-NW68HOLDRG3	345.00
22.	BEATRCE7	115.00-STEINER7	115.00	59.	PAULINE3	345.00-PAULINE7	115.00
23.	BELDEN 7	115.00-HARTGTN7	115.00	60.	SIDNEY 3	345.00-SIDNEY1-LNX	3345.00
24.	BELDEN 7	115.00-HOSKINS7	115.00	61.	SIDNEY 3	345.00-STEGALL3	345.00
25.	BELDEN 7	115.00-TWIN CH7	115.00	62.	HOSKINS3	345.00-HOSKINS4	230.00
26.	BLMFLD 7	115.00-CREITON7	115.00	63.	HOSKINS3	345.00-HOSKINS7	115.00
27.	BLMFLD 7	115.00-GAVINS 7	115.00	64.	HOSKINS4	230.00-HOSKINS7	115.00
28.	CARLICT7	115.00-HEBRN N7	115.00	65.	TWIN CH4	230.00-TWIN CH7	115.00
29.	CLRWATR7	115.00-NELIGH 7	115.00	66.	HOLT.CO3	345.00-GRPRAR1-LNX	3345.00
30.	CO.LINE7	115.00-ANTELOPE	7115.00	67.	ANTELOPE	3345.00-ANTELOPE	7115.00
31.	COOPER 3	345.00-MOORE 3	345.00	68.	GR PRAIRIE	3345.00-GRPRAR1-LNX	3345.00
32.	CREITON7	115.00-ANTELOPE	7115.00	69.	GR PRAIRIE	3345.00-GRPRAR2-LNX	3345.00
33.	EMERSON7	115.00-TWIN CH7	115.00	70.	STEGALL4	230.00-STGXFMR4	230.00
34.	FAIRBRY7	115.00-HARBINE7	115.00	71.	WAYSIDE4	230.00-STEGALL-LNX	3230.00
35.	GENTLMN3	345.00-KEYSTON3	345.00	72.	STEGALL7	115.00-STEGALL3	345.00
36.	HARTGTN7	115.00-GAVINS 7	115.00	73.	STEGALL3	345.00-STGXFMR4	230.00
37.	HOSKINS3	345.00-ANTELOPE	3345.00				

The Short Circuit Analysis was performed to evaluate the fault interrupting capability of existing devices in the area and protection coordination issues following the generation interconnection projects and network upgrades. The results of this analysis showed that two existing protective devices (Columbus East 1110 & 1112 Circuit Switchers) were subject to replacement due to the proposed interconnection projects.

The Stability Analysis was performed to evaluate the impact of the proposed generation interconnection projects and network upgrades on the existing GGS Stability constrained interface in Nebraska. Based on the results of this analysis, the NPPD transmission system with the current planned future projects meets the stability performance requirements for all Planning Event and Extreme Event conditions that were considered in this study.

Overall, the *NPPD DISIS-2016-001-1 Facility Study* documents the performance of the network following the addition of the generation interconnection projects and network upgrades. The Facility Study has documented the transmission plan required for interconnection to the NPPD transmission system and the details of this plan are listed below. There is no generation interconnection capability available until the projects listed below are completed as required.

### **DISIS-2016-001-1 Interconnection Plan**

#### Interconnection Facilities

- GEN-2016-021: Construct satellite 345 kV Substation near Hoskins 345 kV substation to accommodate new GI.  

**\$ 7,250,000\***
- GEN-2016-043: Construct satellite 345 kV Substation near Hoskins 345 kV substation to accommodate new GI.  

**\$ 7,250,000\***
- GEN-2016-050: Construct Macon 345 kV Substation to accommodate new GI.  

**\$ 16,500,000**

*\*Total Cost for satellite substation is \$14,500,000*



### Network Upgrades

- Construct Banner County – Keystone 345 kV line & substation expansions.  
**\$ 260,000,000**
- Construct Keystone – GGS 345 kV line & substation expansions.  
**\$ 69,750,000**
- Install 10 MVAR cap bank at SUNC Atwood 115 kV substation.  
**\$ TBD**
- Upgrade Columbus East 230/115 kV Transformer.  
**\$ 4,250,000**
- Upgrade Twin Church – Sioux City 230 kV Line (NPPD portion).  
**\$ 3,300,000**
- Upgrade Twin Church – Sioux City 230 kV Line (WAPA portion).  
**\$ TBD**
- Upgrade Ogallala NPPD – Ogallala TSGT 115 kV substation tie (NPPD portion).  
**\$ 50,000**
- Upgrade Ogallala NPPD – Ogallala TSGT 115 kV substation tie (TSGT portion).  
**\$ TBD**
- Upgrade Ogallala – Grant 115 kV Line #1 (TSGT portion).  
**\$ TBD**
- Upgrade Columbus East 1110 and 1112 Circuit Switchers (Loup Power District).  
**\$ 200,000**

*Previously-allocated Network Upgrades*

- Hoskins – Neligh (Antelope) 345/115 kV Transmission expansion project
- Gentleman – Thedford - Holt County (R-Project) and Thedford 345/115 kV Transformer project

*Previously-identified Required Transmission Upgrades for prior queued requests*

- Uprate Belvidere-Fairbury 115 kV line.
- Uprate Beatrice-Harbine 115 kV line.
- Reconductor Albion - Petersburg - North Petersburg 115 kV
- Rebuild Gavins Point - Yankton Junction 115 kV (WAPA upgrade)
- Antelope 115 kV substation expansion (for GEN-2015-053)
- Belden 115 kV substation expansion (for GEN-2015-076)
- Construct Belvidere 115 kV Substation (for GEN-2015-087)
- Construct Tobias 345 kV Substation (for GEN-2015-088)
- Dixon County 230 kV substation (for GEN-2010-051)
- Upgrade Twin Church-DixonCounty-Hoskins 230kV line
- Antelope 115 kV substation expansion (for GEN-2013-032)
- Upgrade Antelope-County Line-Battle Creek 115 kV line
- Upgrade Meadow Grove-Prairie Breeze 230 kV Gen-Tie line
- Friend 115 kV substation (for GEN-2014-039)
- Rosemont 115 kV substation (for GEN-2008-123N)
- Hoskins 345 kV substation expansion (for GEN-2015-007)
- Holt County 345 kV substation expansion (for GEN-2015-023)

## 1.0 Introduction

In February 2018, NPPD was notified that several generation interconnection requests in the SPP generation interconnection queue had advanced to the facility study stage. These generation interconnection requests were evaluated by SPP in multiple Definitive Interconnection System Impact Studies (DISIS-2016-001, DISIS-2016-001-1). The generation interconnection requests are listed below:

<u>Project</u>	<u>MW</u>	<u>Type</u>	<u>Point-of-Interconnection</u>
GEN-2015-089	200.00	Wind	WAPA Utica Junction 230kV
GEN-2016-021	300.00	Wind	NPPD Hoskins 345kV
GEN-2016-023	150.50	Wind	WAPA Interconnect Laramie River – Sidney (Banner Co) 345kV
GEN-2016-029	150.00	Wind	WAPA Interconnect Laramie River – Sidney (Banner Co) 345kV
GEN-2016-043	230.00	Wind	NPPD Hoskins 345kV
GEN-2016-050	250.70	Wind	NPPD Interconnect Axtell- Post Rock (Macon) 345kV
GEN-2016-075	<u>50.00</u>	Wind	WAPA Grand Prairie 345kV
	1331.2		

SPP entered into a facility study agreement with each of the generation interconnection customers and subsequently requested that NPPD perform the Facility Study for each request. In response to the SPP request, NPPD has performed a Facility Study for the generation interconnection requests.

This facility study (NPPD-DISIS-2016-001-1) includes a detailed loadflow, stability and short circuit analysis. The Facility Study also includes detailed cost estimates and estimated project schedules for the interconnection and network upgrades identified in the System Impact Study and Facility Study. The System Impact Study did identify several network upgrades required for interconnection of the new generation projects. Both of these generation interconnection requests are contingent upon the completion of the Hoskins-Neligh 345 kV projects and the GGS-Thedford-Holt 345 kV R-project which were previously approved through the SPP ITP processes. The GGS-Thedford-Holt 345 kV R-project is being developed and behind the original project schedule. The current projected in-service date for the R-project is 12/31/2020.

