Southwest Power Pool

Modification Request For Generator Interconnection Request GEN-2011-027

SPP Generator Interconnection Studies

GEN-2011-027

November 2013

Executive Summary

The GEN-2011-027 interconnection customer has requested a system impact restudy to determine the impacts of modifying the interconnection configuration and effects of changing wind turbine generators from the previously studied Nordex 2.5MW wind turbine generators to a combination of GE1.7MW and GE 1.85MW wind turbine generators. Modification requests are performed under GIP Section 4.4. POWER-tek Global Inc. (POWER-tek) was commissioned to perform this restudy, and a report of the results is attached.

In this restudy the project uses sixty (60) GE 1.85MW and five (5) GE 1.7MW wind turbine generators for an aggregate power of 119.5MW and is located in Dixon County, Nebraska. For this study the interconnection configuration of GEN-2011-027 was modified from a separate generator lead to being collocated with GEN-2010-051 and sharing a common generator lead from the generators to the point of interconnection (POI), a new 230kV substation on the Hoskins to Twin Church 230kV line (proposed Dixon County Substation). The interconnection restudy request shows that both models of GE wind turbine generators will have the optional +/-0.90 power factor capabilities installed.

The restudy showed that no stability problems were found during the summer and the winter peak conditions as a result of changing to the GE 1.85MW and GE 1.7MW wind turbine generators. Additionally, the project wind farm was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

A power factor analysis was performed in this study. The facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VARs) power factor at the POI.

It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator[s] may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. Because of this, it is likely that the **Customer may be required to reduce their generation output to 0 MW under certain system conditions** to allow system operators to maintain the reliability of the transmission network.

With the assumptions outlined in this report and with all the required network upgrades from the GEN-2011-027 GIA in place, GEN-2011-027 should be able to reliably interconnect to the SPP transmission grid. The requested modifications by the Interconnection Customer are acceptable under GIP Section 4.4.

Nothing in this study should be construed as a guarantee of transmission service. If the customer wishes to obtain deliverability to a specific customer, a separate request for transmission service shall be requested on Southwest Power Pool's OASIS by the Customer.

Southwestern Power Pool Inc. (SPP)

Definitive Impact Study

GEN-2011-027 System Impact Restudy (GE 1.85MW & 1.7MW)

Draft Report Submitted to
Southwest Power Pool Inc.
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1. Executive Summary

This report presents the results of impact study comprising of power factor and stability analyses of the proposed interconnection projects under GEN-2011-027 GE 1.85 MW (the Project) as described in the following table.

Table 1.1: Interconnection Request

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2011-027	119.5	GE 1.85MW and 1.7MW (60 1.85MW wind turbines and 5 1.7MW wind turbines) (580020)	Tap on the GEN-2010-051 - Hoskins 230kV line (560347)

Power factor analysis and transient stability simulations were performed for the Project in service at its full output. SPP provided three base cases for summer and winter conditions for year 2014, and summer conditions for year 2023, respectively, each comprising of a power flow and corresponding dynamics database. The previous queued request projects are already modeled in the base cases.

The power factor analysis consists of running all N-1, three phase contingencies shown in the Fault Definitions table (Table 3 in the RFP) in power flow to advise the necessary power factor at the point of interconnection (POI) for each contingency.

The power factor analysis indicates that interconnection request GEN-2011-027 will be required to provide 0.99 lagging (supplying vars) and 1.00 leading (absorbing vars) power factor at the Point Of Interconnection (POI) (Tap on the GEN-2010-051 - Hoskins 230kV line-560347) based on the contingencies studied. Per the SPP OATT, the Interconnection Customer will be required to provide 95% lagging (supplying vars) and 95% leading (absorbing vars) at the POI.

There are no impacts on the stability performance of the SPP system for the contingencies simulated on the supplied base cases. The study Project stayed on-line and stable for all simulated faults. The Project stability simulations with Fifty One (51) specified test disturbances did not show instability problems in the SPP system and oscillations were damped out.

2. Introduction

2.1. Project Overview and Assumptions

The GEN-2011-027 Impact Study is a generation interconnection study performed by POWER-tek Global Inc. for Southwest Power Pool (SPP). This report presents the results of impact study comprising of power factor and stability analyses of the proposed interconnection project under GEN-2011-027 ("The Project") as described in Table 1.1 below:

Table 1.1: Interconnection Requests

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2011-027	119.5	GE 1.85MW and 1.7MW (60 1.85MW wind turbines and 5 1.7MW wind turbines) (580020)	Tap on the GEN-2010-051 - Hoskins 230kV line (560347)

Figure 1.1 shows the single line diagram for the interconnection of the Project to present and planned system of SPP. This arrangement was modeled and studied in power flow cases for this Project.

