Impact Study for Generation Interconnection Request GEN–2007–006

SPP Tariff Studies
(#GEN-2007-006)

January 2008

Summary

Pursuant to the tariff and at the request of the Southwest Power Pool (SPP), S&C Electric Company (S&C) performed the following Impact Study to satisfy the Impact Study Agreement executed by the requesting customer and SPP for SPP Generation Interconnection request GEN-2007-006. 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.

Interconnection Facilities

The Impact Study has determined that a number of issues are encountered due to the addition of GEN-2007-006. The Customer requested to use Suzlon S88 2.1MW wind turbines for this interconnection request. To maintain a unity power factor during normal operation, the Impact Study determined that a total of 36 Mvars of 34.5kV capacitor banks are required for the operation of GEN-2007-006. This capacitor bank(s) should be staged so that excessive voltage variations are not experienced on the OG&E transmission system.

To meet the low voltage requirements of FERC Order #661A, the Impact Study determined that the Interconnection Customer will be required to install two (2) 34.5kV STATCOM devices within the Interconnection Customer's substation. These STATCOM devices were initially sized at +/-21 MVA each for a total of +/-42 MVA. However, exact sizing will need to be performed by the manufacturer of the devices using exact dynamic models provided by the manufacturer. The size of these devices or possibly even the need for the devices may change depending upon a number of factors, including whether prior queued interconnection requests in the local area withdraw or whether new transmission lines are built in the area of the interconnection request as a result of transmission service request studies.

The Impact Study also determined that for certain contingencies, the addition of GEN-2007-006 will depress voltages enough in the area to cause two prior queued projects in the area to develop unstable oscillations in power, speed, and voltage. These two prior queued generation interconnection requests, GEN-2001-014 and GEN-2006-046 both use Suzlon S88 wind turbines, which is also used by GEN-2007-006. The Suzlon turbines oscillations at observed voltages at less than 0.92 per unit may only be an issue with the dynamic model provided by the manufacturer. However, the dynamic model is the basis of this study. To prevent these oscillations by the two previous queued interconnection requests, additional capacitor banks are required to be installed for these two wind farms.

At GEN-2001-014, the additional 12 Mvar of capacitance necessary for stable operation is located at the wind farm. However, it is unknown if proper switching equipment is present at this station to accommodate the necessary switching procedure. This will be evaluated during the Facility Study.

At GEN-2006-046, the capacitance specified is in addition to the capacitance specified in the Impact Study for this request. Therefore, the Interconnection Customer for GEN-2007-006 is responsible for the cost to install additional capacitors at GEN-2006-046. These costs will be further evaluated in the Facility Study.

The need for these capacitor banks and switching devices at GEN-2001-014 and GEN-2006-046 may change depending upon a number of factors, including whether prior queued interconnection requests in the local area withdraw or whether new transmission lines are built in the area of the interconnection request as a result of transmission service request studies.

The interconnection facilities necessary for this generation interconnection request are listed below in Table 1 and Table 2. These cost estimates will be refined if the Customer executes a Facility Study Agreement. These costs do not include costs associated with short circuit analysis. A short circuit study will be performed when the Customer executes a Facility Study Agreement.

Table 1: Direct Assignment Facilities

FACILITY	ESTIMATED COST (2008 DOLLARS)
Customer – 138/34.5 kV Substation facilities.	*
Customer – 138 kV transmission line facilities between Customer facilities and the Roman Nose Substation.	*
Customer - Right-of-Way for Customer facilities.	*
Customer –Two (2) 34.5 kV, 18 Mvar staged capacitor bank(s) in Customer substation.	*
Customer – Two (2) 34.5kV, +/-21 MVA STATCOM devices in Customer substation	*
GEN-2001-014 – Switching devices to properly switch capacitor banks to prevent voltage oscillations of wind turbines (Cost to be borne by GEN-2007-006 Customer)	**
GEN-2006-046 – 34.5kV, 20 Mvar capacitor bank to prevent voltage oscillations of wind turbines (Cost to be borne by GEN-2007-006 Customer)	***
OKGE – Add 138 kV line terminal equipment including revenue metering at Roman Nose Substation (Cost to be borne by GEN-2007-006 Customer)	$350,000
Total	$350,000

* Estimates of cost to be determined by Customer.
** Estimates of cost to be determined by GEN-2001-014 Customer during Facility Study
*** Estimates of cost to be determined by GEN-2006-046 Customer during Facility Study

Table 2: Required Interconnection Network Upgrade Facilities

FACILITY	ESTIMATED COST (2007 DOLLARS)
OKGE – Rebuild Roman Nose Substation into three breaker 138 kV ring bus, disconnect switches, and associated equipment.	$700,000
Total	$700,000

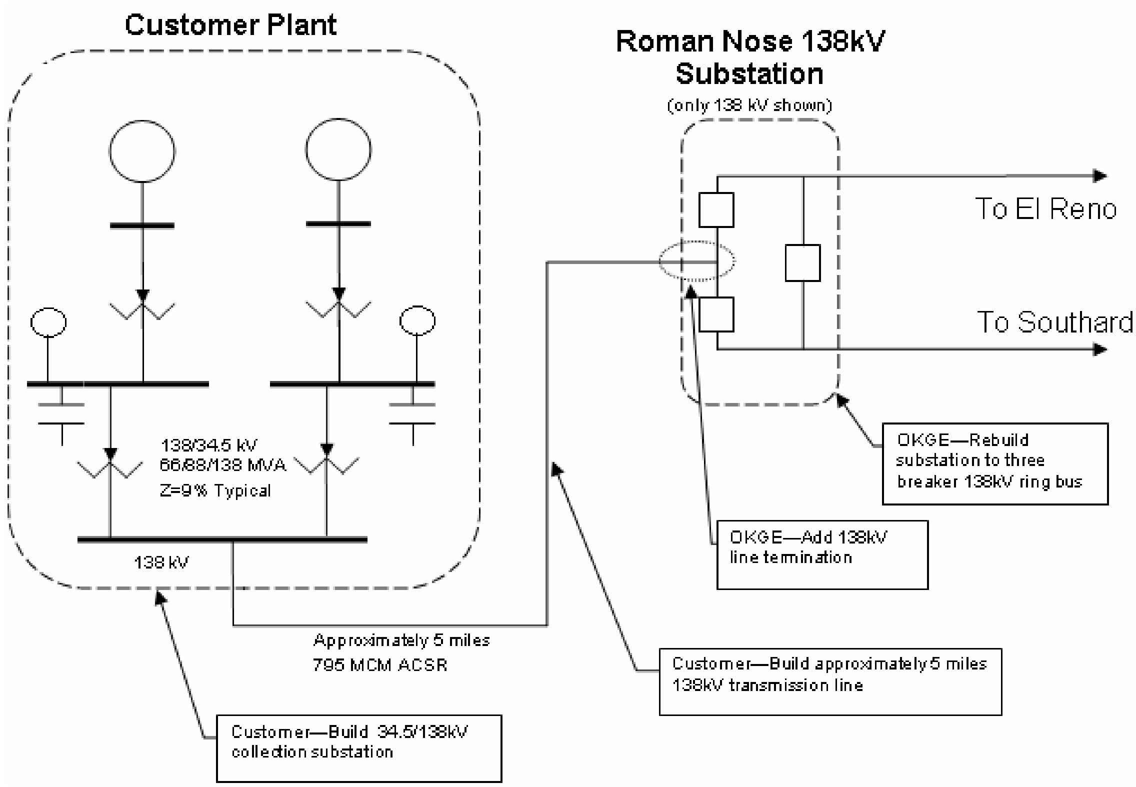

Figure 1: Proposed Interconnection
(Final substation design to be determined)

