Southwest Power Pool

GEN-2010-040
Impact Restudy

SPP Generation Interconnection Studies

GEN-2010-040

November 2011

Executive Summary

The Generation Interconnection Customer has requested a generator interconnection through the Southwest Power Pool (SPP) Tariff. A Definitive Interconnection System Impact Study (SPP Definitive Impact Study DISIS 2010-002, posted January 31, 2011) has been completed for the Customer's generator interconnection project, GEN-2010-040 However, subsequent to the completion of DISIS-2010-002, the customer has requested an impact restudy due to a change in the wind turbine generator.

The project has a maximum power output of 300MW and is to be located in Canadian County Oklahoma. The project has two 34.5/345kV substation transformers that will connect to the Customer's 345kV transmission line to the Point of Interconnection (POI), Cimarron 345kV Substation. The generators for this impact restudy will be one-hundred-forty-six (146) REpower MM92 2.05MW wind turbine generators for a gross power output of 299.3MW. Previously, the generators evaluated in the Definitive Impact Study DISIS 2010-002 were the Suzlon S88 2.1MW wind turbine generators.

The findings of the restudy (which follows this summary) show that no stability problems were found during the summer or the winter peak conditions due to the use of the REpower MM92 2.05MW wind turbine generators.

A power factor analysis was performed. The facility will be required to maintain a 95% lagging (providing vars) and 95% leading (absorbing vars) power factor a the point of interconnection. Based on data provided to SPP, the generators operate at unity power factor at the generator terminal. Therefore, capacitor banks in multiple stages are required to meet the power factor requirement.

With the assumptions outlined in this report, GEN-2010-040 should be able to reliably interconnect to the SPP transmission grid.

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

GEN-2010-040 Impact Restudy

FINAL REPORT

REPORT NO.: E-00007531
Issued On: November 11, 2011

Prepared for:
Southwest Power Pool, Inc.

ABB Inc.
Power Systems Division
Grid Systems Consulting
940 Main Campus Drive, Suite 300
Raleigh, NC 27606

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ABB Inc – Grid Systems Consulting

Technical Report

Southwest Power Pool, Inc.	**No.** E-00007531	
GEN-2010-040 System Impact Re-study	Date: 11/11/11	# Pages 21

Author(s):	**Reviewed by:**	**Approved by:**
B Kondala Rao	Seshadri Subramanian	Willie Wong

Executive Summary

Southwest Power Pool, Inc. (SPP) commissioned ABB Inc. to perform a System Impact re-study for the proposed GEN-2010-040, which consisted of a wind-based generation with a maximum output of 299.3 MW. The re-study was necessary due to a change in the wind turbine generator for this proposed interconnection. The proposed wind farm is located in Canadian County, Oklahoma and the POI is at Cimarron 345kV.

This study evaluated the impact of the GEN-2010-040 project on the SPP Transmission System. The scope of this study was limited to the power factor evaluation and transient stability analysis.

A summary of the study findings is given below:

Power factor analysis

SPP requires that the Interconnection Customer's wind farm maintain at least +/- 0.95 power factor at the POI for any system condition. The maximum reactive power capability necessary to maintain a 0.95 power factor at the POI was found to be roughly 130 MVAR, considering the worst tested contingencies for summer and winter load conditions.

Since the proposed wind farm operates at unity power factor at its terminals (i.e. zero reactive power generation), added capacitor compensation would be necessary to adhere to SPP's interconnection standard (power factor).

Based on the above study findings, capacitor bank(s) of 130 MVAR of multiple stages will be necessary to maintain a power factor of 0.95 at the POI. However, if only the collector system reactive requirements are to be met from the wind farm locally (i.e. no reactive power exchanges with the grid – unity power factor at the POI), then a 60 MVAR capacitor bank would suffice.

Stability Analysis

A stability analysis was performed to determine the impact, if any, of the proposed project on the stability of SPP system. The system was stable for all the simulated 3-

Phase and single-phase faults. The proposed GEN-2010-040 wind farm stayed on-line throughout the duration of the fault and thereof. The voltage recovery was acceptable, and the oscillations were positively damped.

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FERC Order 661A Compliance

Selected faults were simulated at the Point of Interconnection (POI) of the proposed GEN-2010-040 wind farm to determine the compliance with FERC 661 – A; post-transition period LVRT standard. The results indicated that the proposed project met the FERC LVRT requirement for wind farm interconnection.

Based on the results of the analysis, it can be concluded that the proposed GEN-2010-040 wind farm does not adversely impact the transmission performance of the SPP system.

The results of this analysis are based on available data and assumptions made at the time of conducting this study. If any of the data and/or assumptions made in developing the study model change, the results provided in this report may not apply.

Rev No.	Revision Description	Date	Authored by	Reviewed by	Approved by
0	Draft Report	10/31/2011	B Kondalarao	Subramanian, S	Wong, W
	Final Report	11/11/2011	B Kondalarao	Subramanian, S	Wong, W
DISTRIBUTION: Raymond Offenbacker – Southwest Power Pool, Inc.					

TABLE OF CONTENTS

1 INTRODUCTION

Southwest Power Pool, Inc. (SPP) commissioned ABB Inc. to perform a System Impact re-study for the proposed GEN-2010-040, which consisted of a wind-based generation with a maximum output of 299.3 MW. The re-study was necessary due to a change in the wind turbine generator for this proposed interconnection. The proposed wind farm is located in Canadian County, Oklahoma and the POI is at Cimarron 345 kV. Figure 1-1 shows the POI of the proposed generation project on a Geographical Transmission Map.

This study evaluated the impact of the GEN-2010-040 project on the SPP Transmission System. The scope of this study was limited to the power factor evaluation and transient stability analysis.

The main objectives of this study were

1) To determine the need for reactive power compensation, if any, for the proposed wind farm, to maintain acceptable power factor at the POI.
2) To determine the impact of the proposed Project (GEN-2010-040, 299.3 MW) on the stability of SPP transmission system and nearby generating stations.
3) To validate the compliance with FERC LVRT requirement for the wind farm.

To achieve these objectives the following analyses were performed on the 2010-2011 Summer and Winter Peak system conditions with GEN-2010-040 project(s) in-service

- Power factor analysis for selected contingencies.
- Transient stability analysis for various local and regional contingencies.

The study was performed on the cases, provided by SPP. This report documents the methods, analysis and results of the system impact study.

Table 1-1: GEN-2010-040 Project

Project	Size (MW)	Wind Turbine Type	Point of Interconnection	Location
GEN-2010-040	299.3	REpower MM92 2.05MW	Cimarron 345kV (bus #514901)	Canadian, Oklahoma

1.1 REPORT ORGANIZATION

This report is organized as follows:

Section 2: Description of project
Section 3: Study methodology
Section 4: Model Development
Section 5: Power Factor Analysis Results
Section 6: Stability Analysis Results
Section 7: Conclusions

The detailed study results are included in separate Appendices.