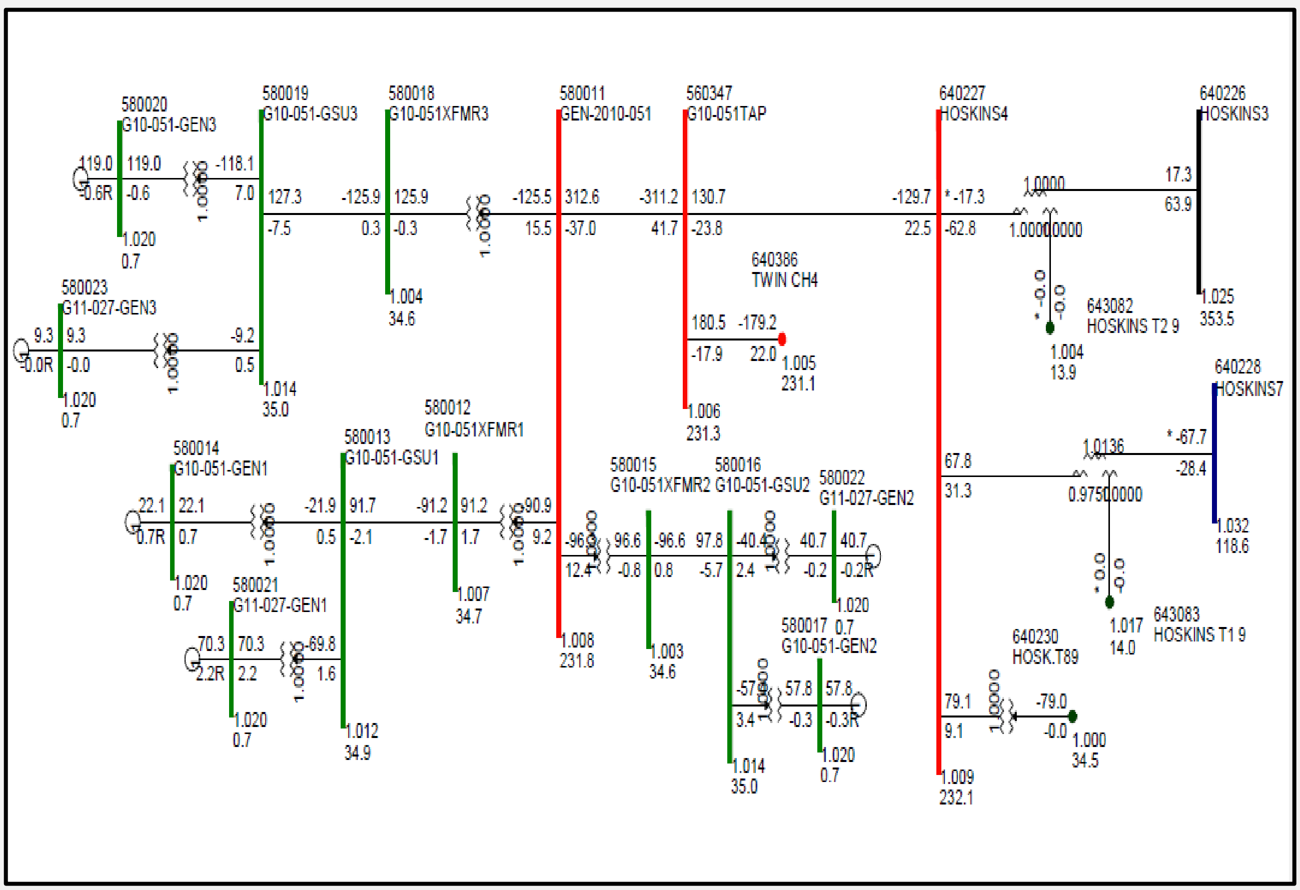

Figure 1.1: Power Flow Single Line Diagram for GEN-2011-027 and surrounding system components

Appendix-D contains the machines, interconnection, and machine user model parameters.

Table 1.2 below shows the list of prior queued projects modeled in the base case.

Table 1.2: List of previous queued request projects

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2011-018	73.6	Siemens 2.3MW	Steele County 115kV (640426)
GEN-2011-056A	3.6 MW increase (Pmax=21.6MW)	GENSAL	Johnson 1 115kV (640240)
GEN-2011-056B	4.5 MW increase (Pmax=23.5MW)	GENSAL	Johnson 2 115kV (640242)
GEN-2003-021N	75	GE 1.5MW	Tap on the Ainsworth – Calamus 115kV line (640050)
GEN-2004-005N	30	GE 1.5MW	St Francis 115kV (640351)
GEN-2004-023N	75	GENROU	Columbus 115kV (640119)
GEN-2006-020N	42	Vestas 3.0MW	Bloomfield 115kV (640084)
GEN-2006-037N1	75	GE 1.5MW	Broken Bow 115kV (640089)
GEN-2006-038N005	79.5	GE 1.5MW	Broken Bow 115kV (640089)
GEN-2006-038N019	79.5	Generic wind turbine 1.5MW	Petersburg 115kV (640444)
GEN-2006-044N	40.5	GE 1.5MW	Petersburg 115kV (640444)
GEN-2007-011N08	81	Vestas 3.0MW	Bloomfield 115kV (640084)
GEN-2008-086N02	199.5	GE 1.5MW	Tap on the Columbus – Ft Randall 230kV line (560006)
GEN-2008-119O	60	GE 1.5MW	S1399 161kV (646399)
GEN-2008-123N	89.7	Siemens 2.3MW	Tap on the Pauline – Guide Rock 115kV (560137)
GEN-2009-040	73.8	Vestas V90 1.8MW	Marshall 115kV (533349)
GEN-2010-041	10.5	GE 1.5MW	S1399 161kV (646399)
GEN-2010-044	99	Siemens 3.0MW	Harbine 115kV (640208)
GEN-2010-051	199.65	GE 1.7MW and GE 1.85MW	Tap on the Twin Church – Hoskins 230kV line (560347)

ATC (Available Transfer Capability) studies were not performed as part of this study. These studies will be required at the time transmission service is actually requested. Additional transmission upgrades may be required based on that analysis.

Study assumptions in general have been based on the specific information and data provided by SPP. The accuracy of the conclusions contained within this study is dependent on the assumptions made with respect to other generation additions and transmission improvements planned by other entities. Changes in the assumptions of the timing of other generation additions or transmission improvements may affect this study's conclusions.

2.2. Objectives

The objectives of the study are to conduct power factor analysis and to determine the impact on system stability of interconnecting the proposed wind farm to SPP's transmission system.

2.3. Models and Simulations Tools Used

Version 32 of the Siemens, PSS/E^{TM} power system simulation program was used in this study.

SPP provided its latest stability database cases for both summer and winter peak seasons for year 2014, and summer peak case for year 2023. The Project's PSS/E model had been developed prior to this study and was included in the power flow case and the dynamics database. Machine, interconnection and dynamic model data for the Project plant is provided in Appendix D.

Power flow single line diagram of the projects in summer peak condition is shown in Figure 1.1. This Figure shows that wind farm model includes representation of the radial transmission line, the substation transformer from transmission voltage to 34.5V and 230 kV respectively. The remainder of each wind farm is represented by lumped equivalents including a generator, a step-up transformer, and collector system impedance.

No special modeling is required of line relays in these cases, except for the special modeling related to the wind-turbine tripping.

All generators in Areas 531, 534, 536, 540, 541, 640, 645, 650, and 652 were monitored. Additionally, adjacent generating units in the WAPA system have been monitored.

3. Power Factor Analysis

3.1. Methodology

Power factor analysis was conducted for the Project using the following methodology:

1. Replace the wind farm by a generator at the high side bus 345 kV, 138 kV, or 69 kV bus, as applicable, with the MW of the wind farms at that point of interconnection and with no var capability (both GEN-2011-027 and GEN-2010-051).
2. Turn off the wind farm as modeled (as well as previous queued projects at the same point of interconnection).
3. Model a var generator at the Project's high voltage side, 345 kV, 138 kV, or 69kV bus, as applicable. The var generator is set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter or 1.0 pu voltage, whichever is higher.
4. Perform the steady state contingency analysis to determine the power factor necessary at the POI for each contingency.
5. If the required power factor at the POI is beyond the capability of the studied wind turbines to meet (at the POI) capacitor banks may be considered for the stability analysis. The preference is to locate the capacitance banks on the 34.5 kV customer side. Factors to sizing capacitor banks include:
   - 5.1. The ability of the wind farm to meet FERC Order 661A (low voltage ride through) with and without capacitor banks.
   - 5.2. The ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage).
   - 5.3. If wind farms trips on high voltage, power factor lower than unity may be required.

3.2. Analysis

Analysis was performed for proposed Project with all prior queued projects in service. A var generator was modeled at the point of interconnection and was set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases. These voltages for this Project are summarized in Table 2.2. All upgrades and instructions were made in the base cases. No other changes were made in the base cases provided, other than the addition of the var generators. Contingency analysis was run for provided list of contingencies.

Table 2.2: POI voltages for the summer and winter peak cases

Request	Point of Interconnection	Size (MW)	Base Case Voltage (p.u.)		
			Summer 2014 Peak	Winter 2014 Peak	Summer 2023 Peak
GEN-2011-027	Tap on the GEN-2010-051 - Hoskins 230kV line (560347)	119.5	1.008	1.008	1.003

POI: (560347) – Tap on GEN-2010-051 - Hoskins 230 line

It was observed that during all contingencies the var generator supplies reactive power remains within machine capability, which means the power factor control at the subject requested interconnection is within the capability of the machine. The details of the var requirement during contingencies are highlighted in Table 2.3, 2.4, and 2.5. The highest and the lowest values obtained are highlighted in these tables and as follows:

1. For 2014 summer case, the maximum var generator supply is 23.1 MVARs at 1.0 (lagging power factor) for the outage of 640226 [HOSKINS3 345.0] TO BUS 640227 [HOSKINS4 230.00] TO BUS 643082 [HOSKINST2 13.8] Transformer outage. The minimum var requirement is -18.7 MVAR at 1.0 (leading power factor) for outage of 640227 [HOSKINS4 230.0] TO Bus 640228 [HOSKINS7 115.0] TO Bus 643083 [HPSKINST1 13.8] Transformer outage.

