SPP Southwest Power Pool

Impact Study For Generation Interconnection Request GEN-2006-040

SPP Tariff Studies

(#GEN-2006-040)

October 2007

Summary

Pursuant to the tariff and at the request of the Southwest Power Pool (SPP), Pterra Consulting (Pterra) conducted the following Impact Study to satisfy the Impact Study Agreement executed by the requesting customer and SPP for SPP Generation Interconnection request GEN-2006-040. The request for interconnection was placed with SPP in accordance SPP's Open Access Transmission Tariff, which covers new generation interconnections on SPP's transmission system.

Facilities

The Impact Study determined that no SVC or STATCOM device was necessary for the requested generation using the Suzlon S88 wind turbines using the manufacturer's package for low voltage ride through. It was determined that a 34.5kV, 10Mvar capacitor bank is necessary for reactive compensation at the point of interconnection.

It was also found that the addition of the wind farm causes the Colby generator to go out of step for a loss of the Mingo 345/115kV autotransformer. The only solution to the Colby generator problem was found to be a replacement of the excitation system to an IEEE Static type exciter.

The latest facility estimates are given in Table 1 and Table 2. These costs will be refined if the Customer executes a Facility Study Agreement. These costs do not include facilities that may be required after a fault study analysis. This analysis will be conducted if the Customer executes a Facility Study Agreement.

Table 1: Direct Assignment Facilities

FACILITY	ESTIMATED COST (2007 DOLLARS)
Customer – 115/34.5 kV Substation facilities.	*
Customer – 115 kV transmission line facilities between Customer facilities and Mingo Substation.	*
Customer – Right-of-Way for Customer facilities.	
Customer – 34.5 kV, 10 Mvar capacitor bank(s) in Customer substation.	*
MIDW – Replace excitation system at Colby power station	$70,000
Total	*****

Note: *Estimates of cost to be determined by Customer.

Table 2: Required Interconnection Network Upgrade Facilities

Facility	ESTIMATED COST (2007 DOLLARS)
SUNC – Add one 115 kV terminal including one 115 kV circuit breaker, associated switches, buswork, relaying and all miscellaneous equipment at Mingo Substation.	$304,000 *
Total	**$304,000**

**Requires that Customer line enter Mingo Substation from the South. Estimate will be slightly higher if Customer line enters Mingo substation from any other direction.*

