Southwest Power Pool

Impact Study For Generation Interconnection Request GEN-2005-013

SPP Tariff Studies

(#GEN-2005-013)

March 2010

Executive Summary

<OMITTED TEXT> (Customer) has requested an Impact Study under the Southwest Power Pool Open Access Transmission Tariff (OATT) for interconnection of approximately 199.80 MW of wind generation within the control area of Westar Energy in Latham County, Kansas. The facility studied with Vestes V-90 1.8MW wind generators. The interconnection request was previously studied with GE wind generators.

The following study was conducted by Excel Engineering. The stability study shows that the change in wind turbine technology creates a need for increased reactive power capability requirement for the generation facility. The impact study has identified the need for the wind farm to be able to provide 95% lagging power factor (supplying vars) at the point of interconnection. For the Vestes wind turbines, this will require the addition of multiple banks of capacitors. It is estimated that 110 Mvar of capacitors will be needed on the 34.5kv buses of the wind farm to meet the power factor requirement. The interconnection customer shall size the capacitors in multiple banks to avoid voltage variations on the 345kV bus. With the addition of the capacitors, the transmission system was found to be stable.

The interconnection agreement for this facility will need to be amended to reflect this change in technology.

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

SPP GEN-2005-013 Impact Restudy

Draft Report for

Southwest Power Pool

Prepared by:
Excel Engineering, Inc.

March 9, 2010

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0. Certification

I hereby certify that this plan, specification, or report was prepared by me or under my direct supervision and that I am a duly Licensed Professional Engineer under the Laws of the State of **Arkansas**.

William Quaintance
Arkansas Registration Number 13865

1. Background and Scope

The GEN-2005-013 Impact Restudy is a generation interconnection study performed by Excel Engineering, Inc. for its non-affiliated client, Southwest Power Pool (SPP). Its purpose is to study the impacts of interconnecting the project shown in Table 1-1. The in-service date assumed for the generation addition was 2010.

Table 1-1. Interconnection Requests Evaluated

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2005-013	199.8	Vestas V90 1.8 MW	Latham (532800) – GEN-2005-016 (156) 345kV

The previously-queued requests shown in Table 1-2 were included in this study. These previously-queued requests were dispatched at 100% of rated capacity.

Table 1-2. Nearby Interconnection Requests Already in the Queue

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2002-004	201	G.E. 1.5MW	Latham 345kV (532800)
GEN-2004-010	300	Clipper 2.5MW	Latham 345kV (532800)
GEN-2005-016	150	Gamesa 2.0 MW	GEN-2005-013 (574000) - Neosho (532793)

This study is primarily a stability analysis for the proposed interconnection request. Since the interconnection request in this study is wind project, a power factor analysis was performed.

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

Study assumptions in general have been based on Excel's knowledge of the electric power system and on the specific information and data provided by SPP. The accuracy of the conclusions contained within this study is sensitive to the assumptions made with respect to other generation additions and transmission improvements being contemplated by other entities. Changes in the assumptions of the timing of other generation additions or transmission improvements will affect this study's conclusions.

2. Executive Summary

The GEN-2005-013 Impact Restudy evaluated the impacts of interconnecting project GEN-2005-013 to the SPP electric system.

One steady-state stability problem was found in this study. The power flow solution will not solve following outage of the Rose Hill – Latham 345 kV line. A QV (reactive power – voltage) analysis showed a reactive power deficit following this contingency. With GEN-2005-013 turned off, this problem does not exist. The dynamic simulation of this contingency showed low but stable voltages. The reactive power additions required by the power factor analysis are sufficient to mitigate this problem. The reactive power devices need not be high speed or continuously controlled.

No other stability problems were found during summer or winter peak conditions due to the addition of this generator.

Power factor requirements were determined, and the study plant must install sufficient reactive power resources to meet these requirements listed in Table 4-2. The reactive power resources need not be dynamically controlled. However, any change in wind turbine model or controls could change the stability results, possibly resulting in a need for a dynamically controlled reactive power supply.

With the assumptions and solutions described in this report, GEN-2005-013 should be able to connect without causing any stability problems on the SPP transmission grid.

3. Study Development and Assumptions

3.1 Simulation Tools

The Siemens Power Technologies, Inc. PSS/E power system simulation program Version 30.3.3 was used in this study.

3.2 Models Used

SPP provided its latest stability database cases for both summer and winter peak seasons. The study plant's PSS/E model was developed in this study and was included in the power flow case and the dynamics database. The project was dispatched against SPP generation. Power flow and dynamic model data for the study plants are provided in Appendix D.

A power flow one-line diagram of the study project in summer peak conditions is shown in Figure 3-1. As the figure shows, the plant model includes explicit representation of the 345 kV line connecting the plant substation to the POI (point of interconnection) and the substation transformer from transmission voltage to 34.5 kV. The remainder of the wind farm is represented by one lumped equivalent including a generator, a step-up transformer, and a collector system impedance. Figure 3-2 shows the power flows on the local transmission system.

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

3.3 Monitored Facilities

All generators in Areas 536, 541, 544, and 524 were monitored.