## 2.0 Study Scope

### 2.1 Overview

This Facility Study will evaluate the impact of the requested generation interconnection projects on the NPPD transmission system. This study will evaluate generator interconnection requests in the SPP Generator Interconnection Queue studied in the SPP Definitive Interconnection System Impact Study, SPP DISIS-2016-001-1, and progressed to the facilities study stage. The GI projects on the NPPD transmission system included in the DISIS-2016-001-1 study are as follows:

<u>Project</u>	<u>MW</u>	<u>Type</u>	<u>Point-of-Interconnection</u>
GEN-2015-089	200.00	Wind	WAPA Utica Junction 230kV
GEN-2016-021	300.00	Wind	NPPD Hoskins 345kV
GEN-2016-023	150.50	Wind	WAPA Interconnect Laramie River – Sidney (Banner Co) 345kV
GEN-2016-029	150.00	Wind	WAPA Interconnect Laramie River – Sidney (Banner Co) 345kV
GEN-2016-043	230.00	Wind	NPPD Hoskins 345kV
GEN-2016-050	250.70	Wind	NPPD Interconnect Axtell- Post Rock (Macon) 345kV
GEN-2016-075	<u>50.00</u>	Wind	WAPA Grand Prairie 345kV
	1331.2		

NPPD will perform a Facility Study of the generation interconnection requests that includes a detailed loadflow and short circuit analysis. The facility study will also include stability analysis to assess the impacts of the proposed generation interconnection requests on existing stability constraints (GGS Eastflow) and potential stability issues highlighted in the System Impact Study. The Facility Study also includes detailed cost estimates and estimated project schedules for the interconnection and network upgrades identified in the System Impact Study and Facility Study. The following network upgrades are required for ERIIS per the System Impact Study:

- Build Banner County - Keystone 345 kV
- Build Keystone - Gentleman 345 kV CKT 2
- Install 10 MVAR capacitor bank at SUNC Atwood 115 kV substation

The following previously allocated network upgrades were required for interconnection of the DISIS-2016-001-1 projects:

- Reconnector Albion - Petersburg - North Petersburg 115kV
- Rebuild Gavins Point - Yankton Junction 115 kV (WAPA upgrade)
- R-Project: GGS-Thedford-Holt County 345 kV & Thedford 345/115 kV Transformer
- Upgrade Twin Church - Dixon County 230kV
- Rebuild County Line-Antelope 115 kV
- Rebuild Battle Creek-County Line 115 kV

At the time of this facility study, there were several active generation interconnection requests in the SPP GI queue in the Nebraska area. Due to time

constraints, this facility study must proceed assuming the following generation interconnection projects and associated network upgrades remain active projects in the SPP GI process. If any of these GI projects or network upgrades withdraw from the SPP GI queue, then a re-study of this DISIS-2016-001-1 facility study will be required. The previously-queued GI projects and network upgrades in the Nebraska area are as follows:

Generation Interconnection Number	MW	CA	Substation	Status
GEN-2010-051	200	NPPD	Dixon County 230kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2011-027	120	NPPD	Dixon County 230kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2013-032	204	NPPD	Antelope 115kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2014-032	10.2	NPPD	Meadow Grove 230kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2014-039	73.4	NPPD	Friend 115kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2008-123N	89.7	NPPD	Rosemont 115kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-007	160	NPPD	Hoskins 345 kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-023	300.7	NPPD	Holt County 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-053	50	NPPD	Antelope 115 kV	IA PENDING
GEN-2015-076	158.4	NPPD	Belden 115 kV	IA PENDING
GEN-2015-087	66	NPPD	Belvedere 115 kV (Hebron-Fairbury)	IA PENDING
GEN-2015-088	300	NPPD	Tobias 345 kV (Pauline-Moore)	IA PENDING

#### Previously allocated interconnection facilities & network upgrades

- Uprate Belvidere-Fairbury 115 kV line.
- Uprate Beatrice-Harbine 115 kV line.
- Reconductor Albion - Petersburg - North Petersburg 115 kV
- Rebuild Gavins Point - Yankton Junction 115 kV (WAPA upgrade)
- Antelope 115 kV substation expansion (for GEN-2015-053)
- Belden 115 kV substation expansion (for GEN-2015-076)
- Construct Belvidere 115 kV Substation (for GEN-2015-087)
- Construct Tobias 345 kV Substation (for GEN-2015-088)
- Dixon County 230 kV substation (for GEN-2010-051)
- Upgrade Twin Church-DixonCounty-Hoskins 230kV line
- Antelope 115 kV substation expansion (for GEN-2013-032)
- Upgrade Antelope-County Line-Battle Creek 115 kV line
- Upgrade Meadow Grove-Prairie Breeze 230 kV Gen-Tie line
- Friend 115 kV substation (for GEN-2014-039)
- Rosemont 115 kV substation (for GEN-2008-123N)
- Hoskins 345 kV substation expansion (for GEN-2015-007)

- Holt County 345 kV substation expansion (for GEN-2015-023)

This facility study will assess the new system state with the generation interconnection requests. The facility study will also identify any additional transmission issues that would require mitigation to meet mandatory NERC reliability standards following the addition of the generation interconnection projects and network upgrades. The Facility Study will include the following study phases:

1. Loadflow Analysis
2. Stability Analysis
3. Short Circuit Analysis

The loadflow analysis will be an assessment of the transmission system following the addition of the generation interconnection projects and network upgrades. The loadflow analysis will evaluate the transmission system for compliance with NERC Reliability Standards and identify any thermal and voltage issues that would require mitigation. The stability analysis will evaluate the impacts of the generation interconnection projects on the transmission system and existing stability constraints (GGS Eastflow). The short circuit analysis will evaluate the impacts of the generation interconnection project and network upgrades on existing fault currents in the area and determine if the capability of existing fault interrupting devices are adequate.

The intent of the facility study is to perform a detailed assessment of the proposed generation interconnection facility and associated transmission and validate adherence to system reliability criteria. This study will be performed in accordance with NERC Reliability Standards and the criteria set forth under those standards. This facility study will document the required transmission facility interconnection plan for the proposed uprate and will be performed in accordance with the methodologies described in NPPD's Facility Connection Requirements Document.

## **2.2 Loadflow Analysis**

NPPD Transmission Planning will perform a loadflow analysis to screen the steady state performance of the network following the addition of the generation interconnection project and network upgrades. The powerflow models used for the loadflow analysis will be 2017 Series SPP MDWG models. These models will represent expected near-term system conditions with the generation interconnection projects and will represent worst-case seasonal conditions. The powerflow models utilized for the analysis will be:

2018 Spring Load Case (18G)  
2018 Light Load Case (18L)  
2018 Summer Load Case (18S)  
2018 Winter Load Case (18W)

The base SPP MDWG powerflow models will be updated with planned transmission facility additions in the area of the generation interconnection requests. Specifically, the base models will be updated to include the GGS-Thedford-Holt 345 kV project as it was found to be a required network upgrade to accommodate the generation interconnection projects. The base models will also include all identified ERIIS network upgrades per the System Impact Study.

The loadflow analysis will be split into three phases:

Phase 1 : System-wide Single Contingency N-1 Analysis

Phase 2 : System-wide Multiple Element Contingency N-2 Analysis

Phase 3 : Local Area Full N-2 Contingency Analysis

PHASE 1: This Phase is considered a comprehensive single contingency analysis of the entire Nebraska subregion. Every single element rated from 115 kV – 345 kV in the NPPD, OPPD, and LES areas plus ties will be outaged and monitored through activity ACCC. The results of the contingency screening will be assessed and documented. Phase 1 will also further investigate all critical contingencies identified from the ACCC contingency screening. Phase 1 will be utilized to document the performance characteristics of the system in accordance with NERC Reliability Standards.

PHASE 2: This Phase is considered a comprehensive multiple element contingency analysis of the entire Nebraska region. Multiple element contingencies rated from 115 kV – 345 kV will be outaged and monitored through activity ACCC. The multiple element contingencies consist of stuck breaker contingencies and double circuit tower contingencies identified by Nebraska transmission owners and utilized during MRO and SPP screening processes. The results of the contingency screening will be assessed and documented. Phase 2 will also further investigate all critical contingencies identified from the ACCC contingency screening comparison. Phase 2 will be utilized to document the performance characteristics of the system in accordance with NERC Reliability Standards.

PHASE 3: This Phase will evaluate the impacts of worst case independent N-2 double contingency conditions for the local area transmission outlet paths associated with the generation interconnection projects. The purpose of this

Phase will be to evaluate sufficient generator outlet transmission capacity for the generation interconnection requests and evaluate potential prior outage limitations.

### **2.3 Stability Analysis**

The purpose of the Stability Analysis will be to evaluate the impacts of the proposed generation interconnection projects on an existing stability constraint on the NPPD transmission system (GGS Eastflow). The analysis will evaluate worst-case disturbances impacting stability limitations in western Nebraska. The analysis will also evaluate disturbances and prior outage combinations near the proposed generation interconnection projects to evaluate any potential stability issues.