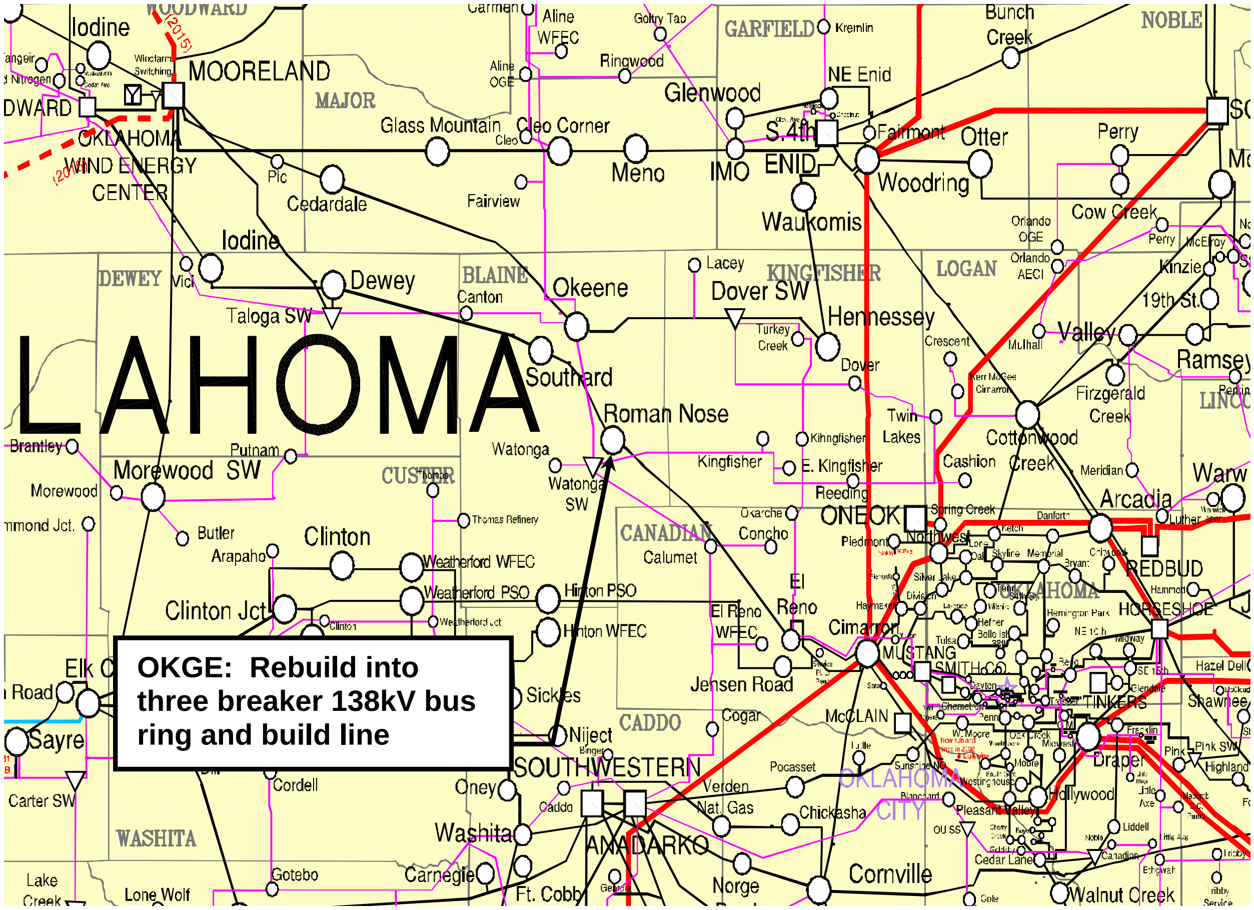

FIGURE 2: MAP OF THE LOCAL AREA

Report

For

Southwest Power Pool

From

S&C Electric Company

IMPACT STUDY FOR GENERATION INTERCONNECTION REQUEST GEN-2007-006

S&C Project No. 2682

January 23, 2007

S&C Electric Company

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1. Executive Summary

This system impact study was performed in response to a generation interconnection study request for GEN-2007-006, a 200 MW wind farm in Blaine County to be interconnected to the existing Roman Nose 138 kV substation owned by (OKGE) Oklahoma Gas & Electric. To accommodate the project's interconnection; Roman Nose will be rebuilt into a ring bus. The SPP footprint will be displaced.

The main purpose of this study is to determine the impact of the present project on the electrical system stability and determine if additional reactive compensation requirement exists to assist with voltage ride-through requirements of wind turbine generators in present and previously queued projects. Steady-state and dynamic studies were performed at 100% MW output (full load) per original request. Dynamic simulations were conducted for fault contingency cases specified in scope of work from SPP for GEN-2007-006. Two seasonal power flow cases were provided by SPP, winter peak 2008 and summer peak 2012. Suzlon S88 – 2.1 MW / 60 Hz wind turbine generators were studied.

Study results show that additional reactive compensation is needed within the project. Zero reactive power exchange is required at Roman Nose, the point of interconnection for GEN-2007-006. The wind turbine manufacturer will supply compensation at terminal bus of up to 0.9995 capacitive power factor at full load. There is not sufficient reactive power to compensate for collector system and transformer losses. <u>Static shunt reactive compensation located at both 34.5 kV collector buses will be needed to supply the additional steady-state reactive power requirement</u>. When all contingency lines are in service, this requirement is a total of 36 MVARs (18 MVARs at each 34.5 kV collector bus). When Elk City to Morewood Switch is off, the requirement increases to a total of 43 MVARs (22 MVARs at T1 34.5 kV collector bus and 21 MVARs at T2 34.5 kV collector bus). Static shunt reactive compensation should be divided in appropriately sized steps and switched in and out automatically by a SCADA/PLC system in response to changes in the transmission grid as well as variations in wind farm production levels.

The wind farm project must comply with <u>**FERC Order 661A**</u> for voltage ride-thru of wind turbine generators for faults at Roman Nose. <u>The wind turbine generators will not survive a three-phase fault at Roman Nose with tripping and reclosing of the Roman Nose to El Reno 138 kV line</u>. Fast and continuously controlled reactive compensation is required. The use of generic PSS/E CSTATT model and equipment parameters used in previous SPP studies, found the <u>need for 42 MVARs of dynamic reactive compensation (21 MVAR at each</u>

34.5 kV collector bus) with 25% overload capability to keep wind turbine generators connected. The STATCOM sizing study in this report is preliminary and does not necessarily translate to actual equipment size. Sizing study must be completed using user-written dynamic models provided by the STATCOM or SVC equipment manufacturer.

Study results also show that there is need for additional MSSCs to switch on and off dynamically to maintain stable operation of the Suzlon S88 wind turbine generators at GEN-2001-014 and GEN-2006-046. Without the additional MSSCs coming on after the disturbance, GEN-2001-014 and GEN-2006-046 generators will have unstable oscillations after a three-phase or single-line-to-ground fault at Roman Nose with tripping, reclosing, and tripping of the Roman Nose to El Reno 138 kV transmission line. GEN-2006-046 and GEN-2001-014 generators did not exhibit this response before the addition of GEN-2007-006; therefore, the customer is responsible for the addition of 25 MVAR of MSSCs at GEN-2006-046 and 12 MVAR of MSSCs at GEN-2001-014 as well as associated capacitor controls.

2. Power Flow Analysis and Results

2.1. Load Flow Model

The customer provided a collector system layout and impedance information. Each feeder is represented as a lumped generator to simplify representation in PSS/E. Shunt capacitance was added to each 34.5 kV collector bus and transformer tap setting selected after looking at voltages in the wind farm. Refer to Appendix A for short-circuit results and impedance calculations. Refer to Appendix B for PSS/E power flow diagrams.