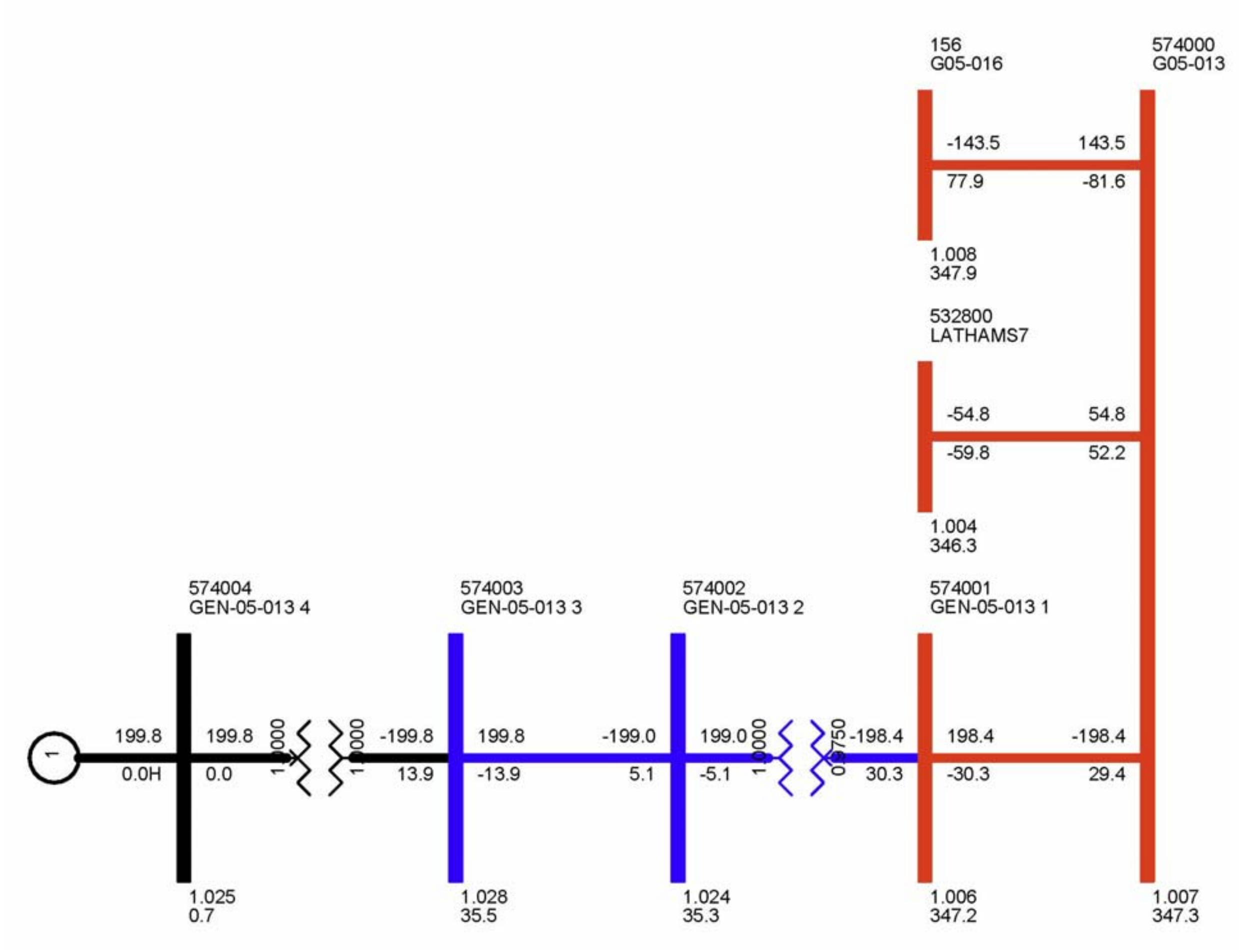

Figure 3-1. Power Flow One-line for GEN-2005-013 and adjacent equipment (SP)

