Southwest Power Pool

GEN-2009-008
Impact Restudy

SPP Generation
Interconnection Studies

GEN-2009-008

April 2011

Executive Summary

This report contains the impact study results of GEN-2009-008. The GEN-2009-008 interconnection request was studied as part of the DISIS-2010-001 Definitive Impact Study, Cluster Group #11, which was originally posted in July 2010. A subsequent restudy was posted January 2011.

DISIS-2010-001 Definitive Impact Study, Cluster Group #11 and the subsequent report, for GEN-2009-008, erroneously reflects the modeling consideration of the GE 1.5MW wind turbine generator for a total of 199.5MW. The GE wind turbine model used in the stability study for the GEN-2009-008 under DISIS-2010-001 Definitive Impact Study, Cluster Group #11 and the subsequent report was the GE 1.6MW wind turbine generator for a total of 200.1MW.

With the assumptions outlined in this report, GEN-2009-008 should be able to reliably connect to the SPP transmission grid.

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

Pterra Consulting

Technical Report R142-10

Impact Study for Generation Interconnection Request GEN-2010-001 Group 11 (Draft)

Submitted to

Southwest Power Pool

July 2010

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Executive Summary

This report presents the results of impact study comprising of power factor and stability analyses of the proposed interconnection projects under DISIS-2010-001 Group 11 (the “Project”) as described in the following table:

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2009-008	200	GE 1.6 MW	South Hays (530582) 230kV
GEN-2009-020	48.6	Vestas V90 1.8 MW	Balzine (530585) – Nekoma (530564) 69kV (Bus 575041)
GEN-2009-040	73.8	Vestas V90 1.8 MW	Smittyville (533338) – Knob Hill (533332) 115kV (Bus 560287)

The analysis was conducted through the Southwest Power Pool (“SPP”) Tariff. Power factor analysis and transient stability simulations were conducted with all three projects in service at their full output.

Two base cases, summer 2010 and winter 2009 conditions, each comprising of a power flow and corresponding dynamics database, were provided by SPP. The three plants are already modeled in the base cases.

Power Factor Test

The results of the Power Factor analysis showed that with the MVAR capability of the three WTG’s and without reactive compensation, the wind farm will not be able to keep the voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter.

For projects Gen-2009-008 and Gen-2009-040 involving the contingency Gen_2009_020-Nekoma 69 kV line, a fixed shunt capacitor needs to be added at the 34.5 kV bus of Gen_2009_020 in order to prevent voltage collapse. The capacitor sizes are 7 and 9 MVAR for summer and winter cases, respectively.

Stability Simulations

Fifty-one (51) disturbances were considered for the transient stability simulations which include 3-phase faults as well as 1-phase to ground faults at the locations defined by SPP.

For contingency Gen_2009_020-Nekoma 69 kV line, the simulations showed oscillations in the voltage, power and frequency of the plant Gen_2009_020 in both the summer and winter cases. Addition of a 15 MVAR SVC placed at the 34.5 kV bus of Gen_2009_020 plant was needed to eliminate these oscilations.

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

Section 1. Introduction

1.1. Project Overview

This report presents the results of impact study comprising of power factor and stability analyses of the proposed interconnection projects under DISIS-2010-001 Group 11 (the "Project") as described in Table 1-1:

Table 1-1 Projects Included Under DISIS-2010-001 (Group 11)

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2009-008	200	GE 1.6 MW	South Hays 230kV
GEN-2009-020	48.6	Vestas V90 1.8 MW	Balzine-Nekoma 69 kV line
GEN-2009-040	73.8	Vestas V90 1.8 MW	Smittyville-Knob Hill 115 kV line

Figures 1-1, 1-2, and 1-3 show the interconnection diagrams of the Project to SPP's system as modeled in the power flow cases.