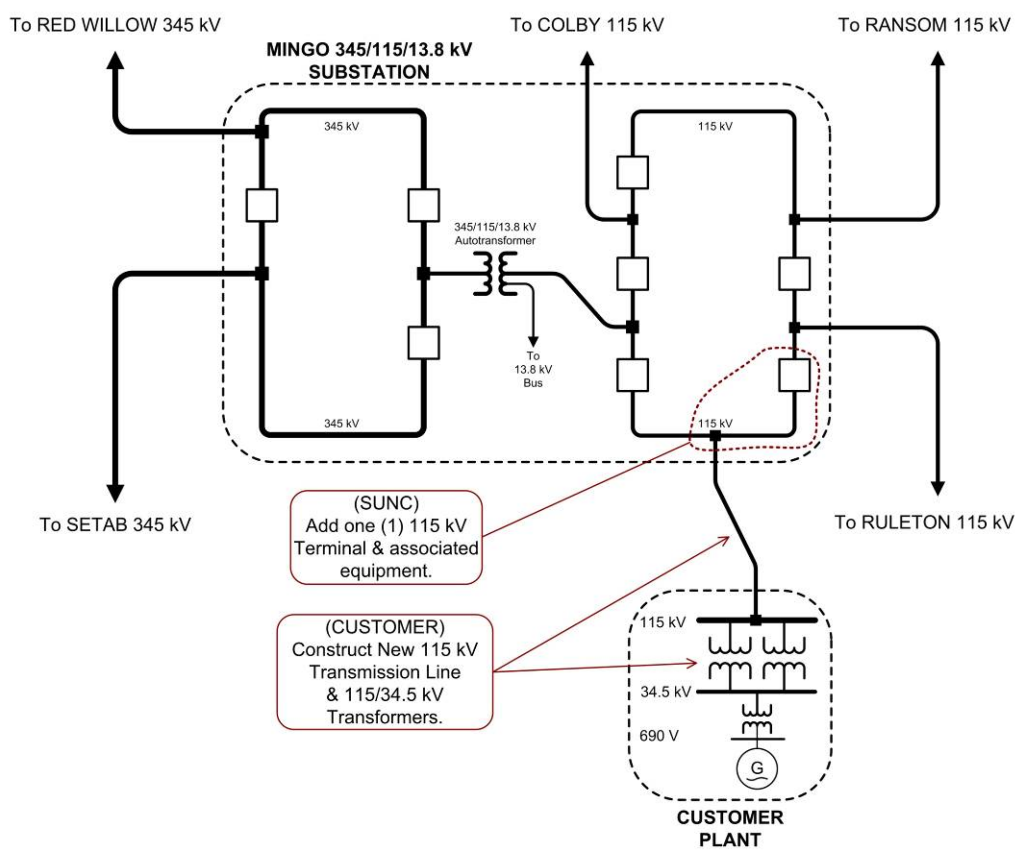

Figure 1: Proposed Interconnection
(Final substation design to be determined)

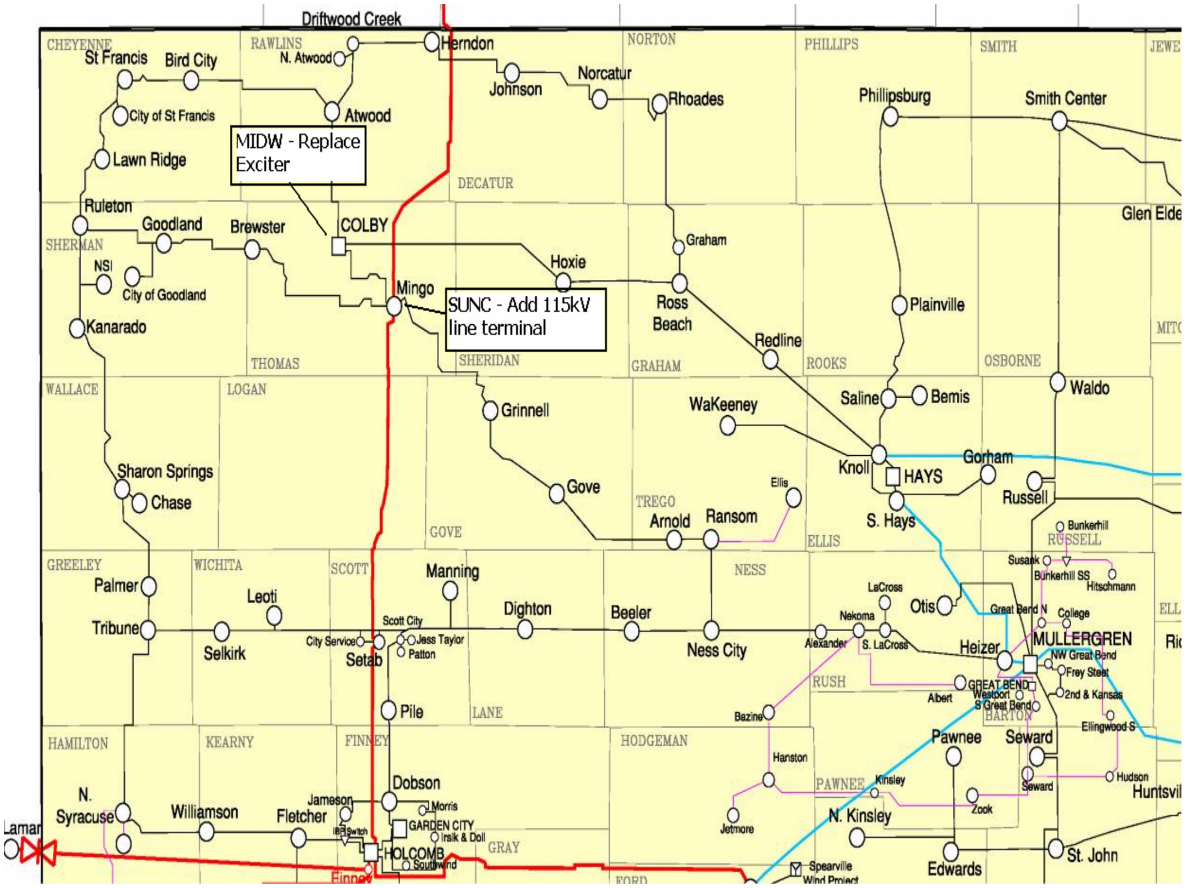

FIGURE 2. MAP OF THE LOCAL AREA

Pterra Consulting

Draft Report No. R126-07

"Impact Study for Generation Interconnection Request GEN-2006-040"

Submitted to

The Southwest Power Pool

August 2007

Pterra

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Report No. R126-07

"Impact Study for Generation Interconnection Request GEN-2006-040"

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1. Executive Summary

This report presents the stability simulation findings of the impact study of a proposed interconnection plant (GEN-2006-040). The analysis was conducted through the Southwest Power Pool Tariff for a 115 kV interconnection for 107 MW wind farm in Thomas County, Kansas. This wind farm would be interconnected by adding a new 115kV line terminal into the existing Mingo 115kV substation. This substation is owned by Sunflower Electric Power Corp. (SUNC). The customer has asked for a study case of 100% MW. The customer has requested using Suzlon S88-2.1 MW wind turbines using the low voltage ride through package.

