Southwest Power Pool

Impact Study for Generation Interconnection Request GEN–2006–046

SPP Tariff Studies
(#GEN-2006-046)

November 2007

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-2006-046. 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 total of 25 Mvars of 34.5kV capacitor banks are necessary for the operation of GEN-2006-046. This capacitor bank(s) should be staged so that excessive voltage variations are not experienced on the OG&E transmission system.

The Impact Study determined that a STATCOM or SVC device was not necessary for the studied Suzlon S88 turbines to meet FERC Order #661A low voltage ride through provisions.

The interconnection facilities necessary for this generation interconnection request were listed in the Feasibility Study for this request. These cost estimates are repeated 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 (2007 DOLLARS)
Customer – 138/34.5 kV Substation facilities.	*
Customer – 138 kV transmission line facilities between Customer facilities and the Dewey Substation.	*
Customer - Right-of-Way for Customer facilities.	
Customer – 34.5 kV, 26 MVAR capacitor bank(s) in Customer substation.	*
OKGE – Add 138 kV line terminal equipment including revenue metering at Dewey Substation	$589,697
Total	$589,697

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

Table 2: Required Interconnection Network Upgrade Facilities

FACILITY	ESTIMATED COST (2007 DOLLARS)
OKGE – Add 138 kV circuit breaker, disconnect switches, and associated equipment at Dewey Substation	$135,000
Total	$135,000

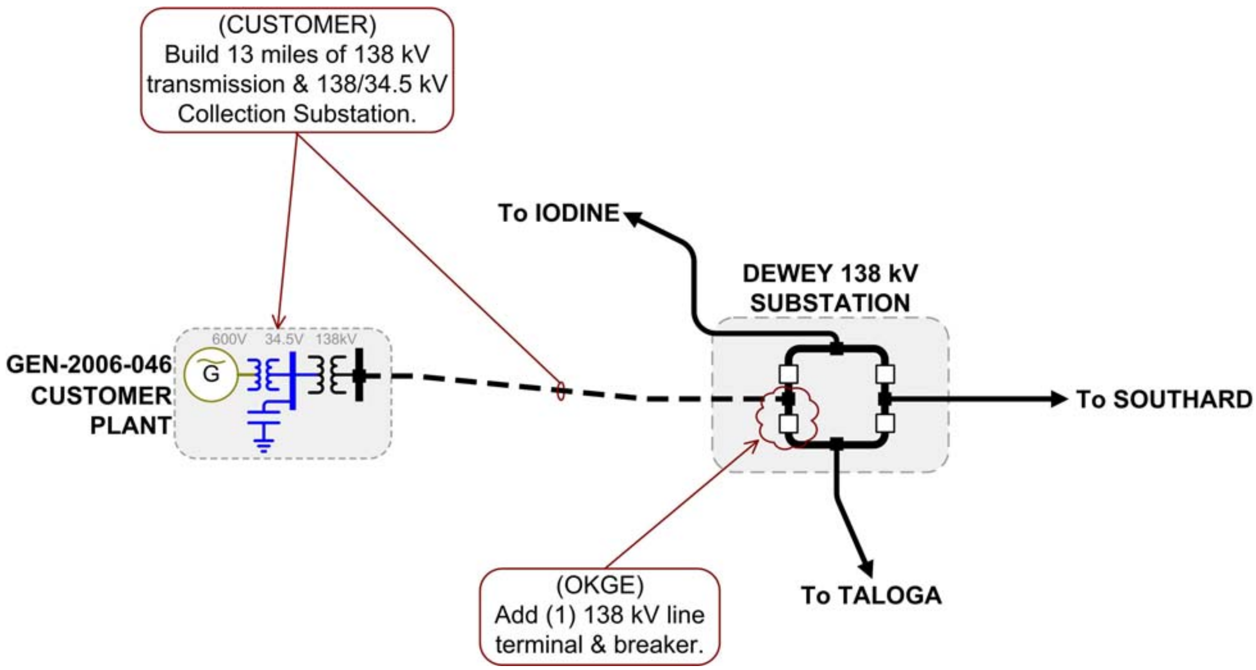

Figure 1: Proposed Interconnection
(Final substation design to be determined)