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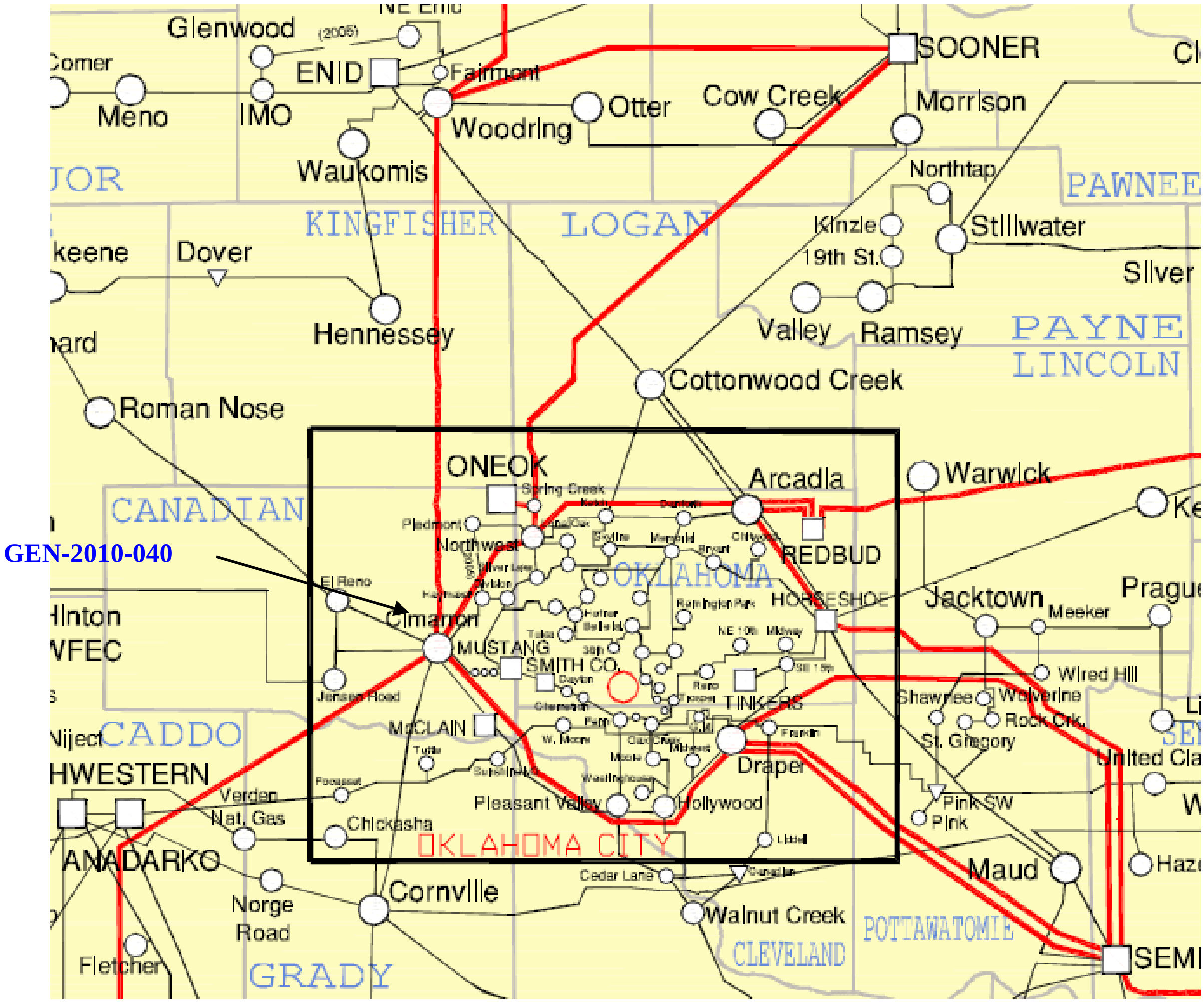

Figure 1-1 Geographical Transmission Map with GEN-2010-040 Project location (approx.)

2 DESCRIPTION OF THE PROJECT

The details of load flow and dynamic data for the GEN-2010-040 wind farm project is included in Appendix A.

- Wind farm size: 299.3 MW
- Interconnection:

  Voltage: 345 kV

  POI: Cimarron 345 kV substation. The wind-farm will be connected to the POI via 345 kV line.

  Transformer: Two (2) step-up transformer connecting to the 345 kV

  MVA: 100 MVA

  Voltage: 345/34.5 kV

  Z: 8.5 % on 100 MVA

- Wind Turbines:

  Number: One Hundred Forty Six (146)

  Manufacturer: REpower

  Type: Doubly-fed Induction Generator

Machine Terminal voltage: 0.575 kV

  Rated Power: 2.05 MW

  Frequency: 60 Hz

  Generator Step-up Transformer

  MVA: 2.35
  High voltage: 34.5 kV
  Low voltage: 0.575 kV
  Impedance: 7.0% on 2.35 MVA

Reactive Power Capability: Constant Power Factor (Default Design: Unity PF)

- Fault Ride-through: Manufacturer's default ride-through capability was modeled
- PSSE Model Used wt3_p3033ivf_w401.lib

3 STUDY METHODOLOGY

3.1 POWER FACTOR ANALYSIS

SPP requires that the Interconnection Customer's wind farm maintain at least +/- 0.95 power factor at the POI for any system condition. The purpose of the power factor analysis was to determine whether the proposed wind farm project will meet the power factor requirement at the Point of Interconnection (POI) for system intact as well as contingency conditions.

The Power Factor Analysis involved the following Steps:

- The wind farm as modeled (with the collector system) was turned off for the power factor analysis. The wind farm was then replaced by a generator at the high side bus with the MW of the wind farm at that point of interconnection and no reactive power capability.
- A VAR generator with large capacity (e.g. +/- 9999 MVar) was modeled at the POI (high voltage side) of the subject wind farm. The VAR generator was set to hold the POI voltage consistent with the voltage schedule in the power flow base cases.
- A list of selected contingencies in the vicinity of the subject wind farm was simulated. The results were used to identify the most-limiting contingency from steady state voltage and power factor perspective.
- If the required reactive power support, to maintain an acceptable power factor at the POI, was found to be beyond the capability of proposed wind-farm then the additional reactive power compensation (e.g. static capacitor banks) was considered.

It is important to note that the reactive power compensation identified in this analysis is primarily needed to meet steady state criteria. The need for dynamic reactive power support, if any, was determined through transient stability analysis.

3.2 TRANSIENT STABILITY ANALYSIS

The purpose of the transient stability analysis is to determine the impact, if any, of the proposed wind farm project on the stability performance of the SPP transmission system and generating stations in the interconnection vicinity.

Stability analysis was performed using Siemens-PTI's PSS/E^{TM} dynamics program V30.3.3. Three-phase and single-line-to-ground (SLG) (with re-closure where applicable) were simulated for the specified duration and synchronous machine rotor angles and wind turbine generator speeds were monitored to check whether the system is stable following the fault clearing. In addition, the voltage at the wind-farm POI and vicinity was also monitored.

For three-phase faults, a fault admittance of –j2E9 was used (essentially infinite admittance representing a bolted fault). The PSS/E dynamics program only simulates the positive sequence network. However, the unbalanced fault current computation (e.g. single-phase-ground) requires the knowledge of positive, negative, and zero sequence impedances. For a single-line-to-ground (SLG) fault, the fault admittance then equals the inverse of the sum of the positive, negative and zero sequence impedances. Typically, a single line to ground fault results in a voltage of roughly 60%. The admittance needed (over and above the positive sequence) to achieve this voltage value was computed using activity TYSL in PSS/E. This additional admittance value is the equivalent of the sum of positive and negative sequence admittances. The admittance value computed in the above step is then inserted at the faulted bus and the single line to ground fault current is computed.

The voltages at all local buses (115 kV and above) were monitored for all tested contingencies.