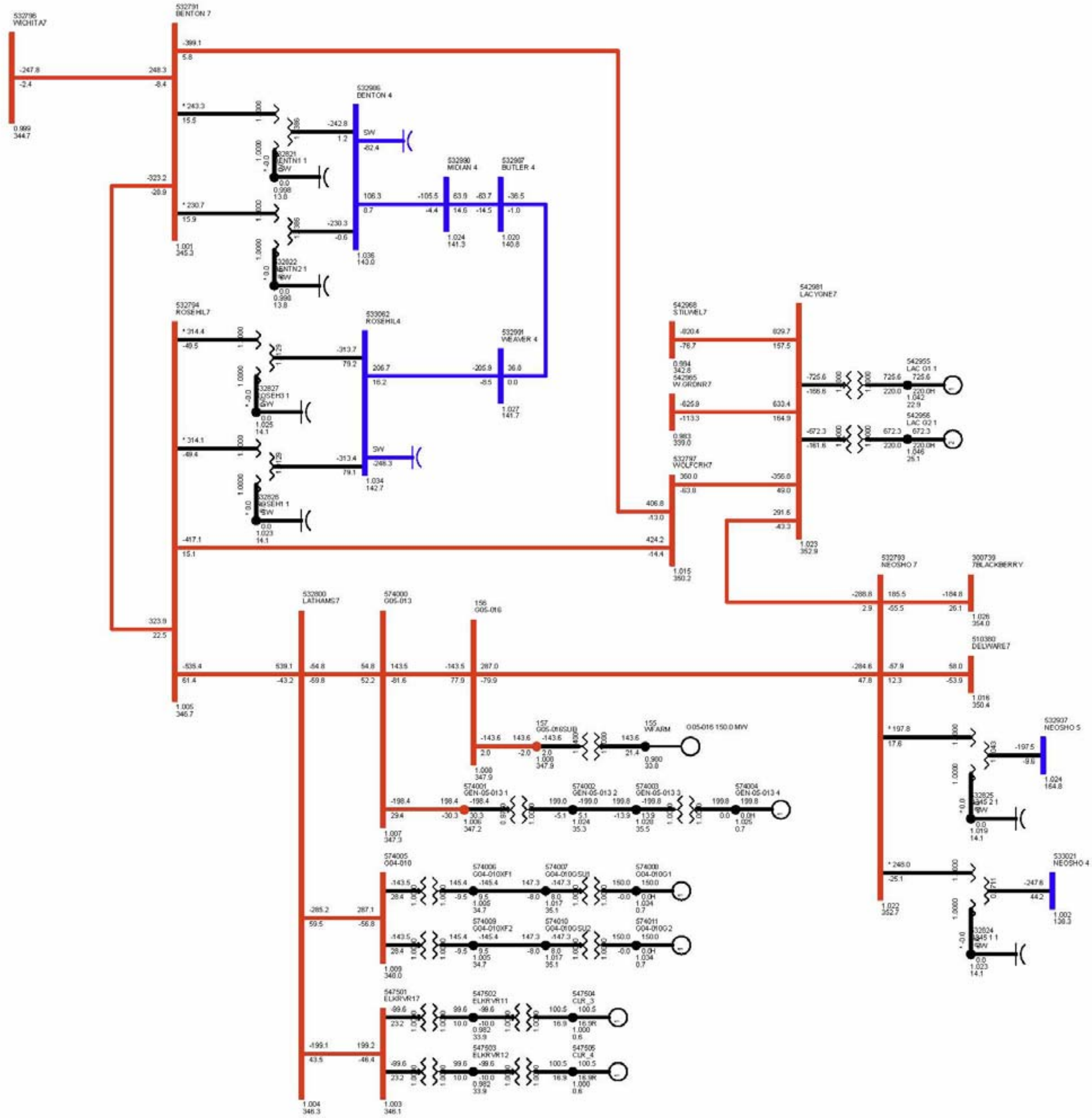

Figure 3-2. Transmission System near GEN-2005-013 (SP)

3.4 Performance Criteria

The wind generators must comply with FERC Order 661A on low voltage ride through for wind farms. Therefore, the wind generators should not trip off line for faults at the Point of Interconnection. If a wind generator trips off line, an appropriately sized SVC or STATCOM device may need to be specified to keep the wind generator on-line for the fault. SPP was consulted to determine if the addition of an SVC or STATCOM is warranted for the specific condition.

Contingencies that resulted in a prior-queued project tripping off-line, if any, were re-run with the prior-queued project's voltage and frequency tripping disabled to check for stability issues.

3.5 Performance Evaluation Methods

Since the interconnection request is a wind project, a power factor analysis was performed. The power factor analysis consisted of modeling a var generator in each wind farm holding a voltage schedule at the POI. The voltage schedule was set equal to the higher of the voltage with the wind farm off-line or 1.0 per unit.

If the required power factor at the POI is beyond the capability of the studied wind turbines, then capacitor banks would be considered. Factors used in sizing capacitor banks would include two requirements of FERC Order 661A: the ability of the wind farm to ride through low voltage with and without capacitor banks and the ability of the wind farm to recover to pre-fault voltage. If a wind generator trips on high voltage, a leading power factor may be required.

Stability analysis was performed for the proposed interconnection request. Faults were simulated on transmission lines at the POIs and on other nearby transmission equipment. The faults in Table 3-1 were run for each case (three phase and single phase as noted).

Table 3-1. Fault Definitions for GEN-2005-013

Cont. No.	Contingency Name	Description
1	FLT13PH	Three phase fault on the Rose Hill (532794) to the Latham Switching Station (532800), 345kV line, (at Mid Line). a. Apply Fault at the Mid-line bus. b. Clear Fault after 5 cycles by removing the line from Rose Hill to Mid-line bus and from Mid-line bus to Latham Switching Station c. Wait 300 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	Three phase fault on the Wind Farm Switching Station (574000) to GEN-2005-016 (156) 345 kV line, near GEN-2005-016. a. Apply fault at the GEN-2005-016 substation bus. b. Clear fault after 5 cycles by removing the line from the Wind Farm Switching Station to GEN-2005-016. c. Wait 300 cycles, and then re-close the line in (b) 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	Three phase fault on the Neosho (532793) to Blackberry (300739), 345kV line, (at Mid-line). Establish a new bus (Mid-line bus) in the electrical middle of this 345 kV line. a. Apply Fault at the Mid-line bus. b. Trip the line after 5 cycles by removing the line from Neosho to the Mid-line bus to Blackberry and remove the fault. c. Wait 300 cycles, and then re-close the line in (b) 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	Three phase fault on the Rose Hill (532794) to Wolf Creek (532797) 345 kV line, near Rose Hill. a. Apply fault at the Rose Hill. b. Clear fault after 5 cycles by tripping the line from Rose Hill to Wolf Creek. c. Wait 300 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	Three phase fault on the Rose Hill (532794) to Benton (532791) 345 kV line, near Benton. a. Apply fault at the Benton. b. Clear fault after 5 cycles by tripping the line from Rose Hill to Benton . c. Wait 60 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