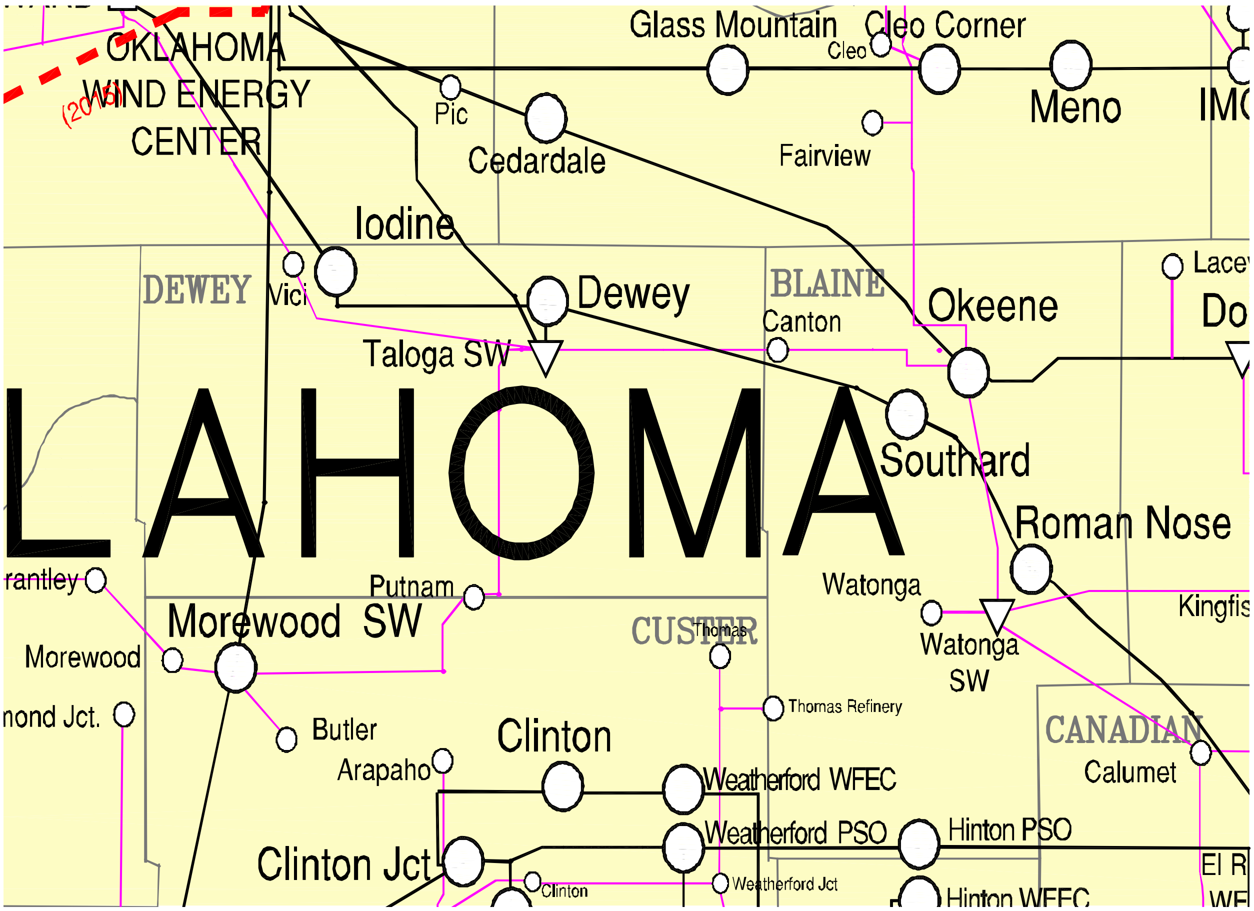

FIGURE 2. MAP OF THE LOCAL AREA

REPORT ON

130.2 MW WIND GENERATION PROJECT
(GEN-2006-046)

INTERCONNECTION SYSTEM IMPACT STUDY

NOVEMBER 7, 2007

Rev	Date	Prepared	Approved	Description
0	10/26/07	G. Tsai Li	V. Stewart	Draft report issued
1	11/01/07	G. Tsai Li	V. Stewart	Final report issued
2	11/06/07	G. Tsai Li	V. Stewart	Revised reference to voltage settling at Iodine to 1.0916 p.u. (pg. 15) and 1.0987 p.u. (pg. 16)
3	11/07/07	G. Tsai Li	V. Stewart	Final report issued for public posting

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1. Summary

This system impact study was performed in response to an interconnection study request for GEN-2006-046, 130 MW of wind farm generation to be interconnected into existing Dewey 138 kV substation owned by (OKGE) Oklahoma Gas & Electric. The purpose of this study is to evaluate transmission system voltage stability with the new project and determine interconnection requirements for voltage ride-through of wind turbine generators in present and previously queued projects. Steady-state and dynamic simulation studies were performed for 100% wind farm generation output. Dynamic simulations were conducted for fault contingency cases specified in scope of work by SPP and S&C proposal BD-1960 dated August 24, 2007. Make and model of the wind turbine generators associated with this study and project is the Suzlon S88 – 2.1 MW/60 Hz.

This study has identified action items independent of interconnection requirements:

1. 12 MVAR switched shunt capacitor at GEN-2001-014 should be in service for winter and summer load peaks.
2. There should be a second 70 MVA, 138/69 kV transformer in parallel with existing transformer at FTSUPLY area.
3. GEN-2001-014 main transformer fixed primary winding tap should be set to 5% above.

Power flow analysis and dynamic simulation results have identified the following requirements for interconnection:

1. GEN-2005-008 main transformer fixed primary winding tap should be set to 5% above
2. Additional shunt reactive compensation is required by GEN-2006-046 to meet unity power factor at Dewey 138 kV:
   a) 24 MVAR of mechanically switch shunt capacitors at 34.5 kV collector bus for winter peak.
   b) 25 MVAR of mechanically switch shunt capacitors at 34.5 kV collector bus for summer peak.

Static shunt reactive compensation shall be divided in certain number of steps and switched in and out automatically by a SCADA/PLC system to cater varying wind farm output levels. SCADA/PLC controls must coordinate with wind turbine power factor correction capacitor switching controls. There might be need for smooth and continuous reactive power equipment such as PureWave™ DSTATCOM to reduce capacitor bank switching operations and provide fine adjustments in reactive power compensation.

3. Study results did not reveal the need for fast and continuously controlled reactive power equipment such as PureWave^{TM} DSTATCOM to maintain present and prior queued projects (except for GEN-2001-037) connected at full load for voltage ride through. Other fault contingencies (i.e., breaker failure) may exist that could reveal the need for fast and continuously controlled reactive power at GEN-2006-046. Even though the scope of study focuses on fault contingencies at full load, it is advisable that a number of cases be considered with light wind farm loading to reveal potential problems with overvoltages that may reveal need for fast reactive power.

2. Power Flow Analysis and Results

SPP provided power flow SAV files:

gen-2006-046_08wp.sav: history file compatible with PTI PSS/E version 30.2.1 for 2008 winter peak loading.

gen-2006-046_12sp.sav: history file compatible with PTI PSS/E version 30.2.1 for 2012 summer peak loading.

SPP provided power flow SAV file revisions by S&C and SPP:

gen-2006-046_08wp_mod.sav: history file compatible with PTI PSS/E version 30.2.1 for 2008 winter peak loading. The following changes were made to **gen-2006-046_08wp.sav**:

a) Changed GEN-2001-014 main GSU primary winding tap setting to 5% above.
b) Added a 12 MVAR switched shunt capacitor on GEN-2001-014 138 kV bus.

gen-2006-046_12sp_mod.sav: history file compatible with PTI PSS/E version 30.2.1 for 2012 summer peak loading. The following changes were made to **gen-2006-046_12sp.sav**:

a) Changed GEN-2001-014 main GSU primary winding tap setting to 5% above.
b) Added a 12 MVAR switched shunt capacitor on GEN-2001-014 138 kV bus.
c) Added a second 70 MVA, 138/69 kV transformer in parallel with existing transformer at FTSUPLY area.