Another important aspect of the stability analysis was to determine the ability of the wind generators to stay connected to the grid during disturbances. This is primarily determined by their low-voltage ride-through capabilities – or lack thereof – as represented in the models by low-voltage trip settings. The Federal Energy Regulatory Commission (FERC) Post-transition period LVRT standard for Interconnection of Wind generating plants includes a Low Voltage Ride-Through (LVRT) requirement. The key features of LVRT requirements are:

- A wind generating plant must remain in-service during three-phase faults with normal clearing (maximum 9 cycles) and single-line-to-ground faults with delayed clearing, and have subsequent post-fault recovery to pre-fault voltage unless the clearing of the fault effectively disconnects the generator from the system.
- The maximum duration the wind generating plant shall be required to withstand a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the GSU connected at POI.

These criteria were used to evaluate the LVRT capability of the wind farm.

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4 MODEL DEVELOPMENT

SPP provided two power flow cases for this study – i) "MDWG_2010_2011SP_DISIS-2010-002-2-G7.sav" and ii) "MDWG_2010_2011WP_DISIS-2010-002-2-G7.sav" – representing respectively the 2010-2011 Summer Peak and Winter Peak conditions.

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
Blue Canyon I (GEN-2001-026)	74	CIMTR (521214)	Washita 138kV (521089)
Blue Canyon II (GEN-2003-004)	151	Vestas V80 (579086)	Washita 138kV (521089)
Weatherford (GEN-2003-022 GEN-2004-020)	147	G.E. 1.5MW (511952)	Weatherford 138kV (511506)
GEN-2003-005	100	G.E. 1.5MW (560919)	Anadarko – Paradise 138kV (521129)
GEN-2006-002	100	GE 1.5MW (578984) and GE 1.6MW (578986)	Sweetwater 230kV (511541)
GEN-2006-035	224	Gamesa (560934)	Sweetwater 230kV (511541)
GEN-2006-043	101.2	Siemens 2.3MW (560957)	Sweetwater 230kV (511541)
GEN-2007-032	150	Acciona 1.5MW (560936)	Clinton Jct. – Clinton 138kV (560939)
GEN-2007-043	200	G.E. 1.6MW (579289)	Cimarron – Anadarko 345kV (210431)
GEN-2007-052	150	Gas Turbine (579333, 579334, 579335)	Anadarko 138kV (520814)
GEN-2008-023	150	G.E. 1.6MW (579444)	Hobart Junction (511463) 138kV
GEN-2009-016	100	GE 1.6MW (579050)	Falcon Road 138KV (511511)
GEN-2008-037	100.8	Vestas V90 1.8MW (573574)	Washita (521089) – Blue Canyon (521103) 138kV (Bus 573570)
GEN-2009-060	85.5	GE 1.5MW (575033)	Gotebo 69kV (520925)
GEN-2010-012	65.0	Clipper 2.5MW (578567)	Brantley 138kV (520832)

4.1 MODEL DEVELOPMENT FOR GEN-2010-040 PROJECT

The models (power flow and dynamics) for the proposed project were included in the data supplied by SPP. A cursory review of the study models was performed to ensure the wind farm and the associated collector system representation is in agreement with the data provided for this study. The subject wind farm is comprised of REpower MM92 WTGs that are operated at constant power factor and therefore did not have reactive power capability. The default settings corresponded to unity power factor.

Figure 4-1 and Figure 4-2 show the one-line diagram in the local area of GEN-2010-040 for 2010-2011 summer peak and winter peak conditions respectively.

The dynamic model setup with the "snapshot" for performing stability analysis was provided by SPP. We performed a no-disturbance simulation to verify the models initialized correctly and there is no drift from the respective steady state quantities (e.g. machine angle, speeds, bus voltage etc.) over time.

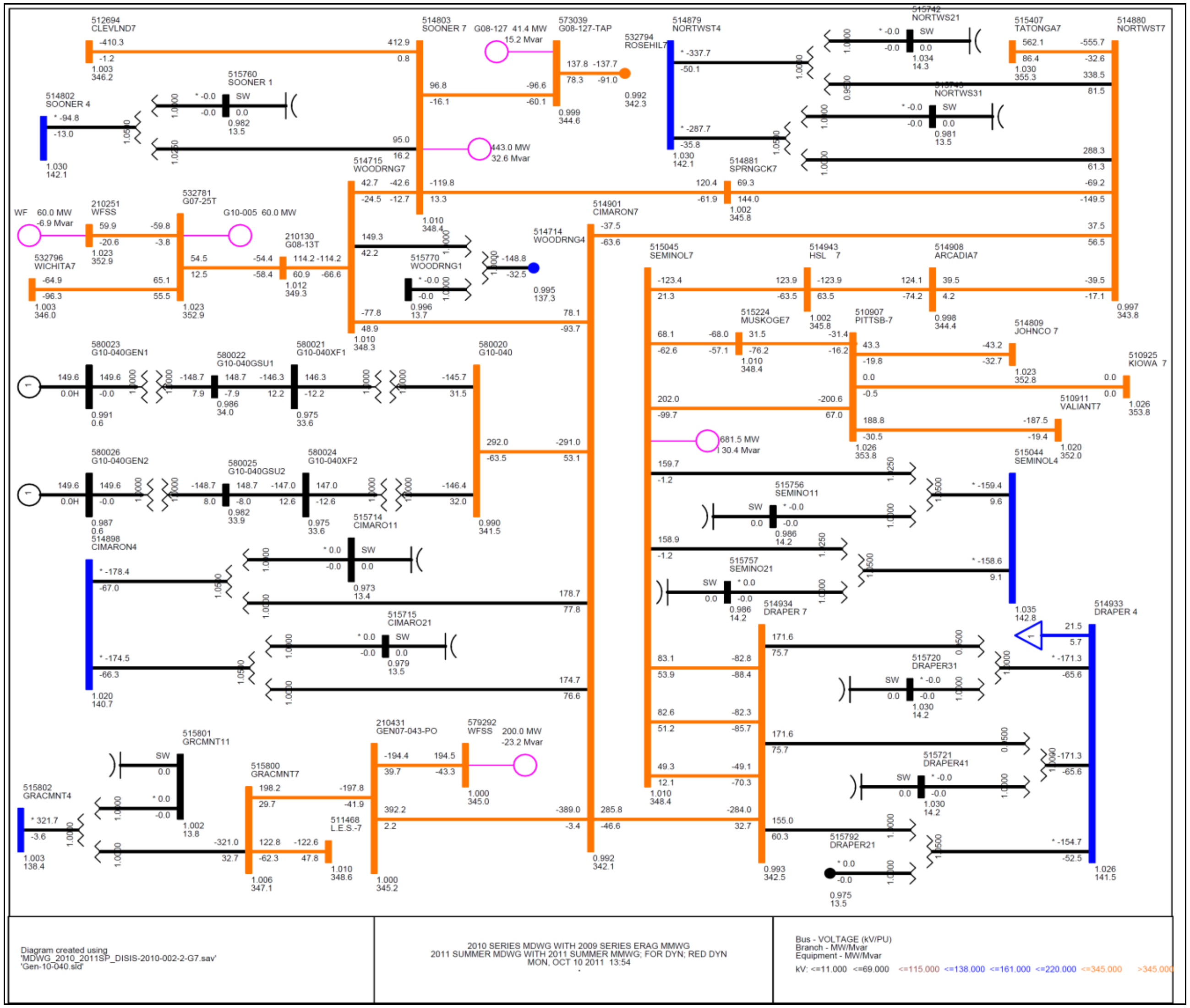

Figure 4-1 One-line Diagram of the local area of GEN-2010-040 (2010-2011 Summer Peak)

