GEN-2015-015

Impact Restudy for Generator Modification (Turbine Change)

Published on October 2017

By Generator Interconnection

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
10/10/2017	Generator Interconnection		Initial issue of the report

EXECUTIVE SUMMARY

The GEN-2015-015 Interconnection Customer has requested a modification to its Interconnection Request. SPP has performed this system impact restudy to determine the effects of changing wind turbine generators from the previously studied Siemens 2.415MW wind turbine generators (64 machines total) to nine (9) Siemens 2.3MW wind turbine generators and fifty-one (51) Siemens 2.625MW (60 machines total). The total nameplate remains the same at 154.6MW.

The point of interconnection (POI) for GEN-2015-015 is at a tap on the Oklahoma Gas & Electric (OKGE) Coyote to Medford Tap 138kV line. The Interconnection Customer has provided documentation that shows the Siemens 2.3MW and Siemens 2.625MW wind turbine generators have a reactive capability of 0.95 lagging (providing VARS) and 0.95 leading (absorbing VARS) power factor.

This study was performed to determine whether the request for modification is considered Material. To determine this, study models that included Interconnection Requests through DISIS-2015-001 were used that analyzed the timeframes of 2016 winter, 2017 summer, and 2025 summer models.

The restudy showed that the stability analysis has determined with all previously assigned Network Upgrades in service, generators in the monitored areas remained stable and within the pre-contingency, voltage recovery, and post fault voltage recovery criterion of 0.7pu to 1.2pu for the entire modeled disturbances. Additionally, the project wind farm was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A. The requested modification is not considered Material.

A power factor analysis and a low-wind/no-wind condition analysis were performed for this modification request. The facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VARs) power factor at the POI. Additionally, the project will be required to install approximately 8 Mvar of reactor shunts on its substation 34.5kV bus(es). This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind/no-wind conditions.

The interconnection customer provided a Siemens "Weak Grid Option" module for the Siemens PSSE wind turbine model. The stability study was performed both with and without the "Weak Grid Option". It was determined that the "Weak Grid Option" was not needed. The results shown in this report are without the "Weak Grid Option"

With the assumptions outlined in this report and with all the required network upgrades from the DISIS 2015-001 in place, GEN-2015-015 with the Siemens 2.3MW and Siemens 2.625MW wind turbine generators should be able to interconnect reliably to the SPP transmission grid.

It should be noted that this study analyzed the requested modification to change generator technology, manufacturer, and layout. Powerflow analysis was not performed. This study analyzed many of the most probable contingencies, but it is not an all-inclusive list and cannot account for every operational situation. It is likely that the customer may be required to reduce its generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.

CONTENTS

SECTION 1: INTRODUCTION

GEN-2015-015 Impact Restudy is a generation interconnection study performed to study the impacts of interconnecting the project shown in Table 1-1. This restudy evaluates the requested modification to change from sixty-four (64) Siemens 2.415MW wind turbine generators to nine (9) Siemens 2.3MW and fifty-one (51) Siemens 2.625MW wind turbine generators.

TABLE 1-1: INTERCONNECTION REQUEST

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2015-015	154.6	9 Siemens 2.3MW & 51 Siemens 2.625 generators	Tap on Coyote – Medford Tap 138kV (560031)

The prior-queued, equally-queued and lower queued requests shown in Table 1-2 were included in this study and the wind farms were dispatched to 100% of rated capacity.