Table 1: Power flow model parameters for GEN-2007-006

Feeder A1, B1, A2, B2, and A3	Parameters
10 Suzlon S88 2.1 MW wind turbine generators at 600 V	10 * 2.1 MW = 21 MW 10 * 2.1 MVA = 21 MVA Power factor at 600 V bus: 1.0
10 Pad mounted wind turbine generator transformers 0.6 / 34.5 kV transformers	10 * 2.0 MVA = 20 MVA Z1 = 5.75% X/R = 4.9 Z1 = 0.0252381 + 0.49619048j p.u. on 20 MVA base
Feeder A1/B1 equivalent 34.5 kV collector system	Z1 = 0.01708677 + 0.01336392j p.u. on 100 MVA base B1 = 0.00270663 p.u. on 100 MVA base
Feeder A2/B2 equivalent 34.5 kV collector system	Z1 = 0.02527561 + 0.02601015j p.u. on 100 MVA base B1 = 0.00403495 p.u. on 100 MVA base
Feeder A3 equivalent 34.5 kV collector system	Z1 = 0.03346572 + 0.03865846j p.u. on 100 MVA base B1 = 0.00536327 p.u. on 100 MVA base

Table 1: Power flow model parameters for GEN-2007-006 (Continued)

Feeder B3, A4, B4, A5, and B5	Parameters
9 Suzlon S88 2.1 MW wind turbine generators at 600 V	9 * 2.1 MW = 18.9 MW 9 * 2.1 MVA = 18.9 MVA Power factor at 600 V bus: 1.0
9 Pad mounted wind turbine generator transformers 0.6 / 34.5 kV transformers	9 * 2.0 MVA = 18 MVA Z1 = 5.75% X/R = 4.9 Z1 = 0.0252381 + 0.49619048j p.u. on 18 MVA base
Feeder B3 equivalent 34.5 kV collector system	Z1 = 0.03482454 + 0.03905181j p.u. on 100 MVA base B1 = 0.00516473 p.u. on 100 MVA base
Feeder A4/B4 equivalent 34.5 kV collector system	Z1 = 0.04301342 + 0.05170883j p.u. on 100 MVA base B1 = 0.00649305 p.u. on 100 MVA base
Feeder A5/B5 equivalent 34.5 kV collector system	Z1 = 0.05119839 + 0.06434343j p.u. on 100 MVA base B1 = 0.00782137 p.u. on 100 MVA base

Substation	Parameters
34.5 / 138 kV main transformer T1/T2	MVA ratings = 60/100 MVA Z1 = 9 % on self-cooled MVA rating X/R = 27.67 (assumed) Z1 = 0.0032505 + 0.08994128j p.u. on 60 MVA base Fixed HV tap setting = 2.5% above (141.45 kV)
Switched Shunt Capacitor at T1 34.5 kV collector bus	18 MVAR
Switched Shunt Capacitor at T2 34.5 kV collector bus	18 MVAR
138 kV transmission line, 1000 ft, 954 MCM ACSR	Z1 = 0.000097661 + 0.00077361j p.u. on 100 MVA base (assumed) B1 = 0.0001953 p.u. on 100 MVA base (assumed)

2.2. Power Flow Study

Steady-state analysis was performed to evaluate steady-state stability and determine static shunt reactive compensation requirements to satisfy negligible MVAR exchange at Roman Nose for outage contingencies from the SPP scope of work. The results are summarized in Table 2.

Table 2: Shunt reactive compensation requirements for outage contingencies

	Outage Contingency	08wp		12sp	
		MSSC at Phase 1 (MVAR)	MSSC at Phase 2 (MVAR)	MSSC at Phase 1 (MVAR)	MSSC at Phase 2 (MVAR)
1	All lines in service	18	18	18	18
2	Roman Nose (514823) to Southard (514822) 138kV line	15	15	16	15
3	Roman Nose (514823) to El Reno (514819) 138 kV line	----	----	----	----
4	Dewey (514787) to Taloga (521065) 138 kV line	19	18	18	18
5	Dewey (514787) to Iodine (514796) 138 kV line	18	18	18	18
6	Elk City (511458) to Morewood Switch (521001) 138 kV line	22	21	22	21
7	Mooreland (520999) – Cedardale (520848) 138 kV line	21	20	20	20
8	Woodward (514785) – Iodine (OG&E) (514796) 138kV line	18	18	18	18
9	Cimarron autotransformer (514898-514901-515715)	19	18	19	18
10	Woodring autotransformer (514715-514714-515770)	19	18	18	18
11	Mooreland (520999) – GEN-2001-037 (514785) 138 kV line	20	19	21	20
12	Cimarron (514898) – Jensen Tap (514821) – El Reno (514819) 138 kV, 3-terminal line	19	18	19	18
13	Cimarron (514898) – El Reno (514819) 138kV line	19	18	19	19

No reasonable amount of reactive compensation can be added at 138 kV or 34.5 kV when the 138 kV line from Roman Nose to El Reno is outaged. The power flow solution diverges.

3. Dynamic Simulations and Voltage Stability Results

Dynamic simulations were performed for fault contingencies in Table 3 with and without GEN-2007-006.

Table 3: Contingencies Evaluated

Cont. No.	*Cont. Name*	*Description*
1	*FLT13PH*	3 phase fault on the Roman Nose (514823) to Southard (514822) 138kV line, near Roman Nose. a. Apply fault at Roman Nose. b. Clear fault after 5 cycles by tripping the line from Roman Nose to Southard. 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	*Single phase fault and sequence like Cont. No. 1*
3	*FLT33PH*	3 phase fault on the Roman Nose (514823) to El Reno (514819) 138 kV line, near Roman Nose. a. Apply fault at Roman Nose. b. Clear fault after 5 cycles by tripping the line from Roman Nose to El Reno. 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	*Single phase fault and sequence like Cont. No. 3*
5	*FLT53PH*	3 phase fault on the Dewey (514787) to Taloga (521065) 138 kV line, near Dewey. a. Apply fault at Dewey. b. Clear fault after 5 cycles by tripping the line from Dewey to Taloga. 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	*Single phase fault and sequence like Cont. No. 5*
7	*FLT73PH*	3 phase fault on the Dewey (514787) to Iodine (514796) 138 kV line, near Dewey. a. Apply fault at Dewey. b. Clear fault after 5 cycles by tripping the line from Dewey to Iodine. 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.
8	FLT81PH	*Single phase fault and sequence like Cont. No. 7*
9	FLT93PH	3 phase fault on the Elk City (511458) to Morewood Switch (521001) 138 kV line, near Elk City. a. Apply fault at the Elk City 138kV bus. b. Clear fault after 5 cycles by tripping the line from Elk City – Morewood Switch. 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	*Single phase fault and sequence like Cont. No.9*
11	FLT113PH	3 phase fault on the Mooreland (520999) – Cedardale (520848) 138 kV line, near Cedardale. a. Apply fault at the Cedardale 138kV bus. b. Clear fault after 5 cycles by tripping the line from Mooreland - Cedardale. 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.

Cont. No.	*Cont. Name*	*Description*
12	FLT121PH	*Single phase fault and sequence like Cont. No.11*
13	FLT133PH	3 phase fault on the Woodward (514785) – Iodine (OG&E) (514796) 138kV line near Woodward. a. Apply fault at the Woodward bus. b. Clear fault after 5 cycles by tripping the line from Woodward-Iodine. 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	*Single phase fault and sequence like Cont. No.13*
15	FLT153PH	3 phase fault on the Cimarron autotransformer (514898-514901-515715) a. Apply fault at the Cimaron 138kV bus. b. Clear fault after 5 cycles by taking the auto out of service
16	FLT161PH	*Single phase fault and sequence like Cont. No.15*
17	FLT173PH	3 phase fault on the Woodring autotransformer (514715-514714-515770) a. Apply fault at the Woodring 138kV bus. b. Clear fault after 5 cycles by taking the auto out of service
18	FLT181PH	*Single phase fault and sequence like Cont. No.17*
19	FLT193PH	3 phase fault on the Mooreland (520999) – GEN-2001-037 (515785) 138 kV line, near Mooreland. a. Apply fault at the Mooreland 138kV bus. b. Clear fault after 5 cycles by tripping the line from Mooreland – GEN-2001-037. 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	FLT201PH	*Single phase fault and sequence like Cont. No.19*
21	FLT213PH	3 phase fault on the Cimarron (514898) – Jensen Tap (514820) 138kV line near Cimarron. a. Apply fault at the Cimarron bus. b. Clear fault after 5 cycles by tripping the line from Cimarron – Jensen Tap – Jensen (514821) – El Reno (514819). 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	FLT221PH	*Single phase fault and sequence like Cont. No.21*
23	FLT233PH	3 phase fault on the Cimarron (514898) – El Reno (514819) 138kV line near Cimarron. a. Apply fault at the Cimarron bus. b. Clear fault after 5 cycles by tripping the line from Cimarron – El Reno (514819). 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	FLT241PH	*Single phase fault and sequence like Cont. No.23*

Sink areas monitored are 520, 56, 525, 524, 536, 539, 541

Prior queued projects monitored are:

a. GEN-2001-037; 102MW of GE turbines
b. GEN-2001-014; 94MW of Suzlon turbines
c. GEN-2003-022/GEN-2004-020; 147MW of GE turbines
d. GEN-2005-008; 120MW of GE turbines
e. GEN-2006-024; 20MW of Suzlon turbines
f. GEN-2006-046; 130MW of Suzlon turbines

3.1. Pre-Project Dynamic Simulation

Customary to all interconnection impact study is to evaluate the power flow cases, user written models, and dynamic input file parameters and other information received for the study. Any abnormal system behavior such as nuisance tripping of previously studied wind farm projects, unusual voltage collapse, system voltage instability, and initialization problems on flat runs are addressed prior to addition of the new wind farm project to provided base cases and dynamic simulation files.