Table 2.3: Var Generator Output in 2014 Summer Peak Case for GEN-2011-027

2014 Summer Peak Case Power Factor Study:

Rated MW of Wind Farms at POI = 319.15MW Rated MVAR (lagging) of Wind Farms = 154.5 MVAR Rated MVAR (leading) of Wind Farms = -154.5 MVAR

Cont. Name	From Bus (# & Name)		To Bus (# & Name)		ID	MVAR at POI	% of Max MVAR	P.F at POI	Solution Result
Base Case MVAR Flow					N/A	-10.3	-6.67	1.00	Converged
FLT01-3PH	560347	G10-051TAP 230.00	640227	HOSKINS4 230.00	CKT 1	1.1	0.71	1.00	Converged
FLT02-3PH	640226	HOSKINS3 345.00	640227	HOSKINS4 230.00	T/F	20.6	13.33	1.00	Converged
FLT03-3PH	640227	HOSKINS4 230.00	640228	HOSKINS7 115.00	T/F	-18.7	-12.10	1.00	Converged
FLT04-3PH	560347	G10-051TAP 230.00	640386	TWIN CH4 230.00	CKT 1	-12	-7.77	1.00	Converged
FLT05-3PH	640386	TWIN CH4 230.00	652565	SIOUXCY4 230.00	CKT 1	20.2	13.07	1.00	Converged
FLT6-3PH	640386	TWIN CH4 230.00	640387	TWIN CH7 115.00	T/F	-7.8	-5.05	1.00	Converged
FLT7-3PH	640263	MADISON7 115.00	640151	CRESTON7 115.00	CKT 1	-9.7	-6.28	1.00	Converged
FLT8-3PH	640263	MADISON7 115.00	640298	NORFOLK7 115.00	CKT 1	-10.8	-6.99	1.00	Converged
FLT9-3PH	640318	PETRSBG7 115.00	640054	ALBION 7 115.00	CKT 1	-7.4	-4.79	1.00	Converged
FLT10-3PH	640293	NELIGH 7 115.00	640115	CO.LINE7 115.00	CKT 1	-8.8	-5.70	1.00	Converged
	640318	PETRSBG7 115.00	640054	ALBION 7 115.00	CKT 1				
FLT11-3PH	640318	PETRSBG7 115.00	640444	PETERSBRG.N7115.00	CKT 1	-6.9	-4.47	1.00	Converged
FLT12-3PH	640444	PETERSBRG.N7115.00	640293	NELIGH 7 115.00	CKT 1	-9.3	-6.02	1.00	Converged
FLT13-3PH	640113	CLRWATR7 115.00	640293	NELIGH 7 115.00	CKT 1	-10.8	-6.99	1.00	Converged
	640113	CLRWATR7 115.00	640305	ONEILL 7 115.00	CKT 1				
FLT14-3PH	640115	CO.LINE7 115.00	640293	NELIGH 7 115.00	CKT 1	-10.6	-6.86	1.00	Converged
	640115	CO.LINE7 115.00	640072	BATTLCR7 115.00	CKT 1				
FLT16-3PH	640293	NELIGH 7 115.00	640149	CREITON7 115.00	CKT 1	-9.1	-5.89	1.00	Converged

Cont. Name	From Bus (# & Name)		To Bus (# & Name)		ID	MVAR at POI	% of Max MVAR	P.F at POI	Solution Result
FLT18-3PH	640054	ALBION 7 115.00	640181	GENOA 7 115.00	CKT 1	-9.6	-6.21	1.00	Converged
FLT20-3PH	640054	ALBION 7 115.00	640347	SPALDNG7 115.00	CKT 1	-10.1	-6.54	1.00	Converged
FLT21-3PH	652511	GAVINS 7 115.00	640212	HARTGTN7 115.00	CKT 1	-4	-2.59	1.00	Converged
FLT23-3PH	560006	MADISON CO 230.00	640133	COLMBUS4 230.00	CKT 1	-0.3	-0.19	1.00	Converged
FLT24-3PH	640126	E.COL. 4 230.00	640133	COLMBUS4 230.00	CKT 1	-8.2	-5.31	1.00	Converged
FLT25-3PH	640131	COLMB.W4 230.00	640133	COLMBUS4 230.00	CKT 1	-8.7	-5.63	1.00	Converged
FLT27-3PH	640343	SHELCRK4 230.00	640133	COLMBUS4 230.00	CKT 1	-11.1	-7.18	1.00	Converged
FLT28-3PH	640133	COLMBUS4 230.00	640134	KELLY 7 115.00	T/F	-8.2	-5.31	1.00	Converged
FLT29-3PH	560006	MADISON CO 230.00	652509	FTRANDL4 230.00	CKT 1	-6.4	-4.14	1.00	Converged
FLT30-3PH	652509	FTRANDL4 230.00	652516	LAKPLAT4 230.00	CKT 1	-9.3	-6.02	1.00	Converged
FLT31-3PH	652509	FTRANDL4 230.00	652526	UTICAJC4 230.00	CKT 1	-5.6	-3.62	1.00	Converged
FLT32-3PH	652509	FTRANDL4 230.00	652565	SIOUXCY4 230.00	CKT 1	-4	-2.59	1.00	Converged
FLT33-3PH	640226	HOSKINS3 345.00	635200	RAUN 3 345.00	CKT 1	13.7	8.87	1.00	Converged
FLT34-3PH	640226	HOSKINS3 345.00	640227	HOSKINS4 230.00	T/F	23.1	14.95	1.00	Converged
FLT35-3PH	640226	HOSKINS3 345.00	640342	SHELCRK3 345.00	CKT 1	2.9	1.88	1.00	Converged
FLT36-3PH	640226	HOSKINS3 345.00	640228	HOSKINS7 115.00	T/F	-1	-0.65	1.00	Converged
FLT37-3PH	640080	BELDEN 7 115.00	640228	HOSKINS7 115.00	CKT 1	-7.4	-4.79	1.00	Converged
FLT38-3PH	640080	BELDEN 7 115.00	640387	TWIN CH7 115.00	CKT 1	-8.4	-5.44	1.00	Converged
FLT39-3PH	652565	SIOUXCY4 230.00	652536	RASMUSN4 230.00	CKT 1	-6.6	-4.27	1.00	Converged
FLT40-3PH	652565	SIOUXCY4 230.00	652567	DENISON4 230.00	CKT 1	-6.6	-4.27	1.00	Converged
FLT41-3PH	652565	SIOUXCY4 230.00	659900	EAGLE 4 230.00	CKT 1	-12.4	-8.03	1.00	Converged
FLT42-3PH	652565	SIOUXCY4 230.00	652509	FTRANDL4 230.00	CKT 1	-4.6	-2.98	1.00	Converged
FLT43-3PH	652564	SIOUXCY3 345.00	652565	SIOUXCY4 230.00	T/F	-6.9	-4.47	1.00	Converged
FLT44-3PH	652565	SIOUXCY4 230.00	652566	SIOUXCY5 161.00	T/F	-9.7	-6.28	1.00	Converged
FLT45-3PH	635200	RAUN 3 345.00	631138	LAKEFLD3 345.00	CKT 1	-8.8	-5.70	1.00	Converged
FLT46-3PH	635200	RAUN 3 345.00	636010	LEHIGH 3 345.00	CKT 1	-8.2	-5.31	1.00	Converged