Two base cases each comprising of a power flow and corresponding dynamics database for 2007 summer peak and 2011 winter peak were provided by SPP. Transient stability simulations were conducted with the proposed wind farm in service with a full output of 107 MW. In order to integrate the proposed 107 MW wind farm in SPP system, the existing generation in the SPP footprint was re-dispatched as provided by SPP. Unity power factor at the interconnection point was achieved by using 10 MVAR capacitor located on the 34.5kV customer side.

Twenty (20) disturbances were considered for the transient stability simulations which included 3-phase faults as well as 1-phase to ground faults at the locations defined by SPP.

The proposed Suzlon S88-2.1 MW wind turbines were modeled with under/over voltage/frequency ride through protection. The settings were in accordance with standard or default settings. The simulations conducted in the study using the Suzlon S88-2.1MW model provided by the customer found that system stability concerns exist for fault / contingency # 7 (3 phase fault at Mingo 345 kV followed by the loss of the Mingo autotransformer and 50 MVAr reactors). No other angular or voltage instability problems were observed for any other contingency.

For the aforementioned fault in the winter peak case, stability simulations showed the existing Colby steam plant, also connected to the Mingo 115 kV, went out-of-step (unstable) in the case with the project and showed stable response in the case without the Project. This demonstrates that the project degrades the stability performance of the system. However, the stability performance in the case with the project could be brought to an acceptable level. For example, replacing the exciter at the Colby unit with a static type could improve the stability performance and avoid the out-of-step (unstable) response in the case with the Project.

In conclusion, the study finds that the proposed 107 MW project shows stable performance of SPP system for the contingencies tested on the supplied base cases, except for Fault #7 in winter peak case in which a remedy (such as replacing the Colby Plant’s exciter) would be required.

2. Introduction

2.1 Project Overview

The proposed 107 MW wind farm will be interconnected electrically into a new 115 kV line terminal into the existing Mingo 115kV substation. This substation is owned by Sunflower Electric Power Corp. (SUNC). Figure 1 shows a conceptual interconnection diagram of the proposed GEN-2006-040 project to the 115 kV sub-transmission network. The detailed connection diagram of the wind farm was provided by SPP.

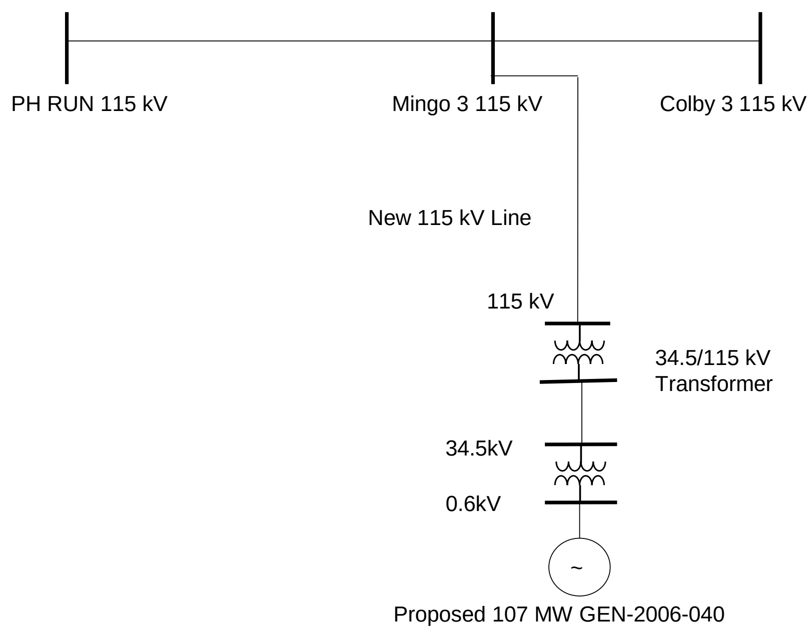

Figure 1. Interconnection Point for GEN-2006-040 to the 115 kV System

In order to integrate the proposed 107 MW wind farm in SPP system as an energy resource, existing generation in the SPP footprint is displaced to maintain current area interchange totals.