### **2.4 Short Circuit Analysis**

The purpose of the Short Circuit Analysis will be to evaluate the impacts of the proposed generation interconnection projects on the existing substation equipment fault duty ratings in the area. The substations to be evaluated are those electrically close to the interconnection points of the generation interconnection projects.

The Short Circuit Analysis will include short circuit calculations, an evaluation of the adequacy of existing circuit breaker interrupting ratings and an evaluation of the adequacy of the fault withstand capability of other substation equipment located at the monitored substations. The Short Circuit Analysis will be performed by NPPD Engineering Protection & Control personnel.

### **2.5 Detailed Cost Estimates & Project Schedule**

NPPD Engineering, Asset Management, and Project Management departments will review any additional transmission upgrades identified in the SPP DISIS-2016-001-1 facility study. Detailed cost estimates and project schedules will be developed by these groups to implement the proposed transmission upgrades using standard NPPD construction and procurement practices. If any additional transmission upgrades are identified in this facility study, a detailed cost estimate and project schedule for these additional upgrades will be developed and provided as required.



## 3.0 Model Development

### Overview

This study was conducted using Power Technology Inc.'s (PTI's) Power System Simulator (PSS/E) software package and the following SPP 2017 Series MDWG powerflow models:

2018 Spring Peak Load Case  
2018 Light Load Case  
2018 Summer 100% Peak Load Case  
2018-19 Winter 100% Peak Load Case

The powerflow models were updated to include the generation interconnection projects and network upgrades as well as the latest transmission upgrades documented in the latest regional transmission plans. Specifically, the base models were updated to include the GGS-Thedford-Holt 345 kV project as it was found to be a required network upgrade to accommodate the generation interconnection projects. Also, the models were re-dispatched to ramp up wind generation and adjacent generators to the new proposed generation interconnection locations. A 2015 Series 16W stability case was also re-dispatched to stress transfer limitations in western Nebraska and the GGS Stability Interface. The 16W model was established with GGS Eastflow at the 1850 MW transfer level with the projected system topology for 2016 (without the R-Project). The prior-queued wind generation, R-Project, and DISIS-2016-001 wind projects were then added to this model to establish the baseline for the stability analysis.

The following prior-queued generation interconnection projects were included in the base powerflow models:

Generation Interconnection Number	MW	CA	Substation	Status
GEN-2010-051	200	NPPD	Dixon County 230kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2011-027	120	NPPD	Dixon County 230kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2013-032	204	NPPD	Antelope 115kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2014-032	10.2	NPPD	Meadow Grove 230kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2014-039	73.4	NPPD	Friend 115kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2008-123N	89.7	NPPD	Rosemont 115kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-007	160	NPPD	Hoskins 345 kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-023	300.7	NPPD	Holt County 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-053	50	NPPD	Antelope 115 kV	IA PENDING
GEN-2015-076	158.4	NPPD	Belden 115 kV	IA PENDING
GEN-2015-087	66	NPPD	Belvedere 115 kV (Hebron-Fairbury)	IA PENDING
GEN-2015-088	300	NPPD	Tobias 345 kV (Pauline-Moore)	IA PENDING

The proposed future generation interconnection projects were dispatched off-system. The new generation interconnection projects listed below were then added to the models and dispatched at 100%. The total output from the new generation interconnection projects was dispatched off-system.

Generation Interconnection Number	MW	CA	Substation	Status
GEN-2015-089	200	WAPA	Utica Junction 230kV	FACILITY STUDY STAGE
GEN-2016-021	300	NPPD	Hoskins 345kV	FACILITY STUDY STAGE
GEN-2016-023	150.5	WAPA	Interconnect Laramie River – Sidney (Banner Co) 345kV	FACILITY STUDY STAGE
GEN-2016-029	150	WAPA	Interconnect Laramie River – Sidney (Banner Co) 345kV	FACILITY STUDY STAGE
GEN-2016-043	230	NPPD	Hoskins 345kV	FACILITY STUDY STAGE
GEN-2016-050	250.7	NPPD	Interconnect Axtell- Post Rock (Macon) 345kV	FACILITY STUDY STAGE
GEN-2016-075	50	WAPA	Grand Prairie 345kV	FACILITY STUDY STAGE

Three network upgrades were incorporated into the models with the new generation interconnection projects that were identified in the SPP DISIS report. These network upgrades are listed below:

- Build Banner County - Keystone 345 kV
- Build Keystone - Gentleman 345 kV CKT 2
- Install 10 MVAR capacitor bank at SUNC Atwood 115 kV substation

### Wind Generation Models

Each of the new wind generation interconnection projects were modeled with a +/- 0.95 power factor range with voltage control capability at the designated point-of-interconnection. Some of the new projects may have a larger reactive power range available, but the reactive capability of each generation interconnection project was limited to +/- 0.95 power factor to match the power factor requirements identified in the system impact study. The dynamics models for the new wind projects were standard PSS/E Type 3 WTG models.

## 4.0 Study Criteria

The following criteria were used for the Steady-State Analysis:

### Facility Loading Criteria

Overloads of equipment are defined as greater than 100% of the normal continuous rating (Rate A).

### Voltage Criteria

Normal steady-state voltage levels are defined as 0.95 to 1.05 pu. Emergency steady-state voltage levels are defined as 0.90 – 1.10 pu and may be utilized for less than 30 minutes.

The following criteria were used for the Stability Analysis:

### Transient Voltage Criteria

Bus voltage excursions outside the band of 0.70 to 1.2 PU any time after the fault is cleared is considered unacceptable.

### Damping Criteria

All significant machine rotor angle oscillations must be positively damped and meet the criteria below. The criteria does not apply to bus voltages. The Damping Factor will be 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:

$$\text{SPPR} = \text{Successive swing amplitude} / \text{Previous swing amplitude}$$

$$\text{Damping Factor} = (1 - \text{SPPR}) * 100 \text{ (in \%)}$$

The Damping Criteria are as follows (with increased damping required for higher probability events):

$$\text{For Disturbances with faults: SPPR (maximum)} = 0.95$$

$$\text{Damping Factor (minimum)} = 5\%$$

$$\text{For Line Trips: SPPR (maximum)} = 0.90$$

$$\text{Damping Factor (minimum)} = 10\%$$

## 5.0 Loadflow Analysis

### 5.1 Phase 1 Results (P0-P1 events)

PSS/E activity ACCC was used as a screening tool on each of the base cases to identify those contingencies which deserve closer study. ACCC analyzed the system by sequentially taking each transmission element greater than 100kV in the NPPD, OPPD, and LES areas out of service. P1 events for each of these areas were also included in this analysis. Transmission facilities in the NPPD, OPPD, and LES areas were then monitored for violations of loading or bus voltage criteria. Contingencies which resulted in facility loadings or bus voltages outside of acceptable limits will be discussed in the summary of each case. The Phase 1 ACCC analysis is performed to assess the performance of the transmission system following the addition of the generation interconnection projects and proposed new network upgrades according to NERC standards.

Phase 1 analysis further addressed contingencies flagged in the screened ACCC run with additional AC powerflow analysis as required. In the NPPD area, there are loadflow solution issues associated with voltage regulation bandwidths. Consequently, most of the capacitors and reactors are modeled as fixed mode switched shunts, which must be manually switched to achieve optimal voltage profiles.

#### Phase 1 – 2018 Light Load

##### *System Intact Results:*

There were no impacted transmission facility overloads or bus voltages outside of limits under system intact or base case conditions.

##### *N-1 Contingency Results:*

There were several impacted transmission facility overloads discovered under N-1 conditions (P1). There were no impacted bus voltages outside of limits that were discovered under N-1 conditions (P1).