Cont. Name	From Bus (# & Name)		To Bus (# & Name)		ID	MVAR at POI	% of Max MVAR	P.F at POI	Solution Result
FLT47-3PH	635200	RAUN 3 345.00	652564	SIOUXCY3 345.00	CKT 1	4.5	2.91	1.00	Converged
FLT48-3PH	635200	RAUN 3 345.00	645451	S3451 3 345.00	CKT 1	-8.3	-5.37	1.00	Converged
FLT49-3PH	640228	HOSKINS7 115.00	640296	NORFK.N7 115.00	CKT 1	-9.2	-5.95	1.00	Converged
FLT50-3PH	640228	HOSKINS7 115.00	640298	NORFOLK7 115.00	CKT 1	-8.6	-5.57	1.00	Converged
FLT51-3PH	640228	HOSKINS7 115.00	640363	STNTN.N7 115.00	CKT 1	-9.2	-5.95	1.00	Converged

2. For 2014 winter case, the maximum var generator supply is 17.0 MVARs at 1.0 (lagging power factor) for the outage of 640226 [HOSKINS3 345.0] TO BUS 640227 [HOSKINS4 230.00] TO BUS 643082 [HOSKINST2 13.8] Transformer outage. The minimum var requirement is -21.6 MVAR at 1.0 (leading power factor) for outage of 640227 [HOSKINS4 230.0] TO Bus 640228 [HOSKINS7 115.0] TO Bus 643083 [HPSKINST1 13.8] Transformer outage.

Table 2.4: Var Generator Output in 2014 Winter Peak Case for GEN-2013-010

2014 Winter Peak Case Power Factor Study

Rated MW of Wind Farms at POI = 319.15MW Rated MVAR (lagging) of Wind Farms = 154.5 MVAR Rated MVAR (leading) of Wind Farms = -154.5 MVAR

Cont. Name	From Bus (# & Name)		To Bus (# & Name)		ID	MVAR at POI	% of Max MVAR	P.F at POI	Solution Result
Base Case MVAR Flow					N/A	-13.8	-8.93	1.00	Converged
FLT01-3PH	560347	G10-051TAP 230.00	640227	HOSKINS4 230.00	CKT 1	-1.1	-0.71	1.00	Converged
FLT02-3PH	640226	HOSKINS3 345.00	640227	HOSKINS4 230.00	T/F	14.5	9.39	1.00	Converged
FLT03-3PH	640227	HOSKINS4 230.00	640228	HOSKINS7 115.00	T/F	-21.6	-13.98	1.00	Converged
FLT04-3PH	560347	G10-051TAP 230.00	640386	TWIN CH4 230.00	CKT 1	-13.8	-8.93	1.00	Converged
FLT05-3PH	640386	TWIN CH4 230.00	652565	SIOUXCY4 230.00	CKT 1	6.2	4.01	1.00	Converged
FLT6-3PH	640386	TWIN CH4 230.00	640387	TWIN CH7 115.00	T/F	-12.2	-7.90	1.00	Converged
FLT7-3PH	640263	MADISON7 115.00	640151	CRESTON7 115.00	CKT 1	-13.3	-8.61	1.00	Converged
FLT8-3PH	640263	MADISON7 115.00	640298	NORFOLK7 115.00	CKT 1	-13.9	-9.00	1.00	Converged

Cont. Name	From Bus (# & Name)		To Bus (# & Name)		ID	MVAR at POI	% of Max MVAR	P.F at POI	Solution Result
FLT9-3PH	640318	PETRSBG7 115.00	640054	ALBION 7 115.00	CKT 1	-10	-6.47	1.00	Converged
FLT10-3PH	640293	NELIGH 7 115.00	640115	CO.LINE7 115.00	CKT 1	-14	-9.06	1.00	Converged
	640318	PETRSBG7 115.00	640054	ALBION 7 115.00	CKT 1				
FLT11-3PH	640318	PETRSBG7 115.00	640444	PETERSBRG.N7115.00	CKT 1	-9.6	-6.21	1.00	Converged
FLT12-3PH	640444	PETERSBRG.N7115.00	640293	NELIGH 7 115.00	CKT 1	-14.1	-9.13	1.00	Converged
FLT13-3PH	640113	CLRWATR7 115.00	640293	NELIGH 7 115.00	CKT 1	-13.5	-8.74	1.00	Converged
	640113	CLRWATR7 115.00	640305	ONEILL 7 115.00	CKT 1				
FLT14-3PH	640115	CO.LINE7 115.00	640293	NELIGH 7 115.00	CKT 1	-14.5	-9.39	1.00	Converged
	640115	CO.LINE7 115.00	640072	BATTLCR7 115.00	CKT 1				
FLT16-3PH	640293	NELIGH 7 115.00	640149	CREITON7 115.00	CKT 1	-13.3	-8.61	1.00	Converged
FLT18-3PH	640054	ALBION 7 115.00	640181	GENOA 7 115.00	CKT 1	-11.4	-7.38	1.00	Converged
FLT20-3PH	640054	ALBION 7 115.00	640347	SPALDNG7 115.00	CKT 1	-12.6	-8.16	1.00	Converged
FLT21-3PH	652511	GAVINS 7 115.00	640212	HARTGTN7 115.00	CKT 1	-8.6	-5.57	1.00	Converged
FLT23-3PH	560006	MADISON CO 230.00	640133	COLMBUS4 230.00	CKT 1	-6.1	-3.95	1.00	Converged
FLT24-3PH	640126	E.COL. 4 230.00	640133	COLMBUS4 230.00	CKT 1	-11.4	-7.38	1.00	Converged
FLT25-3PH	640131	COLMB.W4 230.00	640133	COLMBUS4 230.00	CKT 1	-11.5	-7.44	1.00	Converged
FLT27-3PH	640343	SHELCRK4 230.00	640133	COLMBUS4 230.00	CKT 1	-15	-9.71	1.00	Converged
FLT28-3PH	640133	COLMBUS4 230.00	640134	KELLY 7 115.00	T/F	-11.5	-7.44	1.00	Converged
FLT29-3PH	560006	MADISON CO 230.00	652509	FTRANDL4 230.00	CKT 1	-9.9	-6.41	1.00	Converged
FLT30-3PH	652509	FTRANDL4 230.00	652516	LAKPLAT4 230.00	CKT 1	-12.4	-8.03	1.00	Converged
FLT31-3PH	652509	FTRANDL4 230.00	652526	UTICAJC4 230.00	CKT 1	-9	-5.83	1.00	Converged
FLT32-3PH	652509	FTRANDL4 230.00	652565	SIOUXCY4 230.00	CKT 1	-6.6	-4.27	1.00	Converged
FLT33-3PH	640226	HOSKINS3 345.00	635200	RAUN 3 345.00	CKT 1	6	3.88	1.00	Converged
FLT34-3PH	640226	HOSKINS3 345.00	640227	HOSKINS4 230.00	T/F	17	11.00	1.00	Converged
FLT35-3PH	640226	HOSKINS3 345.00	640342	SHELCRK3 345.00	CKT 1	-2.4	-1.55	1.00	Converged
FLT36-3PH	640226	HOSKINS3 345.00	640228	HOSKINS7 115.00	T/F	-6.7	-4.34	1.00	Converged