Cont. No.	Contingency Name	Description
11	FLT113PH	Three phase fault on the Benton (532791) to Wichita (532796) 345 kV line, near Wichita. a. Apply fault at the Wichita bus b. Clear fault after 5 cycles by tripping the line Benton to Wichita. c. Wait 60 cycles, and then re-close 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	Three phase fault on the Benton (532986) to Midian (532990) 138 kV line, near Midian. a. Apply fault at the Midian bus. b. Clear fault after 7 cycles by tripping the line from Benton to Midian. c. Wait 25 cycles, and then re-close line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
14	FLT141PH	Single phase fault and sequence like Cont. No. 13
15	FLT153PH	Three Phase fault on the Midian (532990) to Butler (532987) 138 kV line, near Butler. a. Apply fault at the Butler bus. b. Clear fault after 7 cycles by tripping the line from Midian to Butler c. Wait 25 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
16	FLT161PH	Single phase fault and sequence like Cont. No. 15
17	FLT173PH	Three phase fault on the Rose Hill (533062) to Weaver (532991) 138 kV line a. Apply fault at the Weaver bus (532991). b. Clear fault after 7 cycles by tripping the line from Rose Hill (533062) to Weaver (532991). c. Wait 25 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
18	FLT181PH	Single phase fault and sequence like Cont. No. 17
19	FLT193PH	FERC 661A Fault; Three phase fault on the Wind Farm Switching Station (574000) to GEN-2005-016 (156) 345 kV line, at the POI. a. Apply fault at the Wind Farm Switching Station 345kV. b. Clear fault after 5 cycles by removing the line from the Wind Farm Switching Station to GEN-2005-016. c. Wait 300 cycles, and then reclose the line in (b) back into the faults d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT203PH	FERC 661A Fault; Three phase fault on the Wind Farm Switching Station (547000) to Latham substation (532800) 345 kV line, at the POI. a. Apply fault at the Wind Farm Switching Station 345kV. b. Clear fault after 5 cycles by removing the line from the Wind Farm Switching Station to Latham substation. c. Wait 300 cycles, and then reclose the line in (b) back into the faults d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault

Cont. No.	Contingency Name	Description
21	FLT213PH	3 phase fault on the Neosho (532793) – LaCygne (542981) 345kV line near Neosho. a. Apply fault at the Neosho 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line and remove the fault.
22	FLT221PH	Single-phase fault on the Neosho (532793) – LaCygne (542981) 345kV line near Neosho. a. Apply fault at the Neosho 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line. c. Wait 300 cycles, and then re-close Neosho 345 kV end back into the fault. d. Leave the fault on for 3.6 cycles, then trip the line and remove the fault.
23	FLT233PH	3 phase fault on the West Gardner (542965) – LaCygne (542981) 345kV line near LaCygne. a. Apply fault at the LaCygne 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line. c. Wait 1200 cycles, and then re-close the West Gardner end of the line back into the fault. d. Leave fault on for 3.6 cycles, then trip the line in (b) and remove fault.
24	FLT241PH	Single phase fault and sequence like previous
25	FLT253PH	3 phase fault on the Wolf Creek (532797) – LaCygne (542981) 345kV line near LaCygne. a. Apply fault at the LaCygne 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line and remove the fault.
26	FLT261PH	Single phase fault on the Wolf Creek (532797) – LaCygne (542981) 345kV line near LaCygne. a. Apply fault at the LaCygne 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line and remove the fault.
27	FLT273PH	3 phase fault on the Neosho (532793) – Delaware (510380) 345kV line near Delaware. a. Apply fault at the Delaware 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line and remove the fault.
28	FLT281PH	Single phase fault on the Neosho (532793) – Delaware (510380) 345kV line near Delaware. a. Apply fault at the Delaware 345kV bus. b. Clear fault after 3.6 cycles by tripping the faulted line and remove the fault.

4. Results and Observations

4.1 Stability Analysis Results

All faults were run for both summer and winter peak conditions. If a previously-queued generator tripped for any of these faults, the voltage and frequency tripping was disabled, and the fault was re-run to check for system stability. No tripping occurred in this study.

Table 4-1 summarizes the overall results for all faults run. Figure 4-1 and Figure 4-2 show representative summer peak season plots for faults at the POI for the study project. Complete sets of plots for both summer and winter peak seasons for each fault are included in Appendices A and B.

The system remains stable for all simulated faults. The study project and all other prior-queued projects stay on-line and stable for all simulated faults.