TABLE 1-2: PRIOR AND LATER QUEUED INTERCONNECTION REQUESTS

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2002-004	199.5	GE.1.5MW	Latham 345kV (532800)
GEN-2005-013	199.8	Vestas V90 1.8MW	Caney River 345kV (532780)
GEN-2007-025	299.2	GE 1.6MW	Viola 345kV (532798)
GEN-2008-013	300	G.E. 1.68MW	Hunter 345kV (515476)
GEN-2008-021	1261 Summer 1283 Winter	GENROU	Wolf Creek 345kV (532797)
GEN-2008-098	100.8	Vestas V100 1.8MW	Tap on the Wolf Creek – LaCygne 345kV line (560004)
GEN-2009-025	59.8	Siemens 2.3MW	Tap on the Deerck – Sincblk 69KV line (Nardins 69kV, 515528)
GEN-2010-003	100.8	Vestas V100 1.8MW	Tap on the Wolf Creek – LaCygne 345kV line (560004)
GEN-2010-005	299.2	GE 1.6MW	Viola 345kV (532798)

Request	Capacity (MW)	Generator Model	Point of Interconnection
ASGI-2010-006	150	GE1.5MW	Remington 138kV (301369)
GEN-2010-055	4.8	GENROU	Wekiwa 138kV (509757)
GEN-2011-057	150.4	GE 1.6MW	Creswell 138kV (532981)
KCPL Distributed: Osawatomie	76.0	GENROU (543078)	Paola 161kV
GEN-2012-032	300	Vestas V112 3.0MW	Tap Rose Hill-Sooner 345kV (562318)
GEN-2012-033	98.8	GE 1.62MW	Tap Bunch Creek-South 4th 138kV(562303)
GEN-2012-041	85 Summer 121.5 Winter	GENROU	Tap Rose Hill-Sooner 345kV (562318)
GEN-2013-012	4 x 168.0MW Summer 4 x 215MW Winter	GENROU (514910) (514911) (514912) (514942)	Redbud 345kV (514909)
GEN-2013-029	300	Vestas V100 VCSS 2MW (583753, 583756)	Renfrow 345kV(515543)
GEN-2014-001	200.6	GE 1.7MW 100m (583853,583856)	Tap Wichita to Emporia Energy Center 345kV (562476)
GEN-2014-028	35 (Uprate) (Pgen=259W/256S)	GENROU	Riverton 161kV (547469)
GEN-2014-064	248.4	GE 2.3MW	Otter 138kV (514708)
ASGI-2014-014	56.4W/54.3S	GENROU	Ferguson 69kV (512664)

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2015-001	200.0	Vestas V110 2.0MW	Ranch Road 345kV
GEN-2015-016	200.0	Vestas V110 2.0MW	Tap Centerville – Marmaton 161kV
GEN-2015-024	220.0	GE 2.0MW	Tap on Thistle to Wichita 345kV, ckt1&2 (560033)
GEN-2015-025	220.0	GE 2.0MW	Tap on Thistle to Wichita 345kV, ckt1&2 (560033)
GEN-2015-028	3.0 uprate to GEN-2009-025 for total 62.8MW	Siemens 2.3MW with Power Boost (115kW => 2.415MW)	Nardins 69kV
GEN-2015-030	200.1	GE 2.3MW	Sooner 345kV
ASGI-2015-004	54.300 Summer 56.364 Winter	GENSAL	Coffeyville Municipal Light & Power Northern Industrial Park Substation 69kV (512735)

The study included a stability analysis of the interconnection request. 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 relays disabled. Also a low-wind/no-wind analysis was performed on this project since it is a non-synchronous resource. The analyses were performed on three seasonal models, the modified versions of the 2016 winter peak, the 2017 summer peak, and the 2025 summer peak cases. The stability analysis determines the impacts of the new interconnecting project on the stability and voltage recovery of the nearby systems and the ability of the interconnecting project to meet FERC Order 661A. If problems with stability or voltage recovery are identified, the need for reactive compensation or system upgrades is investigated. The three-phase faults and the single line-to-ground faults listed in Table 3-1 were used in the stability analysis.