Cont. Name	From Bus (# & Name)		To Bus (# & Name)		ID	MVAR at POI	% of Max MVAR	P.F at POI	Solution Result
FLT37-3PH	640080	BELDEN 7 115.00	640228	HOSKINS7 115.00	CKT 1	-9.7	-6.28	1.00	Converged
FLT38-3PH	640080	BELDEN 7 115.00	640387	TWIN CH7 115.00	CKT 1	-9.8	-6.34	1.00	Converged
FLT39-3PH	652565	SIOUXCY4 230.00	652536	RASMUSN4 230.00	CKT 1	-8	-5.18	1.00	Converged
FLT40-3PH	652565	SIOUXCY4 230.00	652567	DENISON4 230.00	CKT 1	-8.3	-5.37	1.00	Converged
FLT41-3PH	652565	SIOUXCY4 230.00	659900	EAGLE 4 230.00	CKT 1	-10.9	-7.06	1.00	Converged
FLT42-3PH	652565	SIOUXCY4 230.00	652509	FTRANDL4 230.00	CKT 1	-4.4	-2.85	1.00	Converged
FLT43-3PH	652564	SIOUXCY3 345.00	652565	SIOUXCY4 230.00	T/F	-10.5	-6.80	1.00	Converged
FLT44-3PH	652565	SIOUXCY4 230.00	652566	SIOUXCY5 161.00	T/F	-9.7	-6.28	1.00	Converged
FLT45-3PH	635200	RAUN 3 345.00	631138	LAKEFLD3 345.00	CKT 1	-9.4	-6.08	1.00	Converged
FLT46-3PH	635200	RAUN 3 345.00	636010	LEHIGH 3 345.00	CKT 1	-10	-6.47	1.00	Converged
FLT47-3PH	635200	RAUN 3 345.00	652564	SIOUXCY3 345.00	CKT 1	-0.6	-0.39	1.00	Converged
FLT48-3PH	635200	RAUN 3 345.00	645451	S3451 3 345.00	CKT 1	-13.8	-8.93	1.00	Converged
FLT49-3PH	640228	HOSKINS7 115.00	640296	NORFK.N7 115.00	CKT 1	-14.9	-9.64	1.00	Converged
FLT50-3PH	640228	HOSKINS7 115.00	640298	NORFOLK7 115.00	CKT 1	-14.4	-9.32	1.00	Converged
FLT51-3PH	640228	HOSKINS7 115.00	640363	STNTN.N7 115.00	CKT 1	-14.9	-9.64	1.00	Converged

3. For 2023 summer case, the maximum var generator supply is 55.2 MVARs at 0.99 (lagging power factor) for the outage of 640226 [HOSKINS3 345.0] TO BUS 640227 [HOSKINS4 230.00] TO BUS 643082 [HOSKINST2 13.8] Transformer outage. The minimum var requirement is -28.6 MVAR at 1.0 (leading power factor) for outage of 640227 [HOSKINS4 230.0] TO Bus 640228 [HOSKINS7 115.0] TO Bus 643083 [HPSKINST1 13.8] Transformer outage.

Table 2.5: Var Generator Output in 2023 Summer Peak Case for GEN-2013-010

2023 Summer Peak Case Power Factor Study

Rated MW of Wind Farms at POI = 319.15MW Rated MVAR (lagging) of Wind Farms = 154.5 MVAR Rated MVAR (leading) of Wind Farms = -154.5 MVAR

Cont. Name	From Bus (# & Name)		To Bus (# & Name)		ID	MVAR at POI	% of Max MVAR	P.F at POI	Solution Result
Base Case MVAR Flow					N/A	-5.9	-3.82	1.00	Converged
FLT01-3PH	560347	G10-051TAP 230.00	640227	HOSKINS4 230.00	CKT 1	0.4	0.26	1.00	Converged
FLT02-3PH	640226	HOSKINS3 345.00	640227	HOSKINS4 230.00	T/F	55	35.57	0.99	Converged
FLT03-3PH	640227	HOSKINS4 230.00	640228	HOSKINS7 115.00	T/F	-28.6	-18.50	1.00	Converged
FLT04-3PH	560347	G10-051TAP 230.00	640386	TWIN CH4 230.00	CKT 1	-13.6	-8.80	1.00	Converged
FLT05-3PH	640386	TWIN CH4 230.00	652565	SIOUXCY4 230.00	CKT 1	26.1	16.88	1.00	Converged
FLT6-3PH	640386	TWIN CH4 230.00	640387	TWIN CH7 115.00	T/F	-8.1	-5.24	1.00	Converged
FLT7-3PH	640263	MADISON7 115.00	640151	CRESTON7 115.00	CKT 1	-9.4	-6.08	1.00	Converged
FLT8-3PH	640263	MADISON7 115.00	640298	NORFOLK7 115.00	CKT 1	-10.6	-6.86	1.00	Converged
FLT9-3PH	640318	PETRSBG7 115.00	640054	ALBION 7 115.00	CKT 1	-7.9	-5.11	1.00	Converged
FLT10-3PH	640521	NELIGH.EAST7 115.00	640115	CO.LINE7 115.00	CKT 1	-8	-5.18	1.00	Converged
	640318	PETRSBG7 115.00	640054	ALBION 7 115.00	CKT 1				
FLT11-3PH	640318	PETRSBG7 115.00	640444	PETERSBRG.N7115.0 0	CKT 1	-6.1	-3.94	1.00	Converged
FLT12-3PH	640444	PETERSBRG.N7115. 00	640521	NELIGH.EAST7 115.00	CKT 1	-3.8	-2.46	1.00	Converged
FLT13-3PH	640521	NELIGH.EAST7 115.00	640113	CLRWATR7 115.00	CKT 1	-5.3	-3.43	1.00	Converged
	640113	CLRWATR7 115.00	640305	ONEILL 7 115.00	CKT 1				
FLT14-3PH	640521	NELIGH.EAST7 115.00	640115	CO.LINE7 115.00	CKT 1	-6.9	-4.47	1.00	Converged
	640115	CO.LINE7 115.00	640072	BATTLCR7 115.00	CKT 1				