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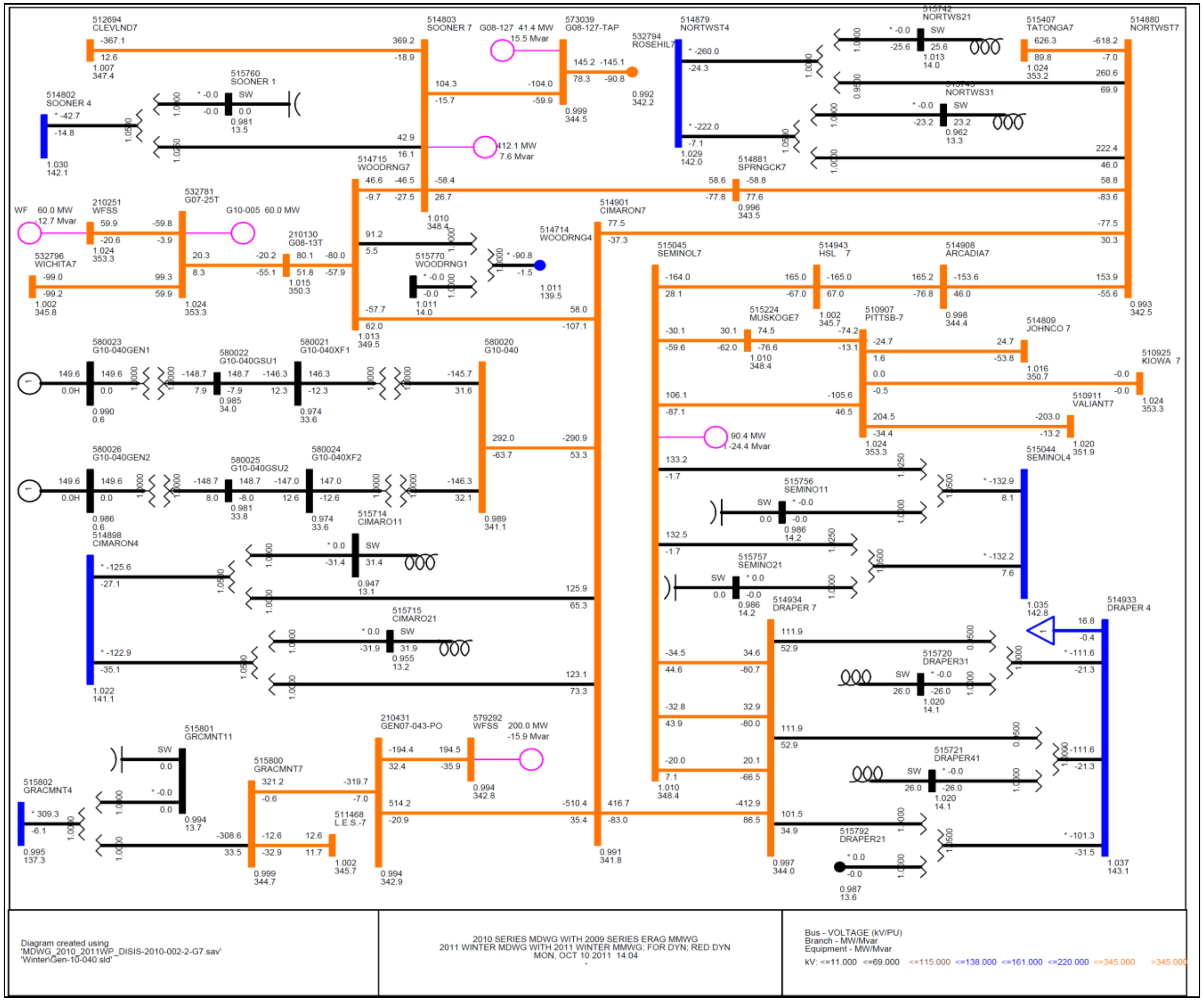

Figure 4-2 One-line Diagram of the local area of GEN-2010-040 (2010-2011 Winter Peak)

5 POWER FACTOR ANALYSIS RESULTS

The Power Factor analysis was performed to verify the wind-farm interconnection requirements based on SPP's standard for POI power factor needs.

As described in section 3.1, a VAR generator was modeled at POI. The VAR generator was set to hold the 345 kV POI (high voltage side) voltage equal to that in the pre-project base case or 1.0 p.u voltage (whichever is higher). The POI voltage in SPP provided base case were roughly, 0.99 p.u for summer as well as winter peak conditions. Hence, the VAR generator was set to hold the 345 kV POI voltage equal to 1.0 p.u. The contingencies shown in Table 5-1 were simulated on 2010-2011 summer peak and winter peak load conditions.

For summer peak load condition, *CONT*_05 [Northwest (514880) to Spring Creek (514881) line outage] and for winter peak load condition *CONT*_07 [Northwest (514880) to Tatonga (515407) line outage]) showed maximum reactive power output from the VAR generator at POI. This contingency showed a var deficiency of 224 Mvars with a corresponding power factor of 0.80. The output of the VAR generator as shown in Table 5-2 for the tested conditions are necessary to maintain a unity voltage at the POI and for most of these cases, beyond the SPP power factor requirement of 0.95 (lag/lead).

As a next step, the same contingencies (Table 5-1) were re-simulated, but without the VAR generator at the POI. The proposed wind farm was represented along with the collector system impedances. The voltage and power factor at the POI was monitored. It may be noted that roughly 60 MVAR of reactive power is necessary to maintain unity power factor at the POI which also helped to maintain pre-project voltages (~0.99 p.u).

Further, the maximum reactive power capability necessary to maintain a 0.95 power factor (lag; none of the tested contingencies require the wind farm to absorb reactive power and therefore leading power factor operation is not foreseen) at the POI is roughly 130 MVAR, considering the worst tested contingencies (i.e. the wind farm would export reactive power to the grid, at 0.95 pf at the POI) for summer and winter load conditions.

Since the proposed wind farm operates at unity power factor at its terminals (i.e. zero reactive power generation), added capacitor compensation would be necessary to adhere to SPP's interconnection standard (power factor).

Based on the above study findings, capacitor bank(s) of 130 MVAR will be necessary to maintain a power factor of 0.95 at the POI. This capacitance should be in multiple stages/banks as to not cause excessive voltage excursions on the Transmission System. However, if only the collector system reactive requirements are to be met from the wind farm locally (i.e. no reactive power exchanges with the grid – unity power factor at the POI), then a 60 MVAR capacitor bank would suffice.

The complete results of the above contin*gency* analysis are included in **Error! Reference source not found.**.