PSS/E version 30.2.1 was used to perform dynamic stability studies.

Non-disturbance runs of 20 second were carried out on Winter Peak 2008 and Summer Peak 2012 base cases to verify proper initialization of dynamic models.

Winter Peak 2008

Evaluation of SPP dynamic files for fault contingencies in Table 3 revealed tripping of prior queued project GEN-2005-008 for three-phase faults at Mooreland with tripping and reclosing of the Mooreland to GEN-2001-037 138 kV line (FLT193PH). The original GEN-2005-008 VTGTPA settings were rectified:

Before: 70% for 100 ms **After:** 70% for 625 ms

Also a 12 MVAR shunt capacitor was added to GEN-2001-014 34.5 kV collector bus and main transformer tap set to 5% buck.

Wind turbine generators at GEN-2001-037 did not behave properly after a disturbance. Changes to a GE wind turbine model input parameter were required per SPP input.

Pre-project study results indicate that GEN-2001-037 will trip off on the 70%, 100 ms under voltage setting for three-phase faults at Mooreland with tripping and reclosing of the Mooreland to GEN-2001-037 138 kV line (FLT193PH).

Pre-project study results are summarized in Table 5.

Summer Peak 2012

Evaluation of SPP dynamic files for fault contingencies in Table 3 revealed that GEN-2001-037 will trip off on the 70%, 100 ms under voltage setting for contingencies FLT133PH and FLT193PH. FLT133PH corresponds to three-phase faults at Woodward with tripping and reclosing of the 138 kV line from Woodward to Iodine (OG&E).

Pre-project study results are summarized in Table 5.

3.2. Modeling of Wind Turbine Generators in Dynamics

Suzlon S88 2.1 MW/60 Hz wind turbine generators were studied. The Suzlon S88 2.1 MW/60 Hz wind turbine generators are variable slip with electrical pitch system. The manufacturer provides 14 steps of capacitor banks intended for local power factor control. At full load, the wind turbine generator can operate between 0.92 inductive to 0.9995 capacitive power factor. The PSS/E model of the Suzlon wind turbine generator comes with built-in protection package. Voltage and frequency relay settings are summarized in Table 4.

Table 4: Suzlon S88 2.1 MW/60 Hz wind turbine generator trip settings

Grid Voltage and Frequency Protection					
Relay trips if |Vbus|<	90%		UV Relay 1	0.90	Pu
for t =	60	s		60.00	S
Relay trips if |Vbus|<	80%		UV Relay 2	0.80	Pu
for t =	2.8	s		2.80	S
Relay trips if |Vbus|<	60%		UV Relay 3	0.60	Pu
for t =	1.6	s		1.60	S
Relay trips if |Vbus|<	40%		UV Relay 4	0.40	Pu
for t =	0.7	s		0.70	S
Relay trips if |Vbus|<	15%		UV Relay 5	0.15	Pu
for t =	0.08	s		0.08	S
Relay trips if |Vbus|>	115%		OV Relay 1	1.15	Pu
for t =	60	s		60.00	S
Relay trips if |Vbus|>	120%		OV Relay 2	1.20	Pu
for t =	0.08	s		0.08	S
Relay trips if Fbus <	57	Hz	UF Relay 1	0.95	Pu
for t =	0.2	s		0.20	S
Or Fbus <	63	Hz	OF Relay 1	1.05	Pu
for t =	0.2	s		0.20	S

Suzlon S88 -2.1MW/60 Hz version V30, V20.2 for PSS/E was provided for dynamic stability studies.

3.3 Dynamic Simulations with GEN-2007-006

Non-disturbance runs of 20 second were carried out on Winter Peak 2008 and Summer Peak 2012 base cases to verify proper initialization of dynamic models and valid power flow cases.

Simulations indicate that when GEN-2007-006 and previous queued wind farms are dispatched across the SPP footprint, wind turbine generators in GEN-2007-006 will not survive fault contingency FTL33PH and FLT41PH, three-phase and single-phase to ground faults at Roman Nose with tripping and reclosing of the 138 kV line from Roman Nose to El Reno. Because FERC Order 661A Compliance requires wind turbine generators to remain connected for contingency FLT33PH, the solution to this problem should be implemented at large within GEN-2007-006.

Winter Peak 2008

Figure 1 shows that wind turbine generators at GEN-2007-006 will fail to survive contingency FLT33PH. Feeder A1, A2, A3, A4, and A5 trip off on over voltage relay OV2. Feeder B1, B2, B3, B4, and B5 trip off on under voltage relay UV5.

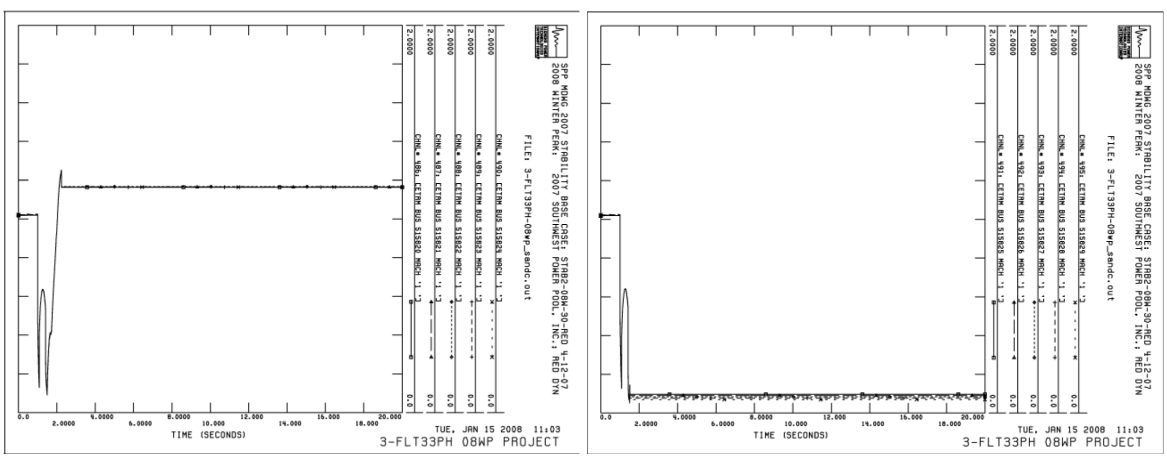


Figure 1: Suzlon S88-2.1 MW/60Hz response to FLT33PH

Adding a STATCOM at T1 34.5 kV collector bus and another one at T2 34.5 kV collector bus will help wind turbine generators survive this fault contingency. PSS/E model CSTATT was used to represent a generic STATCOM device. Model parameters were chosen to match those used in previous SPP studies. The STATCOM device was assumed to have a symmetrical inductive and capacitive range and to not contribute any output in steady-state. Sensitivity analysis performed suggests that there is minimum requirement of 42 MVARs dynamic (21 MVAR at each 34.5 kV collector bus) with 25% overload capability to keep wind turbine generators connected. When half of the wind farm is out of service (i.e., T1 or T2 is taken out of service), the wind turbine generators can survive a FLT33PH and FLT41PH fault contingency with no need of a STATCOM. The STATCOM sizing study in this report is preliminary and does not necessarily translate to actual equipment size. Sizing study must be completed using user-written dynamic models provided by STATCOM or SVC equipment manufacturers.