GEN-2006-046 in revised power flow SAV files:

gen-2006-046_08wp_sandc.sav: history file compatible with PTI PSS/E version 30.2.1 for 2008 winter peak loading. The following changes were made to **gen-2006-046_08wp_mod.sav**:

a) Added equivalent model based on collector system impedance information provided by the customer.
b) The model consists of a simplified representation. Each Feeder is represented by a lumped generator, lumped transformer and equivalent collector impedance.
c) Missing information, which consists of transmission line impedance and main GSU X/R ratio, was assumed based on typical.
d) Changed GEN-2005-008 main GSU primary winding tap setting to 5% above.

gen-2006-046_12sp_sandc.sav: history file compatible with PTI PSS/E version 30.2.1 for 2012 summer peak loading. The following changes were made to **gen-2006-046_12sp_mod.sav**:

a) Added equivalent model based on collector system impedance information provided by the customer.
b) The model consists of a simplified representation. Each Feeder was represented by a lumped generator, lumped transformer and equivalent collector impedance.
c) Missing information, which consists of transmission line impedance and main GSU X/R ratio, was assumed based on typical.
d) Changed GEN-2005-008 main GSU primary winding tap setting to 5% above.

2.1. Load Flow Model

To calculate equivalent collector feeder impedance, the complete discrete wind farm consisting of 62 wind turbine generators and cable runs was modeled in CYME PSAF 3.10. Fault current contribution was determined from each feeder for fault on the 34.5 kV collector bus to calculate the equivalent impedance of each feeder. Refer to Appendix A for short-circuit study results and impedance calculations.

Additional shunt reactive compensation is required by GEN-2006-046 to meet unity power factor at Dewey 138 kV:

1. 24 MVAR of mechanically switch shunt capacitors at 34.5 kV collector bus for winter peak.
2. 25 MVAR of mechanically switch shunt capacitors at 34.5 kV collector bus for summer peak.

Table 2.1: Power flow model parameters for GEN-2006-046

Feeder 1, 3, 5	Parameters
12 Suzlon S88 2.1 MW wind turbine generators at 600 V	12 * 2.1 MW = 25.2 MW 12 * 2.1 MVA = 25.2 MVA Power factor at 600 V bus: 0.9995 capacitive
12 Pad mounted wind turbine generator transformers 0.6 / 34.5 kV transformers	12 * 2.5 MVA = 30 MVA Z1 = 7.25% X/R = 4.9 Z1 = 0.01450 + j0.07104 p.u. on 30 MVA base
Feeder 1 equivalent 34.5 kV collector system	Z1 = 0.01965 + j0.02034 p.u. on 100 MVA base B1 = 0.00433 p.u. on 100 MVA base
Feeder 3 equivalent 34.5 kV collector system	Z1 = 0.01794 + j0.01886 p.u. on 100 MVA base B1 = 0.00408 p.u. on 100 MVA base
Feeder 5 equivalent 34.5 kV collector system	Z1 = 0.01906 + j0.01782 p.u. on 100 MVA base B1 = 0.00419 p.u. on 100 MVA base

Feeder 2	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: 0.9995 capacitive
10 Pad mounted wind turbine generator transformers 0.6 / 34.5 kV transformers	10 * 2.5 MVA = 25 MVA Z1 = 7.25% X/R = 4.9 Z1 = 0.01450 + j0.07104 p.u. on 25 MVA base
Feeder equivalent 34.5 kV collector system	Z1 = 0.02996 + j0.02607 p.u. on 100 MVA base B1 = 0.00487 p.u. on 100 MVA base

Feeder 4	Parameters
16 Suzlon S88 2.1 MW wind turbine generators at 600 V	16 * 2.1 MW = 33.6 MW 16 * 2.1 MVA = 33.6 MVA Power factor at 600 V bus: 0.9995 capacitive
16 Pad mounted wind turbine generator transformers 0.6 / 34.5 kV transformers	16 * 2.5 MVA = 40 MVA Z1 = 7.25% X/R = 4.9 Z1 = 0.01450 + j0.07104 p.u. on 40 MVA base
Feeder equivalent 34.5 kV collector system	Z1 = 0.02528 + j0.01888 p.u. on 100 MVA base B1 = 0.00870 p.u. on 100 MVA base

Table 2.1: Power flow model parameters for GEN-2006-046 (Continued)

Substation	Parameters
34.5 / 138 kV main transformer GSU	MVA ratings = 90/120/150 MVA Z1 = 10 % on self-cooled MVA rating X/R = 27.67 (assumed) Z1 = 0.00361 + j0.09993 p.u. on 90 MVA base Fixed HV tap setting = 5% above (144.9 kV)
Switched Shunt Capacitor at 34.5 kV collector bus (winter peak)	24 MVA
Switched Shunt Capacitor at 34.5 kV collector bus (summer peak)	25 MVA
138 kV transmission line, 13 miles, 795 MCM ACSR	Z1 = 0.00900 + j0.04917 p.u. on 100 MVA base (assumed) B1 = 0.01458 p.u. on 100 MVA base (assumed)