Table 5-1: List of contingencies simulated

Contingency Name	Contingency Description
CONT_00	BASE CASE
CONT_01	Loss of Cimarron (514901) to GEN-2007-043(210431) 345kV line
CONT_02	Loss of Cimarron (514901) to Northwest (514880) 345kV line
CONT_03	Loss of Cimarron (514901) to Draper (514934) 345kV line
CONT_04	Loss of Cimarron (514901) to Woodring (514715) 345kV line
CONT_05	Loss of Northwest (514880) to Spring Creek (514881) 345kV line
CONT_06	Loss of Northwest (514880) to Arcadia (514908) 345kV line
CONT_07	Loss of Northwest (514880) to Tatonga (515407) 345kV line
CONT_08	Loss of Woodring (514715) to G08-13T (210130) 345kV line
CONT_09	Loss of Woodring (514715) to Sooner (514803) 345kV line
CONT_10	Loss of Draper (514934) to Seminole (515045) 345kV line CKT 2
CONT_11	Loss of GEN-2007-043 (210431) to Gracemont (515800) 345kV line
CONT_12	Loss of Gracemont (515800) to Lawton Eastside (511468) 345kV line
CONT_13	Loss of Tatonga (515407) to Woodward (515375) 345kV line
CONT_14	Loss of Spring Creek (514881) to Sooner (514803) 345kV line
CONT_15	Loss of Arcadia (514908) to Horseshoe Lake (514943) 345kV line
CONT_16	Loss of Horseshoe Lake (514943) to Seminole (515045) 345kV line
CONT_17	Loss of Cimarron (514898) to Tuttle Conoco Tap (511425) 138kV line
CONT_18	Loss of Cimarron (514898) to El Reno (514819) 138kV line
CONT_19	Loss of Cimarron (514898) to Jensen Tap (514820) 138kV line
CONT_20	Loss of Cimarron (514898) to Haymaker (514863) 138kV line
CONT_21	Loss of Cimarron (514898) to Czech Hall (514894) 138kV line
CONT_22	Loss of Cimarron (514898) to Sara (514895) 138kV line
CONT_23	Loss of Cimarron (514898) 138 kV to Cimarron (514901) 345kV transformer
CONT_24	Loss of Northwest (514879) 138 kV to Northwest (514880) 345kV transformer
CONT_25	Loss of Woodring (514714) 138 kV to Woodring (514715) 345kV transformer
CONT_26	Loss of Draper (514933) 138 kV to Draper (514934) 345kV transformer

Table 5-2 VAR generator output at the GEN-2010-040 POI

Contingency	VOLTAGE OF VAR Gen. Summer Peak (#514901)	VOLTAGE OF VAR Gen. Winter Peak (#514901)	Power factor at VAR Gen. terminal: Summer Peak Q (MVAR)	Summer Peak P (MW)	Summer Peak p.f	Winter Peak Q (MVAR)	Winter Peak P (MW)	Winter Peak p.f
CONT_00	1.00	1.00	100	299.2	0.948	120.1	299.2	0.928
CONT_01	1.00	1.00	133.8	299.2	0.913	131.3	299.2	0.916
CONT_02	1.00	1.00	112.8	299.2	0.936	95	299.2	0.953
CONT_03	1.00	1.00	102.1	299.2	0.946	148.5	299.2	0.896
CONT_04	1.00	1.00	166.9	299.2	0.873	199.5	299.2	0.832
CONT_05	1.00	1.00	**182.8**	**299.2**	**0.853**	155.2	299.2	0.888
CONT_06	1.00	1.00	93.7	299.2	0.954	132.6	299.2	0.914
CONT_07	1.00	1.00	179.4	299.2	0.858	**224.2**	**299.2**	**0.800**
CONT_08	1.00	1.00	131.2	299.2	0.916	144.4	299.2	0.901
CONT_09	1.00	1.00	104.6	299.2	0.944	117.5	299.2	0.931
CONT_10	1.00	1.00	132.3	299.2	0.915	142.3	299.2	0.903
CONT_11	1.00	1.00	119.9	299.2	0.928	115.5	299.2	0.933
CONT_12	1.00	1.00	129.7	299.2	0.918	132.7	299.2	0.914
CONT_13	1.00	1.00	103.8	299.2	0.945	128.2	299.2	0.919
CONT_14	1.00	1.00	122.6	299.2	0.925	151.9	299.2	0.892
CONT_15	1.00	1.00	103.6	299.2	0.945	116.8	299.2	0.932
CONT_16	1.00	1.00	102.9	299.2	0.946	123.5	299.2	0.924
CONT_17	1.00	1.00	91	299.2	0.957	117.2	299.2	0.931
CONT_18	1.00	1.00	92.6	299.2	0.955	118.2	299.2	0.930
CONT_19	1.00	1.00	91.6	299.2	0.956	117.3	299.2	0.931
CONT_20	1.00	1.00	99.8	299.2	0.949	123.6	299.2	0.924
CONT_21	1.00	1.00	88.1	299.2	0.959	129.7	299.2	0.918
CONT_22	1.00	1.00	91.1	299.2	0.957	121.7	299.2	0.926
CONT_23	1.00	1.00	47.3	299.2	0.988	56.7	299.2	0.983
CONT_24	1.00	1.00	95.8	299.2	0.952	100.1	299.2	0.948
CONT_25	1.00	1.00	87.8	299.2	0.960	116.6	299.2	0.932
CONT_26	1.00	1.00	96.4	299.2	0.952	110.3	299.2	0.938

Table 5-3: Voltage & p.f. at POI without VAR generator: GEN-2010-040

Contingency	POI VOLTAGES		GEN-2010-040 POI power factor					
	Summer Peak	Winter Peak	Summer Peak			Winter Peak		
	(#514901)		Q (MVAR)	P (MW)	p.f	Q (MVAR)	P (MW)	p.f
CONT_00	0.992	0.991	53.1	-291.0	0.984	53.3	-290.9	0.984
CONT_01	0.988	0.988	53.9	-290.9	0.983	54.0	-290.9	0.983
CONT_02	0.987	0.988	54.3	-290.9	0.983	54.0	-290.9	0.983
CONT_03	0.989	0.986	53.6	-290.9	0.983	54.5	-290.8	0.983
CONT_04*	**0.986**	**0.984**	**54.4**	**-290.9**	**0.983**	**54.9**	**-290.8**	**0.983**
CONT_05	0.987	0.988	54.3	-290.9	0.983	54.0	-290.9	0.983
CONT_06	0.991	0.988	53.2	-290.9	0.984	53.1	-290.9	0.984
CONT_07	0.987	0.984	54.2	-290.9	0.983	55.0	-290.8	0.983
CONT_08	0.990	0.989	53.5	-290.9	0.984	53.7	-290.9	0.983
CONT_09	0.991	0.990	53.2	-290.9	0.984	53.4	-290.9	0.984
CONT_10	0.990	0.989	53.5	-290.9	0.984	53.7	-290.9	0.983
CONT_11	0.990	0.990	53.5	-290.9	0.984	53.6	-290.9	0.983
CONT_12	0.990	0.989	53.5	-290.9	0.984	53.6	-290.9	0.983
CONT_13	0.991	0.990	53.2	-290.9	0.984	53.6	-290.9	0.983
CONT_14	0.990	0.988	53.5	-290.9	0.984	53.9	-290.9	0.983
CONT_15	0.991	0.990	53.1	-290.9	0.984	53.4	-290.9	0.984
CONT_16	0.992	0.990	53.1	-290.9	0.984	53.4	-290.9	0.984
CONT_17	0.992	0.991	53.0	-291.0	0.984	53.2	-290.9	0.984
CONT_18	0.992	0.991	53.0	-291.0	0.984	53.3	-290.9	0.984
CONT_19	0.992	0.991	53.0	-291.0	0.984	53.3	-290.9	0.984
CONT_20	0.992	0.990	53.1	-291.0	0.984	53.4	-290.9	0.984
CONT_21	0.992	0.990	53.0	-291.0	0.984	53.5	-290.9	0.984
CONT_22	0.992	0.990	53.0	-291.0	0.984	53.4	-290.9	0.984
CONT_23	0.994	0.994	52.5	-291.0	0.984	52.6	-291.0	0.984
CONT_24	0.992	0.991	53.0	-291.0	0.984	53.2	-290.9	0.984
CONT_25	0.992	0.991	52.9	-291.0	0.984	53.3	-290.9	0.984
CONT_26	0.992	0.991	53.0	-291.0	0.984	53.2	-290.9	0.984

(1) *CONT_04: Loss of Cimarron (514901) to Woodring (514715) 345kV line*

6 STABILITY ANALYSIS

Stability simulations were performed to examine the transient behavior of GEN-2010-040 project and its impact on the SPP system. Several faults, both three-phase and single phase faults (with re-closing where applicable) were simulated. The fault clearing times and re-closing times used for the simulations are shown in Table 6-1.