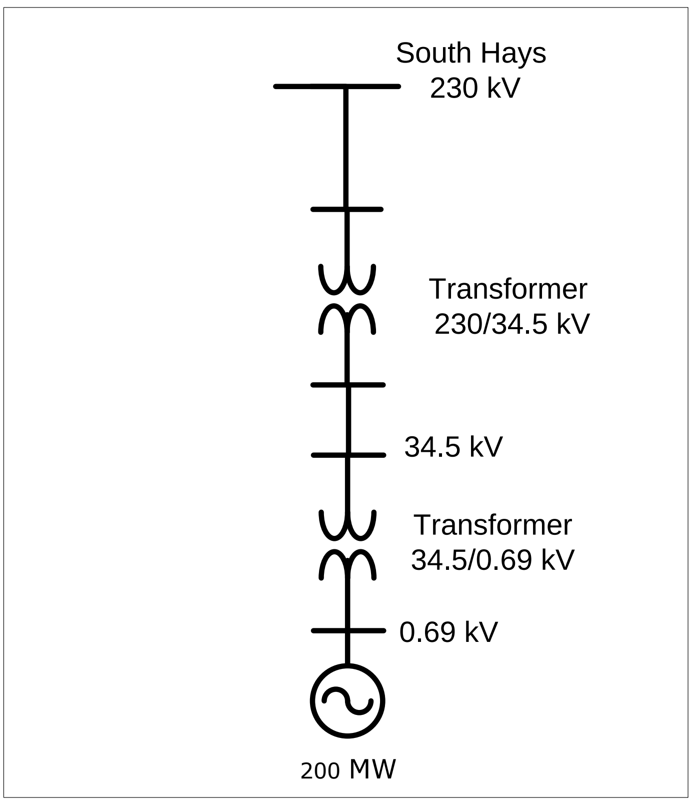

Figure 1-1 Power Flow Model for Gen-2009-008

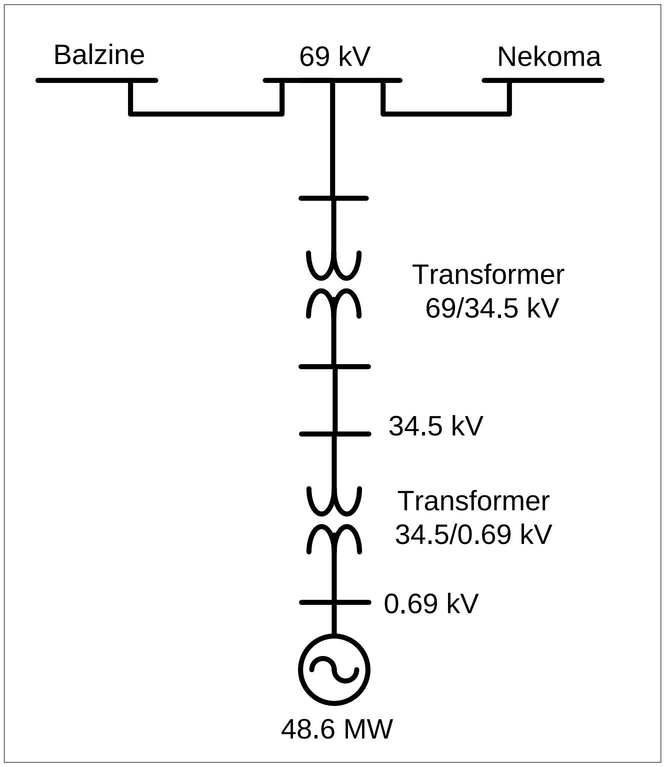

Figure 1-2 Power Flow Model for Gen-2009-020

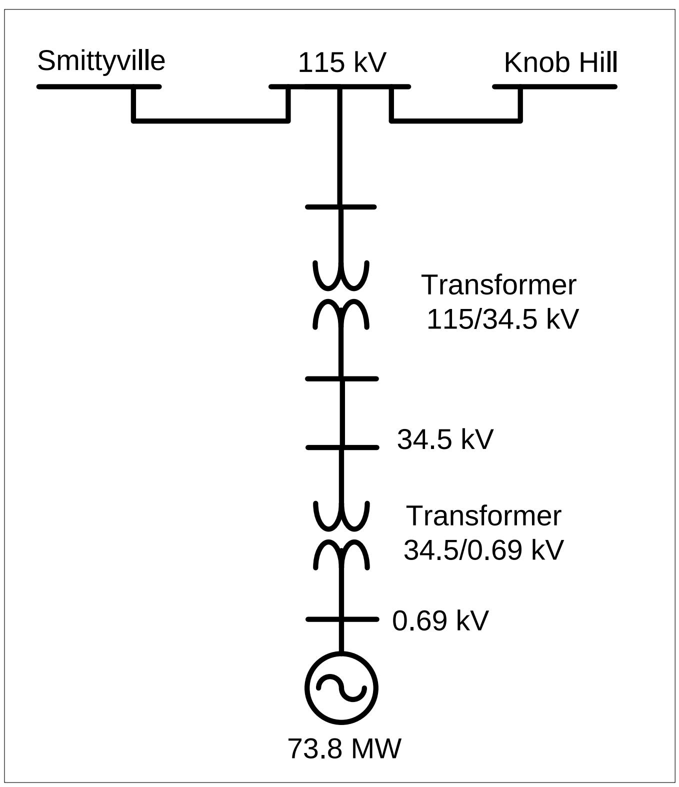

Figure 1-3 Power Flow Model for Gen-2009-040

Table 1-2 shows the list of prior queued projects modeled in the base case.

Table 1-2 List of Prior Queued Projects

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2003-006A	200	Vestas V90 3.0MW	Elm Creek 230kV (539639)
GEN-2003-019	250	GE 1.5MW	Smoky Hills 230kV (530592)
GEN-2006-031	75	Gas	Knoll 115kV (530561)
GEN-2006-032	200	Gamesa 2.0MW	South Hays 230kV (530582)
GEN-2008-092	200	GE 1.5MW	Knoll 230kV (530558)
GEN-2009-011	50	Gamesa 2.0MW	Tap Plainville (539686) – Phillipsburg (539685) 115kV. (Bus 570911)

1.2. 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 farms to SPP's transmission system.

Section 2. Power Factor Analysis

2.1. Methodology

Power factor analysis was conducted for the Project using a methodology which is summarized as follows:

1. Model a VAR generator at the Project's 230, 115, or 69 kV bus, whichever is 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.

2. Steady state contingency analysis is conducted to determine the power factor necessary at the POI for each contingency.

3. According to the contingency analysis results, determine whether capacitors are required for the Project or not.

4. If the required power factor at the POI is beyond the capability of the studied wind turbines, capacitor banks are considered. The preference is to locate the capacitance banks on the 34.5 kV customer side. Factors to sizing capacitor banks include:

    4.1. The ability of the wind farm to meet FERC Order 661A (low voltage ride through) with and without capacitor banks.

    4.2. The ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage).

    4.3. If wind farms trips on high voltage, power factor lower than unity may be required.

2.2. Analysis

Analysis was performed for each proposed project with all three projects in service. A VAR generator was modeled at each 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 are summarized in the Table 2-1.

Table 2-1 Pre-contingency Voltages at POI

Request	Point of Interconnection	Size (MW)	Base Case Voltage (p.u.)	
			Summer Peak	Winter Peak
GEN-2009-008	South Hays (530582) 230kV	200	1.007	1.015
GEN-2009-020	Balzine (530585) – Nekoma (530564) 69kV (Bus 575041)	48.6	1.011	1.014
GEN-2009-040	Smittyville (533338) – Knob Hill (533332) 115kV (Bus 560287)	73.8	1.008	1.009

A. Gen-2009-008

POI: South Hays 230 kV

The VAR generator either supplies or absorbs reactive power at different contingencies as summarized in Table 2-2. The highest values obtained are as follows:

1. For the summer case, the VAR generator supplies 52.41 MVAR for the outage of Knoll-Gen_2010_016 345 kV line and absorbs 6.28 MVAR for the loss of Knoll-Saline 115 kV line. Power factors are 0.97 and near-unity, respectively.
2. For the winter case, the VAR generator supplies 49.99 MVAR for the outage of Knoll-Gen_2010_016 345 kV line and absorbs 6.56 MVAR for the loss of Mullergren 230/115 kV transformer. Power factors are 0.97 and near-unity, respectively.