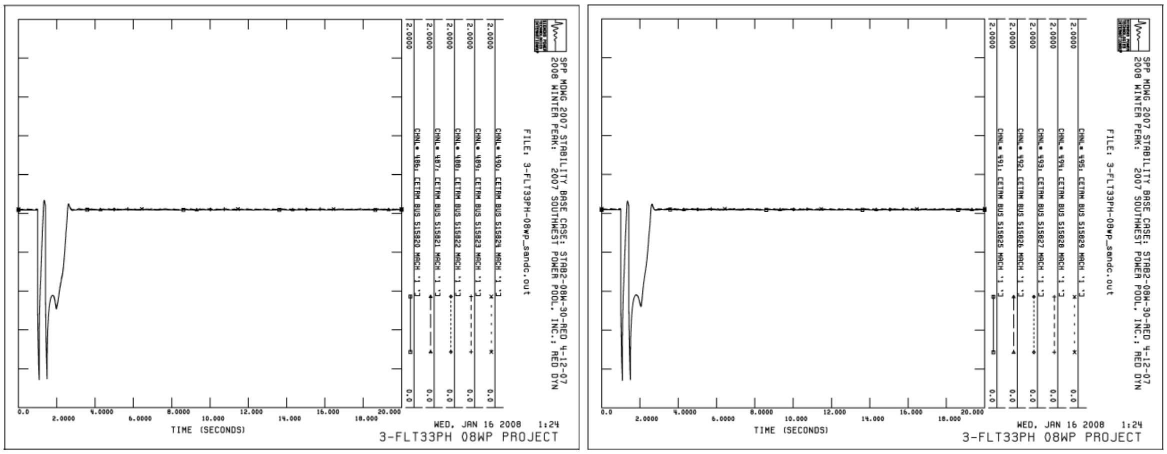


Figure 2: Suzlon S88-2.1 MW/60Hz response to FLT33PH with STATCOM

Following tripping and lockout of the 138 kV line from Roman Nose to El Reno for contingencies FLT33PH and FLT41PH, Sleeping Bear GEN-2001-014 and Taloga GEN-2006-046 Suzlon S88-2.1 MW/60 Hz wind turbine generators will exhibit sustained and undamped voltage, power, frequency, and speed oscillations (Figure 3). This is presumably due to lack of reactive power (lack of voltage regulation) required to keep the generator terminal voltage above 0.90 pu. There is also the possibility that these sustained oscillations are an issue with the dynamic model provided by the manufacturer for voltages around 0.90 pu. These conditions do not exist at either GEN-2001-014 or GEN-2006-046 prior to the addition of GEN-2007-006.

A cost-effective solution is to add 12 MVAR of MSSCs, which are likely already installed at GEN-2001-014 and additional 25 MVAR of MSSCs at GEN-2006-046 to be switched on and off dynamically based on voltage level at the 34.5 kV collector bus. For these studies, the MSSCs will switch on when bus voltages are below 0.95 pu for 1.5 seconds. Breaker times have been assumed at 5 cycles for tripping and closing. The definite-time delay should be set at or slightly longer than the sum of the initial fault trip duration, first shot reclosing, and voltage recovery time for most faults. MSSCs should trip off when bus voltages are high after some time delay. For these studies, the MSSCs will trip off when bus voltages are 1.05 pu after a long time delay of 1.5 seconds. This will insure that the MSSCs will trip off when the 138 kV line from Roman Nose to El Reno is put back in service. A second set of settings could be specified so that the MSSCs will trip off when the voltage is above 1.1 pu after a short time delay of 120 ms to prevent high voltages from tripping the wind turbine generators. A third set of settings could be specified so that the MSSCs will trip off when the voltage is above 1.15 pu instantaneously. Figure 4 shows dynamic results after adding MSSCs at GEN-2001-014 and GEN-2006-046.

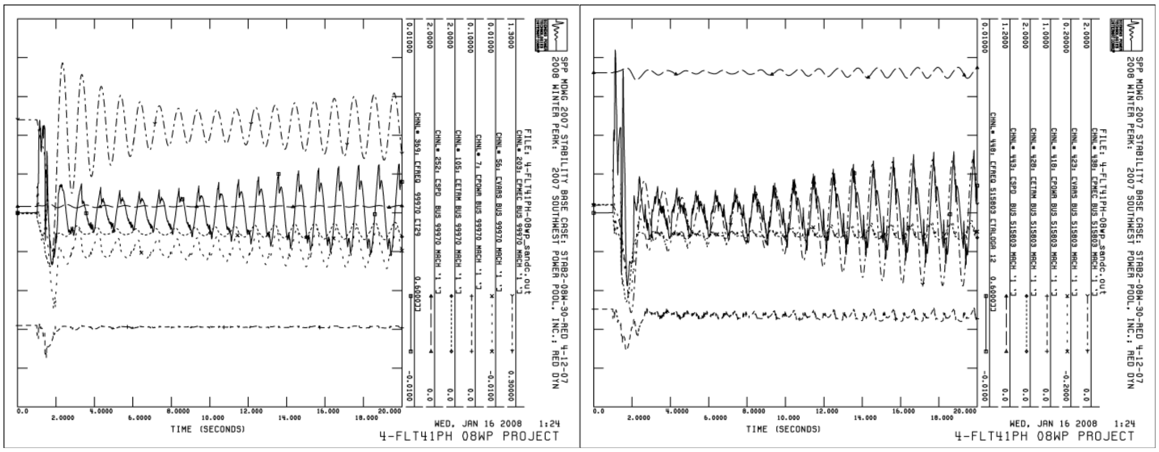


Figure 3: GEN-2001-014 (left) and GEN-2006-046 (right) instable operation

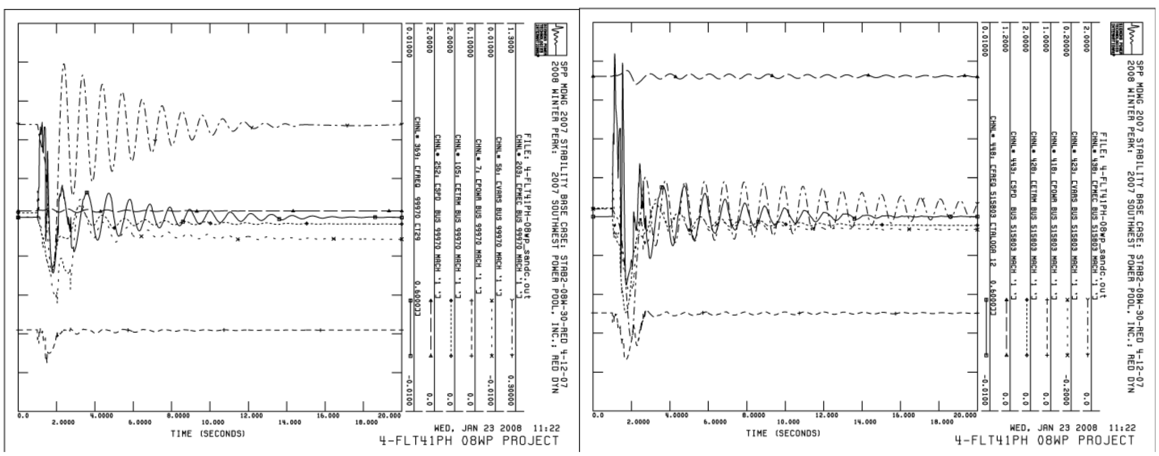


Figure 4: GEN-2001-014 (left) and GEN-2006-046 (right) with dynamic switched MSSCs

Summer Peak 2012

Similar discussion for Winter Peak 2008 applies to Summer Peak 2012. Figure 5 shows that wind turbine generators at GEN-2007-006 will fail to survive contingency FLT33PH. Feeder A1, A2, A3, A4, and A5 trip off on over voltage relay OV2. Feeder B1, B2, B3, B4, and B5 trip off on under voltage relay UV5.