Table 4-1. Summary of Stability Results

Cont. No.	Contingency Name	Description	Summer Peak Results	Winter Peak Results
1	FLT13PH	Three phase fault on the Rose Hill (532794) to the Latham Switching Station (532800), 345kV line, (at Mid Line).	OK	OK
2	FLT21PH	Single phase fault and sequence like Cont. No. 1	OK	OK
3	FLT33PH	Three phase fault on the Wind Farm Switching Station (574000) to GEN-2005-016 (156) 345 kV line, near GEN-2005-016.	OK	OK
4	FLT41PH	Single phase fault and sequence like Cont. No. 3	OK	OK
5	FLT53PH	Three phase fault on the Neosho (532793) to Blackberry (300739), 345kV line, (at Mid-line). Establish a new bus (Mid-line bus) in the electrical middle of this 345 kV line.	OK	OK
6	FLT61PH	Single phase fault and sequence like Cont. No. 5	OK	OK
7	FLT73PH	Three phase fault on the Rose Hill (532794) to Wolf Creek (532797) 345 kV line, near Rose Hill.	OK	OK
8	FLT81PH	Single phase fault and sequence like Cont. No. 7	OK	OK
9	FLT93PH	Three phase fault on the Rose Hill (532794) to Benton (532791) 345 kV line, near Benton.	OK	OK
10	FLT101PH	Single phase fault and sequence like Cont. No. 9	OK	OK
11	FLT113PH	Three phase fault on the Benton (532791) to Wichita (532796) 345 kV line, near Wichita.	OK	OK
12	FLT121PH	Single phase fault and sequence like Cont. No. 11	OK	OK
13	FLT133PH	Three phase fault on the Benton (532986) to Midian (532990) 138 kV line, near Midian.	OK	OK
14	FLT141PH	Single phase fault and sequence like Cont. No. 13	OK	OK
15	FLT153PH	Three Phase fault on the Midian (532990) to Butler (532987) 138 kV line, near Butler.	OK	OK

Cont. No.	Contingency Name	Description	Summer Peak Results	Winter Peak Results
16	FLT161PH	Single phase fault and sequence like Cont. No. 15	OK	OK
17	FLT173PH	Three phase fault on the Rose Hill (533062) to Weaver (532991) 138 kV line	OK	OK
18	FLT181PH	Single phase fault and sequence like Cont. No. 17	OK	OK
19	FLT193PH	FERC 661A Fault; Three phase fault on the Wind Farm Switching Station (574000) to GEN-2005-016 (156) 345 kV line, at the POI.	OK	OK
20	FLT203PH	FERC 661A Fault; Three phase fault on the Wind Farm Switching Station (547000) to Latham substation (532800) 345 kV line, at the POI.	OK	OK
21	FLT213PH	3 phase fault on the Neosho (532793) – LaCygne (542981) 345kV line near Neosho.	OK	OK
22	FLT221PH	Single-phase fault on the Neosho (532793) – LaCygne (542981) 345kV line near Neosho.	OK	OK
23	FLT233PH	3 phase fault on the West Gardner (542965) – LaCygne (542981) 345kV line near LaCygne.	OK	OK
24	FLT241PH	Single phase fault and sequence like previous	OK	OK
25	FLT253PH	3 phase fault on the Wolf Creek (532797) – LaCygne (542981) 345kV line near LaCygne.	OK	OK
26	FLT261PH	Single phase fault on the Wolf Creek (532797) – LaCygne (542981) 345kV line near LaCygne.	OK	OK
27	FLT273PH	3 phase fault on the Neosho (532793) – Delaware (510380) 345kV line near Delaware.	OK	OK
28	FLT281PH	Single phase fault on the Neosho (532793) – Delaware (510380) 345kV line near Delaware.	OK	OK

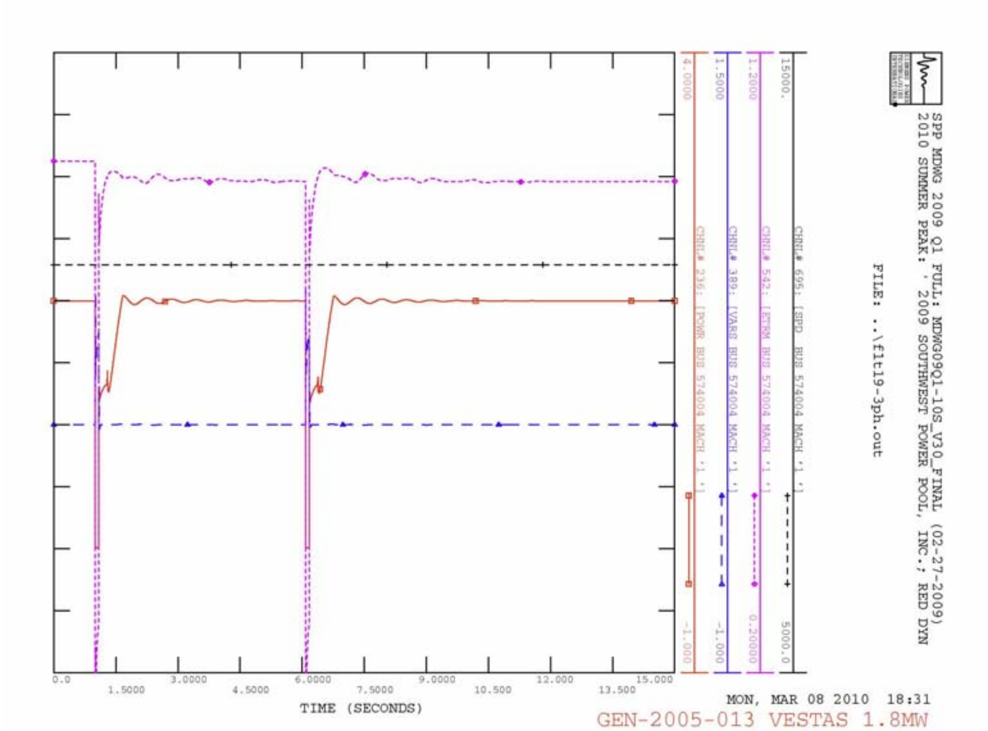

Figure 4-1. **GEN-2005-013 Plot for Fault 19 – FERC 661A Fault; 3-Phase Fault on the GEN-2005-013 to GEN-2005-016 345 kV line, near GEN-2005-013**