To simplify the model of the wind farm while capturing the effect of the different impedances of cables (due to change of the conductor size and length), the wind turbines connected to the same 34.5kV feeder were aggregated into one equivalent unit. An equivalent impedance of that feeder was represented by taking the equivalent series impedances of the different feeders connecting the wind turbines. Using this approach, the proposed 107 MW wind farm was modeled with 18 equivalent units as shown in Figure 2. The number in each circle in the diagram shows the number of individual wind turbine units that were aggregated at that bus. SPP provided the impedance values for the different feeders at 34.5kV level. SPP provided the data for the following equipment:

1. 34.5 kV feeders
2. Generating unit step up transformers
3. 115/34.5 kV transformers
4. 115 kV line from the high side of 115/34.5 kV transformers (mentioned above) to the point of interconnection.

Unity power factor was achieved at the interconnection point using 8 MVAR capacitor located at the 34.5 kV side of the 115/34.5 kV Transformer.

2.2 Objective

The objective of the study is to determine the impact on system stability of connecting the proposed 107 MW wind farm to SPP's 115 kV sub-transmission system.

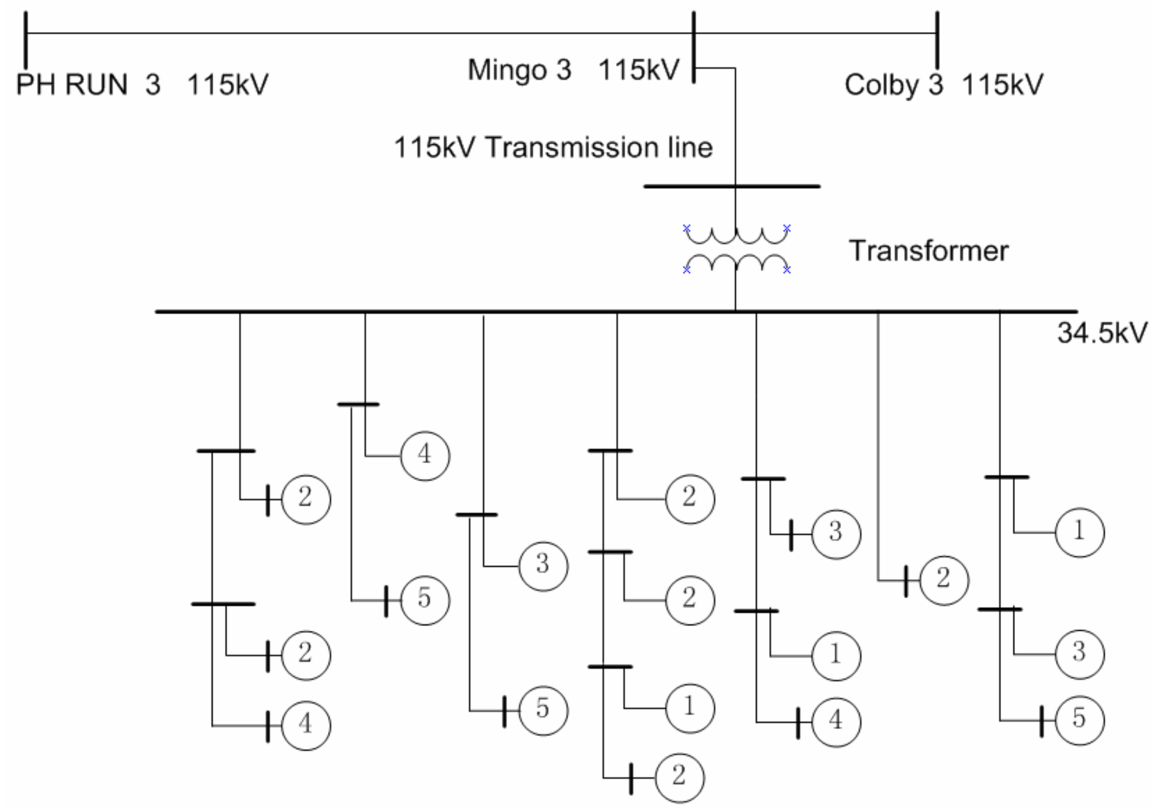

Figure 2. Wind Farm Model in Load Flow (51 Suzlon S88-2.1 MW WTGs or Total of 107 MW)

3. Stability Analysis

3.1 Modeling of the Suzlon S88-2.1 MW Wind Turbine Generators

Equivalents for the wind turbine and generator step-up (GSU) transformer in the load flow case were modeled. For the stability simulations, the Suzlon S88-2.1 MW WTGs were modeled using the provided Suzlon S88-2.1 MW wind turbine dynamic model set, as shown in Table 1.