Cont. Name	From Bus (# & Name)		To Bus (# & Name)		ID	MVAR at POI	% of Max MVAR	P.F at POI	Solution Result
FLT16-3PH	640149	CREITON7 115.00	640521	NELIGH.EAST7 115.00	CKT 1	-4.4	-2.85	1.00	Converged
FLT18-3PH	640054	ALBION 7 115.00	640181	GENOA 7 115.00	CKT 1	-4.4	-2.85	1.00	Converged
FLT20-3PH	640054	ALBION 7 115.00	640347	SPALDNG7 115.00	CKT 1	-5.2	-3.36	1.00	Converged
FLT21-3PH	652511	GAVINS 7 115.00	640212	HARTGTN7 115.00	CKT 1	2.6	1.68	1.00	Converged
FLT23-3PH	560006	MADISON CO 230.00	640133	COLMBUS4 230.00	CKT 1	5.2	3.36	1.00	Converged
FLT24-3PH	640126	E.COL. 4 230.00	640133	COLMBUS4 230.00	CKT 1	-2.1	-1.36	1.00	Converged
FLT25-3PH	640131	COLMB.W4 230.00	640133	COLMBUS4 230.00	CKT 1	-2.8	-1.81	1.00	Converged
FLT27-3PH	640343	SHELCRK4 230.00	640133	COLMBUS4 230.00	CKT 1	-5.7	-3.69	1.00	Converged
FLT28-3PH	640133	COLMBUS4 230.00	640134	KELLY 7 115.00	T/F	-2.2	-1.42	1.00	Converged
FLT29-3PH	560006	MADISON CO 230.00	652509	FTRANDL4 230.00	CKT 1	-0.7	-0.45	1.00	Converged
FLT30-3PH	652509	FTRANDL4 230.00	652516	LAKPLAT4 230.00	CKT 1	-3.1	-2.00	1.00	Converged
FLT31-3PH	652509	FTRANDL4 230.00	652526	UTICAJC4 230.00	CKT 1	0.7	0.45	1.00	Converged
FLT32-3PH	652509	FTRANDL4 230.00	652565	SIOUXCY4 230.00	CKT 1	1.7	1.10	1.00	Converged
FLT33-3PH	640226	HOSKINS3 345.00	635200	RAUN 3 345.00	CKT 1	9.6	6.21	1.00	Converged
FLT34-3PH	640226	HOSKINS3 345.00	640227	HOSKINS4 230.00	T/F	55.2	35.70	0.99	Converged
FLT35-3PH	640226	HOSKINS3 345.00	640342	SHELCRK3 345.00	CKT 1	0.5	0.32	1.00	Converged
FLT36-3PH	640226	HOSKINS3 345.00	640228	HOSKINS7 115.00	T/F	0.6	0.39	1.00	Converged
FLT37-3PH	640080	BELDEN 7 115.00	640228	HOSKINS7 115.00	CKT 1	-2.4	-1.55	1.00	Converged
FLT38-3PH	640080	BELDEN 7 115.00	640387	TWIN CH7 115.00	CKT 1	-4	-2.59	1.00	Converged
FLT39-3PH	652565	SIOUXCY4 230.00	652536	RASMUSN4 230.00	CKT 1	-1.8	-1.16	1.00	Converged
FLT40-3PH	652565	SIOUXCY4 230.00	652567	DENISON4 230.00	CKT 1	-2	-1.29	1.00	Converged
FLT41-3PH	652565	SIOUXCY4 230.00	659900	EAGLE 4 230.00	CKT 1	-8	-5.17	1.00	Converged
FLT42-3PH	652565	SIOUXCY4 230.00	652509	FTRANDL4 230.00	CKT 1	0.1	0.06	1.00	Converged
FLT43-3PH	652564	SIOUXCY3 345.00	652565	SIOUXCY4 230.00	T/F	-1.5	-0.97	1.00	Converged
FLT44-3PH	652565	SIOUXCY4 230.00	652566	SIOUXCY5 161.00	T/F	-4.8	-3.10	1.00	Converged
FLT45-3PH	635200	RAUN 3 345.00	635368	SHELDON 3 345.00	CKT 1	-4.2	-2.72	1.00	Converged

Cont. Name	From Bus (# & Name)		To Bus (# & Name)		ID	MVAR at POI	% of Max MVAR	P.F at POI	Solution Result
FLT46-3PH	635200	RAUN 3 345.00	636010	LEHIGH 3 345.00	CKT 1	-3.8	-2.46	1.00	Converged
FLT47-3PH	635200	RAUN 3 345.00	652564	SIOUXCY3 345.00	CKT 1	8.6	5.56	1.00	Converged
FLT48-3PH	635200	RAUN 3 345.00	645451	S3451 3 345.00	CKT 1	-3.9	-2.52	1.00	Converged
FLT49-3PH	640228	HOSKINS7 115.00	640296	NORFK.N7 115.00	CKT 1	-3.9	-2.52	1.00	Converged
FLT50-3PH	640228	HOSKINS7 115.00	640298	NORFOLK7 115.00	CKT 1	-4	-2.59	1.00	Converged
FLT51-3PH	640228	HOSKINS7 115.00	640363	STNTN.N7 115.00	CKT 1	-4.3	-2.78	1.00	Converged

3.3. Conclusions

The power factor analysis indicates the GEN-2011-027 interconnection request requires 0.99 lagging (supplying vars) and 1.00 leading (absorbing vars) power factors at the point of interconnection (Tap on the GEN-2010-051 - Hoskins 230kV line-BUS 560347) based on the contingencies studied.

4. Stability Analysis

4.1. Faults Simulated

Fifty One (51) faults were considered for the transient stability simulations which included three phase faults, as well as single phase line faults, at the locations defined by SPP. Single-phase line faults were simulated by applying fault impedance to the positive sequence network at the fault location. As per the SPP current practice to compute the fault levels, the fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. Concurrently and previously queued projects as respectively shown in Table 1a and Table 2 of the study request i.e., (GEN-2011-018, GEN-2011-056A , GEN-2011-056B, GEN-2003-021N, GEN-2004-005N, GEN-2004-023N, GEN-2006-020N, GEN-2006-037N1, GEN-2006-038N005, GEN-2006-038N019, GEN-2006-044N, GEN-2007-011N08, GEN-2008-086N02, GEN-2008-119O, GEN-2008-123N, GEN-2009-040, GEN-2010-041, GEN-2010-044, GEN-2010-051 other neighboring machines, as well as areas number 531, 534, 536, 540, 541, 640, 645, 650, and 652 were monitored during all the simulations. Table 4.1 shows the list of simulated contingencies. This table also shows the fault clearing time and the time delay before re-closing for all the study contingencies.

Simulations were performed with a 0.1-second steady-state run followed by the appropriate disturbance as described in Table 4.1. Simulations were run for minimum 15-second duration to confirm proper machine damping.

Table 4.1 summarizes the overall results for all faults simulations. Complete sets of plots for both summer and winter peak seasons for year 2014 and summer peak year 2023 for each fault are included in Appendices A, B and C respectively.

For each power flow case, the following faults were run (3-phase and single phase as noted).