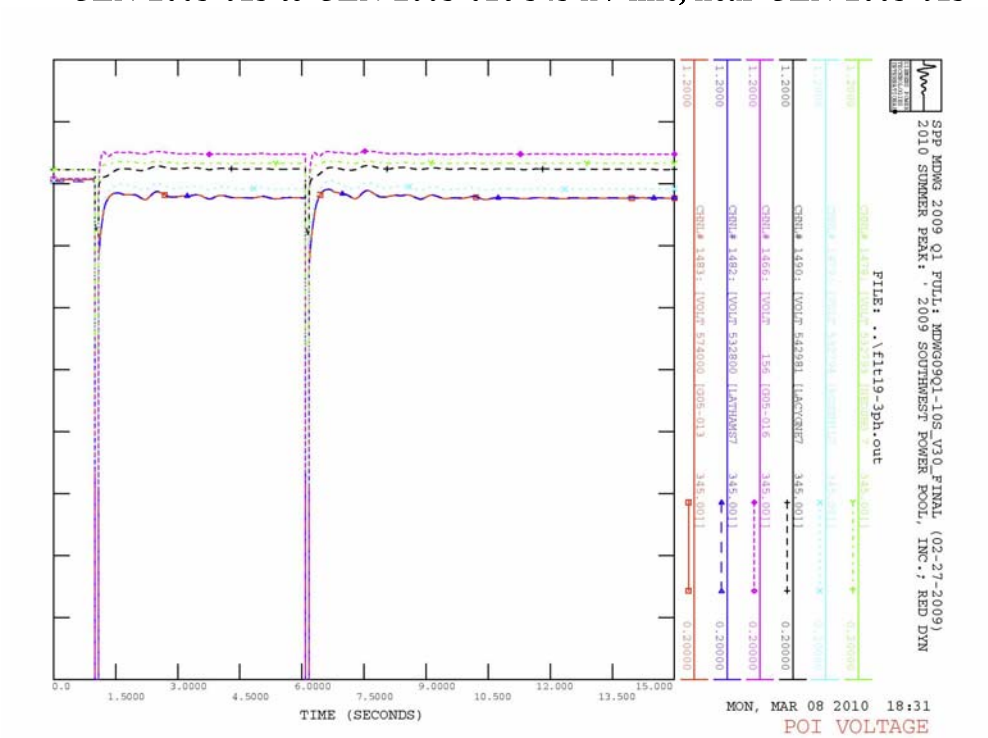

Figure 4-2. **POI Voltage Plot for Fault 19 – FERC 661A Fault; 3-Phase Fault on the GEN-2005-013 to GEN-2005-016 345 kV line, near GEN-2005-013**

4.2 Power Factor Requirements

All stability faults were tested as power flow contingencies to determine the power factor requirements for the wind farm study project to maintain scheduled voltage at its respective point of interconnection (POI). The voltage schedules are set equal to the voltages at the POIs before the project is added, with a minimum of 1.0 per unit. Fictitious reactive power sources were added to the study project to maintain scheduled voltage during all studied contingencies. The MW and Mvar injections from the study project at the POI were recorded and the resulting power factors were calculated for all contingencies for summer peak and winter peak cases. The most leading and most lagging power factors determine the minimum power factor range capability that the study project must install before commercial operation.

If more than one study project shared a single POI (none in this case), the projects were grouped together and a common power factor requirement was determined for those study projects. This ensures that none of the study projects is required to provide more or less than its fair share of the reactive power requirements at a single POI. *Prior-queued* projects at the same POI, if any, were not grouped with the study projects because their interconnection requirements were determined in previous studies.

Per FERC and SPP Tariff requirements, if the power factor needed to maintain scheduled voltage were less than 0.95 lagging, then the requirement would be set to 0.95 lagging. This limit was reached for GEN-2005-013. Much greater reactive power supply would be needed to meet the voltage schedules under some contingencies, but only 0.95 lagging will be required. The limit for leading power factor requirement is also 0.95, but this level was not reached for GEN-2005-013.

The final power factor requirements are shown in Table 4-2 below. These are only the minimum power factor ranges. A project developer may install more capability than this if desired.

The full details for each contingency in summer and winter peak cases are given in Appendix C.

Table 4-2. Power Factor Requirements [1]

Project	MW	Turbine	POI	Final PF Requirement	
				Lagging [2]	Leading [3]
GEN-2005-013	199.8	Vestas V90 1.8 MW	Latham (532800) – GEN-2005-016 (156) 345kV	0.950	0.998

Notes:

1. For each plant, the table shows the minimum required power factor capability at the point of interconnection that must be designed and installed with the wind farm. The power factor capability at the POI includes the net effect of the wind turbine generators, transformer and collector line impedances, and any reactive compensation devices installed on the plant side of the meter. Installing more capability than the minimum requirement is acceptable.
2. Lagging is when the generating plant is supplying reactive power to the transmission grid. In this situation, the alternating current sinusoid “lags” behind the alternating voltage sinusoid, meaning that the current peaks shortly after the voltage.
3. Leading is when the generating plant is taking reactive power from the transmission grid. In this situation, the alternating current sinusoid “leads” the alternating voltage sinusoid, meaning that the current peaks shortly before the voltage.

4.3 Generator Performance

The prior-queued projects perform well for all faults, with no tripping evident.