Table 1. Suzlon S88-2.1 MW WTGs Data

Suzlon S88-2.1 MW – Equivalent synchronous data		4 pole	
Rated voltage (ph-ph)	U	600V	
Rated generator power factor	PF	0.92 (uncompensated)	
Short circuit ratio (without SCS soft start)	IST / IN	5.26	
Rated kVA base	K-Base	2,283 kVA	
Base impedance	Z-Base	0.158 Ohm	
Stator resistance	R1	0.0027 Ohm	0.017 p.u.
Stator leakage reactance	X1	0.0536 Ohm	0.340 p.u.
Synchronous reactance	Xd	2.5636 Ohm	5.402 p.u.
Short-circuit timecon.	Td0	N/A	N/A
Transient reactance	Xd’	0.0941 Ohm	0.198 p.u.
Short-circuit transient timecon.	Td’	0.0206 sec.	N/A
Open circuit transient timecon.	Td0’	N/A	N/A
Subtransient reactance	Xd’’	0.0523 Ohm	0.110 p.u.
Short Circuit subtransient time constant	Td’’	N/A	N/A
Open circuit subtransient timecon.	Td0’’	N/A	N/A
Inertia constant (incl. turbine)	H	4.7 sec.	N/A
Saturation curvepoints (noload)	S (1,0)	N/A	N/A
Saturation curvepoints (noload)	S (1,1)	N/A	N/A
Saturation curvepoints (noload)	S (1,2)	N/A	N/A

The wind turbine generators have ride-through capability for voltage and frequency. Detailed relay settings are shown in the following tables:

Table 2. Over/Under Frequency Relay Settings for Suzlon S88-2.1 MW WTGs

Frequency Settings in Hertz	Time Delay in Seconds
f≤57	0.02
f≥63	0.02

Table 3. Over/Under Voltage Relay Settings for Suzlon S88-2.1 MW WTGs

Voltage Settings Per Unit	Time Delay in Seconds
$V \leq 0.15$	0.08
$0.15 < V \leq 0.40$	0.7
$0.40 < V \leq 0.60$	1.6
$0.60 < V \leq 0.80$	2.8
$0.80 < V \leq 0.90$	60.0
$1.20 < V \leq 1.15$	60.0
$V \geq 1.20$	0.08

3.2 Disturbances Simulated

Twenty (20) disturbances 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. Table 4 shows the list of simulated disturbances. The table also shows the fault clearing time and the time delay before re-closing for all the study disturbances.

Table 4. List of Simulated Disturbances

1. FLT13PH – 3-phase fault

Fault on the Mingo (56429) to Brewster (56351) 115 kV line, near Mingo

a. Apply Fault at Mingo.
b. Clear Fault after 5 cycles by removing the line from the Mingo - Brewster
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.

2. FLT21PH – 1-phase fault

· Same as FLT13PH above

3. FLT33PH – 3-phase fault

Fault on the Mingo (56429) to Colby (56555) 115 kV line, near Mingo

a. Apply Fault at Mingo.
b. Clear Fault after 5 cycles by removing the line from the Mingo - Colby
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. FLT41PH – 1-phase fault

· Same as FLT33PH above

5. FLT53PH – 3-phase fault

Fault on the Mingo (56429) to Grinnell (56412) 115 kV line, near Mingo

a. Apply Fault at Mingo.
b. Clear Fault after 5 cycles by removing the line from the Mingo – PH Run (56559) - Colby
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.

6. FLT61PH – 1-phase fault

· Same as FLT53PH above

7. FLT73PH – 3-phase fault

Fault on the Mingo Autotransformer on the 345kV bus

a. Apply Fault at Mingo (56451).
b. Clear Fault after 5 cycles by open the transformer branch

8. FLT81PH – 1-phase fault

· Same as FLT73PH above

9. FLT9PH – 3-phase fault

Fault on the Mingo (56451) – Setab (56465) 345kV line near Mingo

a. Apply Fault at Mingo 345kV.
b. Clear Fault after 5 cycles by removing the line from Mingo - Setab
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. FLT101PH – 1-phase fault

· Same as FLT93PH above

11. FLT113PH – 3-phase fault

Fault on the Mingo (56451) – Red Willow (64943) 345kV line near Mingo

a. Apply Fault at Mingo 345kV.

b. Clear Fault after 5 cycles by removing the line from Mingo – Red Willow

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. FLT121PH – 1-phase fault

· Same as FLT113PH above

13. FLT133PH – 3-phase fault

Fault on the Colby (56555) to Hoxie (56556) 115 kV line, near Hoxie

a. Apply Fault at the Hoxie bus .

b. Clear Fault after 5 cycles by removing the line from Colby - Hoxie

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.