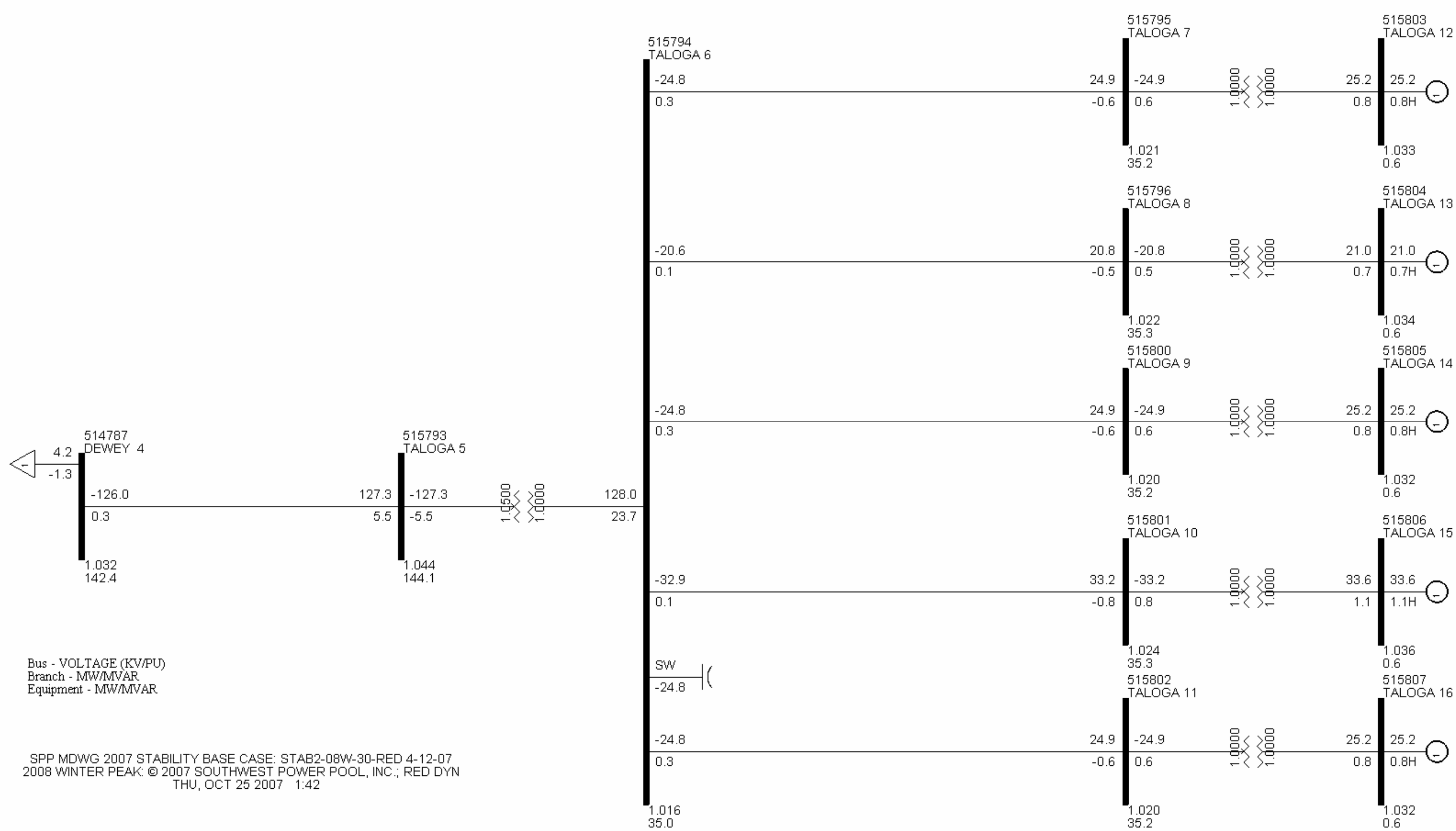

Figure 2.1: Power flow diagram for winter peak

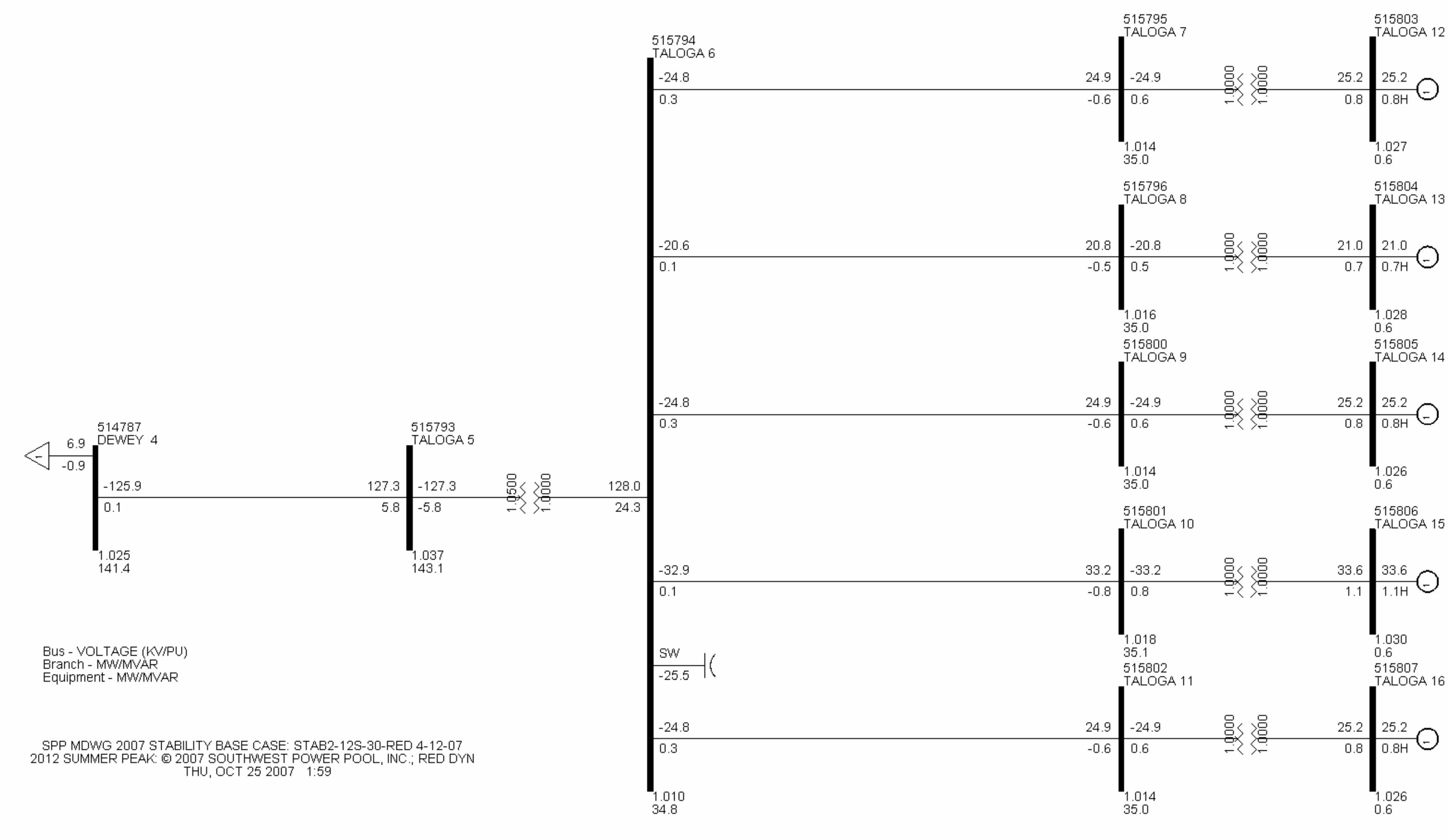

Figure 2.2: Power flow diagram for summer peak

2.2. Steady-State Analysis

GEN-2006-046 will ultimately have an impact on existing equipment ratings, steady-state operating voltages and system losses. Power flow simulations were performed for summer peak and winter peak cases initially with all contingency lines in service to evaluate equipment loading and system voltages with and without the project. After the initial evaluation, power flow simulations were performed for summer and winter peak cases with GEN-2006-046 for line outage contingencies. List of contingency cases provided by SPP are listed in Table 2.2. GEN-2001-037 will trip off as indicated by dynamic simulation results for contingencies FLT113PH, FLT133PH, PLT193PH, and FLT213PH. Power flow simulations were performed with and without GEN-2001-037 for each of these contingencies. Only areas 520, 526, 525, 524, 536, 539, and 541 were monitored for voltage and equipment loading.

Table 2.2: Fault contingency cases

Cont. No.	*Cont. Name*	*Description*
1	*FLT13PH*	3 phase fault on the Dewey (514787) to Iodine (514796) 138kV 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.
2	FLT21PH	*Single phase fault and sequence like Cont. No. 1*
3	*FLT33PH*	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.
4	FLT41PH	*Single phase fault and sequence like Cont. No. 3*
5	*FLT53PH*	3 phase fault on the Dewey (514787) to Southard (514822) 138 kV line, near Dewey. a. Apply fault at Dewey. b. Clear fault after 5 cycles by tripping the line from Dewey 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.
6	FLT61PH	*Single phase fault and sequence like Cont. No.5*
7	FLT73PH	3 phase fault on the Elk City (511458) to GEN-2002-005T (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 – GEN-2002-005T. 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*

Cont. No.	*Cont. Name*	*Description*
9	FLT93PH	3 phase fault on the Mooreland (520999) – Cedardale (520848) 138 kV line, near Cedardale. a. Apply fault at the Cedardale 138 kV 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.
10	FLT101PH	*Single phase fault and sequence like Cont. No. 9*
11	FLT113PH	3 phase fault on the Mooreland (520999) – Glass Mtn. (514788) 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 – Glass Mtn. 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	*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 Mooreland (520999) – Iodine (520957) 138kV line near Iodine. a. Apply fault at the Iodine bus. b. Clear fault after 5 cycles by tripping the line from Mooreland-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.