The study project performs well for all faults, with no tripping evident.

4.4 Steady State Analysis of Faults 1 and 2

Following Faults 1 and 2, the post contingency generator terminal voltage of the study project drops to 0.91 p.u.. The voltages of the local 345 kV buses (GEN-2005-013 POI, GEN-2005-016, Latham) also drop to round 0.90 p.u.. Figure 4-3 and Figure 4-4 show representative summer peak season plots for fault 1 for the study project and local 345 kV buses voltages.

Faults 1 and 2 are 3-phase and 1-phase faults, respectively, on the Rose Hill to Latham Switching Station 345 kV line. In steady state conditions, following the contingency on this 345 kV line, the power flow solution blows up in both summer peak and winter peak cases. With GEN-2005-013 turned off, this problem is not seen.

In order to investigate the voltage stability problem, QV analysis was performed for both summer peak and winter peak conditions. Figure 4-5 shows the QV curves at the GEN-2005-013 345kV POI bus with contingency on the Rose Hill – Latham 345kV Line.

Analysis shows the minimum points of the QV curves under this contingency are at 0.85 p.u. for both summer peak and winter peak conditions, with a reactive power deficit of 10 Mvar in the summer. The reactive additions required by the power factor analysis will make up for this deficit.

With the stable side of the QV curve covering the normal voltage operating range and the dynamic simulations showing stability, mechanically switched capacitors should be an acceptable form of reactive compensation for GEN-2005-013.

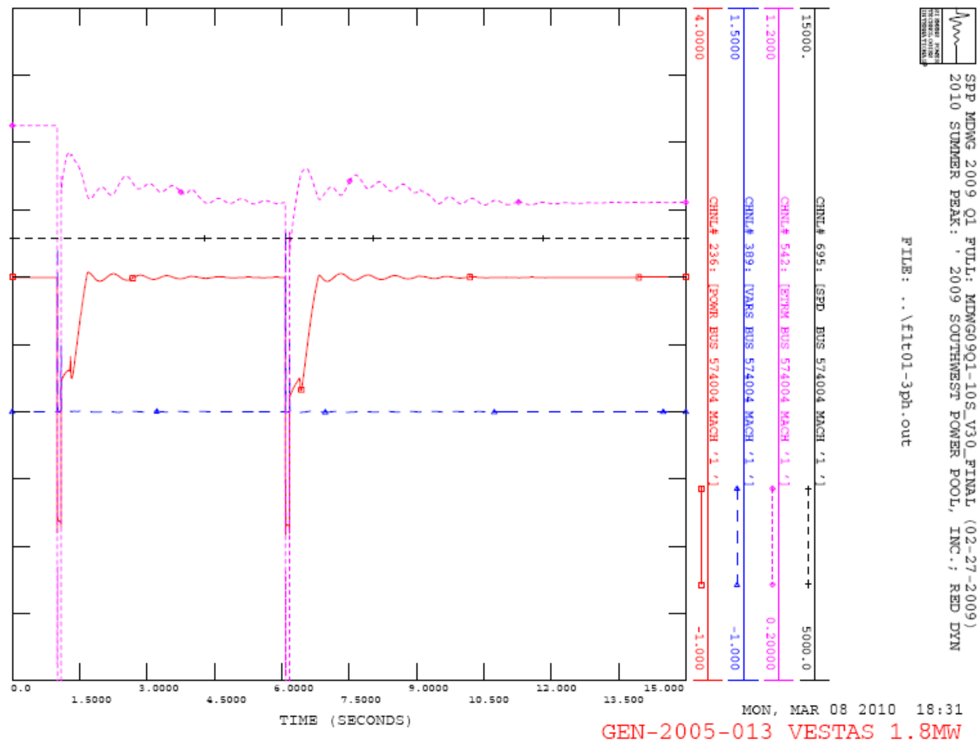

Figure 4-3. GEN-2005-013 Plot for Fault 1 – 3-Phase Fault on the Rose Hill to the Latham Switching Station 345kV Line, at Mid Line