Monitored Element Description	Rating	% Flow	Contingency Description
TWIN CH4-SIOUXCY4 230 CKT 1.0	320	99	OPEN LINE FROM BUS 640070 [BANCFT7 115.00] TO BUS 640163 [EMERSON7 115.00] CKT 1
TWIN CH4-SIOUXCY4 230 CKT 1.0	320	99	TRIP LINE FROM BUS 640070 [BANCFT7 115.00] TO BUS 640300 [OAKLAND7 115.00] CKT 1 AND TRIP LINE FROM BUS 640070 [BANCFT7 115.00] TO BUS 640163 [EMERSON7 115.00] CKT 1
TWIN CH4-SIOUXCY4 230 CKT 1.0	320	100	OPEN LINE FROM BUS 640125 [COLMB.E3 345.00] TO BUS 640342 [SHELCKR3 345.00] CKT 1
TWIN CH4-SIOUXCY4 230 CKT 1.0	320	100	OPEN LINE FROM BUS 640163 [EMERSON7 115.00] TO BUS 640387 [TWIN CH7 115.00] CKT 1
TWIN CH4-SIOUXCY4 230 CKT 1.0	320	101	OPEN LINE FROM BUS 640125 [COLMB.E3 345.00] TO BUS 650114 [NW68HOLDRG3 345.00] CKT 1
TWIN CH4-SIOUXCY4 230 CKT 1.0	320	103	OPEN LINE FROM BUS 640226 [HOSKINS3 345.00] TO BUS 640342 [SHELCKR3 345.00] CKT 1
TWIN CH4-SIOUXCY4 230 CKT 1.0	320	103	OPEN LINE FROM BUS 560347 [G10-51T 230.00] TO BUS 640227 [HOSKINS4 230.00] CKT 1
TWIN CH4-SIOUXCY4 230 CKT 1.0	320	142	OPEN LINE FROM BUS 640226 [HOSKINS3 345.00] TO BUS 635200 [RAUN 3 345.00] CKT 1

### Phase 1 – 2018 Spring Peak Load

#### *System Intact Results:*

There were no impacted transmission facility overloads or bus voltages outside of limits under system intact or base case conditions.

#### *N-1 Contingency Results:*

There was a single impacted transmission facility overloads discovered under N-1 conditions (P1). There were no impacted bus voltages outside of limits that were discovered under N-1 conditions (P1).

Monitored Element Description	Rating	% Flow	Contingency Description
TWIN CH4-SIOUXCY4 230 CKT 1.0	320	120	OPEN LINE FROM BUS 640226 [HOSKINS3 345.00] TO BUS 635200 [RAUN 3 345.00] CKT 1

### Phase 1 – 2018 Summer Peak

#### *System Intact Results:*

There were no impacted transmission facility overloads or bus voltages outside of limits under system intact or base case conditions.

### *N-1 Contingency Results:*

There were several impacted transmission facility overloads discovered under N-1 conditions (P1). There were no impacted bus voltages outside of limits that were discovered under N-1 conditions (P1).

Monitored Element Description	Rating	% Flow	Contingency Description
OGALALANPPD7-OGALALA7 115 CKT Z	239	99	OPEN LINE FROM BUS 653572 [SIDNEY 7 115.00] TO BUS 659134 [SIDNEY 4 230.00] TO BUS 659803 [SIDNEY 8 13.800] CKT 1
OGALALANPPD7-OGALALA7 115 CKT Z	239	99	OPEN LINE FROM BUS 653572 [SIDNEY 7 115.00] TO BUS 659817 [COLTON 7 115.00] CKT 1
OGALALANPPD7-OGALALA7 115 CKT Z	239	101	OPEN LINE FROM BUS 640183 [GENTLMN3 345.00] TO BUS 640325 [REDWILO3 345.00] CKT 1
OGALALANPPD7-OGALALA7 115 CKT Z	239	104	OPEN LINE FROM BUS 640265 [MALONEY7 115.00] TO BUS 640287 [N.PLATT7 115.00] CKT 1
OGALALANPPD7-OGALALA7 115 CKT Z	239	111	OPEN LINE FROM BUS 640304 [OGALALANPPD7115.00] TO BUS 659800 [GRANTNB7 115.00] CKT 2
TWIN CH4-SIOUXCY4 230 CKT 1	320	108	OPEN LINE FROM BUS 640226 [HOSKINS3 345.00] TO BUS 635200 [RAUN 3 345.00] CKT 1
GRANTNB7-OGALALA7 115 CKT 1	147	100	OPEN LINE FROM BUS 640304 [OGALALANPPD7115.00] TO BUS 659800 [GRANTNB7 115.00] CKT 2

### Phase 1 – 2018 Winter Peak

#### *System Intact Results:*

There were no impacted transmission facility overloads or bus voltages outside of limits under system intact or base case conditions.

#### *N-1 Contingency Results:*

There were several impacted transmission facility overloads discovered under N-1 conditions (P1). There were no impacted bus voltages outside of limits that were discovered under N-1 conditions (P1).

Monitored Element Description	Rating	% Flow	Contingency Description
E.COL. 4-COL.EAST T3 WND 2 CKT 1.0	187	101	OPEN LINE FROM BUS 640125 [COLMB.E3 345.00] TO BUS 640342 [SHELCKR3 345.00] CKT 1
TWIN CH4-SIOUXCY4 230 CKT 1.0	320	107	OPEN LINE FROM BUS 640226 [HOSKINS3 345.00] TO BUS 635200 [RAUN 3 345.00] CKT 1

### Phase 1 Results Summary

The Phase 1 screening did not identify any significantly impacted NPPD facilities for system intact conditions.

Several facilities were found to overload for N-1 conditions. These facilities would need to be uprated to accommodate the new generation interconnection facilities. These facilities are listed below:

- NPPD Twin Church – Sioux City\* 230 kV Line \*(WAPA Owns Sioux City terminal)
- NPPD Columbus East 230/115 kV Transformer
- NPPD Ogallala – Ogallala TSGT\*\* 115 kV Substation Tie \*\* (TSGT Owns Ogallala TSGT terminal)
- TSGT Ogallala – Grant 115 kV Line #1 (TSGT Owned Facility)

The Phase 1 screening did not discover any impacted bus voltages outside of limits for system intact or N-1 conditions.



## 5.2 Phase 2 Results (P2-P7 Events)

PSS/E activity ACCC was used as a screening tool on each of the base cases to identify those multiple element contingencies which deserve closer study. ACCC analyzed the system by sequentially taking select multiple element contingencies in the Nebraska area out-of-service. P2-P7 contingency events from these areas were utilized in this analysis. Transmission facilities in the NPPD, OPPD, and LES areas were then monitored for violations of loading or bus voltage criteria. The Phase 2 ACCC analysis is performed to assess the performance of the transmission system following the addition of the generation interconnection projects and proposed new network upgrades according to NERC standards.

### Phase 2 – 2018 Light Load

There were several impacted transmission facility overloads discovered under multiple element contingency conditions. There were no impacted bus voltages outside of limits that were discovered under multiple element contingency conditions.

Monitored Element Description	Rating	% Flow	Contingency Description
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	106	EE:345:NPPD:SUB-HOS-345
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	100	P22:115:NPPD:OAKLAND7:115KV
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	100	P22:115:NPPD:EMERSON7:115KV
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	103	P22:230:NPPD:HOSKINS4:230KV
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	102	P42:345:NPPD:BKR-CE-3306
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	103	P42:345:NPPD:BKR-SC-3306
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	132	P42:345:NPPD:BKR-HOS-3304
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	102	P71:345:NPPD:TWR-ETR-PH
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	102	P71:345:NPPD:TWR-ETR-SP
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	102	P71:345:NPPD:TWR-ETR-RS
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	102	P71:345:NPPD:TWR-ETR-CR
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	103	P71:345:NPPD:TWR-SCH-NH
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	105	P71:345:NPPD:TWR-SCH-CC
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	105	P71:345:NPPD:TWR-SCH-CM
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	106	P71:345:NPPD:TWR-SCH-MN

### Phase 2 – 2018 Spring Peak Load

There were several impacted transmission facility overloads discovered under multiple element contingency conditions. There were no impacted bus voltages outside of limits that were discovered under multiple element contingency conditions.

Monitored Element Description	Rating	% Flow	Contingency Description
G15087_T-FAIRBRY7 115.0 CKT 1.0	120	101	EE:345:NPPD:SUB-MOR-345
CRETE 7-FRIEND 7 115.0 CKT 1.0	137	110	EE:345:NPPD:SUB-MOR-345
FAIRBRY7-HARBINE7 115.0 CKT 1.0	99	108	EE:345:NPPD:SUB-MOR-345
TWIN CH4-SIOUXCY4 230.0 CKT 1.0	320	107	P42:345:NPPD:BKR-HOS-3304

### Phase 2 – 2018 Summer Peak

There were several impacted transmission facility overloads discovered under multiple element contingency conditions. There were no impacted bus voltages outside of limits that were discovered under multiple element contingency conditions.