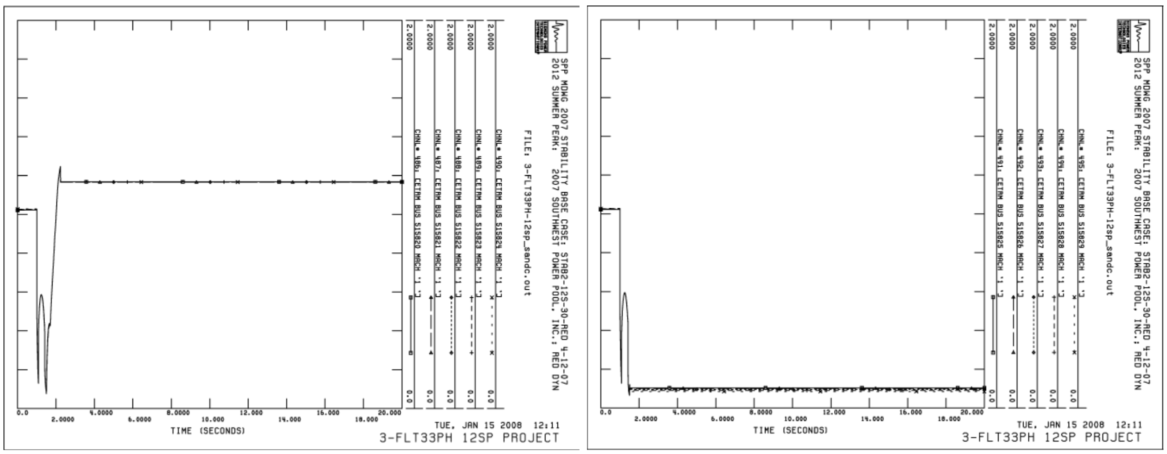


Figure 5: Suzlon S88-2.1 MW/60Hz response to FLT33PH

After adding a 42 MVARs of STATCOM (21 MVAR at each 34.5 kV collector bus) with 25% overload capability, wind turbine generators in the project are able to survive contingency FLT33PH and FLT41PH.

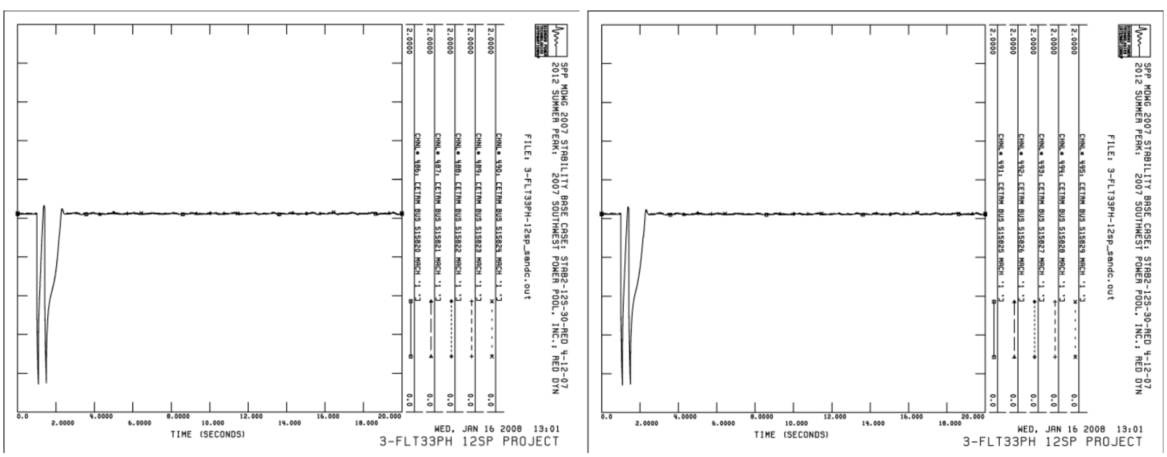


Figure 6: Suzlon S88-2.1 MW/60Hz response to FLT33PH with STATCOM

Similar discussion for Winter Peak 2008 applies to Summer Peak 2012. Following tripping and lockout of the 138 kV line from Roman Nose to El Reno for contingencies FLT33PH and FLT41PH, Sleeping Bear GEN-2001-014 and Taloga GEN-2006-046 Suzlon S88-2.1 MW/60 Hz wind turbine generators will exhibit sustained and undamped voltage, power, and speed oscillations which will eventually lead to instability and cause these wind farms to trip off. Figure 7 shows the instability at GEN-2001-014 and GEN-2006-046. Figure 8 shows dynamic results after adding MSSCs at GEN-2001-014 and GEN-2006-046.

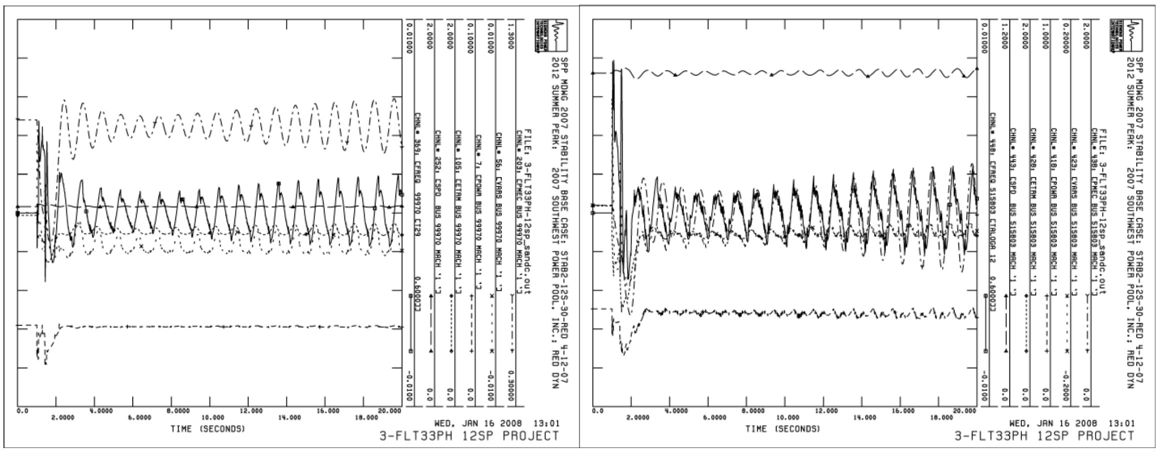


Figure 7: GEN-2001-014 (left) and GEN-2006-046 (right) instable operation

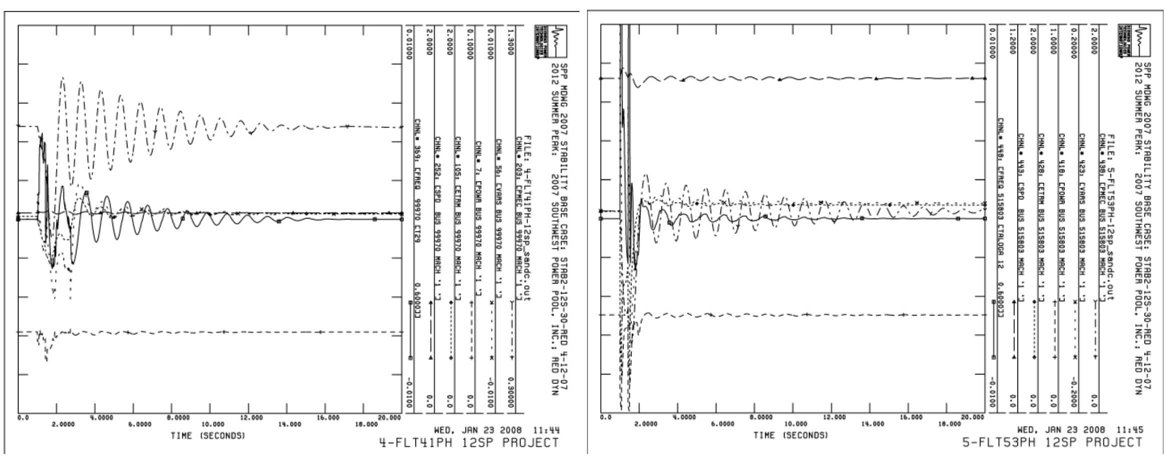


Figure 8: GEN-2001-014 (left) and GEN-2006-046 (right) with dynamic switched MSSCs