Table 4.1: List of simulated faults for stability analysis

Cont. #	Contingency Name	Description	2014 Summer Results	2014 Winter Results	2023 Summer Results
1	FLT01-3PH	3 phase fault on the GEN-2010-051 Tap (560347) to Hoskins (640227) 230kV near GEN-2011-027 Tap. a. Apply fault at GEN-2011-027 Tap 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
2	FLT02-3PH	3 phase fault on the Hoskins 230kV (640227) to 345kV (640226)/ 13.8kV (643082) transformer near the 230kV bus. a. Apply fault at Hoskins 230kV bus. b. Clear fault after 5.5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
3	FLT03-3PH	3 phase fault on the Hoskins 230kV (640227) to 115kV (640228)/13.8kV (643083) transformer near the 230kV bus. a. Apply fault at Hoskins 230kV bus. b. Clear fault after 5.5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
4	FLT04-3PH	3 phase fault on the GEN-2010-051 Tap (560347) to Twin Church (640386) 230kV near GEN-2010-051 Tap. a. Apply fault at GEN-2010-051 Tap 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
5	FLT05-3PH	3 phase fault on the Twin Church (640386) to Sioux City (652565) 230kV near Twin Church. a. Apply fault at Twin Church 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
6	FLT06-3PH	3 phase fault on one of the Twin Church 230kV (640386) to 115kV (640387) /13.8kV (643155) transformer near the 230kV bus. a. Apply fault at Twin Church 230kV bus. b. Clear fault after 5.5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
7	FLT07-3PH	3 phase fault on the Madison (640263) to Creston (640151) 115kV line, near Madison. a. Apply fault at the Madison 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
8	FLT08-3PH	3 phase fault on the Madison (640263) to Norfolk (640298) 115kV line, near Madison County. a. Apply fault at the Madison County 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2014 Summer Results	2014 Winter Results	2023 Summer Results
9	FLT09-3PH	3 phase fault on the Petersburg (640318) to Albion (640054) 115kV line, near Petersburg. a. Apply fault at the Petersburg 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
10	FLT10-3PH	3 phase fault on the Petersburg (640318) to Albion (640054) 115kV line, near Petersburg. Prior outage of the Neligh (640293) to County Line (640115) 115 kV line a. Prior Outage: Neligh to County Line 115 kV line. b. Apply fault at the Petersburg 115kV bus. c. Clear fault after 6.5 cycles by tripping the faulted line. 2023 SP only— 3 phase fault on the Petersburg (640318) to Albion (640054) 115kV line, near Petersburg. Prior outage of the Neligh.East (640521) to County Line (640115) 115 kV line a. Prior Outage: Neligh.East to County Line 115 kV line. b. Apply fault at the Petersburg 115kV bus. c. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
11	FLT11-3PH	3 phase fault on the Petersburg (640318) to Petersburg.N (640444) 115kV line, near Petersburg. a. Apply fault at the Petersburg 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
12	FLT12-3PH	3 phase fault on the Petersburg.N (640444) to Neligh (640293) 115kV line, near Petersburg. a. Apply fault at the Petersburg 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line. 2023 SP only— 3 phase fault on the Petersburg.N (640444) to Neligh.East (640521) 115kV line, near Petersburg.N. a. Apply fault at the Petersburg.N 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2014 Summer Results	2014 Winter Results	2023 Summer Results
13	FLT13-3PH	3 phase fault on the Neligh (640293) to Clearwater (640113) to O'neill (640305) 115kV lines, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line. 2023 SP only— 3 phase fault on the Neligh.East (640521) to Clearwater (640113) to O'neill (640305) 115kV lines, near Neligh.East. a. Apply fault at the Neligh.East 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
14	FLT14-3PH	3 phase fault on the Neligh (640293) to County Line (640115) to Battle Creek (640072) to N. Norfolk 115kV lines, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line 2023 SP only— 3 phase fault on the Neligh.East (640521) to County Line (640115) to Battle Creek (640072) to N. Norfolk 115kV lines, near Neligh.East. a. Apply fault at the Neligh.East 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line	Stable	Stable	Stable
15	FLT15-1PH	Single phase fault on the Neligh (640293) to County Line (640115) to Battle Creek (640072) to N. Norfolk, near Neligh. Stuck PCB at Neligh. a. Apply fault at the Neligh 115 kV bus. b. Clear North Norfolk end of Neligh-County Line-Battle Creek-North Norfolk 115 kV line at 6.5 cycles. Leave fault on open-ended line. c. Clear Neligh 115 kV bus and fault at 18.0 cycles. 2023 SP only— Single phase fault on the Neligh.East (640521) to County Line (640115) to Battle Creek (640072) to N. Norfolk, near Neligh.East. Stuck PCB at Neligh.East. a. Apply fault at the Neligh.East 115 kV bus. b. Clear North Norfolk end of Neligh-County Line-Battle Creek-North Norfolk 115 kV line at 6.5 cycles. Leave fault on open-ended line. c. Clear Neligh 115 kV bus and fault at 18.0 cycles	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2014 Summer Results	2014 Winter Results	2023 Summer Results
16	FLT16-3PH	3 phase fault on the Neligh (640293) to Creighton (640149) 115kV line, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line. 2023 SP only— 3 phase fault on the Neligh.East (640521) to Creighton (640149) 115kV line, near Neligh.East. a. Apply fault at the Neligh.East 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
17	FLT17-1PH	Single phase fault on the Creighton (640149) to Neligh (640293) 115 kV line, near Creighton. Stuck breaker at Creighton. a. Apply fault at Creighton 115 kV bus. b. Clear Neligh end of line at 6.5 cycles. Leave fault on open-ended line from Creighton. c. Clear Creighton 115 kV bus and fault at 18.0 cycles. 2023 SP only— Single phase fault on the Creighton (640149) to Neligh.East (640521) 115 kV line, near Creighton. Stuck breaker at Creighton. a. Apply fault at Creighton 115 kV bus. b. Clear Neligh.East end of line at 6.5 cycles. Leave fault on open-ended line from Creighton. c. Clear Creighton 115 kV bus and fault at 18.0 cycles.	Stable	Stable	Stable
18	FLT18-3PH	3 phase fault on the Albion (640054) to Genoa (640181) 115kV line, near Albion. a. Apply fault at the Albion 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
19	FLT19-1PH	Single phase fault on Albion (640054) to Genoa (640181) 115 kV line near Albion. Stuck PCB at Albion. a. Apply fault on Albion 115 kV bus. b. Clear Genoa end of Albion-Genoa 115 kV line at 6.5 cycles. Leave fault on open-ended line. c. Clear Albion 115 kV bus and fault at 18.0 cycles.	Stable	Stable	Stable
20	FLT20-3PH	3 phase fault on the Albion (640054) to Spalding (640347) 115kV line, near Albion. a. Apply fault at the Albion 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2014 Summer Results	2014 Winter Results	2023 Summer Results
21	FLT21-3PH	3 phase fault on the Gavins Point (652511) to Hartington (640212) 115kV line, near Gavins Point. a. Apply fault at the Gavins Point 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
22	FLT22-1PH	Single phase fault on the Gavins Point (652511) – Hartington (640212) 115 kV line, near Gavins Point. Stuck breaker at Gavins Point. a. Apply fault at Gavins Point 115 kV bus. b. Clear Hartington end of line at 6.5 cycles. Leave fault on open-ended line from Gavins Point. c. Clear Gavins Point 115 kV bus and fault at 18.0 cycles.	Stable	Stable	Stable
23	FLT23-3PH	3 phase fault on the Madison County (570886) to Columbus (640133) 230kV line, near Madison County. a. Apply fault at the Madison County 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