Table 6-1: Fault Clearing Times

Faulted bus kV level	Normal Clearing	Time before reclosing
69	5 cycles	20 cycles
138	5 cycles	20 cycles
230	5 cycles	20 cycles
345	5 cycles	20 cycles

Twenty six (26) three phase and twenty two (22) single-line-to-ground faults (with re-closing where applicable) were simulated. For all tested cases the initial disturbance was applied at t = 0.1 seconds. The breaker clearing was initiated at the appropriate time following the fault inception (see Table 6-1). Table 6-2 lists all the faults simulated for transient stability analysis.

Table 6-2 List of Simulated Faults for GEN-2010-040 SIS

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Cimarron (514901) to GEN-2007-043(210431) 345kV line, near Cimarron. a. Apply fault at the Cimarron 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT02-1PH	*Single phase fault and sequence like previous*
3	FLT03-3PH	3 phase fault on the Cimarron (514901) to Northwest (514880) 345kV line, near Cimarron. a. Apply fault at the Cimarron 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT04-1PH	*Single phase fault and sequence like previous*
5	FLT05-3PH	3 phase fault on the Cimarron (514901) to Draper (514934) 345kV line, near Cimarron. a. Apply fault at the Cimarron 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
6	FLT06-1PH	*Single phase fault and sequence like previous*
7	FLT07-3PH	3 phase fault on the Cimarron (514901) to Woodring (514715) 345kV line, near Cimarron. a. Apply fault at the Cimarron 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on Northwest (514880) to Spring Creek (514881) 345kV line, near Northwest. a. Apply fault at the Northwest 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
10	FLT10-1PH	*Single phase fault and sequence like previous*
11	FLT11-3PH	3 phase fault on Northwest (514880) to Arcadia (514908) 345kV line, near Northwest. a. Apply fault at the Northwest 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT12-1PH	*Single phase fault and sequence like previous*
13	FLT13-3PH	3 phase fault on Northwest (514880) to Tatonga (515407) 345kV line, near Northwest. a. Apply fault at the Northwest 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
14	FLT14-1PH	*Single phase fault and sequence like previous*
15	FLT15-3PH	3 phase fault on Woodring (514715) to G08-13T (210130) 345kV line, near Woodring. a. Apply fault at the Woodring 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
16	FLT16-1PH	*Single phase fault and sequence like previous*
17	FLT17-3PH	3 phase fault on Woodring (514715) to Sooner (514803) 345kV line, near Woodring. a. Apply fault at the Woodring 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on Draper (514934) to Seminole (515045) 345kV line CKT 2, near Draper. a. Apply fault at the Draper 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	3 phase fault on GEN-2007-043 (210431) to Gracemont (515800) 345kV line, near GEN-2007-043. a. Apply fault at the GEN-2007-043345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT22-1PH	*Single phase fault and sequence like previous*
23	FLT23-3PH	3 phase fault on the Gracemont (515800) to Lawton Eastside (511468) 345kV line, near Lawton Eastside. a. Apply fault at the Lawton Eastside 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT24-1PH	*Single phase fault and sequence like previous*
25	FLT25-3PH	3 phase fault on Tatonga (515407) to Woodward (515375) 345kV line, near Tatonga. a. Apply fault at the Tatonga 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT26-1PH	*Single phase fault and sequence like previous*
27	FLT27-3PH	3 phase fault on Spring Creek (514881) to Sooner (514803) 345kV line, near Spring Creek. a. Apply fault at the Spring Creek 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT28-1PH	*Single phase fault and sequence like previous*
29	FLT29-3PH	3 phase fault on Arcadia (514908) to Horseshoe Lake (514943) 345kV line, near Arcadia. a. Apply fault at the Arcadia 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT30-1PH	*Single phase fault and sequence like previous*
31	FLT31-3PH	3 phase fault on Horseshoe Lake (514943) to Seminole (515045) 345kV line, near Horseshoe Lake. a. Apply fault at the Horseshoe Lake 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
32	FLT32-1PH	*Single phase fault and sequence like previous*
33	FLT33-3PH	3 phase fault on the Cimarron (514898) to Tuttle Conoco Tap (511425) 138kV line, near Cimarron. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT34-1PH	*Single phase fault and sequence like previous*
35	FLT35-3PH	3 phase fault on the Cimarron (514898) to El Reno (514819) 138kV line, near Cimarron. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT36-1PH	*Single phase fault and sequence like previous*
37	FLT37-3PH	3 phase fault on the Cimarron (514898) to Jensen Tap (514820) 138kV line, near Cimarron. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
38	FLT38-1PH	*Single phase fault and sequence like previous*
39	FLT39-3PH	3 phase fault on the Cimarron (514898) to Haymaker (514863) 138kV line, near Cimarron. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
40	FLT40-1PH	*Single phase fault and sequence like previous*
41	FLT41-3PH	3 phase fault on the Cimarron (514898) to Czech Hall (514894) 138kV line, near Cimarron. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
42	FLT42-1PH	*Single phase fault and sequence like previous*
43	FLT43-3PH	3 phase fault on the Cimarron (514898) to Sara (514895) 138kV line, near Cimarron. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
44	FLT44-1PH	*Single phase fault and sequence like previous*
45	FLT45-3PH	3 phase fault on one circuit of the Cimarron (514898) 138 kV to Cimarron (514901) 345kV transformer, on the 138kV bus. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
46	FLT46-3PH	3 phase fault on one circuit of the Northwest (514879) 138 kV to Northwest (514880) 345kV transformer, on the 138kV bus. a. Apply fault at the Northwest 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
47	FLT47-3PH	3 phase fault on one circuit of the Woodring (514714) 138 kV to Woodring (514715) 345kV transformer, on the 138kV bus. a. Apply fault at the Woodring 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
48	FLT48-3PH	3 phase fault on one circuit of the Draper (514933) 138 kV to Draper (514934) 345kV transformer, on the 138kV bus. a. Apply fault at the Draper 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

The system was stable for all the simulated 3-Phase and single-phase faults. The proposed GEN-2010-040 wind farm stayed on-line throughout the duration of the fault and thereof. The voltage recovery was acceptable, and the oscillations were positively damped.

The sample response of GEN-2010-040 project for FLT_01_3PH is given in Figure 6-1. This fault is a 3 Phase fault at the POI. Table 6-3 summarizes the stability analysis results for 2010-2011 summer peak and winter peak system conditions. The plots from the transient stability analysis are included in Appendix C.