22	FLT221PH	*Single phase fault and sequence like Cont. No.21*

Summer Peak

Appendix B contains power flow results discussed in this section. Highlighted lines in each of the reports points to equipment loading that exceeds equipment top rating. For instance, the PSS/E reports indicate that GEN-2006-024 main GSU may overload at full wind farm generating output. Transmission line from WINDFRM4 to Mooreland may overload beyond rating B at full wind farm generating output. Another transformer overloaded throughout is the 345/13.2 kV transformer at Redrock. The nature of wind is to blow from late hours at night through early hours in the morning. Absence of direct solar radiation and cooling effect of winds will help equipment and transmission lines handle thermal overloading.

Loading will increase with GEN-2006-046. With all lines in service, the pre-contingency case with GEN-2006-046 shows that loading on the three winding terminal transformer at KNOBHIL will exceed rating A of the transformer, but will not exceed rating B of 65 MVA. Transmission lines from Elk City to Moorewod, from FLINTCR to GENTRY, and from HM-BTTP2 to Moorewod will see loading above rating A, but will not exceed rating B.

Fault contingency FLT53PH, which causes transmission line from Dewey to Southard to trip off, represents the worst case contingency. Loading will exceed the top MVA rating of a large number of transformers and transmission lines.

Expect to see voltages throughout the areas within 0.90 p.u. to 1.1 p.u. with exception to 514897 SMITH 1S 13.8 kV bus, which is consistently above 1.1 p.u.

Winter Peak

Appendix B contains the power flow results discussed in this section. Highlighted lines in each of the reports points to equipment loading that exceeds the equipment top rating. PSS/E power flow reports indicate that GEN-2006-024 main GSU may overload at full wind farm generating output. Transmission line from WINDFRM4 to Mooreland may overload beyond rating A at full wind farm generating output. Winds are stronger during winter; however, lower temperatures may help equipment and transmission lines handle thermal overloading.

Loading will increase with GEN-2006-046. With all lines in service and GEN-2006-046, transmission lines from Elk City to Moorewod, from Mooreland to Moorewod, and from HM-BTTP2 to Moorewod will see loading above rating A, but will not exceed rating B.