Monitored Element Description	Rating	% Flow	Contingency Description
ENDERS 7-GRANTNB7 115 CKT 1	120	107	EE:345:NPPD:SUB-GGS-345
KEYSTON3-KEYSTONE T1 WND 2 CKT 1	336	108	EE:345:NPPD:SUB-GGS-345
KEYSTON7-KEYSTONE T1 WND 1 CKT 1	336	106	EE:345:NPPD:SUB-GGS-345
OGALALANPPD7-OGALALA7 115 CKT Z	239	105	EE:230:NPPD:SUB-GGS-230
OGALALANPPD7-OGALALA7 115 CKT Z	239	125	EE:230:NPPD:SUB-NP-230
OGALALANPPD7-OGALALA7 115 CKT Z	239	128	EE:345:NPPD:SUB-GGS-345
GRANTNB7-SPCREEK7 115 CKT 1	119	100	EE:345:NPPD:SUB-GGS-345
LAMAR 7-SPCREEK7 115 CKT 1	107	103	EE:345:NPPD:SUB-GGS-345
OGALALANPPD7-GRANTNB7 115 CKT 2	147	103	P22:115:NPPD:OGALALA7:WEST
OGALALANPPD7-OGALALA7 115 CKT Z	239	106	P22:115:NPPD:N.PLATT7:WEST
OGALALANPPD7-OGALALA7 115 CKT Z	239	107	P24:115:NPPD:N.PLATT7:1120
N.PLATT7-STOCKVL7 115 CKT 1	137	101	P42:345:NPPD:BKR-GGS-3322
OGALALANPPD7-OGALALA7 115 CKT Z	239	106	P42:115:NPPD:BKR-NP-1110
OGALALANPPD7-OGALALA7 115 CKT Z	239	106	P42:345:NPPD:BKR-GGS-3322
N.PLATT7-STOCKVL7 115 CKT 1	137	101	P71:345:NPPD:TWR-GS-GRW
OGALALANPPD7-OGALALA7 115 CKT Z	239	106	P71:345:NPPD:TWR-GS-GRW

### Phase 2 – 2018 Winter Peak

There were several impacted transmission facility overloads discovered under multiple element contingency conditions. There were no impacted bus voltages outside of limits that were discovered under multiple element contingency conditions.

Monitored Element Description	Rating	% Flow	Contingency Description
G15087_T-FAIRBRY7 115 CKT 1	120	114	EE:345:NPPD:SUB-MOR-345
BEVERLY7-ENDERS 7 115 CKT 1	160	105	EE:345:NPPD:SUB-GGS-345
CRETE 7-FRIEND 7 115 CKT 1	137	129	EE:345:NPPD:SUB-MOR-345
CRETE 7-SHELDON7 115 CKT 1	137	103	EE:345:NPPD:SUB-MOR-345
ENDERS 7-GRANTNB7 115 CKT 1	120	104	EE:345:NPPD:SUB-GGS-345
FAIRBRY7-HARBINE7 115 CKT 1	99	120	EE:345:NPPD:SUB-MOR-345
KEYSTON3-KEYSTONE T1 WND 2 CKT 1	336	101	EE:345:NPPD:SUB-GGS-345
KEYSTON7-KEYSTONE T1 WND 1 CKT 1	336	100	EE:345:NPPD:SUB-GGS-345
N.PLATT7-STOCKVL7 115 CKT 1	137	107	EE:345:NPPD:SUB-GGS-345
PAWNEEL7-SEWARD 7 115 CKT 1	120	100	EE:345:NPPD:SUB-MOR-345
TAMORA 7-YORK 7 115 CKT 1	137	105	EE:345:NPPD:SUB-MOR-345
N.PLATT7-STOCKVL7 115.0 CKT 1.0	137	104	P42:345:NPPD:BKR-GGS-3322
N.PLATT7-STOCKVL7 115.0 CKT 1.0	137	104	P71:345:NPPD:TWR-GS-GRW

## **Phase 2 Results Summary**

The Phase 2 screening identified several facilities that were loaded in excess of facility ratings for multiple element contingencies. Each of the contingencies and overloaded facilities may require curtailment of firm transmission and/or load shed to mitigate these issues. The Phase 2 screening did not discover any impacted bus voltages outside of limits for multiple element contingency conditions.

### **5.3 Phase 3 Results (N-2 Contingency Analysis)**

This phase of the analysis evaluated a select set of independent N-2 contingencies in the local area of the generation interconnection projects. PSS/E activity ACCC was used as a screening tool on the 2016 Winter Peak model with the generation interconnection projects to identify those contingencies which deserve closer study. ACCC analyzed the system by sequentially taking out all independent N-2 contingencies in the local area and monitoring facilities in the NPPD, OPPD, and LES areas for violations of loading or bus voltage criteria.

#### Phase 3 – (Independent N-2 Contingencies)

There were a number of overloaded transmission facilities discovered in the monitored study areas in the independent N-2 ACCC analysis of the 2016 Spring Peak, Light Load, and Winter Peak cases with the generation interconnection additions. Prior outage generation restrictions would be required to ensure the transmission system is able to be operated reliably when certain transmission lines are taken out-of-service. The generation interconnection project curtailments will be subject to “first on, last off” curtailment priorities and operating guides will need to be developed to ensure the transmission system is operated in accordance with mandatory reliability standards. Based on a review of the N-2 contingencies that were flagged in the ACCC analysis, the following list was prepared of transmission facilities that would need detailed prior outage review or operating guides established if all the projects are developed. These transmission facilities were found to be part of an N-2 contingency pairing that resulted in a facility overload on the NPPD transmission system.

### Limiting Prior Outage Facilities

1.	POSTROCK7	345.00-G16-050-TAP	345.00	38.	HOSKINS4	230.00-HOSK.T89	34.500
2.	NOB HL3	115.00-STEELEC7	115.00	39.	HOSKINS7	115.00-NORFK.N7	115.00
3.	G15087_T	115.00-FAIRBRY7	115.00	40.	HOSKINS7	115.00-NORFOLK7	115.00
4.	G15087_T	115.00-HEBRN N7	115.00	41.	HOSKINS7	115.00-STNTN.N7	115.00
5.	G15088_T	345.00-MOORE 3	345.00	42.	KEYSTON3	345.00-SIDNEY1-LNX3	345.00
6.	G15088_T	345.00-PAULINE3	345.00	43.	MCCOOL 3	345.00-MOORE 3	345.00
7.	G1623&1629-T3	345.00-KEYSTON3	345.00	44.	NELIGH 7	115.00-PETERSBRG.N7	115.00
8.	G1623&1629-T3	345.00-LARAMIE3	345.00	45.	NELIGH 7	115.00-ANTELOPE	7115.00
9.	G1623&1629-T3	345.00-SIDNEY2-LNX3	345.00	46.	NORFK.N7	115.00-NORFOLK7	115.00
10.	G16-050-TAP	345.00-AXTELL 3	345.00	47.	PETRSBG7	115.00-PETERSBRG.N7	115.00
11.	G10-51T	230.00-HOSKINS4	230.00	48.	TWIN CH7	115.00-S.SIOUXCITY7	115.00
12.	G10-51T	230.00-TWIN CH4	230.00	49.	VICTRYH4	230.00-STEGALL4	230.00
13.	ALBION 7	115.00-FULERTN7	115.00	50.	WAYSIDE4	230.00-NUNDRWD4	230.00
14.	ALBION 7	115.00-GENOA 7	115.00	51.	THEDFRD3	345.00-HOLT.CO3	345.00
15.	ALBION 7	115.00-PETRSBG7	115.00	52.	HOLT.CO3	345.00-GR ISLD-LNX3	345.00
16.	ALBION 7	115.00-SPALDNG7	115.00	53.	STEGALL4	230.00-STEGALL-LNX3	230.00
17.	AXTELL 3	345.00-PAULINE3	345.00	54.	LARAMIE3	345.00-STEGALL3	345.00
18.	AXTELL 3	345.00-SWEET W3	345.00	55.	HARBINE7	115.00-STEELEC7	115.00
19.	BATTLCR7	115.00-CO.LINE7	115.00	56.	HEBRN N7	115.00-HEBRON 7	115.00
20.	BATTLCR7	115.00-NORFK.N7	115.00	57.	MOORE 3	345.00-SHELDON7	115.00
21.	BEATRCE7	115.00-HARBINE7	115.00	58.	MOORE 3	345.00-NW68HOLDRG3	345.00
22.	BEATRCE7	115.00-STEINER7	115.00	59.	PAULINE3	345.00-PAULINE7	115.00
23.	BELDEN 7	115.00-HARTGTN7	115.00	60.	SIDNEY 3	345.00-SIDNEY1-LNX3	345.00
24.	BELDEN 7	115.00-HOSKINS7	115.00	61.	SIDNEY 3	345.00-STEGALL3	345.00
25.	BELDEN 7	115.00-TWIN CH7	115.00	62.	HOSKINS3	345.00-HOSKINS4	230.00
26.	BLMFLD 7	115.00-CREITON7	115.00	63.	HOSKINS3	345.00-HOSKINS7	115.00
27.	BLMFLD 7	115.00-GAVINS 7	115.00	64.	HOSKINS4	230.00-HOSKINS7	115.00
28.	CARLJCT7	115.00-HEBRN N7	115.00	65.	TWIN CH4	230.00-TWIN CH7	115.00
29.	CLRWATR7	115.00-NELIGH 7	115.00	66.	HOLT.CO3	345.00-GRPRAR1-LNX3	345.00
30.	CO.LINE7	115.00-ANTELOPE	7115.00	67.	ANTELOPE	3345.00-ANTELOPE	7115.00
31.	COOPER 3	345.00-MOORE 3	345.00	68.	GR PRAIRIE	3345.00-GRPRAR1-LNX3	345.00
32.	CREITON7	115.00-ANTELOPE	7115.00	69.	GR PRAIRIE	3345.00-GRPRAR2-LNX3	345.00
33.	EMERSON7	115.00-TWIN CH7	115.00	70.	STEGALL4	230.00-STGXFMR4	230.00
34.	FAIRBRY7	115.00-HARBINE7	115.00	71.	WAYSIDE4	230.00-STEGALL-LNX3	230.00
35.	GENTLMN3	345.00-KEYSTON3	345.00	72.	STEGALL7	115.00-STEGALL3	345.00
36.	HARTGTN7	115.00-GAVINS 7	115.00	73.	STEGALL3	345.00-STGXFMR4	230.00
37.	HOSKINS3	345.00-ANTELOPE	3345.00				