For contingency Gen_2009_020-Nekoma 69 kV line, a fixed shunt capacitor has to be added at Gen_2009_020 34.5 kV bus in order to prevent voltage collapse. The capacitor sizes are 7 and 9 MVAR for summer and winter cases, respectively.

Table 2-2 VAR Generator Output in Summer and Winter Peak Cases for GEN-2009-008

CASE	CONTINGENCY	PF @ POI	PF	MW @ POI	MVAR @ POI
SP	BASE CASE	1.00	Lag	194	0.80
	SETAB 345KV (531465) - 115KV (531464) XFMER	1.00	Lag	194	0.51
	KELLY (533217) 115KV - KELLY (532913) 161KV XFMER	1.00	Lag	194	0.74
	CONCORDIA (539657) 115KV - CONCORDIA (532658) 230KV XFMER	1.00	Lag	194	2.54
	MINGO 345KV (531451) - 115KV (531429) XFMER	1.00	Lag	194	0.35
	MULLERGREN (539678) 230KV - MULLERGREN (539679) 115KV XFMER	1.00	Lag	194	1.00
	KNOLL 230KV (530558) - 115KV (530561) XFMER	1.00	Lag	194	3.36
	NEKOMA (530564) 69KV - NEKOMA (530608) 115KV XFMER	1.00	Lag	194	0.82
	HEIZER (530563) 69KV - HEIZER (530601) 115KV XFMER	1.00	Lag	194	0.59
	HEIZER (530601) 115KV - MULLERGREN (539679) 230KV XFMER	1.00	Lag	194	5.63
	KNOLL 230KV (530558) - 345KV (560004) XFMER	0.99	Lead	194	20.59
	S. HAYS (530582) 230KV - S. HAYS (530553) 115KV XFMER	1.00	Lag	194	5.45
	MINGO (531451) - RED WILLOW (640325) 345KV LINE	1.00	Lead	194	10.96
	HOLCOMB (531449) - GEN-2007-040 (531000) 345KV LINE	1.00	Lag	194	1.23
	KNOLL (560004) - GEN-2010-016 (576704) 345KV LINE	0.97	Lead	194	52.41
	KNOLL (530558) - SMOKY HILLS (530592) 230KV LINE	1.00	Lead	194	12.10
	KNOLL (530558) - SOUTH HAYS (530582) 230KV LINE	0.97	Lead	194	47.14
	KNOLL (530561) - SALINE (530551) 115KV LINE	1.00	Lag	194	6.28
	KNOLL (530561) - REDLINE (530605) 115KV LINE	1.00	Lead	194	1.22
	SOUTH HAYS (530582) - MULLERGREN (539679) 230KV LINE	0.99	Lead	194	31.17
	KNOLL (530561) - N HAYS (530581) 115KV LINE	1.00	Lead	194	3.17
	PIONEER TAP (539642) - MULLERGREN (539678) 115KV LINE	1.00	Lag	194	0.86
	GEN-2009-040 (560287) - SMITTYVILLE (533338) 115KV LINE	1.00	Lead	194	0.46
	GEN-2009-040 (560287) - KNOB HILL (533332) 115KV LINE	1.00	Lag	194	0.91
	GEN-2009-020 (575040) - BALZINE (530585) 69KV LINE	1.00	Lead	194	1.04
	GEN-2009-020 (575040) - NEKOMA (530564) 69KV LINE	1.00	Lead	194	2.75
	SENECA (533337) - KELLY (533217) 115KV LINE	1.00	Lag	194	0.58
	KNOB HILL (533332) - GREEN LEAF (539665) 115KV LINE	1.00	Lead	194	2.35
	HANSTN (530566) - KINSLY (530578) 69KV LINE	1.00	Lag	194	0.03

CASE	CONTINGENCY	PF @ POI	PF	MW @ POI	MVAR @ POI
	HANSTN (530566) - JETMOR (530579) 69KV LINE	1.00	Lag	194	0.96
	MULLERGREN (539679) – CIRCLE (532871) 230KV LINE	1.00	Lag	194	1.68
	MULLERGREN (539679) – SPEARVILLE (539695) 230KV LINE	0.99	Lead	194	23.36
WP	BASE CASE	1.00	Lag	194.0	0.28
	SETAB 345KV (531465) - 115KV (531464) XFMER	1.00	Lead	194.0	0.31
	KELLY (533217) 115KV – KELLY (532913) 161KV XFMER	1.00	Lag	194.0	0.07
	CONCORDIA (539657) 115KV – CONCORDIA (532658) 230KV XFMER	1.00	Lag	194.0	5.39
	MINGO 345KV (531451) - 115KV (531429) XFMER	1.00	Lead	194.0	0.57
	MULLERGREN (539678) 230KV – MULLERGREN (539679) 115KV XFMER	1.00	Lag	194.0	6.56
	KNOLL 230KV (530558) - 115KV (530561) XFMER	1.00	Lag	194.0	1.57
	NEKOMA (530564) 69KV – NEKOMA (530608) 115KV XFMER	1.00	Lag	194.0	0.28
	HEIZER (530563) 69KV – HEIZER (530601) 115KV XFMER	1.00	Lag	194.0	0.16
	HEIZER (530601) 115KV – MULLERGREN (539679) 230KV XFMER	1.00	Lag	194.0	1.82
	KNOLL 230KV (530558) - 345KV (560004) XFMER	0.99	Lead	194.0	19.77
	S. HAYS (530582) 230KV – S. HAYS (530553) 115KV XFMER	1.00	Lag	194.0	5.00
	MINGO (531451) - RED WILLOW (640325) 345KV LINE	1.00	Lead	194.0	10.75
	HOLCOMB (531449) - GEN-2007-040 (531000) 345KV LINE	1.00	Lag	194.0	2.17
	KNOLL (560004) - GEN-2010-016 (576704) 345KV LINE	0.97	Lead	194.0	49.99
	KNOLL (530558) - SMOKY HILLS (530592) 230KV LINE	1.00	Lead	194.0	10.95
	KNOLL (530558) - SOUTH HAYS (530582) 230KV LINE	0.98	Lead	194.0	36.60
	KNOLL (530561) - SALINE (530551) 115KV LINE	1.00	Lag	194.0	2.50
	KNOLL (530561) - REDLINE (530605) 115KV LINE	1.00	Lead	194.0	2.79
	SOUTH HAYS (530582) - MULLERGREN (539679) 230KV LINE	0.99	Lead	194.0	25.54
	KNOLL (530561) - N HAYS (530581) 115KV LINE	1.00	Lead	194.0	0.46
	PIONEER TAP (539642) - MULLERGREN (539678) 115KV LINE	1.00	Lead	194.0	0.21
	GEN-2009-040 (560287) - SMITTYVILLLE (533338) 115KV LINE	1.00	Lead	194.0	1.26
	GEN-2009-040 (560287) - KNOB HILL (533332) 115KV LINE	1.00	Lag	194.0	0.21
	GEN-2009-020 (575040) - BALZINE (530585) 69KV LINE	1.00	Lead	194.0	1.65
	GEN-2009-020 (575040) - NEKOMA (530564) 69KV LINE	1.00	Lead	194.0	10.48
	SENECA (533337) - KELLY (533217) 115KV LINE	1.00	Lag	194.0	0.22
	KNOB HILL (533332) - GREEN LEAF (539665) 115KV LINE	1.00	Lead	194.0	2.65
	HANSTN (530566) - KINSLY (530578) 69KV LINE	1.00	Lead	194.0	0.77
	HANSTN (530566) - JETMOR (530579) 69KV LINE	1.00	Lag	194.0	0.30
	MULLERGREN (539679) – CIRCLE (532871) 230KV LINE	1.00	Lag	194.0	3.95
	MULLERGREN (539679) – SPEARVILLE (539695) 230KV LINE	0.99	Lead	194.0	28.74