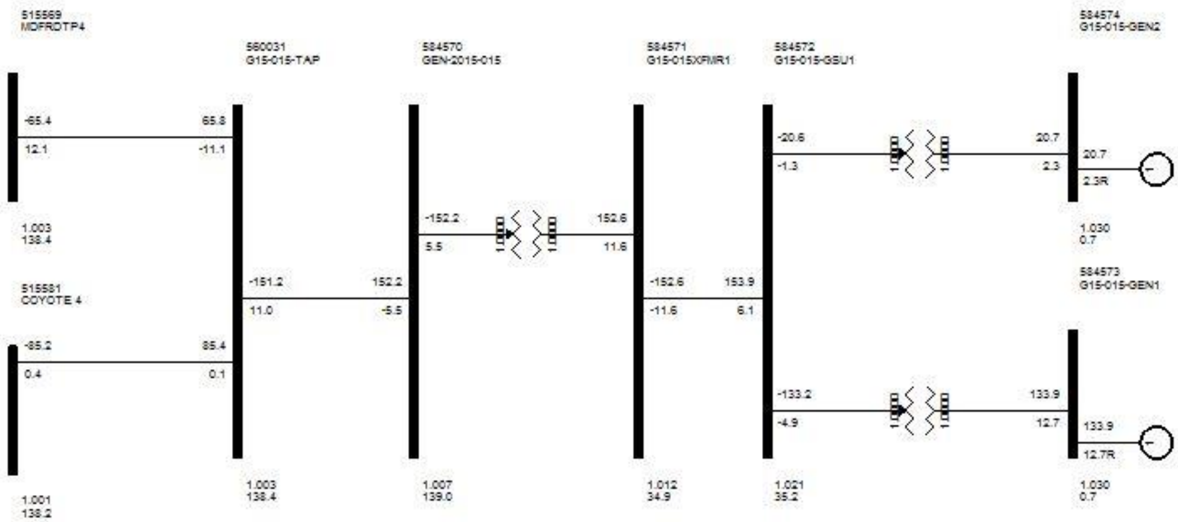
A Power factor analysis was performed on the 2016 winter peak, the 2017 summer peak and the 2025 summer peak cases for the three phase faults listed in Table 3-1.

The low-wind/no-wind analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line capacitance. A shunt reactor size was determined to offset the capacitive effect and to maintain zero Mvar flow at the POI when the plant generators and capacitors are off-line such as might be seen in low-wind or no-wind conditions.

SECTION 2: FACILITIES

A one-line drawing for the GEN-2015-015 generation interconnection request is shown in Figure 2-1. The POI is a new tap on the OKGE Coyote – Medford Tap 138kV line.

FIIGURE 2-1: GEN-2015-015 ONE-LINE DIAGRAM



SECTION 3: STABILITY ANALYSIS

Transient stability analysis is used to determine if the transmission system can maintain angular stability and ensure bus voltages stay within planning criteria bandwidth during and after a disturbance while considering the addition of a generator interconnection request.

MODEL PREPARATION

Transient stability analysis was performed using modified versions of the 2015 series of Model Development Working Group (MDWG) dynamic study models including the 2016 winter peak, the 2017 summer peak, and the 2025 summer peak seasonal models. The cases are then loaded with prior queued interconnection requests and network upgrades assigned to those interconnection requests. Finally the prior queued and study generation are dispatched into the SPP footprint. Initial simulations are then carried out for a no-disturbance run of twenty (20) seconds to verify the numerical stability of the model.

The interconnection customer provided a Siemens "Weak Grid Option" module for the Siemens PSSE wind turbine model. The stability study was performed both with and without the "Weak Grid Option". It was determined that the "Weak Grid Option" was not needed. The results shown in this report are without the "Weak Grid Option"

DISTURBANCES

Twenty (20) contingencies were identified for use in this study and are listed in Table 3-1. These contingencies included three-phase faults and single-phase line faults at locations defined by SPP. Single-phase line faults were simulated by applying fault impedance to the positive sequence network at the fault location to represent the effect of the negative and zero sequence networks on the positive sequence network. The fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. This method is in agreement with SPP current practice.