### Phase 3 Results Summary

There were several independent N-2 contingencies that resulted in overloads and would require prior-outage generation limitations to mitigate the identified issues if all the proposed projects are developed. Future planned outages of the facilities listed above could result in significant curtailment of the output levels for the proposed generation interconnection facilities.

## 6.0 Short Circuit Analysis

### 6.1 Model Development

#### Computer Programs

The Aspen OneLiner software program was utilized to perform short circuit simulations and studies on the transmission system. Where elements were added to the short-circuit model, best estimates for impedance parameters were used based on available data and typical modeling practices. Short-circuit calculation options used were as follows:

- Flat voltage profile with  $V(\text{pu}) = 1.0$
- Generator Impedance = Subtransient
- Ignore loads, transmission line  $G+jB$ , and shunts with positive sequence values

OneLiner was used to calculate three-phase (3PH) and single-line-to-ground (SLG) system-intact bus fault currents for all system buses associated with interrupting devices being evaluated in this study. For devices that the full bus fault current approached or exceeded the device's interrupting rating, more detailed fault calculations were done, calculating the maximum phase current through the breaker for close-in faults, close-in faults with the remote end open, and bus faults with all other branches to the bus open. The maximum phase current of these faults was recorded. For comparison with the breaker interrupting ratings, maximum phase current was multiplied by a factor of 1.05 to account for the possibility of the system operating at up to the maximum normal operating voltage of 1.05 per-unit.

#### Base System Model Additions (“Base Case”)

The base system model used by the transmission system protection department as of March 21, 2018 was used as the starting point for the short-circuit model used for this study. The base system model included all projects that were in-service at the time the model was copied. All Nebraska-area generation in the short-circuit model was enabled in order to provide maximum short-circuit current. For the study base case, planned system upgrades in the area of the studied projects and prior-queued large generator interconnections expected to be in-service prior to the projects being studied were added to the base case model. The following table lists the prior-queued large generator interconnections that were added to the base model for this study.

### Prior Queued Large Generator Interconnections

Queue Designation	Proposed POI	Capacity (MW)
GEN-2010-051	Dixon County 230kV	200
GEN-2011-027	Dixon County 230kV	120
GEN-2013-032	Antelope 115kV	204
GEN-2014-039	Friend 115kV	73.4
GEN-2015-007	Hoskins 345 kV	160
GEN-2015-023	Holt County 345kV	300.7
GEN-2015-053	Antelope 115 kV	50
GEN-2015-076	Belden 115 kV	158.4
GEN-2015-087	Belvedere 115 kV (Hebron-Fairbury)	66
GEN-2015-088	Tobias 345 kV (Pauline-Moore)	300

In addition to the prior-queued large generator interconnections, planned system upgrades in the area of the studied projects were added to the base model. The planned 345 kV line from GGS – Thedford – Holt County was included with a 345 – 115 kV tie transformer at Thedford 115 kV. The planned 115 kV line from Ord to Broken Bow Wind/Muddy Creek substation was included. The planned Monolith 345 – 115 kV tie adjacent to Mark Moore 345 kV / Sheldon 115 kV was also included.

### Model Additions for Projects Being Studied (“Study Case”)

The base-case study model was modified to include the new generation interconnections being considered in this study as well as the system upgrades identified to accommodate this additional generation. The following table lists the large generator interconnections that were added to the study-case model for this study.

### Large Generator Interconnections Added to Study Case

Queue Designation	Proposed POI	Capacity (MW)
GEN-2015-089	WAPA Utica Junction 230kV	200
GEN-2016-021	NPPD Hoskins 345kV	300
GEN-2016-023	WAPA Interconnect Laramie River – Sidney (Banner Co) 345kV	150.5
GEN-2016-029	WAPA Interconnect Laramie River – Sidney (Banner Co) 345kV	150
GEN-2016-043	NPPD Hoskins 345kV	230
GEN-2016-050	NPPD Interconnect Axtell- Post Rock (Macon) 345kV	250.7
GEN-2016-075	WAPA Grand Prairie 345kV	50

The study model also includes the network upgrades of the Banner County - Keystone 345 kV (170 miles) and Keystone - Gentleman 345 kV CKT 2 (30 miles).

## 6.2 Study Methodology

Circuit breaker, circuit switcher, and fuse ratings were identified by querying NPPD's SAP equipment database and extracting equipment data including short-circuit ratings. Breaker ratings given on an asymmetrical (total current) basis were converted to symmetrical current ratings using an assumed maximum system operating voltage of 1.05 per unit.

The calculated short-circuit current at the equipment bus was extracted from the short-circuit results from Aspen OneLiner and compared against the interrupting device interrupting rating. It is recommended that all equipment be replaced if it is found to be at or above 95% of its interrupting rating and seeing an increase of 1% or more in its interrupting duty as a result of the studied projects.

## 6.3 Results

The following devices were found to be above 95% of their interrupting rating due to the addition of the projects considered in this study and are recommended for replacement.

Location – Circuit Switcher	Manuf.	Model Number	Interrupting Rating	Max Expected Interrupting (A)	Max Current (% of Rating)	Relative Change (%)
<b>COLUMBUS EAST 1110</b>	S&C	2030	25000	24210	<b>97%</b>	1.7%
<b>COLUMBUS EAST 1112</b>	S&C	2030	25000	24210	<b>97%</b>	1.7%

NOTE: The Columbus East equipment listed above is owned by Loup Power District, not Nebraska Public Power District.



## 7.0 Stability Analysis

### 7.1 Model

The stability case was created from the 2016 Winter Peak power flow base case from the 2015 Series SPP MDWG dynamics package. The power flow base case includes re-dispatched western Nebraska resources to maximum output with the various western NE/SD DC ties flowing at maximum capacity from west to east. The net generation and DC tie dispatch levels are listed below:

GGs #1	=	678.0 MW
GGs #2	=	700.0 MW
Laramie River Station #1	=	570.0 MW
Sidney DC West-to-East	=	200.0 MW
Stegall DC West-to-East	=	110.0 MW
Rapid City DC West-to-East	=	200.0 MW
Kingsley Hydro #1	=	50.0 MW

Additional wind generation to the north and south of NPPD was dispatched to provide a worst-case system bias of west to east across the NPPD system and establish a GGS Eastflow transfer level of 1850 MW. Next, additional prior queued wind generation resources in eastern Nebraska were added to the base model as well as the R-project (GGs-Thedford-Holt County 345 kV). Finally, the new DISIS-2016-001-1 generation interconnection projects were added to the base model. The following lists the Nebraska area wind generation dispatched in the base model.