B. Gen-2009-020

POI: Balzine-Nekoma 69 kV Line

The VAR generator either supplies or absorbs reactive power at different contingencies as summarized in Table 2-3. The highest values obtained are as follows:

1. For the summer case, the VAR generator supplies 9.31 MVAR for the outage of Gen_2009_020-Nekoma 69 kV line and absorbs 3.77 MVAR for the loss of Gen_2009_020-Balzine 69 kV line. Power factors are 0.98 and near-unity, respectively.
2. For the winter case, the VAR generator supplies 8.58 MVAR for the outage of Gen_2009_020-Nekoma 69 kV line and absorbs 1.18 MVAR for the loss of Gen_2009_020-Balzine 69 kV line. Power factors are 0.98 and near-unity, respectively.

Table 2-3 VAR Generator Output in Summer and Winter Peak Cases for GEN-2009-020

CASE	CONTINGENCY	PF @ POI	PF	MW @ POI	MVAR @ POI
SP	BASE CASE	1.00	Lead	47.9	0.10
	SETAB 345KV (531465) - 115KV (531464) XFMER	1.00	Lead	47.9	1.18
	KELLY (533217) 115KV - KELLY (532913) 161KV XFMER	1.00	Lag	47.9	0.03
	CONCORDIA (539657) 115KV - CONCORDIA (532658) 230KV XFMER	1.00	Lag	47.9	0.12
	MINGO 345KV (531451) - 115KV (531429) XFMER	1.00	Lead	47.9	0.51
	MULLERGREN (539678) 230KV - MULLERGREN (539679) 115KV XFMER	1.00	Lag	47.9	0.05
	KNOLL 230KV (530558) - 115KV (530561) XFMER	1.00	Lag	47.9	0.14
	NEKOMA (530564) 69KV - NEKOMA (530608) 115KV XFMER	1.00	Lag	47.9	0.03
	HEIZER (530563) 69KV - HEIZER (530601) 115KV XFMER	1.00	Lead	47.9	0.09
	HEIZER (530601) 115KV - MULLERGREN (539679) 230KV XFMER	1.00	Lead	47.9	4.51
	KNOLL 230KV (530558) - 345KV (560004) XFMER	1.00	Lead	47.9	0.42
	S. HAYS (530582) 230KV - S. HAYS (530553) 115KV XFMER	1.00	Lag	47.9	0.10
	MINGO (531451) - RED WILLOW (640325) 345KV LINE	1.00	Lead	47.9	1.30
	HOLCOMB (531449) - GEN-2007-040 (531000) 345KV LINE	1.00	Lead	47.9	0.81
	KNOLL (560004) - GEN-2010-016 (576704) 345KV LINE	1.00	Lead	47.9	1.01
	KNOLL (530558) - SMOKY HILLS (530592) 230KV LINE	1.00	Lead	47.9	0.33
	KNOLL (530558) - SOUTH HAYS (530582) 230KV LINE	1.00	Lead	47.9	0.50
	KNOLL (530561) - SALINE (530551) 115KV LINE	1.00	Lag	47.9	0.13
	KNOLL (530561) - REDLINE (530605) 115KV LINE	1.00	Lead	47.9	0.06
	SOUTH HAYS (530582) - MULLERGREN (539679) 230KV LINE	1.00	Lead	47.9	0.25
	KNOLL (530561) - N HAYS (530581) 115KV LINE	1.00	Lead	47.9	0.04
	PIONEER TAP (539642) - MULLERGREN (539678) 115KV LINE	1.00	Lag	47.9	0.39
	GEN-2009-040 (560287) - SMITTYVILLE (533338) 115KV LINE	1.00	Lead	47.9	0.07
	GEN-2009-040 (560287) - KNOB HILL (533332) 115KV LINE	1.00	Lag	47.9	0.04
	GEN-2009-020 (575040) - BALZINE (530585) 69KV LINE	1.00	Lag	47.9	3.77
	GEN-2009-020 (575040) - NEKOMA (530564) 69KV LINE	0.98	Lead	47.9	9.31
	SENECA (533337) - KELLY (533217) 115KV LINE	1.00	Lag	47.9	0.01
	KNOB HILL (533332) - GREEN LEAF (539665) 115KV LINE	1.00	Lead	47.9	0.11
	HANSTN (530566) - KINSLY (530578) 69KV LINE	1.00	Lag	47.9	0.38
	HANSTN (530566) - JETMOR (530579) 69KV LINE	1.00	Lag	47.9	0.65
	MULLERGREN (539679) - CIRCLE (532871) 230KV LINE	1.00	Lag	47.9	0.34
	MULLERGREN (539679) - SPEARVILLE (539695) 230KV LINE	1.00	Lead	47.9	1.30