Table 6-3 Results of stability analysis

FAULT	Summer Peak Post-Project Stable?	Summer Peak Post-Project Acceptable Voltages?	Winter Peak Post-Project Stable?	Winter Peak Post-Project Acceptable Voltages?
FLT01-3PH	STABLE	YES	STABLE	YES
FLT02-1PH	STABLE	YES	STABLE	YES
FLT03-3PH	STABLE	YES	STABLE	YES
FLT04-1PH	STABLE	YES	STABLE	YES
FLT05-3PH	STABLE	YES	STABLE	YES
FLT06-1PH	STABLE	YES	STABLE	YES
FLT07-3PH	STABLE	YES	STABLE	YES
FLT08-1PH	STABLE	YES	STABLE	YES
FLT09-3PH	STABLE	YES	STABLE	YES
FLT10-1PH	STABLE	YES	STABLE	YES
FLT11-3PH	STABLE	YES	STABLE	YES
FLT12-1PH	STABLE	YES	STABLE	YES
FLT13-3PH	STABLE	YES	STABLE	YES
FLT14-1PH	STABLE	YES	STABLE	YES
FLT15-3PH	STABLE	YES	STABLE	YES
FLT16-1PH	STABLE	YES	STABLE	YES
FLT17-3PH	STABLE	YES	STABLE	YES
FLT18-1PH	STABLE	YES	STABLE	YES
FLT19-3PH	STABLE	YES	STABLE	YES
FLT20-1PH	STABLE	YES	STABLE	YES
FLT21-3PH	STABLE	YES	STABLE	YES
FLT22-1PH	STABLE	YES	STABLE	YES
FLT23-3PH	STABLE	YES	STABLE	YES
FLT24-1PH	STABLE	YES	STABLE	YES
FLT25-3PH	STABLE	YES	STABLE	YES
FLT26-1PH	STABLE	YES	STABLE	YES
FLT27-3PH	STABLE	YES	STABLE	YES
FLT28-1PH	STABLE	YES	STABLE	YES

	Summer Peak		Winter Peak	
	Post-Project		Post-Project	
FAULT	**Stable?**	**Acceptable Voltages?**	**Stable?**	**Acceptable Voltages?**
FLT29-3PH	STABLE	YES	STABLE	YES
FLT30-1PH	STABLE	YES	STABLE	YES
FLT31-3PH	STABLE	YES	STABLE	YES
FLT32-1PH	STABLE	YES	STABLE	YES
FLT33-3PH	STABLE	YES	STABLE	YES
FLT34-1PH	STABLE	YES	STABLE	YES
FLT35-3PH	STABLE	YES	STABLE	YES
FLT36-1PH	STABLE	YES	STABLE	YES
FLT37-3PH	STABLE	YES	STABLE	YES
FLT38-1PH	STABLE	YES	STABLE	YES
FLT39-3PH	STABLE	YES	STABLE	YES
FLT40-1PH	STABLE	YES	STABLE	YES
FLT41-3PH	STABLE	YES	STABLE	YES
FLT42-1PH	STABLE	YES	STABLE	YES
FLT43-3PH	STABLE	YES	STABLE	YES
FLT44-1PH	STABLE	YES	STABLE	YES
FLT45-3PH	STABLE	YES	STABLE	YES
FLT46-3PH	STABLE	YES	STABLE	YES
FLT47-3PH	STABLE	YES	STABLE	YES
FLT48-3PH	STABLE	YES	STABLE	YES

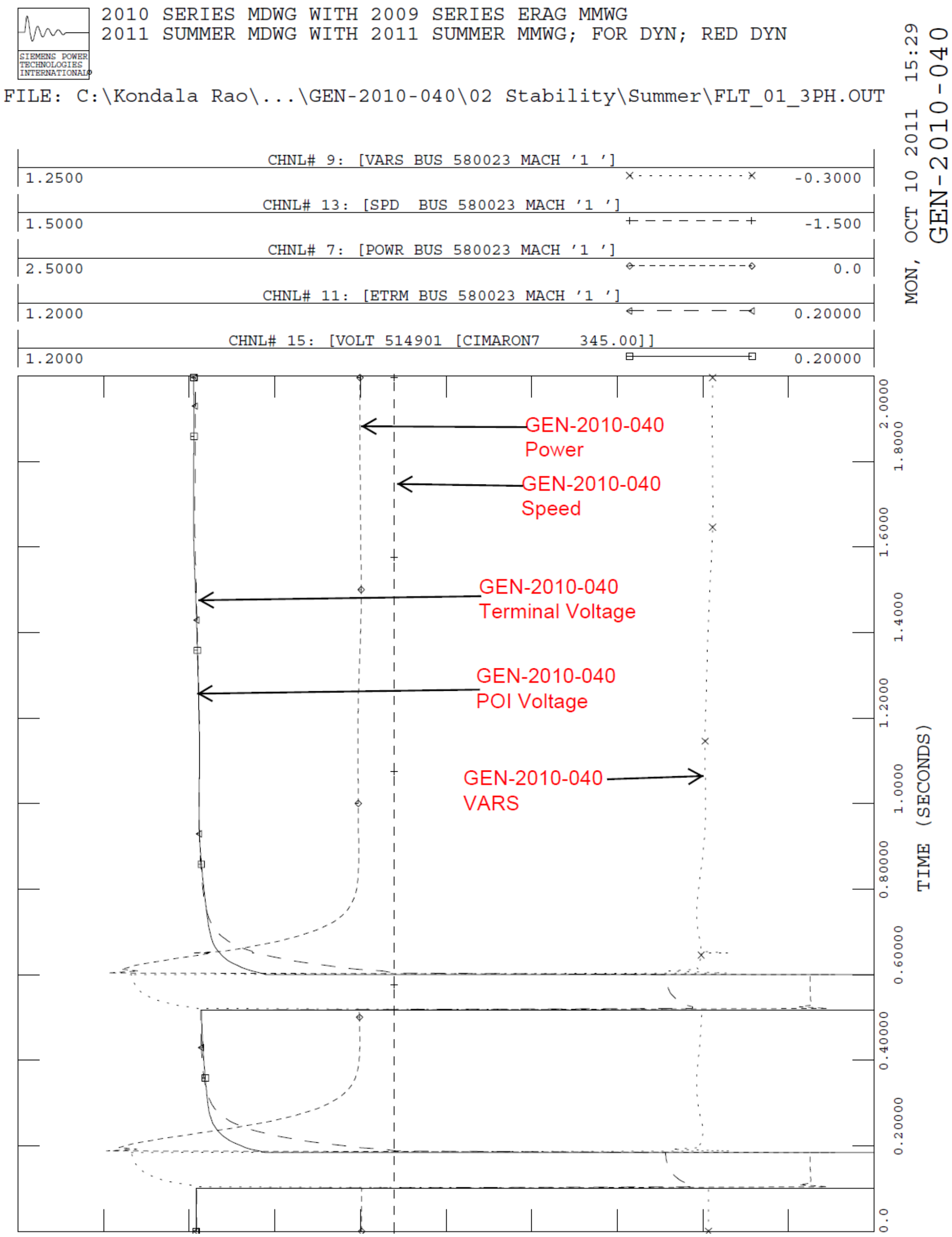

Figure 6-1 Response of GEN-2010-040 project for FLT_01_3PH (summer peak)

ABB

6.1 FERC LVRT COMPLIANCE

This section discusses the FERC mandated LVRT compliance verification for GEN-2010-040 project. As explained in section 2, the proposed project was modeled with manufacturer's default settings for ride-through (frequency and voltage). To determine the compliance of the subject wind farm project Eight (8) faults were simulated. These faults were simulated at the POI of wind farm project and cleared after 9 cycles for 3-phase and 15 cycles for 1-phase faults (i.e. 9 cycle primary clearing followed by a 6 cycle back-up clearing due to a breaker stuck event). Table 6-4 gives the description of faults simulated for LVRT analysis.