Table 5: Summary of Fault Simulation Results

Cont. Name	Description	Winter Peak 2008				Summer Peak 2012			
		Pre-Project	With GEN-2007-006			Pre-Project	With GEN-2007-06		
			No STATCOM	With STATCOM and No MSSCs (at GEN-2001-14 and GEN-2006-46)	With STATCOM and With MSSCs (at GEN-2001-14 and GEN-2006-46)		No STATCOM	With STATCOM and No MSSCs (at GEN-2001-14 and GEN-2006-46)	With STATCOM and With MSSCs (at GEN-2001-14 and GEN-2006-46)
FLT13PH	3 phase fault on the Roman Nose (514823) to Southard (514822) 138kV line, near Roman Nose.	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
FLT21PH	*Single phase fault and sequence like Cont. No. 1*	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
FLT33PH	3 phase fault on the Roman Nose (514823) to El Reno (514819) 138 kV line, near Roman Nose.	STABLE	STABLE GEN-2007-006 Trips off	UNSTABLE	STABLE	STABLE	STABLE GEN-2007-006 Trips off	UNSTABLE	STABLE
FLT41PH	*Single phase fault and sequence like Cont. No. 3*	STABLE	STABLE GEN-2007-006 Trips off	UNSTABLE	STABLE	STABLE	STABLE GEN-2007-006 Trips off	UNSTABLE	STABLE
FLT53PH	3 phase fault on the Dewey (514787) to Taloga (521065) 138 kV line, near Dewey.	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT61PH	*Single phase fault and sequence like Cont. No. 5*	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT73PH	3 phase fault on the Dewey (514787) to Iodine (514796) 138 kV line, near Dewey.	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT81PH	*Single phase fault and sequence like Cont. No. 7*	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE

Cont. Name	Description	Winter Peak 2008				Summer Peak 2012			
		Pre-Project	With GEN-2007-006			Pre-Project	With GEN-2007-06		
			No STATCOM	With STATCOM and No MSSCs (at GEN-2001-14 and GEN-2006-46)	With STATCOM and With MSSCs (at GEN-2001-14 and GEN-2006-46)		No STATCOM	With STATCOM and No MSSCs (at GEN-2001-14 and GEN-2006-46)	With STATCOM and With MSSCs (at GEN-2001-14 and GEN-2006-46)
FLT93PH	3 phase fault on the Elk City (511458) to Morewood Switch (521001) 138 kV line, near Elk City.	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT101PH	*Single phase fault and sequence like Cont. No.9*	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT113PH	3 phase fault on the Mooreland (520999) – Cedardale (520848) 138 kV line, near Cedardale.	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT121PH	*Single phase fault and sequence like Cont. No.11*	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT133PH	3 phase fault on the Woodward (514785) – Iodine (OG&E) (514796) 138kV line near Woodward.	STABLE	(Note 1)	STABLE	STABLE	STABLE GEN-01-37 Trips off	(Note 1)	STABLE	STABLE
FLT141PH	*Single phase fault and sequence like Cont. No.13*	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT153PH	3 phase fault on the Cimarron autotransformer (514898-514901-515715)	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT161PH	*Single phase fault and sequence like Cont. No.15*	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT173PH	3 phase fault on the Woodring autotransformer (514715-514714-515770)	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE

Cont. Name	Description	Winter Peak 2008				Summer Peak 2012			
		Pre-Project	With GEN-2007-006			Pre-Project	With GEN-2007-06		
			No STATCOM	With STATCOM and No MSSCs (at GEN-2001-14 and GEN-2006-46)	With STATCOM and With MSSCs (at GEN-2001-14 and GEN-2006-46)		No STATCOM	With STATCOM and No MSSCs (at GEN-2001-14 and GEN-2006-46)	With STATCOM and With MSSCs (at GEN-2001-14 and GEN-2006-46)
FLT181PH	*Single phase fault and sequence like Cont. No.17*	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT193PH	3 phase fault on the Mooreland (520999) – GEN-2001-037 (515785) 138 kV line, near Mooreland.	STABLE GEN-01-37 Trips off	(Note 1)	STABLE	STABLE	STABLE GEN-01-37 Trips off	(Note 1)	STABLE	STABLE
FLT201PH	*Single phase fault and sequence like Cont. No.19*	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT213PH	3 phase fault on the Cimarron (514898) – Jensen Tap (514820) 138kV line	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT221PH	*Single phase fault and sequence like Cont. No.21*	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT233PH	3 phase fault on the Cimarron (514898) – El Reno (514819) 138kV line near Cimarron.	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE
FLT241PH	*Single phase fault and sequence like Cont. No.23*	STABLE	(Note 1)	STABLE	STABLE	STABLE	(Note 1)	STABLE	STABLE

Notes:

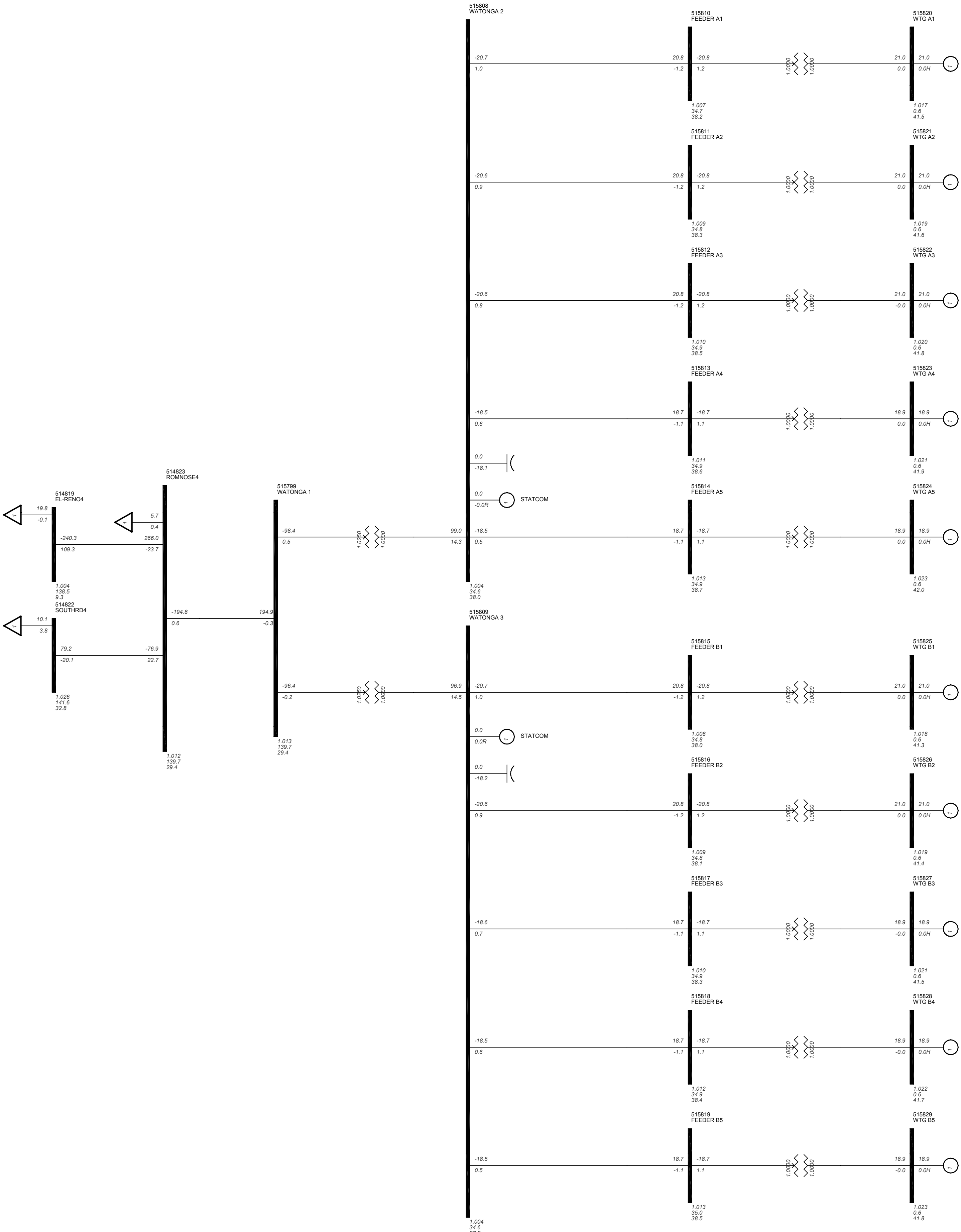
1. Not studied after early simulations indicated need for STATCOM or SVC equipment.