CASE	CONTINGENCY	PF @ POI	PF	MW @ POI	MVAR @ POI
WP	BASE CASE	1.00	Lead	48.0	0.10
	SETAB 345KV (531465) - 115KV (531464) XFMER	1.00	Lead	48.0	1.12
	KELLY (533217) 115KV – KELLY (532913) 161KV XFMER	1.00	Lead	48.0	0.11
	CONCORDIA (539657) 115KV – CONCORDIA (532658) 230KV XFMER	1.00	Lag	48.0	0.28
	MINGO 345KV (531451) - 115KV (531429) XFMER	1.00	Lead	48.0	0.03
	MULLERGREN (539678) 230KV – MULLERGREN (539679) 115KV XFMER	1.00	Lead	48.0	1.88
	KNOLL 230KV (530558) - 115KV (530561) XFMER	1.00	Lead	48.0	0.08
	NEKOMA (530564) 69KV – NEKOMA (530608) 115KV XFMER	1.00	Lead	48.0	0.10
	HEIZER (530563) 69KV – HEIZER (530601) 115KV XFMER	1.00	Lead	48.0	0.11
	HEIZER (530601) 115KV – MULLERGREN (539679) 230KV XFMER	1.00	Lead	48.0	2.89
	KNOLL 230KV (530558) - 345KV (560004) XFMER	1.00	Lead	48.0	0.70
	S. HAYS (530582) 230KV – S. HAYS (530553) 115KV XFMER	1.00	Lead	48.0	0.00
	MINGO (531451) - RED WILLOW (640325) 345KV LINE	1.00	Lead	48.0	1.55
	HOLCOMB (531449) - GEN-2007-040 (531000) 345KV LINE	1.00	Lead	48.0	0.58
	KNOLL (560004) - GEN-2010-016 (576704) 345KV LINE	1.00	Lead	48.0	0.94
	KNOLL (530558) - SMOKY HILLS (530592) 230KV LINE	1.00	Lead	48.0	0.83
	KNOLL (530558) - SOUTH HAYS (530582) 230KV LINE	1.00	Lead	48.0	0.71
	KNOLL (530561) - SALINE (530551) 115KV LINE	1.00	Lead	48.0	0.06
	KNOLL (530561) - REDLINE (530605) 115KV LINE	1.00	Lead	48.0	0.19
	SOUTH HAYS (530582) - MULLERGREN (539679) 230KV LINE	1.00	Lead	48.0	1.24
	KNOLL (530561) - N HAYS (530581) 115KV LINE	1.00	Lead	48.0	0.12
	PIONEER TAP (539642) - MULLERGREN (539678) 115KV LINE	1.00	Lag	48.0	0.01
	GEN-2009-040 (560287) - SMITTYVILLLE (533338) 115KV LINE	1.00	Lead	48.0	0.25
	GEN-2009-040 (560287) - KNOB HILL (533332) 115KV LINE	1.00	Lead	48.0	0.11
	GEN-2009-020 (575040) - BALZINE (530585) 69KV LINE	1.00	Lag	48.0	1.18
	GEN-2009-020 (575040) - NEKOMA (530564) 69KV LINE	0.98	Lead	48.0	8.58
	SENECA (533337) - KELLY (533217) 115KV LINE	1.00	Lead	48.0	0.11
	KNOB HILL (533332) - GREEN LEAF (539665) 115KV LINE	1.00	Lead	48.0	0.29
	HANSTN (530566) - KINSLY (530578) 69KV LINE	1.00	Lead	48.0	0.15
	HANSTN (530566) - JETMOR (530579) 69KV LINE	1.00	Lag	48.0	0.11
	MULLERGREN (539679) – CIRCLE (532871) 230KV LINE	1.00	Lag	48.0	0.35
	MULLERGREN (539679) – SPEARVILLE (539695) 230KV LINE	1.00	Lead	48.0	0.47

C. Gen-2009-040
POI: Smittyville-Knob Hill 115 kV Line

The VAR generator either supplies or absorbs reactive power at different contingencies as summarized in Table 2-4. The highest values obtained are as follows:

1. For the summer case, the VAR generator supplies 15.75 MVAR for the outage of Kelly 161/115 kV transformer and absorbs 9.92 MVAR for the loss of Knob Hill-Green Leaf 115 kV line. Power factors are 0.98 and 0.99, respectively.

2. For the winter case, the VAR generator supplies 17.38 MVAR for the outage of Seneca-Kelly 115 kV line and absorbs 9.79 MVAR for the loss of Knob Hill-Green Leaf 115 kV line. Power factors are 0.97 and 0.99, respectively.

For contingency Gen_2009_020-Nekoma 69 kV line, a fixed shunt capacitor has to be added at Gen_2009_020 34.5 kV bus in order to prevent voltage collapse. The capacitor sizes are 7 and 9 MVAR for summer and winter cases, respectively.