14. FLT141PH – 1-phase fault

· Same as FLT133PH above.

15. FLT153PH – 3-phase fault

Fault on the Holcomb (56449) to Spearville (56469) 345 kV line, near Spearville

a. Apply Fault at the Spearville bus

b. Clear Fault after 5 cycles by removing the line from Holcomb - Spearville

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. FLT161PH – 1-phase fault

· Same as FLT153PH above

17. FLT173PH – 3-phase fault

Fault on the Tribune Switch (56438) to Selkirk (56434) 115 kV line, near Tribune Switch

a. Apply Fault at the Tribune Switch bus (56438).

b. Clear Fault after 5 cycles by removing the line from Tribune Switch - Selkirk

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. FLT181PH – 1-phase fault

· Same as FLT173PH above

19. FLT93PH – 3-phase fault

Fault on the Colby (56555) to Atwood (56554) 115 kV line, near Atwood

a. Apply Fault at the Atwood bus (56554).

b. Clear Fault after 5 cycles by removing the line from Colby-Atwood

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. FLT121PH – 1-phase fault

·	Same as FLT193PH above.

3.3 Simulation Results

Simulations were performed with a 0.5-second steady-state run followed by the appropriate disturbance as described in Table 4. Simulations were run for minimum 10-second duration to confirm proper machine damping.

The results of the stability simulations, for the disturbances listed in Table 4, found that stability concerns exist for contingency # 7 (3 phase fault at Mingo 345 kV followed by the loss of the Mingo autotransformer and 50 MVAr reactors). No other angular of voltage instability problems with the Suzlone 2.1MW WTG were observed for any other contingency.

For the aforementioned fault in the winter peak case, stability simulations showed the existing Colby steam plant, also connected to the Mingo 115 kV, went out-of-step (unstable) in the case with the project and showed stable response in the case without the Project. This demonstrates that the project degrades the stability performance of the system. However, the stability performance in the case with the project could be brought to an acceptable level. For example, replacing the exciter at the Colby unit with a static type could improve the stability performance and avoid the out-of-step (unstable) response in the case with the Project.

Comparison plots are provided to compare rotor angle and voltage responses in the case without the project, with the project, and with the project plus replacement of the Colby plant's exciter to a static type (in this case, the study uses ESST3A).

In addition, a complete set of the transient stability plots for the two base cases with the proposed 107 MW wind farm in service are provided in the accompanying CD-ROM. The plots include rotor angle, speed, frequency, and voltages for the monitored buses and machines in the SPP.

4. Conclusion

The stability simulation findings of the impact study of a proposed interconnection plant (GEN-2006-040) were presented in this report. The impact study case considered 100% MW of the wind farm proposed output. Suzlon S88-2.1 MW WTGs were studied according to the customer request.

The 2007 summer and 2011 winter load flow cases together with the necessary data needed for the transient stability simulations were provided by SPP. Transient stability simulations were conducted with the proposed wind farm in service with a full output of 107 MW. In order to integrate the proposed 107 MW wind farm in SPP system, re-dispatch for the existing SPP footprint generation was provided by SPP. Unity power factor at the interconnection point was achieved by adding 8 MVAR capacitor at the 34.5kV side of the project substation.

Twenty (20) disturbances were considered for the transient stability simulations which included three phase faults as well as single line to ground faults at the locations defined by SPP.

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In conclusion, the study finds that the proposed 107 MW project shows stable performance of SPP system for the contingencies tested on the supplied base cases, except for Fault #7 in winter peak case in which a remedy (such as replacing the Colby Plant’s exciter) would be required.

Appendix A. Project Data

S88001 V2.0
BMI 14/11/05

Base and Loadflow Information			
Prated	2.10	Machine Active Power Rating (MW)	MBASE
Vrated	0.6	Stator Voltage Rating (kV)	
Busbar	90200	Connection busbar number	
Gen ID	1	Generator Identifier	
Rg	0.0053	Generator Resistance in Loadflow (pu, Rs)	
Xg	0.2116	Generator Reactance in Loadflow (pu, Xs+(Xr*Xm)/(Xr+Xm))	
Srated	2.5	Unit Transformer Rating (MVA)	Note 1
Rt	0.001	Unit Transformer Resistance (pu)	Note 1
Xt	0.06	Unit Transformer Reactance (pu)	Note 1