GI #	MW	Substation or Line
GEN-2003-021N	59.4	Ainsworth Wind Tap 115kV
GEN-2006-020N	42.0	Bloomfield 115kV
GEN-2006-037N1	75.0	Broken Bow 115kV
GEN-2006-038N005	80.0	Broken Bow 115kV
GEN-2006-038N019	80.0	Petersburg North 115kV
GEN-2006-044N	40.5	North Petersburg 115kV
GEN-2007-011N08	81.0	Bloomfield 115kV
GEN-2008-086N02	201.0	Meadow Grove 230kV
GI-0717	166.0	WAPA Grand Prairie 345kV
GI-0718	234.0	WAPA Grand Prairie 345kV
GEN-2008-123N	89.7	Rosemont
GEN-2010-051	200.0	Tap Twin Church - Hoskins 230kV
GEN-2011-018	73.6	Steele City 115kV
GEN-2011-027	120.0	Tap Twin Church @ Hoskins 230kV
GEN-2013-008	1.2	Steele City 115kV
GEN-2013-032	204.0	Antelope 115 kV
GEN-2014-013	73.5	Meadow Grove (GEN-2008-086N2 Sub) 230kV
GEN-2014-031	35.8	Meadow Grove 230kV
GEN-2014-039	73.4	Friend
GEN-2015-007	160.0	Hoskins 345 kV
GEN-2015-023	300.7	Holt County 345kV substation
GEN-2015-053	50	Antelope 115 kV
GEN-2015-076	158.4	Belden
GEN-2015-087	76	Belvedere
GEN-2015-088	300	Tobias
GEN-2015-089	200	WAPA Utica Junction 230kV
GEN-2016-021	300	Hoskins 345kV
GEN-2016-023	150.5	WAPA Interconnect Laramie River – Sidney (Banner Co) 345kV
GEN-2016-029	150	WAPA Interconnect Laramie River – Sidney (Banner Co) 345kV
GEN-2016-043	230	Hoskins 345kV
GEN-2016-050	250.7	Interconnect Axtell- Post Rock (Macon) 345kV
GEN-2016-075	50	WAPA Grand Prairie 345kV
	2975.2	prior-queued DISIS-2016-001
	<u>1331.2</u>	included in DISIS-2016-001
	4306.4	Total Wind

## 7.2 Results (P1-P7 and Extreme Events)

To assess the impact of the generation interconnection projects, a number of Planning Event and Extreme Event faults were evaluated on the base model. Localized faults near the interconnection locations were considered as well as worst-case faults for the GGS Stability Interface. The stability simulations performed are listed in the table titled, *Disturbance Code Description and Summary Results*. The list of contingencies was developed in accordance with the methodologies described previously in this report. Summary of findings for the disturbances applied in this study can be found in the table. All the NPPD area contingencies listed in the table were performed on the base model. The complete study results are available upon request subject to CEII restrictions. Worst-case critical disturbances that are expected to produce more severe system impacts on the NPPD transmission system were simulated in the stability analysis included in this assessment. Disturbances applicable to NERC Standard TPL-001-4 demonstrated a stable system response with acceptable transient voltage swings for all Planning Events (P1-P7) and Extreme Events that were evaluated. A total of 53 separate disturbance runs were performed for this stability analysis.

### **7.3 Stability Analysis Summary**

Based on the results of this analysis, the NPPD transmission system meets the stability performance requirements for all Planning Event and Extreme Event conditions that were considered in this study.

FAULT CODE	NERC CATEGORY	FAULT DESCRIPTION	2016 WIPK	
			STABILITY RESULTS	VOLTAGE RESULTS
2008	P1.2	3PH FAULT ON GENTLMN4-N.PLATT4	STABLE	NO TVV
2014	P1.2	3PH FAULT ON HOSKINS4-TWIN CH4	STABLE	NO TVV
2016	P1.2	3PH FAULT ON TWIN CH4-SIOUXCY4	STABLE	NO TVV
2018	P1.2	3PH FAULT ON MEADOWGROVE4-PR BRZ 4	STABLE	NO TVV
2019	P1.2	3PH FAULT ON MEADOWGROVE4-FTRANDL4	STABLE	NO TVV
3001	P1.2	3PH FAULT ON POSTROCK7-AXTELL 3	STABLE	NO TVV
3002	P1.2	3PH FAULT ON MINGO 7-REDWILO3	STABLE	NO TVV
3004	P1.2	3PH FAULT ON RAUN 3-HOSKINS3	STABLE	NO TVV
3005	P1.2	3PH FAULT ON AXTELL 3-PAULINE3	STABLE	NO TVV
3006	P1.2	3PH FAULT ON AXTELL 3-SWEET W3	STABLE	NO TVV
3007	P1.2	3PH FAULT ON COLMB.E3-SHELCKR3	STABLE	NO TVV
3008	P1.2	3PH FAULT ON COLMB.E3-NW68HOLDRG3	STABLE	NO TVV
3010	P1.2	3PH FAULT ON GENTLMN3-KEYSTON3	STABLE	NO TVV
3011	P1.2	3PH FAULT ON GENTLMN3-REDWILO3	STABLE	NO TVV
3012	P1.2	3PH FAULT ON GENTLMN3-SWEET W3	STABLE	NO TVV
3013	P1.2	3PH FAULT ON GENTLMN3-SWEET W3	STABLE	NO TVV
3014	P1.2	3PH FAULT ON HOSKINS3-SHELCKR3	STABLE	NO TVV
3015	P1.2	3PH FAULT ON HOSKINS3-ANTELOPE 3	STABLE	NO TVV
3018	P1.2	3PH FAULT ON MCCOOL 3-GR ISLD3	STABLE	NO TVV
3019a	P1.2	3PH FAULT ON MOORE 3-TOBIAS 3	STABLE	NO TVV
3019b	P1.2	3PH FAULT ON TOBIAS 3-PAULINE3	STABLE	NO TVV
3020	P1.2	3PH FAULT ON SWEET W3-GR ISLD3	STABLE	NO TVV
3021	P1.2	3PH FAULT ON HOLT.CO3-THEDFRD3	STABLE	NO TVV
3022	P1.2	3PH FAULT ON HOLT.CO3-GRPRAR1-LNX3	STABLE	NO TVV
3023	P1.2	3PH FAULT ON HOLT.CO3-GR ISLD3	STABLE	NO TVV
3024	P1.2	3PH FAULT ON GENTLMN3-THEDFRD3	STABLE	NO TVV
3025	P1.2	3PH FAULT ON GRPRAR2-LNX3-FTTHOM2-LNX33	STABLE	NO TVV
2020	P1.2	3PH FAULT ON HOSKINS4-G10-51T	STABLE	NO TVV
2021	P1.2	3PH FAULT ON G10-51T-TWIN CH4	STABLE	NO TVV
4009	P1.3	3PH FAULT ON HOSKINS T1	STABLE	NO TVV
4023	P1.3	3PH FAULT ON HOSKN T4	STABLE	NO TVV
4029	P1.3	3PH FAULT ON ANTELOPE T1	STABLE	NO TVV
4033	P1.3	3PH FAULT ON GGS T2	STABLE	NO TVV
4034	P1.3	3PH FAULT ON GI KU3A	STABLE	NO TVV
4035	P1.3	3PH FAULT ON HOSKINS T2	STABLE	NO TVV

FAULT CODE	NERC CATEGORY	FAULT DESCRIPTION	2016 WIPK	
			STABILITY RESULTS	VOLTAGE RESULTS
4036	P1.3	3PH FAULT ON SHELLCREEKT1	STABLE	NO TVV
7154	P4.2	SLG Fault on GENTLMN3-SWEET W3; Delayed Clear; GENTLMN3-THEDFRD3	STABLE	NO TVV
7005	P4.2	SLG Fault on GENTLMN3-SWEET W3; Delayed Clear; GENTLMN3-REDWILO3	STABLE	NO TVV
7008	P4.2	SLG Fault on GENTLMN3-KEYSTON3; Delayed Clear; GGS T2	STABLE	NO TVV
7017	P4.2	SLG Fault on GENTLMN4-N.PLATT4; Delayed Clear; N.PLATT4-GENTLMN4	STABLE	NO TVV
7020	P4.2	SLG Fault on GENTLMN4-OGALALA4; Delayed Clear; GGS T2	STABLE	NO TVV
7071	P4.2	SLG Fault on HOSKINS3-SHELCKR3; DELAYED Clear; HOSKINS T4	STABLE	NO TVV
7072	P4.2	SLG Fault on HOSKINS3-SHELCKR3; DELAYED Clear; HOSKINS T2	STABLE	NO TVV
7073	P4.2	SLG Fault on HOSKINS3-RAUN 3; DELAYED Clear; HOSKINS T2	STABLE	NO TVV
7074	P4.2	SLG Fault on HOSKINS3-RAUN 3; DELAYED Clear; HOSKINS T4	STABLE	NO TVV
7164	P4.2	SLG Fault on HOLT.CO3-GRPRAR1-LNX3; DELAYED Clear; HOLT.CO3-GR ISLD-LNX3	STABLE	NO TVV
7165	P4.2	SLG Fault on HOLT.CO3-GR ISLD-LNX3; DELAYED Clear; HOLT.CO3-THEDFRD3	STABLE	NO TVV
7012	P7.1	SLG Fault on GENTLMN3-SWEET W3 and GENTLMN3-REDWILO3 Double Circuit	STABLE	NO TVV
7024	P7.1	SLG Fault on GENTLMN4-N.PLATT4 and GENTLMN4-N.PLATT4 Double Circuit	STABLE	NO TVV
7077	P7.1	SLG Fault on HOSKINS3-SHELCKR3 and MADISON7-NORFOLK7 Double Circuit	STABLE	NO TVV
7078	P7.1	SLG Fault on HOSKINS3-SHELCKR3 and HOSKINS7-NORFOLK7 Double Circuit	STABLE	NO TVV
7156	Extreme Event	SLG Fault on GENTLMN3-SWEET W3 and GENTLMN3-SWEET W3 Cross Point	STABLE	NO TVV
7160	Extreme Event	SLG Fault on GRPRAR2-LNX3-FTTHOM2-LNX33 and MEADOWGROVE4-FTRANDL4 Cross Point	STABLE	NO TVV
7161	Extreme Event	SLG Fault on HOSKINS3-RAUN 3 and HOSKINS4-TWIN CH4 Cross Point	STABLE	NO TVV