Table 2-4 VAR Generator Output in Summer and Winter Peak Cases for GEN-2009-040

CASE	CONTINGENCY	PF @ POI	PF	MW @ POI	MVAR @ POI
SP	BASE CASE	1.00	Lead	71.5	0.00
	SETAB 345KV (531465) - 115KV (531464) XFMER	1.00	Lag	71.5	0.00
	KELLY (533217) 115KV – KELLY (532913) 161KV XFMER	0.98	Lead	71.5	15.75
	CONCORDIA (539657) 115KV – CONCORDIA (532658) 230KV XFMER	1.00	Lag	71.5	6.83
	MINGO 345KV (531451) - 115KV (531429) XFMER	1.00	Lag	71.5	0.09
	MULLERGREN (539678) 230KV – MULLERGREN (539679) 115KV XFMER	1.00	Lag	71.5	0.99
	KNOLL 230KV (530558) - 115KV (530561) XFMER	1.00	Lead	71.5	0.00
	NEKOMA (530564) 69KV – NEKOMA (530608) 115KV XFMER	1.00	Lead	71.5	0.00
	HEIZER (530563) 69KV – HEIZER (530601) 115KV XFMER	1.00	Lead	71.5	0.00
	HEIZER (530601) 115KV – MULLERGREN (539679) 230KV XFMER	1.00	Lead	71.5	0.01
	KNOLL 230KV (530558) - 345KV (560004) XFMER	1.00	Lead	71.5	0.32
	S. HAYS (530582) 230KV – S. HAYS (530553) 115KV XFMER	1.00	Lag	71.5	0.05
	MINGO (531451) - RED WILLOW (640325) 345KV LINE	1.00	Lead	71.5	1.40
	HOLCOMB (531449) - GEN-2007-040 (531000) 345KV LINE	1.00	Lag	71.5	0.16
	KNOLL (560004) - GEN-2010-016 (576704) 345KV LINE	1.00	Lead	71.5	0.24
	KNOLL (530558) - SMOKY HILLS (530592) 230KV LINE	1.00	Lag	71.5	0.07
	KNOLL (530558) - SOUTH HAYS (530582) 230KV LINE	1.00	Lead	71.5	0.33
	KNOLL (530561) - SALINE (530551) 115KV LINE	1.00	Lag	71.5	1.09
	KNOLL (530561) - REDLINE (530605) 115KV LINE	1.00	Lag	71.5	0.11
	SOUTH HAYS (530582) - MULLERGREN (539679) 230KV LINE	1.00	Lag	71.5	0.22
	KNOLL (530561) - N HAYS (530581) 115KV LINE	1.00	Lead	71.5	0.01
	PIONEER TAP (539642) - MULLERGREN (539678) 115KV LINE	1.00	Lag	71.5	0.81
	GEN-2009-040 (560287) - SMITTYVILLE (533338) 115KV LINE	1.00	Lead	71.5	5.26
	GEN-2009-040 (560287) - KNOB HILL (533332) 115KV LINE	1.00	Lag	71.5	5.26
	GEN-2009-020 (575040) - BALZINE (530585) 69KV LINE	1.00	Lag	71.5	0.01
	GEN-2009-020 (575040) - NEKOMA (530564) 69KV LINE	1.00	Lead	71.5	0.10
	SENECA (533337) - KELLY (533217) 115KV LINE	0.98	Lead	71.5	14.64
	KNOB HILL (533332) - GREEN LEAF (539665) 115KV LINE	0.99	Lag	71.5	9.92
	HANSTN (530566) - KINSLY (530578) 69KV LINE	1.00	Lag	71.5	0.01
	HANSTN (530566) - JETMOR (530579) 69KV LINE	1.00	Lead	71.5	0.01
	MULLERGREN (539679) - CIRCLE (532871) 230KV LINE	1.00	Lead	71.5	0.28
	MULLERGREN (539679) - SPEARVILLE (539695) 230KV LINE	1.00	Lag	71.5	0.22
WP	BASE CASE	1.00	Lag	71.5	1.78
	SETAB 345KV (531465) - 115KV (531464) XFMER	1.00	Lag	71.5	0.16
	KELLY (533217) 115KV – KELLY (532913) 161KV XFMER	0.99	Lead	71.5	12.40
	CONCORDIA (539657) 115KV – CONCORDIA (532658) 230KV XFMER	0.99	Lag	71.5	9.29
	MINGO 345KV (531451) - 115KV (531429) XFMER	1.00	Lead	71.5	0.03
	MULLERGREN (539678) 230KV – MULLERGREN (539679) 115KV XFMER	1.00	Lag	71.5	1.17
	KNOLL 230KV (530558) - 115KV (530561) XFMER	1.00	Lag	71.5	0.07
	NEKOMA (530564) 69KV – NEKOMA (530608) 115KV XFMER	1.00	Lag	71.5	0.18

CASE	CONTINGENCY	PF @ POI	PF	MW @ POI	MVAR @ POI
	HEIZER (530563) 69KV – HEIZER (530601) 115KV XFMER	1.00	Lag	71.5	0.18
	HEIZER (530601) 115KV – MULLERGREN (539679) 230KV XFMER	1.00	Lag	71.5	0.18
	KNOLL 230KV (530558) - 345KV (560004) XFMER	1.00	Lead	71.5	0.44
	S. HAYS (530582) 230KV – S. HAYS (530553) 115KV XFMER	1.00	Lag	71.5	0.22
	MINGO (531451) - RED WILLOW (640325) 345KV LINE	1.00	Lead	71.5	1.60
	HOLCOMB (531449) - GEN-2007-040 (531000) 345KV LINE	1.00	Lag	71.5	0.33
	KNOLL (560004) - GEN-2010-016 (576704) 345KV LINE	1.00	Lead	71.5	0.28
	KNOLL (530558) - SMOKY HILLS (530592) 230KV LINE	1.00	Lag	71.5	0.12
	KNOLL (530558) - SOUTH HAYS (530582) 230KV LINE	1.00	Lead	71.5	0.35
	KNOLL (530561) - SALINE (530551) 115KV LINE	1.00	Lag	71.5	0.93
	KNOLL (530561) - REDLINE (530605) 115KV LINE	1.00	Lag	71.5	0.28
	SOUTH HAYS (530582) - MULLERGREN (539679) 230KV LINE	1.00	Lag	71.5	0.19
	KNOLL (530561) - N HAYS (530581) 115KV LINE	1.00	Lag	71.5	0.17
	PIONEER TAP (539642) - MULLERGREN (539678) 115KV LINE	1.00	Lag	71.5	0.04
	GEN-2009-040 (560287) - SMITTYVILLE (533338) 115KV LINE	1.00	Lead	71.5	4.92
	GEN-2009-040 (560287) - KNOB HILL (533332) 115KV LINE	1.00	Lag	71.5	3.63
	GEN-2009-020 (575040) - BALZINE (530585) 69KV LINE	1.00	Lag	71.5	0.17
	GEN-2009-020 (575040) - NEKOMA (530564) 69KV LINE	1.00	Lead	71.5	0.22
	SENECA (533337) - KELLY (533217) 115KV LINE	0.97	Lead	71.5	17.38
	KNOB HILL (533332) - GREEN LEAF (539665) 115KV LINE	0.99	Lag	71.5	9.79
	HANSTN (530566) - KINSLY (530578) 69KV LINE	1.00	Lag	71.5	0.19
	HANSTN (530566) - JETMOR (530579) 69KV LINE	1.00	Lag	71.5	0.17
	MULLERGREN (539679) – CIRCLE (532871) 230KV LINE	1.00	Lead	71.5	0.37
	MULLERGREN (539679) – SPEARVILLE (539695) 230KV LINE	1.00	Lag	71.5	0.11