Fault contingency FLT53PH, which causes transmission line from Dewey to Southard to trip off, represents one the worst case contingency. Loading will exceed the top MVA rating of large number of transmission lines. Fault contingency FLT93PH, which causes transmission line from Mooreland to Cedardale to trip off, represents one of the other worst case contingencies. Loading will exceed the top MVA rating of large number of transformers.

Expect to see voltages throughout the areas within 0.90 p.u. to 1.1 p.u. with exception to 539716 E LIBER1 34.5 kV bus, which is consistently above 1.1 p.u.

3. Dynamic Simulations and Voltage Stability Results

Dynamic simulations were performed for fault contingencies in Table 2.2 with and without GEN-2006-046. GEN-2001-037 will trip off for certain faults at Mooreland,. Woodward, and Iodine. Contingency cases in which GEN-2001-037 trips off were re-run without wind turbine trip settings to evaluate system voltage stability.

3.1. Pre-Project Dynamic Simulation Files

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.

Files provided by SPP were evaluated with non-disturbance simulation to verify that voltages, MW, MVAR, angles, and frequency would hold a constant value for 20 seconds. Simulation results did not reveal problems with user written models, power flow case or dynamic input file. The response was flat as expected for both summer and winter peak cases.

Summer Peak

Evaluation of SPP dynamic files for fault contingencies in Table 2.2 revealed tripping of prior queued project GEN-2001-014 for fault FLT213PH. Changes to the original summer peak base case were made after consultation with SPP.

1. Changed GEN-2001-014 main GSU primary winding tap setting to 5% above.
2. Added a 12 MVAR switched shunt capacitor on GEN-2001-014 138 kV bus.
3. Added a second 70 MVA, 138/69 kV transformer in parallel with existing transformer at FTSUPLY area.

After the changes were implemented, GEN-2001-014 was able to survive all fault contingencies. Pre-project voltage stability plots (with revisions to SPP files) for each of the fault contingency cases are found in Appendix C.

Winter Peak

Similar issues were encountered in the winter peak case concerning prior queued project, GEN-2001-014. GEN-2001-014 did not trip for fault FLT213PH but significant control chatter was observed for the post fault condition due to marginal low voltage conditions.

Changes were made to the winter peak base case after consultation with SPP.

1. Changed GEN-2001-014 main GSU primary winding tap setting to 5% above.
2. Added a 12 MVAR switched shunt capacitor on GEN-2001-014 138 kV bus.

After changes, the post-fault wind turbine terminal voltage are higher. Iodine settles to 1.0987 p.u. post-fault at t = 20 seconds. Pre-project voltage stability plots (with revisions to SPP files) for each of the fault contingency cases are found in Appendix C.

GEN-2001-037 Low Voltage Ride Through

Simulation results showed for the summer peak case that GEN-2001-037 would not survive three-phase faults (FLT113PH, FLT133PH, FLT193PH, and FLT213PH fault contingencies) at Mooreland (514785), Woodward (514785), and Iodine (520957). SPP indicated that the wind turbine generators at GEN-2001-037 were not required to satisfy low voltage ride through requirements at the time when wind farm was planned, commissioned and place in operation.

Simulation results showed for the winter peak case that GEN-2001-037 may not survive three-phase faults (FLT113PH and FLT193PH fault contingencies) at Mooreland (514785).