## 8.0 Detailed Cost Estimates & Project Schedule

NPPD's Engineering, Asset Management, and Project Management groups have reviewed the list of interconnection facility upgrades that are required for DISIS-2016-001-1 projects. Detailed cost estimates have been prepared for the facility upgrades that were identified in the system impact study for the requests. The prepared cost estimates are budgetary level estimates (+75%/-25%) and assume implementation of standard NPPD construction and procurement practices. The cost estimates for the interconnection facilities and network upgrades are below:

### Interconnection Facilities

- GEN-2016-021: Construct satellite 345 kV Substation near Hoskins 345 kV substation to accommodate new GI.  
**\$ 7,250,000\***
- GEN-2016-043: Construct satellite 345 kV Substation near Hoskins 345 kV substation to accommodate new GI.  
**\$ 7,250,000\***
- GEN-2016-050: Construct Macon 345 kV Substation to accommodate new GI.  
**\$ 16,500,000**

*\*Total Cost for satellite substation is \$14,500,000*

### Network Upgrades

- Construct Banner County – Keystone 345 kV line & substation expansions.  
**\$ 260,000,000**
- Construct Keystone – GGS 345 kV line & substation expansions.  
**\$ 69,750,000**
- Install 10 MVAR cap bank at SUNC Atwood 115 kV substation.  
**\$ TBD**
- Upgrade Columbus East 230/115 kV Transformer.  
**\$ 4,250,000**

- Upgrade Twin Church – Sioux City 230 kV Line (NPPD portion).  

**\$ 3,300,000**
- Upgrade Twin Church – Sioux City 230 kV Line (WAPA portion).  

**\$ TBD**
- Upgrade Ogallala NPPD – Ogallala TSGT 115 kV substation tie (NPPD portion).  

**\$ 50,000**
- Upgrade Ogallala NPPD – Ogallala TSGT 115 kV substation tie (TSGT portion).  

**\$ TBD**
- Upgrade Ogallala – Grant 115 kV Line #1 (TSGT portion).  

**\$ TBD**
- Upgrade Columbus East 1110 and 1112 Circuit Switchers (Loup Power District).  

**\$ 200,000**

The results of DISIS-2016-001-1 documented that these two requests are contingent on the completion of the following previously-allocated required network upgrades:

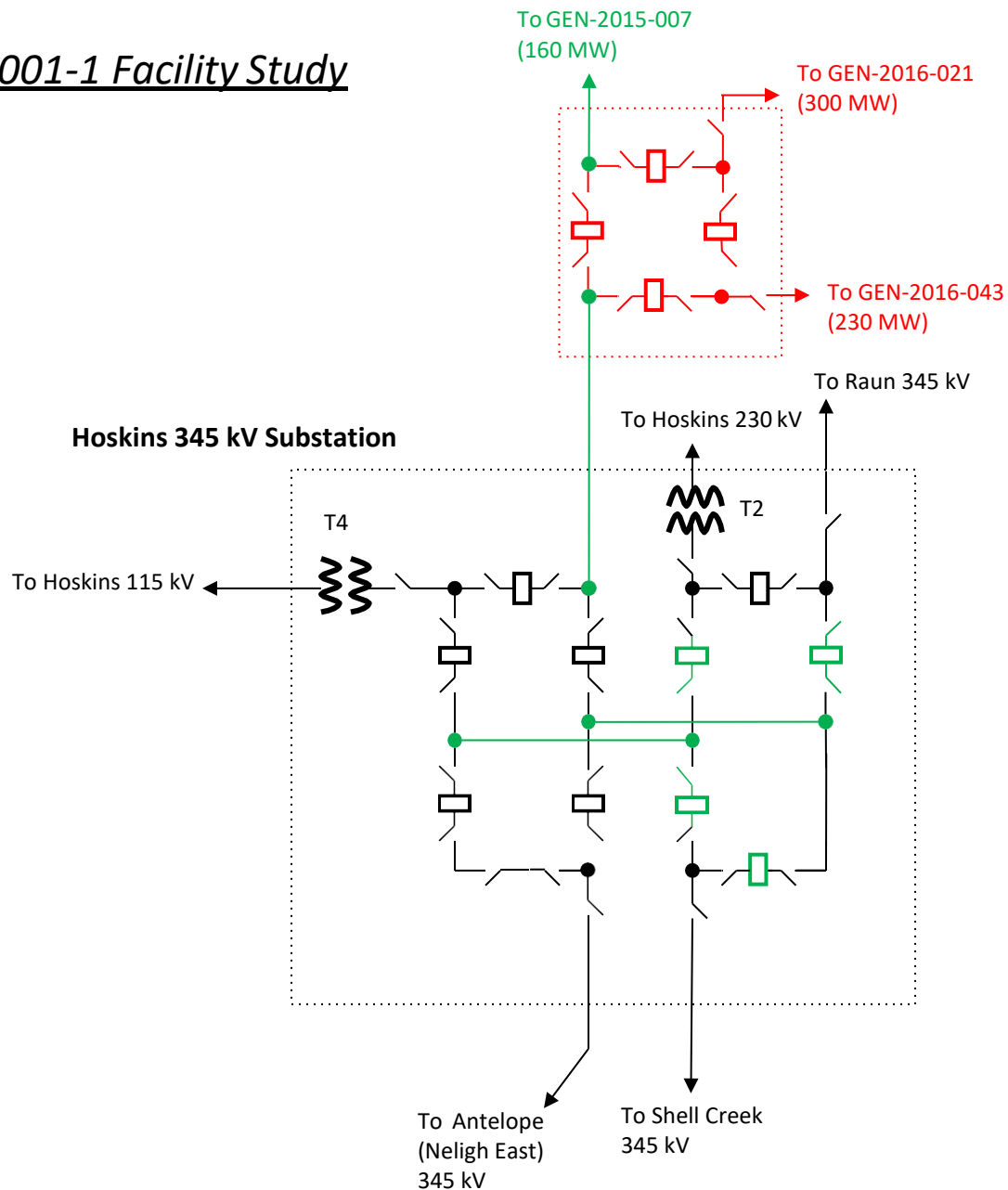
- Hoskins – Neligh (Antelope) 345/115 kV Transmission expansion project
- Gentleman – Thedford - Holt County (R-Project) and Thedford 345/115 kV Transformer project

The substation one-line diagrams highlighting the required facility upgrades for each generator interconnection are on the following pages. NPPD will work with the generation interconnection projects to develop project schedules for the interconnection facilities and network upgrade projects listed above during the development of the generation interconnection agreement. Typical implementation schedules for new transmission lines ( $\geq 115$  kV) are roughly 4 years or longer to accommodate the public routing process and construction schedules. For the DISIS-2016-001-1 network upgrades (Banner County – Keystone – GGS), the construction schedule will likely be much longer ( $> 6$  Years) due to the length of the projects and complex project scope. Substation additions require less land acquisition and typically can be implemented in less time or approximately 2-3 years. Project schedule details will be further discussed in the development of the generator interconnection agreement (GIA) and the milestones associated with the generation interconnection projects.

It should also be noted that the interconnection plan for the DISIS-2016-001-1 generation projects are dependent on the transmission upgrades/additions that are required as part of the previous SPP DISIS GI Studies and SPP ITP Studies. If there are any modifications to these previous studies and related upgrades, then the interconnection plan for the DISIS-2016-001-1 projects could be affected. There is no interconnection capacity for the DISIS-2016-001-1 projects without the previously identified upgrades.



## DISIS-2016-001-1 Facility Study



● DISIS-2015-001 Interconnection Facilities for GEN-2015-007

● DISIS-2016-001 Interconnection Facilities for GEN-2016-021 and GEN-2016-043