2.3. Conclusions

In order to hold a voltage schedule at the POI's of the three projects consistent with the voltage schedule in the provided power flow cases, the wind farm should control the power factor at the POI to be within the ± 0.95 range.

For projects Gen-2009-008 and Gen-2009-040 involving the contingency Gen_2009_020-Nekoma 69 kV line, fixed shunt capacitor needs to be added at the 34.5 kV bus of Gen_2009_020 in order to prevent voltage collapse. The capacitor sizes are 7 and 9 MVAR for summer and winter cases, respectively.

3.1. Assumptions

The following assumptions were adopted for the dynamic simulations:

1. Constant maximum and uniform wind speed for the entire period of study.
2. Wind turbine control models with their default values.
3. Under/over voltage/frequency protection use manufacturer settings.

3.2. 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 a fault impedance to the positive sequence network at the fault location to represent the effect of the negative and zero sequence networks on the positive sequence network. The fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. This method is in agreement with SPP current practice. Prior queued projects shown in Table 1-2 and units in areas 520, 524, 525, 526, 531, 534, 536, 640, 645, and 650 were monitored in the simulations. Table 3-1 shows the list of simulated contingencies. It also shows the fault clearing time and the time delay before re-closing for all the study contingencies.

Table 3-1 List of Simulated Faults

No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Setab 345kV (531465) to 115kV (531464) transformer, near the 345 kV bus. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
2	FLT02-3PH	3 phase fault on the Mingo (531451) to Red Willow (640325) 345kV line, near Mingo. a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
3	FLT03-1PH	Single phase fault on the line in previous fault. a. Apply fault. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT04-3PH	3 phase fault on the Mingo 345kV (531451) to 115kV (531429) transformer, near the 345 kV bus. a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
5	FLT05-3PH	3 phase fault on the Holcomb (531449) to GEN-2007-040 (531000) 345kV line, near Holcomb. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
6	FLT06-1PH	Single phase fault on the line in previous fault. a. Apply fault. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
7	FLT07-3PH	3 phase fault on the Knoll (560004) to Gen-2010-016 (576704) 345kV line, near Knoll. a. Apply fault at the Knoll 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

No.	Cont. Name	Description
8	FLT08-1PH	Single phase fault on the line in previous fault. a. Apply fault. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
9	FLT11-3PH	3 phase fault on the Knoll (530558) to Smoky Hills (530592) 230kV line, near Smoky Hills.. a. Apply fault at the Smoky Hills 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT12-1PH	Single phase fault and sequence like previous
11	FLT13-3PH	3 phase fault on the Knoll (530558) to South Hays (530582) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT14-1PH	Single phase fault and sequence like previous
13	FLT15-3PH	3 phase fault on the Knoll 230kV (530558) to 345kV (560004) transformer, near the 230kV bus. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
14	FLT16-3PH	3 phase fault on one circuit of the Knoll 230kV (530558) to 115kV (530561) transformer, near the 230kV bus. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
15	FLT17-3PH	3 phase fault on the Knoll (530561) to Saline (530551) 115kV line, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
16	FLT18-1PH	Single phase fault and sequence like previous
17	FLT19-3PH	3 phase fault on the Knoll (530561) to Redline (530605) 115kV line, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT20-1PH	Single phase fault and sequence like previous
19	FLT21-3PH	3 phase fault on the South Hays (530582) to Mullergren (539679) 230kV line, near South Hays. a. Apply fault at the South Hays 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT22-1PH	Single phase fault and sequence like previous
21	FLT23-3PH	3 phase fault on the Knoll (530561) to N Hays (530581) 115kV line, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT24-1PH	Single phase fault and sequence like previous
23	FLT25-3PH	3 phase fault on the Pioneer Tap (539642) to Mullergren (539678) 115kV line, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT26-1PH	Single phase fault and sequence like previous