APPENDIX B

POWER FLOW DIAGRAMS

GEN-2007-006

WINTER PEAK 2008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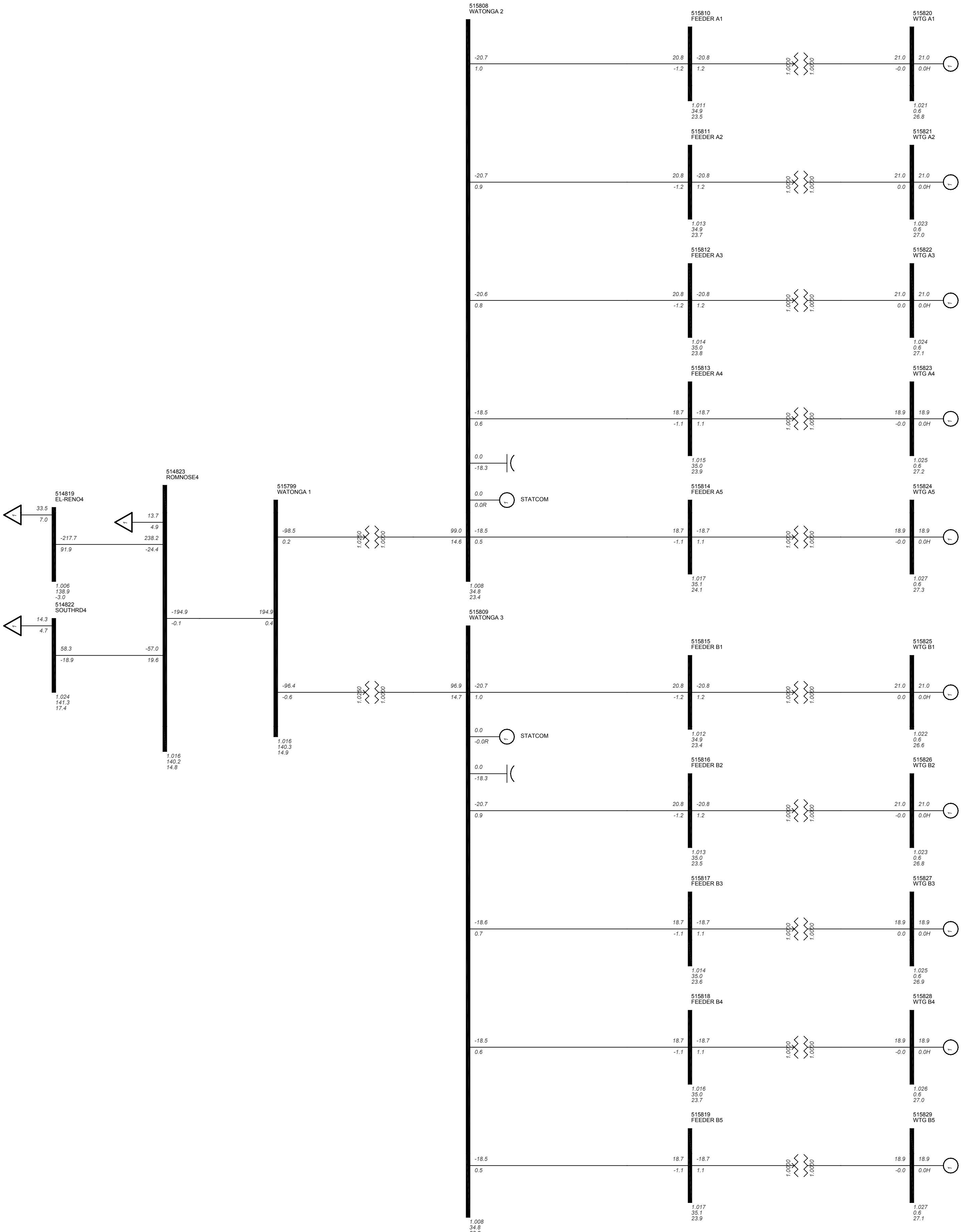
FEEDER A1
515820
WTG A1
515811
FEEDER A2
515821
WTG A2
515812
FEEDER A3
515822
WTG A3
515813
FEEDER A4
515823
WTG A4
515814
FEEDER A5
515824
WTG A5
STATCOM
514823
ROMNOSE4
514819
EL-RENO4
515799
WATONGA 1
514822
SOUTHRD4
515809
WATONGA 3
515815
FEEDER B1
515825
WTG B1
STATCOM
515816
FEEDER B2
515826
WTG B2
515817
FEEDER B3
515827
WTG B3
515818
FEEDER B4
515828
WTG B4
515819
FEEDER B5
515829
WTG B5

SUMMER PEAK 2012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WTG A1
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1.0
20.8
-1.2
-20.8
1.2
1.0000
1.0000
21.0
-0.0
21.0
0.0H
1.011
34.9
23.5
1.021
0.6
26.8
515811
FEEDER A2
515821
WTG A2
-20.7
0.9
20.8
-1.2
-20.8
1.2
21.0
0.0
21.0
0.0H
1.013
34.9
23.7
1.023
0.6
27.0
515812
FEEDER A3
515822
WTG A3
-20.6
0.8
20.8
-1.2
-20.8
1.2
21.0
0.0
21.0
0.0H
1.014
35.0
23.8
1.024
0.6
27.1
515813
FEEDER A4
515823
WTG A4
-18.5
0.6
18.7
-1.1
-18.7
1.1
18.9
-0.0
18.9
0.0H
0.0
-18.3
1.015
35.0
23.9
1.025
0.6
27.2
0.0
0.0R
STATCOM
515814
FEEDER A5
515824
WTG A5
514823
ROMNOSE4
514819
EL-RENO4
515799
WATONGA 1
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7.0
13.7
4.9
-217.7
91.9
238.2
-24.4
-98.5
0.2
1.0250
1.0000
99.0
14.6
-18.5
0.5
18.7
-1.1
-18.7
1.1
18.9
-0.0
18.9
0.0H
1.006
138.9
-3.0
1.008
34.8
23.4
1.017
35.1
24.1
1.027
0.6
27.3
514822
SOUTHRD4
515809
WATONGA 3
14.3
4.7
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-0.1
194.9
0.4
58.3
-18.9
-57.0
19.6
1.024
141.3
17.4
515815
FEEDER B1
515825
WTG B1
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-0.6
1.0250
1.0000
96.9
14.7
-20.7
1.0
20.8
-1.2
-20.8
1.2
21.0
0.0
21.0
0.0H
0.0
-0.0R
STATCOM
1.016
140.3
14.9
1.012
34.9
23.4
1.022
0.6
26.6
1.016
140.2
14.8
0.0
-18.3
515816
FEEDER B2
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WTG B2
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20.8
-1.2
-20.8
1.2
21.0
-0.0
21.0
0.0H
1.013
35.0
23.5
1.023
0.6
26.8
515817
FEEDER B3
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WTG B3
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18.7
-1.1
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18.9
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18.9
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23.6
1.025
0.6
26.9
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FEEDER B4
515828
WTG B4
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0.6
18.7
-1.1
-18.7
1.1
18.9
-0.0
18.9
0.0H
1.016
35.0
23.7
1.026
0.6
27.0
515819
FEEDER B5
515829
WTG B5
-18.5
0.5
18.7
-1.1
-18.7
1.1
18.9
-0.0
18.9
0.0H
1.017
35.1
23.9
1.027
0.6
27.1
1.008
34.8
23.2