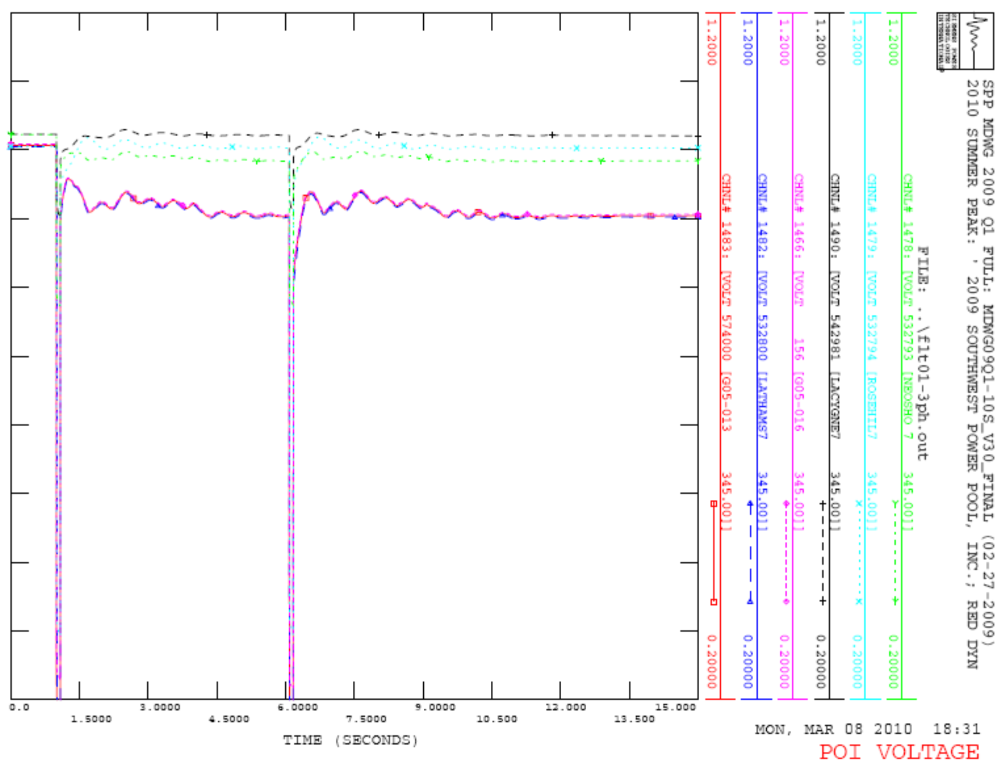

Figure 4-4. Local 345kV Buses Voltages Plot for Fault 1 – 3-Phase Fault on the Rose Hill to the Latham Switching Station 345kV Line, at Mid Line

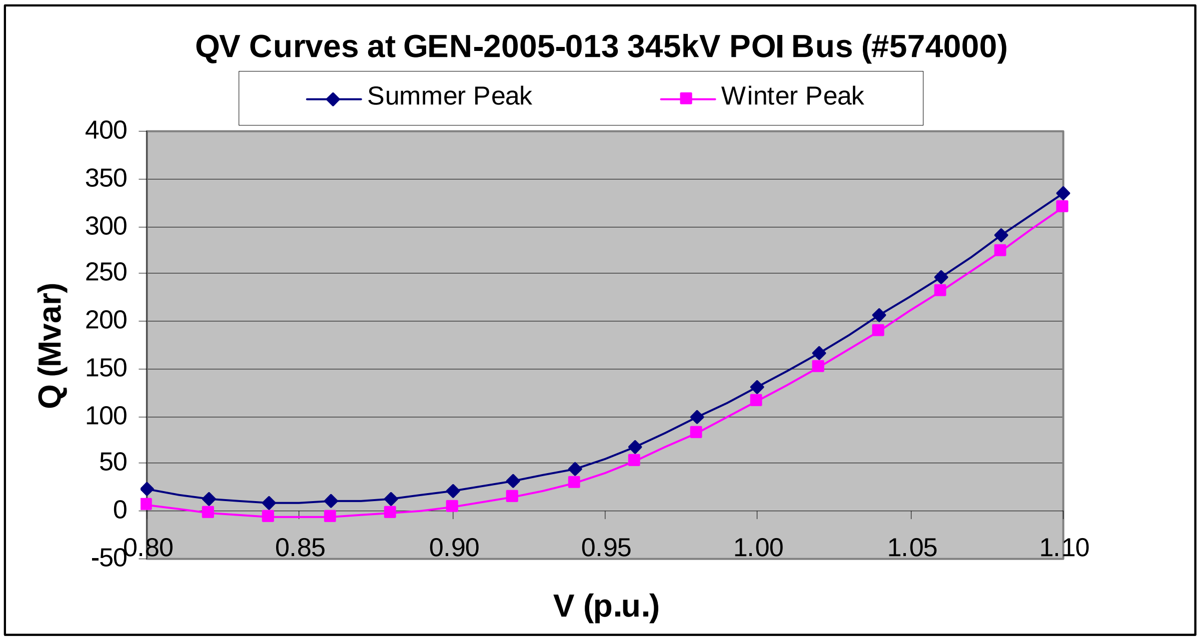

Figure 4-5. QV Curves at GEN-2005-013 345kV POI Bus with Contingency on the Rose Hill – Latham 345 kV Line

5. Conclusions

The GEN-2005-013 Impact Restudy evaluated the impacts of interconnecting the project shown below.

Table 5-1. Interconnection Requests Evaluated

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2005-013	199.8	Vestas V90 1.8 MW	Latham (532800) – GEN-2005-016 (156) 345kV

One steady-state stability problem was found in this study. The power flow solution will not solve following outage of the Rose Hill – Latham 345 kV line. A QV (reactive power – voltage) analysis showed a reactive power deficit following this contingency. With GEN-2005-013 turned off, this problem does not exist. The dynamic simulation of this contingency showed low but stable voltages. The reactive power additions required by the power factor analysis are sufficient to mitigate this problem. The reactive power devices need not be high speed or continuously controlled.

No other stability problems were found during summer or winter peak conditions due to the addition of this generator.

Power factor requirements were determined, and the study plant must install sufficient reactive power resources to meet these requirements listed in Table 4-2. The reactive power resources need not be dynamically controlled. However, any change in wind turbine model or controls could change the stability results, possibly resulting in a need for a dynamically controlled reactive power supply.

With the assumptions and solutions described in this report, GEN-2005-013 should be able to connect without causing any stability problems on the SPP transmission grid.

Appendix A – Summer Peak Plots

See attachment.

Appendix B – Winter Peak Plots

See attachment.

Appendix C – Power Factor Details

See attachment.

Appendix D – Project Model Data

See attachment.