Except for transformer faults, the typical sequence of events for a three-phase and a single-phase fault is as follows:

1. apply fault at particular location
2. continue fault for five (5) cycles, clear the fault by tripping the faulted facility
3. after an additional twenty (20) cycles, re-close the previous facility back into the fault
4. continue fault for five (5) additional cycles
5. trip the faulted facility and remove the fault

Transformer faults are typically modeled as three-phase faults, unless otherwise noted. The sequence of events for a transformer fault is as follows:

1. apply fault for five (5) cycles
2. clear the fault by tripping the affected transformer facility (unless otherwise noted there will be no re-closing into a transformer fault)

TABLE 3-1: CONTINGENCIES EVALUATED

Contingency Number and Name		Description
1	FLT_01_OpenSky_G15052T_345kV_3PH	3 phase fault on the Open Sky (515621) to G15_15_Tap (560031) 345kV line, near Open Sky. a. Apply fault at the Open Sky 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	FLT_02_G15052T_Rosehill_345kV_3PH	3 phase fault on the G15_15_Tap (560031) to Rosehill (532794) 345kV line, near G15_15_Tap. a. Apply fault at the G15_15_Tap 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.
3	FLT_03_RanchRoad_Sooner_345kV_3PH	3 phase fault on the Ranch Road (515576) to Sooner (514803) 345kV line, near Ranch Road. a. Apply fault at the Ranch Road 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	FLT_04_Sooner_SpringCreek_345kV_3PH	3 phase fault on the Sooner (514803) to Spring Creek (514881) 345kV line, near Sooner. a. Apply fault at the Sooner 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.
5	FLT_05_Sooner_G15066T_345kV_3PH	3 phase fault on the Sooner (514803) to G15066T (560056) 345kV line, near Sooner. a. Apply fault at the Sooner 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	FLT_06_G15066T_Cleveland_345kV_3PH	3 phase fault on the G15066T (560056) to Cleveland (512694) 345kV line, near G15066T. a. Apply fault at the G15066T 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.

Contingency Number and Name		Description
7	FLT_07_Sooner_G16061T_345kV_3PH	3 phase fault on the Sooner (514803) to G16061T (560084) 345kV line, near Sooner. a. Apply fault at the Sooner 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	FLT_08_G16061T_Woodring_345kV_3PH	3 phase fault on the G16061T (560084) to Woodring (514715) 345kV line, near G16061T. a. Apply fault at the G16061T 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.
9	FLT_09_G15015Tap_MedfordTap_138kV_3PH	3 phase fault on the G15-015 Tap (560031) to Medford Tap (515569) 138kV line, near G15-015. a. Apply fault at the G15-015 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.
10	FLT_10_G15015Tap_Coyote_138kV_3PH	3 phase fault on the G15-015 Tap (560031) to Coyote (5155581) 138kV line, near G15-015. a. Apply fault at the G15-015 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.
11	FLT_11_Kildare_NewkirkAT_138kV_3PH	3 phase fault on the Kildare (514760) to NewkirkAT (514764) 138kV circuit 1 line, near Kildare. a. Apply fault at the Kildare 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.
12	FLT_12_Kildare_WhiteEagle_138kV_3PH	3 phase fault on the Kildare (514760) to White Eagle (514761) 138kV circuit 1 line, near Kildare. a. Apply fault at the Kildare 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.
13	FLT_13_Renfrow_RenfrowWFEC_138kV_3PH	3 phase fault on the Renfrow (515544) to RenfrowWFEC (520409) 138kV circuit 1 line, near Renfrow. a. Apply fault at the Renfrow 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.