Table 6-4: List of faults for FERC LVRT compliance

Fault Name	Description
LVRT_01_3PH	3 phase fault on the Cimarron (514901) to GEN-2007-043(210431) 345kV line, near Cimarron..
	a. Apply fault at the Cimarron 345kV bus.
	b. Clear fault after 9.0 cycles by tripping the faulted line.
LVRT_02_1PH	*Single Phase fault Delayed Clearing (9 Cycles + 6 Cycles) and sequence like previous*
LVRT_03_3PH	3 phase fault on the Cimarron (514901) to Northwest (514880) 345kV line, near Cimarron.
	a. Apply fault at the Cimarron 345kV bus.
	b. Clear fault after 9.0 cycles by tripping the faulted line.
LVRT_04_1PH	*Single Phase fault Delayed Clearing (9 Cycles + 6 Cycles) and sequence like previous*
LVRT_05_3PH	3 phase fault on the Cimarron (514901) to Draper (514934) 345kV line, near Cimarron.
	a. Apply fault at the Cimarron 345kV bus.
	b. Clear fault after 9.0 cycles by tripping the faulted line.
LVRT_06_1PH	*Single Phase fault Delayed Clearing (9 Cycles + 6 Cycles) and sequence like previous*
LVRT_07_3PH	3 phase fault on the Cimarron (514901) to Woodring (514715) 345kV line, near Cimarron.
	a. Apply fault at the Cimarron 345kV bus.
	b. Clear fault after 9.0 cycles by tripping the faulted line.
LVRT_08_1PH	*Single Phase fault Delayed Clearing (9 Cycles + 6 Cycles) and sequence like previous*

The results of the simulations indicated that the GEN-2010-040 wind farm project stayed online through the fault duration and recovered to acceptable speed and voltage post-fault clearing. Therefore the subject wind farm meets the FERC LVRT criteria for the interconnection (FERC Order 661 – A). The response of GEN-2010-040 project for LVRT_01_3PH is given in Fig. 6-2. This fault is a 3 Phase fault at the POI.

The results from the FERC LVRT compliance evaluation are included in Appendix D.

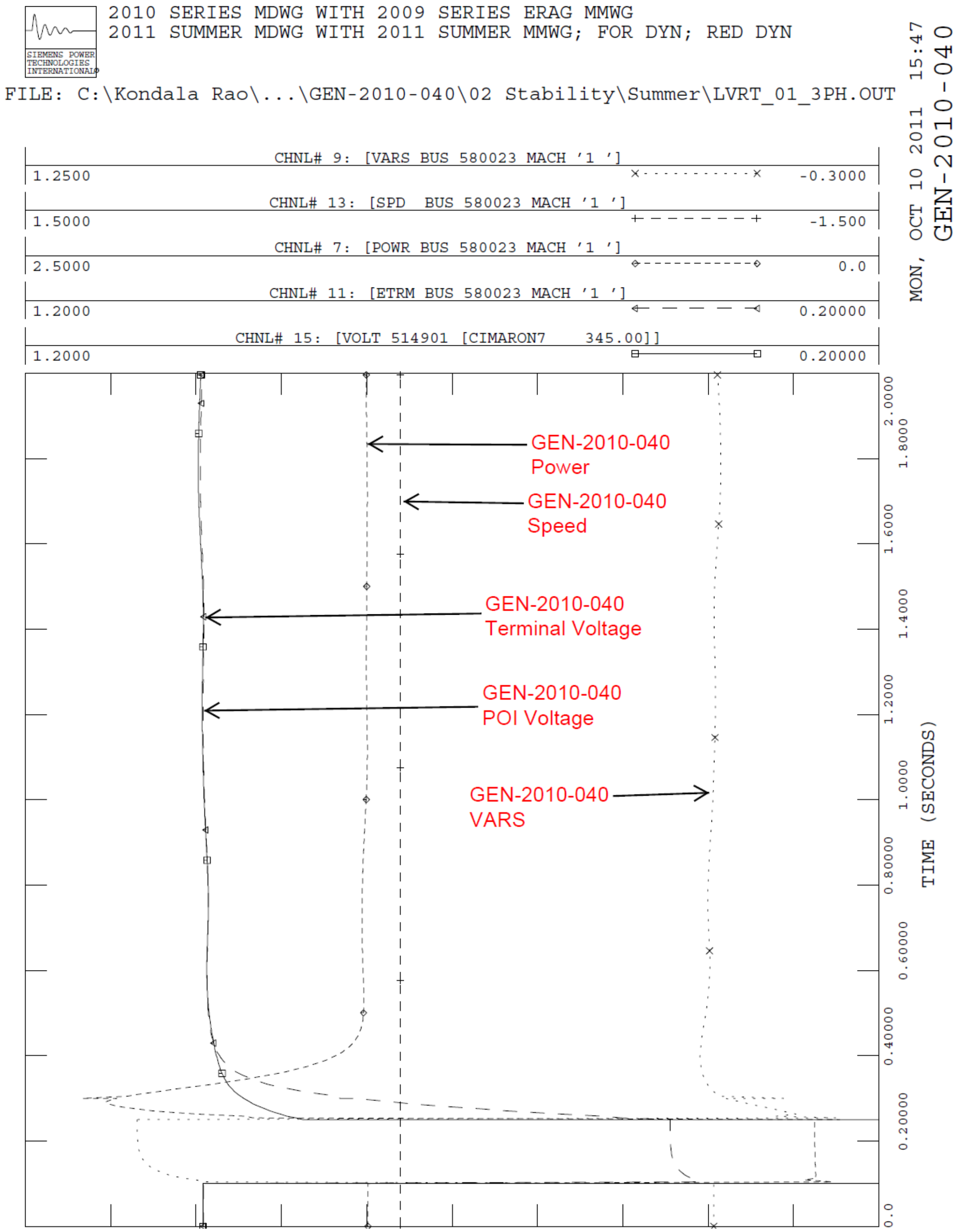

Figure 6-2 GEN-2010-040 response for LVRT_01_3PH (Summer Peak)

7 CONCLUSIONS

A summary of the study findings is given below:

Power factor analysis

SPP requires that the Interconnection Customer's wind farm maintain at least +/- 0.95 power factor at the POI for any system condition. The maximum reactive power capability necessary to maintain a 0.95 power factor at the POI was found to be roughly 130 MVAR, considering the worst tested contingencies for summer and winter load conditions.

Since the proposed wind farm operates at unity power factor at its terminals (i.e. zero reactive power generation), added capacitor compensation would be necessary to adhere to SPP's interconnection standard (power factor).

Based on the above study findings, a capacitor bank(s) of 130 MVAR of multiple stages will be necessary to maintain a power factor of 0.95 at the POI. However, if only the collector system reactive requirements are to be met from the wind farm locally (i.e. no reactive power exchanges with the grid – unity power factor at the POI), then a 60 MVAR capacitor bank would suffice.

Stability Analysis

A stability analysis was performed to determine the impact, if any, of the proposed project on the stability of SPP system. The system was stable for all the simulated 3-Phase and single-phase faults. The proposed GEN-2010-040 wind farm stayed on-line throughout the duration of the fault and thereof. The voltage recovery was acceptable, and the oscillations were positively damped.

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FERC Order 661A Compliance

Selected faults were simulated at the Point of Interconnection (POI) of the proposed GEN-2010-040 wind farm to determine the compliance with FERC 661 – A; post-transition period LVRT standard. The results indicated that the proposed project met the FERC LVRT requirement for wind farm interconnection.

Based on the results of the analysis, it can be concluded that the proposed GEN-2010-040 wind farm does not adversely impact the transmission performance of the SPP system.

The results of this analysis are based on available data and assumptions made at the time of conducting this study. If any of the data and/or assumptions made in developing the study model change, the results provided in this report may not apply and additional analysis may be required.