ICONS	**Value**	**Description**	**Ref:**
M	20	Model Version Number	
M+1	0	Enable Reactive FRT characteristic	
M+2	1	Enable Under-voltage relay 1	
M+3	1	Enable Under-voltage relay 2	
M+4	1	Enable Under-voltage relay 3	
M+5	1	Enable Under-voltage relay 4	
M+6	1	Enable Under-voltage relay 5	
M+7	1	Enable Over-voltage relay 1	
M+8	1	Enable Over-voltage relay 2	
M+9	1	Enable Under-frequency relay 1	
M+10	1	Enable Over-frequency relay 1	

CONs	**Value**	**Description**	**Ref:**
J	0.0053	Stator Resistance (pu, stator base)	
J+1	0.1042	Stator Reactance (pu, stator base)	
J+2	5.0556	Magnetising Reactance (pu, stator base)	
J+3	0.0066	Rotor Resistance (pu, stator base)	
J+4	0.1097	Rotor Reactance (pu, stator base)	
J+5	2.8763	Generator Inertia Constant (MW.s/MVA)	
J+6	4.1622	Rotor Inertia Constant (MW.s/MVA)	
J+7	5.6849	Shaft Damping	
J+8	71.3826	Shaft Stiffness	
J+9	0.3	Speed Controller proportional gain (pu)	
J+10	0.476	Speed Controller time constant (s)	
J+11	0.03	Speed and Power measurement filter time constant (s)	
J+12	0.1697	Maximum value of external resistance (pu, stator base)	
J+13	0.0135	Crowbar resistance (pu, stator base)	
J+14	1.36	Activation current for rotor crowbar (pu, stator	

		base)
J+15	1.22	Reset current for rotor crowbar timer (pu)
J+16	0.15	Reset time for rotor crowbar (s)
J+17	150.0	Pitch Controller proportional gain (pu) - Normal
J+18	25.0	Pitch Controller integral gain (pu) - Normal
J+19	1850	Pitch Controller reference speed (rpm) - Normal
J+20	150.0	Pitch Controller proportional gain (pu) - Fault
J+21	25.0	Pitch Controller integral gain (pu) - Fault
J+22	1820	Pitch Controller reference speed (rpm) - Fault
J+23	37.0	Maximum Pitch Angle Demand (degrees)
J+24	-2.0	Minimum Pitch Angle Demand (degrees)
J+25	88.0	Pitch Angle Demand with machine tripped (degrees)
J+26	0.10	Pitch Servo time constant (s)
J+27	10.0	Pitch Servo maximum positive slew rate (degrees/second)
J+28	-10.0	Pitch Servo maximum negative slew rate (degrees/second)
J+29	18.0	Specified Wind Speed for full load operation (m/s)
J+30	1.225	Air Density (kg/m^3)
J+31	9999	Gust Start Time (s)
J+32	9999	Gust Duration (s)
J+33	0	Gust Peak of base speed (m/s)
J+34	9999	Wind Ramp Start (s)
J+35	9999	Wind Ramp End (s)
J+36	0	Wind Ramp maximum over base (m/s)
J+37	0.90	Under Voltage Relay 1 - Voltage Setting (pu)
J+38	60.00	Under Voltage Relay 1 - Time Setting (s)
J+39	0.80	Under Voltage Relay 2 - Voltage Setting (pu)
J+40	2.80	Under Voltage Relay 2 - Time Setting (s)
J+41	0.60	Under Voltage Relay 3 - Voltage Setting (pu)
J+42	1.60	Under Voltage Relay 3 - Time Setting (s)
J+43	0.40	Under Voltage Relay 4 - Voltage Setting (pu)
J+44	0.70	Under Voltage Relay 4 - Time Setting (s)
J+45	0.15	Under Voltage Relay 5 - Voltage Setting (pu)
J+46	0.08	Under Voltage Relay 5 - Time Setting (s)
J+47	1.15	Over Voltage Relay 1 - Voltage Setting (pu)
J+48	60.00	Over Voltage Relay 1 - Time Setting (s)
J+49	1.20	Over Voltage Relay 2 - Voltage Setting (pu)
J+50	0.08	Over Voltage Relay 2 - Time Setting (s)
J+51	0.95	Under Frequency Relay 1 - Frequency Setting (pu)
J+52	0.20	Under Frequency Relay 1 - Time Setting (s)
J+53	1.05	Over Frequency Relay 1 - Frequency Setting (pu)
J+54	0.20	Over Frequency Relay 1 - Time Setting (s)
J+55	0.90	PFC lower steady-state limit (pu)
J+56	1.10	PFC upper steady-state limit (pu)
J+57	0.00	PFC minimum steady-state reactive power (pu)