No.	Cont. Name	Description
25	FLT28-3PH	3 phase fault on the GEN-2009-040 (560287) to Smittyvillle (533338) 115kV line, near GEN-2009-040. a. Apply fault at the GEN-2009-040 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT29-1PH	Single phase fault and sequence like previous
27	FLT30-3PH	3 phase fault on the GEN-2009-040 (560287) to Knob Hill (533332) 115kV line, near GEN-2009-040. a. Apply fault at the GEN-2009-040 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT31-1PH	Single phase fault and sequence like previous
29	FLT32-3PH	3 phase fault on the GEN-2009-020 (575040) to Balzine (530585) 69kV line, near GEN-2009-020. a. Apply fault at the GEN-2009-020 69kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT33-1PH	Single phase fault and sequence like previous
31	FLT34-3PH	3 phase fault on the GEN-2009-020 (575040) to Nekoma (530564) 69kV line, near GEN-2009-020. a. Apply fault at the GEN-2009-020 69kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
32	FLT35-1PH	Single phase fault and sequence like previous
33	FLT36-3PH	3 phase fault on the Nekoma (530564) 69kV – Nekoma (530608) 115kV autotransformer on the 115kV bus a. Apply fault at the Nekoma 115 kV bus b. Clear fault after 5 cycles by tripping the faulted line.
34	FLT37-3PH	3 phase fault on the Heizer (530563) 69kV – Heizer (530601) 115kV transformer on the 115kV bus a. Apply fault at the Heizer 115 kV bus b. Clear fault after 5 cycles by tripping the faulted line.
35	FLT38-3PH	3 phase fault on one circuit of the Heizer (530601) 115kV – Mullergren (539679) 230kV transformer on the 115kV bus a. Apply fault at the Heizer 115 kV bus b. Clear fault after 5 cycles by tripping the faulted line.
36	FLT39-3PH	3 phase fault on the Mullergren (539679) 230kV – Mullergren (539679) 115kV transformer on the 230kV bus a. Apply fault at the Mullergren 115 kV bus b. Clear fault after 5 cycles by tripping the faulted line.
37	FLT40-3PH	3 phase fault on the S. Hays (530582) 230kV – S. Hays (530553) 115kV transformer on the 115kV bus a. Apply fault at the S. Hays 115 kV bus b. Clear fault after 5 cycles by tripping the faulted line.
38	FLT41-3PH	3 phase fault on the Kelly (533217) 115kV – Kelly (532913) 161kV transformer on the 115kV bus a. Apply fault at the Kelly 115 kV bus b. Clear fault after 5 cycles by tripping the faulted line.
39	FLT42-3PH	3 phase fault on the Concordia (539657) 115kV – Concordia (532658) 230kV transformer on the 230kV bus a. Apply fault at the Concordia 230kV bus b. Clear fault after 5 cycles by tripping the faulted line.

No.	Cont. Name	Description
40	FLT43-3PH	3 phase fault on the Seneca (533337) to Kelly (533217) 115kV line, near Kelly. a. Apply fault at the Kelly 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
41	FLT44-1PH	Single phase fault and sequence like previous
42	FLT47-3PH	3 phase fault on the Knob Hill (533332) to Green Leaf (539665) 115kV line, near Green Leaf. a. Apply fault at the Green Leaf 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
43	FLT48-1PH	Single phase fault and sequence like previous
44	FLT49-3PH	3 phase fault on the Hanstn (530566) to Kinsly (530578) 69kV line, near Hanstn. a. Apply fault at the Hanstn 69kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
45	FLT50-1PH	Single phase fault and sequence like previous
46	FLT51-3PH	3 phase fault on the Hanstn (530566) to Jetmor (530579) 69kV line, near Hanstn. a. Apply fault at the Hanstn 69kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
47	FLT52-1PH	Single phase fault and sequence like previous
48	FLT53-3PH	3 phase fault on the Mullergren (539679) – Circle (532871) 230kV line, near Mullergren. a. Apply fault at the Mullergren 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
49	FLT54-1PH	Single phase fault and sequence like previous
50	FLT55-3PH	3 phase fault on the Mullergren (539679) – Spearville (539695) 230kV line, near Mullergren. a. Apply fault at the Mullergren 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
51	FLT56-1PH	Single phase fault and sequence like previous

Table 3-2 shows the contingencies from the list provided by SPP which are not found in the power flow case provided.

Table 3-2 List of Faults Not Simulated

No.	Cont. Name	Description
1	FLT09-3PH	3 phase fault on the Knoll (530558) to Axtell (640065) 345kV line, near Knoll. a. Apply fault at the Knoll 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
2	FLT10-1PH	Single phase fault on the line in previous fault. a. Apply fault. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
3	FLT27-3PH	3 phase fault on the Smoky Hills 345/230kV autotransformer on the 230kV bus (530592) a. Apply fault at the Smoky Hills 230kV bus b. Clear fault after 5 cycles by tripping the faulted line.
4	FLT45-3PH	3 phase fault on the Knob Hill (533332) to Beatrice (640074) 115kV line, near Knob Hill. a. Apply fault at the Knob Hill 115kV bus b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
5	FLT46-1PH	Single phase fault and sequence like previous

Simulations were performed with a 0.1-second steady-state run followed by the appropriate disturbance as described in Table 3-1. Simulations were run for a minimum 10-second duration to confirm proper machine damping.

3.3. Simulation Results

For contingency Gen_2009_020-Nekoma 69 kV line, the stability simulations showed oscillations in the voltage, power and frequency of the plant Gen_2009_020. Addition of a 15 MVAR SVC placed at the 34.5 kV bus of Gen_2009_020 plant was needed to eliminate these oscilations.

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

Section 4. Conclusions

The findings of the impact study for the proposed interconnection projects under DISIS-2010-001 (Group 11), namely Gen-2009-008, Gen-2009-020, and Gen-2009-040, considered at 100% of their proposed installed capacities are as follows:

1. The results of the power factor analysis showed that with the MVAR capability of the project WTG's and without reactive compensation, each of the three wind farms will not be able to keep the voltage schedule at their respective POI's consistent with the voltage schedule in the provided power flow cases for summer and winter. For each project, additional VAR compensating devices need to be installed in order to control the power factor at their POI's to be within ±0.95 range.

   For projects Gen-2009-008 and Gen-2009-040 involving the contingency Gen_2009_020-Nekoma 69 kV line, fixed shunt capacitor needs to be added at the 34.5 kV bus Gen_2009_020 in order to prevent voltage collapse. The capacitor sizes are 7 and 9 MVAR for the summer and winter cases, respectively.

2. The stability simulations showed oscillations in the voltage, power and frequency of the plant Gen_2009_020 for contingency Gen_2009_020-Nekoma 69 kV line in both the summer and winter cases. Addition of a 15 MVAR SVC placed at the 34.5 kV bus of Gen_2009_020 plant was needed to eliminate these oscilations.

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