Contingency Number and Name		Description
14	FLT_14_Renfrow_Hunter_345kV_3PH	3 phase fault on the Renfrow (515544) to Hunter (515476) 138kV circuit 1 line, near Renfrow. a. Apply fault at the Renfrow 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.
15	FLT_15_G15015Tap_Coyote_138kV_1PH	Single phase fault on the G15-015 Tap (560031) to Coyote (5155581) 138kV line, near G15-015. a. Apply fault at the G15-015 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.
16	FLT_16_G15015Tap_MedfordTap_138kV_1PH	Single phase fault on the G15-015 Tap (560031) to Medford Tap (515569) 138kV line, near G15-015. a. Apply fault at the G15-015 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.
17	FLT_17_Renfrow7_HunterPO_345kV_3PH	**Prior outage on the Renfrow (515543) 345/ (515544) 138/ (515545) 13.8kV transformer** 3 phase fault on the Renfrow (515544) to Hunter (515476) 138kV circuit 1 line, near Renfrow. a. Apply fault at the Renfrow 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.
18	FLT_18_Hunter_WoodringPO_345kV_3PH	**Prior outage on the Wichita (532796) – Benton (532791) 345kV line** 3 phase fault on the Hunter (515476) to Woodring (514715) 345kV line, near Hunter. a. Apply fault at the Hunter 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.
19	FLT_19_Renfrow_GrantCoPO_138kV_3PH	**Prior outage on the Renfrow (515544) – RenfrowWFEC (520409) 138kV line** 3 phase fault on the Renfrow (515544) to Grant Co (515546) 138kV circuit 1 line, near Renfrow. a. Apply fault at the Renfrow 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.

Contingency Number and Name		Description
20	FLT_20_Kildare_ChikaskiaPO_138kV_3PH	Prior outage on the Chikaskia (514757) 138/ (514756) 69/ (515713) 13.2kV transformer 3 phase fault on the Kildare (514760) to Chikaskia (514757) 138kV circuit 1 line, near Kildare. a. Apply fault at the Kildare 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.

RESULTS

The stability analysis was performed and the results are summarized in Table 3-2. Based on the stability results and with all network upgrades in service, GEN-2015-015 did not cause any stability problems and remained stable for all faults studied. No generators tripped or went unstable, and voltages recovered to acceptable levels.

Complete sets of plots for the stability analysis are available on request.

TABLE 3-2: STABILITY ANALYSIS RESULTS

Contingency Number and Name		2015SP	2015WP	2025SP
1	FLT_01_OpenSky_G15052T_345kV_3PH	Stable	Stable	Stable
2	FLT_02_G15052T_Rosehill_345kV_3PH	Stable	Stable	Stable
3	FLT_03_RanchRoad_Sooner_345kV_3PH	Stable	Stable	Stable
4	FLT_04_Sooner_SpringCreek_345kV_3PH	Stable	Stable	Stable
5	FLT_05_Sooner_G15066T_345kV_3PH	Stable	Stable	Stable
6	FLT_06_G15066T_Cleveland_345kV_3PH	Stable	Stable	Stable
7	FLT_07_Sooner_G16061T_345kV_3PH	Stable	Stable	Stable
8	FLT_08_G16061T_Woodring_345kV_3PH	Stable	Stable	Stable
9	FLT_09_G15015Tap_MedfordTap_138kV_3PH	Stable	Stable	Stable
10	FLT_10_G15015Tap_Coyote_138kV_3PH	Stable	Stable	Stable
11	FLT_11_Kildare_NewkirkAT_138kV_3PH	Stable	Stable	Stable

	Contingency Number and Name	2015SP	2015WP	2025SP
12	FLT_12_Kildare_WhiteEagle_138kV_3PH	Stable	Stable	Stable
13	FLT_13_Renfrow_RenfrowWFEC_138kV_3PH	Stable	Stable	Stable
14	FLT_14_Renfrow_Hunter_345kV_3PH	Stable	Stable	Stable
15	FLT_15_G15015Tap_Coyote_138kV_1PH	Stable	Stable	Stable
16	FLT_16_G15015Tap_MedfordTap_138kV_1PH	Stable	Stable	Stable
17	FLT_17_Renfrow7_HunterPO_345kV_3PH	Stable	Stable	Stable
18	FLT_18_Hunter_WoodringPO_345kV_3PH	Stable	Stable	Stable
19	FLT_19_Renfrow_GrantCoPO_138kV_3PH	Stable	Stable	Stable
20	FLT_20_Kildare_ChikaskiaPO_138kV_3PH	Stable	Stable	Stable

FERC LVRT COMPLIANCE

FERC Order #661A places specific requirements on wind farms through its Low Voltage Ride Through (LVRT) provisions. For Interconnection Agreements signed after December 31, 2006, wind farms shall stay on line for faults at the POI that draw the voltage down at the POI to 0.0 pu.