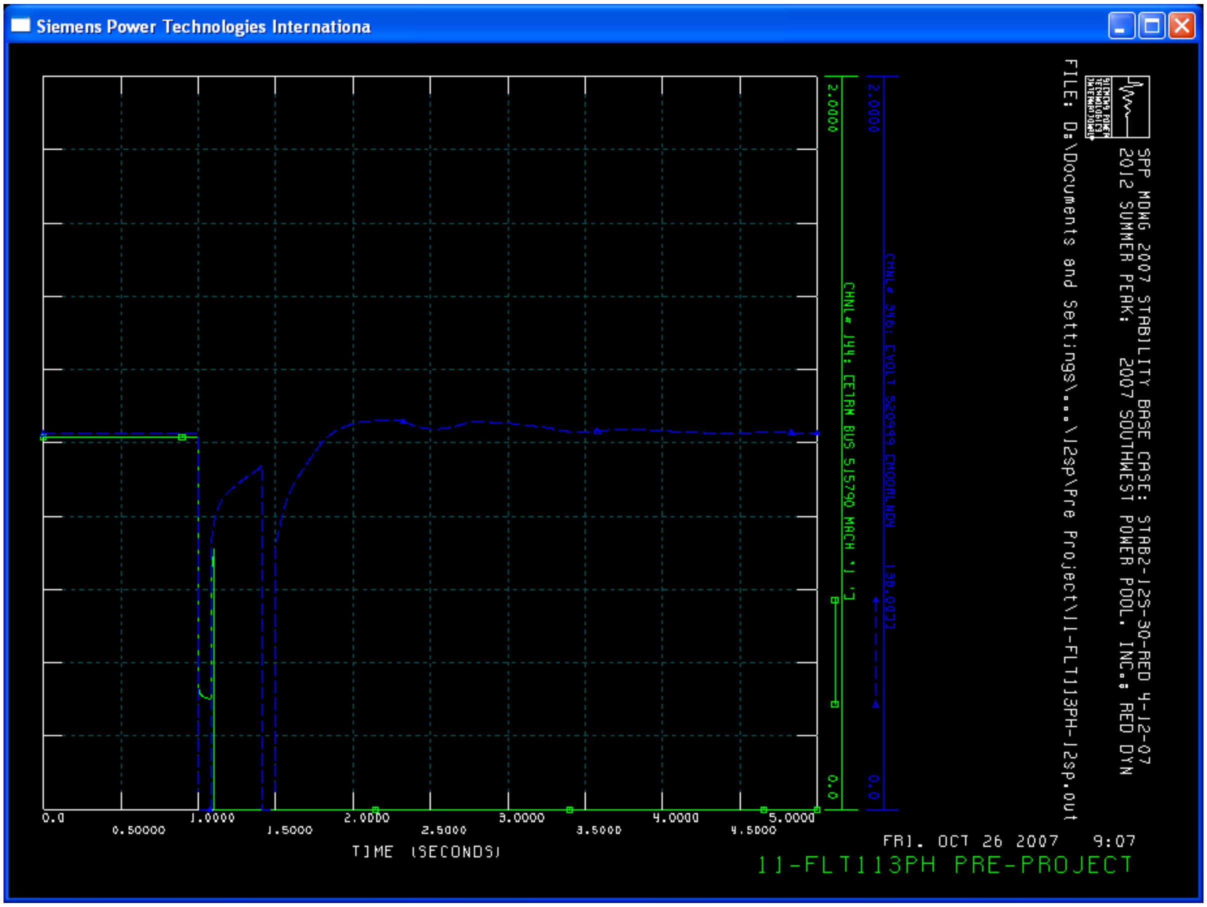

Figure 3.1: FLT113PH and GEN-2001-037 for summer peak case (pre-project)

3.2. Voltage Stability Simulation with Project

GEN-2006-046 was added to the SPP summer and winter power flow cases and dynamic input data file updated to reflect additional Suzlon S88 machines.

Table 3.1: 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

Winter Peak

The 20 second non-disturbance dynamic simulation case revealed initialization problems 1 second into the run. The flat response prior to t = 1 second suggested that at least one user written model had reacted to higher voltage levels reached after adding the project.

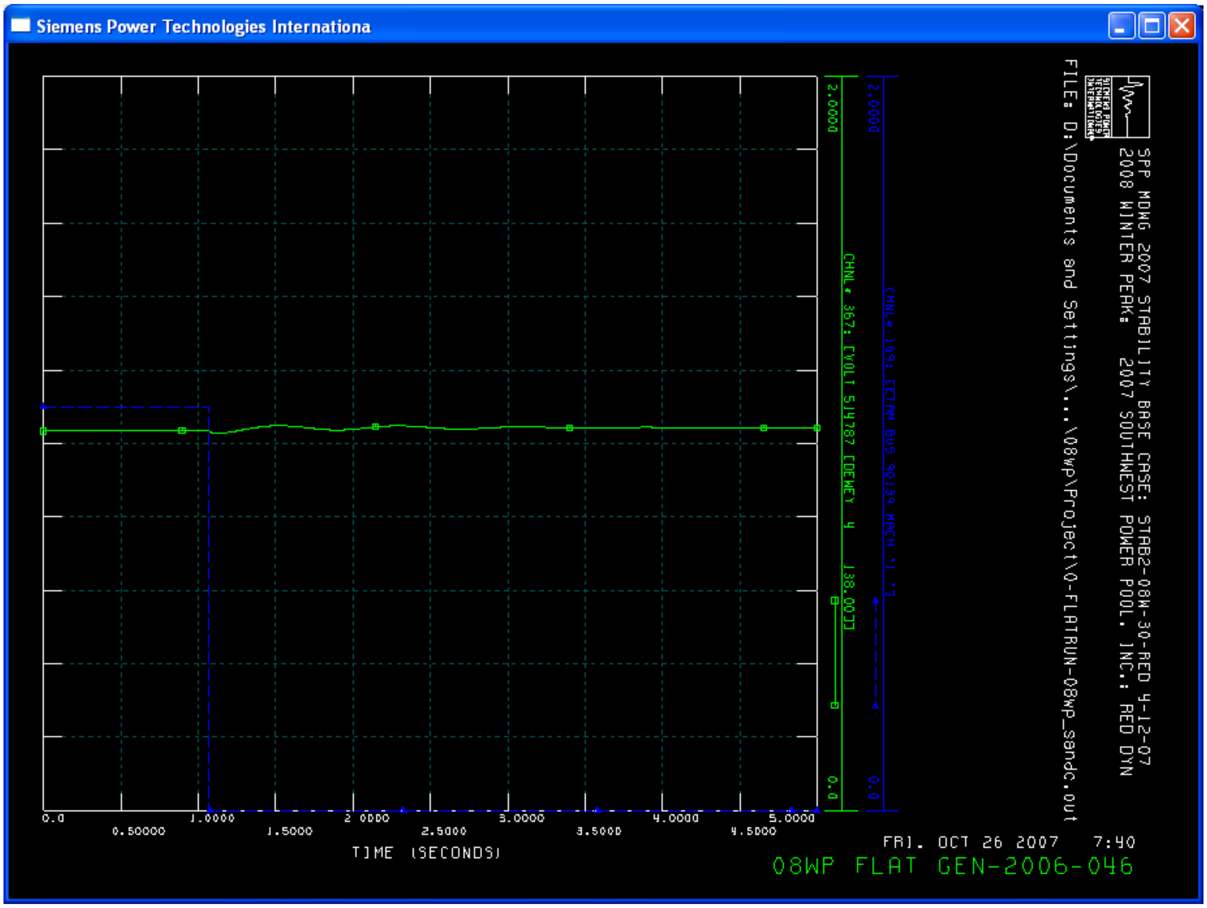

Figure 3.2: Flat run and GEN-2005-008 (90139) for winter peak case with GEN-2006-046

The addition of the 12 MVAR switched shunt capacitor on GEN-2001-014 138 kV bus and GEN-2006-046 both contributed in raising terminal voltages at GEN-2005-008 (90130 to 90139) close to or above 1.1 pu. After consultation with SPP, the primary winding tap setting in GEN-2005-008 main GSU was changed from flat to 5% above.