24	FLT24-3PH	3 phase fault on the East Columbus (640126) to Columbus (640133) 230kV line, near Columbus a. Apply fault at the Columbus 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
25	FLT25-3PH	3 phase fault on the Columbus West (640131) to Columbus (640133) 230kV line, near Columbus a. Apply fault at the Columbus 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
26	FLT26-1PH	Single phase fault on Columbus (640133) to Columbus West (640131) 230 kV line. Stuck PCB at Columbus. a. Apply fault on Columbus 230 kV bus. b. Clear Columbus West end of line at 6.0 cycles. Leave fault on open-ended line. c. Clear Columbus 230 kV bus and fault at 14.5 cycles.	Stable	Stable	Stable
27	FLT27-3PH	3 phase fault on the Shell Creek (640343) to Columbus (640133) 230kV line, near Columbus. a. Apply fault at the Columbus 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
28	FLT28-3PH	3 phase fault on the Kelly 115kV (640134) to Columbus 230kV (640133) transformer near the Kelly 115kV. a. Apply fault at Kelly 115kV bus. b. Clear fault after 5.5 cycles by tripping the faulted transformer.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2014 Summer Results	2014 Winter Results	2023 Summer Results
29	FLT29-3PH	3 phase fault on the Madison County (570886) to Ft. Randall (652509) 230kV line, near Madison County. a. Apply fault at the Madison County 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
30	FLT30-3PH	3 phase fault on the Fort Randall (652509) to Lake Platt (652516) 230kV line, near Fort Randall. a. Apply fault at the Fort Randal 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
31	FLT31-3PH	3 phase fault on the Fort Randall (652509) to Utica Junction (652526) 230kV line, near Fort Randall. a. Apply fault at the Fort Randall 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
32	FLT32-3PH	3 phase fault on the Fort Randall (652509) to Sioux City (652565) 230kV line, near Fort Randall. a. Apply fault at the Fort Randall 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
33	FLT33-3PH	3 phase fault on the Hoskins (640226) to Raun (635200) 345kV line, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 4.5 cycles by tripping the faulted line.	Stable	Stable	Stable
34	FLT34-3PH	3 phase fault on the Hoskins 230kV (640227) to 345kV (640226) transformer at the 230kV bus. a. Apply fault at the Hoskins 230kV bus. b. Clear fault after 5.5 cycles by tripping the faulted transformer	Stable	Stable	Stable
35	FLT35-3PH	3 phase fault on the Hoskins (640226) to Shell Creek (640342) 345kV line, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 4.5 cycles by tripping the faulted line.	Stable	Stable	Stable
36	FLT36-3PH	3 phase fault on the Hoskins 115kV (640228) to 345kV (640226)/13.8kV (640231) transformer at the 115kV bus. a. Apply fault at the Hoskins 115kV bus. b. Clear fault after 5.5 cycles by tripping the faulted transformer	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2014 Summer Results	2014 Winter Results	2023 Summer Results
37	FLT37-3PH	3 phase fault on the Belden (640080) to Hoskins (640228) 115kV line, near Belden a. Apply fault at the Belden 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
38	FLT38-3PH	3 phase fault on the Belden (640080) to Twin Church (640387) 115kV line, near Belden a. Apply fault at the Belden 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
39	FLT39-3PH	3 phase fault on the Sioux City (652565) to Rasmusen (652536) 230kV line, near Sioux City. a. Apply fault at the Sioux City 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
40	FLT40-3PH	3 phase fault on the Sioux City (652565) to Denison (652567) 230kV line, near Sioux City. a. Apply fault at the Sioux City 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
41	FLT41-3PH	3 phase fault on the Sioux City (652565) to Eagle (659900) 230kV line, near Sioux City. a. Apply fault at the Sioux City 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
42	FLT42-3PH	3 phase fault on the Sioux City (652565) to Eagle (652536) 230kV line, near Sioux City. a. Apply fault at the Sioux City 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	Stable	Stable	Stable
43	FLT43-3PH	3 phase fault on the Sioux City 230kV (652565) to 345kV (652564)/ 13.8kV (652304) transformer near the 230kV bus. a. Apply fault at Sioux City 230kV bus. b. Clear fault after 5.5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
44	FLT44-3PH	3 phase fault on the Sioux City 230kV (652565) to 161kV (652566)/ 13.8kV (652308) transformer near the 230kV bus. a. Apply fault at Sioux City 230kV bus. b. Clear fault after 5.5 cycles by tripping the faulted transformer.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2014 Summer Results	2014 Winter Results	2023 Summer Results
45	FLT45-3PH	3 phase fault on the Raun (635200) to Lakefield (631138) 345kV line, near Raun. a. Apply fault at the Raun 345kV bus. b. Clear fault after 4.5 cycles by tripping the faulted line. 2023 SP only— 3 phase fault on the Raun (635200) to Sheldon (635368) 345kV line, near Raun. a. Apply fault at the Raun 345kV bus. b. Clear fault after 4.5 cycles by tripping the faulted line.	Stable	Stable	Stable
46	FLT46-3PH	3 phase fault on the Raun (635200) to Lehigh (636010) 345kV line, near Raun. a. Apply fault at the Raun 345kV bus. b. Clear fault after 4.5 cycles by tripping the faulted line.	Stable	Stable	Stable
47	FLT47-3PH	3 phase fault on the Raun (635200) to Sioux City (652564) 345kV line, near Raun. a. Apply fault at the Raun 345kV bus. b. Clear fault after 4.5 cycles by tripping the faulted line.	Stable	Stable	Stable
48	FLT48-3PH	3 phase fault on the Raun (635200) to S3451 (645451) 345kV line, near Raun. a. Apply fault at the Raun 345kV bus. b. Clear fault after 4.5 cycles by tripping the faulted line.	Stable	Stable	Stable
49	FLT49-3PH	3 phase fault on the Hoskins (640228) to Norfolk North (640296) 115kV line, near Hoskins a. Apply fault at the Hoskins 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
50	FLT50-3PH	3 phase fault on the Hoskins (640228) to Norfolk (640298) 115kV line, near Hoskins a. Apply fault at the Hoskins 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable
51	FLT51-3PH	3 phase fault on the Hoskins (640228) to Station (640357) 115kV line, near Hoskins a. Apply fault at the Hoskins 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	Stable	Stable	Stable

4.2. Simulation Results

There are no impacts on the stability performance of the SPP system for the contingencies tested on the SPP provided base cases.

5. Conclusions

The findings of the impact study for the proposed interconnection projects under GEN-2011-027 (Restudy) considered at 100% of their proposed installed capacity is as follows:

1. The power factor analysis indicates the GEN-2011-027 interconnection request will be required to provide 0.99 lagging (supplying vars) and 1.00 leading (absorbing vars) power factors at the point of interconnection (Tap on the GEN-2010-051 - Hoskins 230kV line-BUS 560347) based on the contingencies studied. Per the SPP OATT, the Interconnection Customer will be required to provide 95% lagging (supplying vars) and 95% leading (absorbing vars) at the POI.
2. There are no impacts on the stability performance of the SPP system for the contingencies tested on the provided base cases. The study machines stayed on-line and stable for all simulated faults. The Project stability simulations with fifty one (51) specified test disturbances did not show instability problems in the SPP system. Any oscillations were damped out.

6. Appendix A: 2014 Summer Peak Case Stability Run Plots

7. Appendix B: 2014 Winter Peak Case Stability Run Plots

8. Appendix C: 2023 Summer Peak Case Stability Run Plots

9. Appendix D: Project Model Data