J+58	1.00	PFC maximum steady-state reactive power (pu)
J+59	0.00	PFC Voltage point 1 (pu)
J+60	0.00	PFC Reactive point 1 (pu, Mbase)
J+61	0.10	PFC Voltage point 2 (pu)
J+62	1.00	PFC Reactive point 2 (pu, Mbase)
J+63	0.20	PFC Voltage point 3 (pu)
J+64	1.00	PFC Reactive point 3 (pu, Mbase)
J+65	0.30	PFC Voltage point 4 (pu)
J+66	1.00	PFC Reactive point 4 (pu, Mbase)
J+67	0.40	PFC Voltage point 5 (pu)
J+68	1.00	PFC Reactive point 5 (pu, Mbase)
J+69	0.50	PFC Voltage point 6 (pu)
J+70	1.00	PFC Reactive point 6 (pu, Mbase)
J+71	0.60	PFC Voltage point 7 (pu)
J+72	0.81	PFC Reactive point 7 (pu, Mbase)
J+73	0.70	PFC Voltage point 8 (pu)
J+74	0.60	PFC Reactive point 8 (pu, Mbase)
J+75	0.80	PFC Voltage point 9 (pu)
J+76	0.41	PFC Reactive point 9 (pu, Mbase)
J+77	0.90	PFC Voltage point 10 (pu)
J+78	0.21	PFC Reactive point 10 (pu, Mbase)

DYRE Data (auto-generated from datasheet information. Copy/paste into DYRE file.)

```
/ S88001 V2.0
 90200 'USRMDL' 1 'S88001' 1 1    11 79 4 32
 20 0 1 1 1 1 1 1 1 1 0.0053 0.1042 5.0556 0.0066 0.1097 2.8763 4.1622 5.6849 71.3826
 0.3 0.476 0.03 0.1697 0.0135 1.36 1.22 0.15 150.0 25.0 1850 150.0 25.0 1820
 37.0 -2.0 88.0 0.10 10.0 -10.0 18.0 1.225 9999 9999 0 9999 9999 0
 0.90 60.00 0.80 2.80 0.60 1.60 0.40 0.70 0.15 0.08 1.15 60.00 1.20 0.08 0.95 0.20 1.05 0.20
 0.90 1.10 0.00 1.00 0.00 0.00 0.10 1.00 0.20 1.00 0.30 1.00 0.40 1.00 0.50 1.00
 0.60 0.81 0.70 0.60 0.80 0.41 0.90 0.21  /
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TNEI Services Ltd / S88001 V2.0

S88001 V2.0

BMI 14/11/05

User Model	S88001
ICONs	11
CONs	79
STATEs	4
VARs	32

STATEs	Description	Ref:
K	Stator power filter	
K+1	Generator speed filter	
K+2	Pitch controller internal state	
K+3	Actual blade pitch angle	

VARs	Description	Ref:
L	Open-circuit machine transient reactance	
L+1	Short-circuit machine transient reactance	
L+2	Rotor current magnitude	
L+3	Electrical torque	
L+4	Mechanical torque	
L+5	Aerodynamic torque	
L+6	Pitch controller demand angle	
L+7	Effective wind speed	
L+8	Machine status (0=OFF, 1=ON)	
L+9	Crowbar status (0=OFF, 1=ON)	
L+10	Elapsed crowbar reset time	
L+11	Asynchronous machine reactive power	
L+12	Elapsed relay time (UV1)	
L+13	Elapsed relay time (UV2)	
L+14	Elapsed relay time (UV3)	
L+15	Elapsed relay time (UV4)	
L+16	Elapsed relay time (UV5)	
L+17	Elapsed relay time (OV1)	
L+18	Elapsed relay time (OV2)	
L+19	Elapsed relay time (UF1)	
L+20	Elapsed relay time (OF1)	
L+21	Reactive compenstator output	
L+22	External rotor resistance	
L+23	Steady-state PFC output for STATCOM PFC mode	Note 3
L+24	Initial Wind speed (for wind model)	
L+25	PFC capacitive admittance for fixed capacitor PFC mode	Note 3
L+26	D-axis transient internal EMF	Note 2
L+27	Q-axis transient internal EMF	Note 2
	Generator	
L+28	Slip	Note 2
L+29	Shaft Angle	Note 2
L+30	Rotor Speed	Note 2
L+31	Speed controller internal state	Note 2

Note 1	Unit transformer is to be explicitly represented in PSS/E network
Note 2	State variables solved using model internal integration solver
Note 3	Depends on which PFC mode has been enabled (ICON M+1)