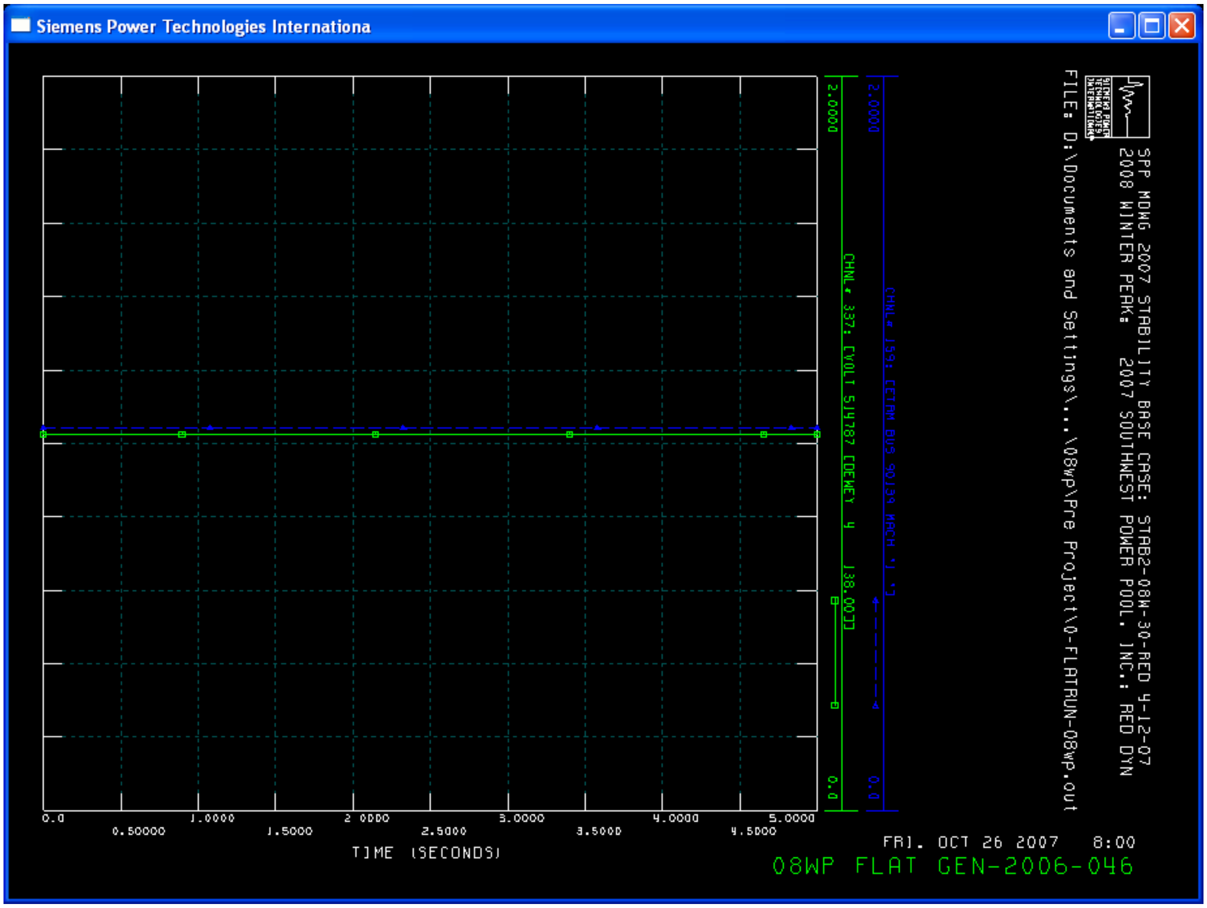

Figure 3.3: Flat run and GEN-2005-008 (90139) for winter peak case with GEN-2006-046 after changes

Appendix D contains stability plots for fault contingency cases in Table 2.2. SLG fault contingencies were simulated by adjusting fault reactance values that result in voltage drops at faulted buses of approximately 60 %. No generation was curtailed or reduced in order to achieve voltage stability. Simulation results show that GEN-2001-037 may not survive three-phase faults (FLT113PH and FLT193PH fault contingencies) at Mooreland (514785). SPP has indicated that the wind turbine generators at GEN-2001-037 are not required to ride through faults. However, in the case that wind turbine generators manage to survive the mentioned fault, SPP is interested in determining their impact on voltage stability. Simulations with wind turbine generator protection disabled at GEN-2001-037 are contained in Appendix E.

Study results do not reveal the need for fast and continuously controlled reactive power equipment such as PureWave™ DSTATCOM to maintain present and prior queued projects (with exception of GEN-2001-037) connected at full load. Fault contingencies other than those specified in Table 2.2 (i.e., breaker failure) may exist that could reveal need for fast and continuously controlled reactive power at GEN-2006-046. However, second level contingencies may not justify the capital expenditure for dynamic reactive power compensation equipment. Even though the scope of study focuses on fault contingencies at full load, it is advisable that a number of cases be considered with light wind farm loading to reveal potential problems with overvoltages that may reveal need for fast reactive power.

Summer Peak

The 20 second non-disturbance dynamic simulation case did not reveal any initialization problems with user written models.

Appendix D contains stability plots for fault contingency cases in Table 2.2. SLG fault contingencies were simulated by adjusting fault reactance values that result in voltage drops at faulted buses of approximately 60 %. No generation was curtailed or reduced in order to achieve voltage stability. Simulation results show that GEN-2001-037 may not survive three-phase faults (FLT113PH, FLT133PH, FLT193PH, and FLT213PH fault contingencies) at Mooreland (514785), Woodward (514785) and Iodine (520957). Wind turbine generators at GEN-2001-037 are not required to ride through faults. However, in the case that wind turbine generators manage to survive the mentioned fault, SPP is interested in determining their impact on voltage stability. Simulations with wind turbine generator protection disabled at GEN-2001-037 are contained in Appendix E.

Study results do not reveal the need for fast and continuously controlled reactive power equipment such as PureWave™ DSTATCOM to maintain present and prior queued projects (with exception of GEN-2001-037) connected at full load. Fault contingencies other than those specified in Table 2.2 (i.e., breaker failure) may exist that could reveal need for fast and continuously controlled reactive power at GEN-2006-046. However, second level contingencies may not justify the capital expenditure for dynamic reactive power compensation equipment. Even though the scope of study focuses on fault contingencies at full load, it is advisable that a number of cases be considered with light wind farm loading to reveal potential problems with overvoltages that may reveal need for fast reactive power.