Contingencies 9 and 10 in Table 3-1 simulated the LVRT contingencies. GEN-2015-015 met the LVRT requirements by staying on line and the transmission system remaining stable.

SECTION 4: POWER FACTOR ANALYSIS

A subset of the stability faults was used as power flow contingencies to determine the power factor requirements for the wind farm to maintain scheduled voltage at the POI. The voltage schedule was set equal to the voltages at the POI before the project is added, with a minimum of 1.0 per unit. A fictitious reactive power source replaced 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.

Per FERC and SPP Tariff requirements, if the power factor needed to maintain scheduled voltage is less than 0.95 lagging, then the requirement is limited to 0.95 lagging. The lower limit for leading power factor requirement is also 0.95. If a project never operated leading under any contingency, then the leading requirement is set to 1.0. The same applies on the lagging side.

The power factor analysis showed a need for reactive capability by the study project at the POI. The final power factor requirement in the Generator Interconnection Agreement (GIA) will be the pro-forma 0.95 lagging to 0.95 leading at the POI, and this requirement is shown in Table 4-1. The detailed power factor analysis tables are in Appendix B. Since the Siemens 2.3MW and Siemens 2.625MW wind turbines as studied have a reactive capability (of 0.95 lagging and 0.95 leading), the generation facility may require external capacitor banks or other reactive equipment to meet the power factor requirement at the POI.

TABLE 4-1: STABILITY ANALYSIS RESULTS

Request	Size (MW)	Generator Model	Point of Interconnection	Final PF Requirement at POI	
				Lagging [b]	Leading [c]
GEN-2015-015	154.6	9 Siemens 2.3MW & 51 Siemens 2.625 generators	Tap on Coyote – Medford Tap 138kV (560031)	0.95[d]	0.95[e]

Notes:

a. The table shows the minimum required power factor capability at the point of interconnection that must be designed and installed with the plant. The power factor capability at the POI includes the net effect of the generators, transformers, line impedances, and any reactive compensation devices installed on the plant side of the meter. Installing more capability than the minimum requirement is acceptable.
b. Lagging is when the generating plant is supplying reactive power to the transmission grid, like a shunt capacitor. In this situation, the alternating current sinusoid "lags" behind the alternating voltage sinusoid, meaning that the current peaks shortly after the voltage.
c. Leading is when the generating plant is taking reactive power from the transmission grid, like a shunt reactor. In this situation, the alternating current sinusoid "leads" the alternating voltage sinusoid, meaning that the current peaks shortly before the voltage.
d. Electrical need is lower, but PF requirement limited to 0.95 by FERC order.
e. The most leading power factor determined through analysis was 1.00.

SECTION 5: REDUCED GENERATION ANALYSIS

Interconnection requests for wind generation projects that interconnect on the SPP system are analyzed for the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, curtailment, etc.) at the generation site.

MODEL PREPARATION

The project generators and capacitors (if any) were turned off in the base case. The resulting reactive power injection into the transmission network comes from the capacitance of the project's transmission lines and collector cables. This reactive power injection is measured at the POI. Shunt reactors were added at the study project substation low voltage bus to bring the Mvar flow into the POI down to approximately zero.

RESULTS

A final shunt reactor requirement for each of the studied interconnection requests is shown in Table 5-1. One line drawings used in the analysis are shown in Appendix D: Low Wind Analysis.

TABLE 5-1: SUMMARY OF SHUNT REACTOR REQUIREMENTS

Request	Capacity	POI	Approximate Shunt Reactor Required
GEN-2015-015	154.6MW	Tap on Coyote – Medford Tap 138kV (560031)	8 Mvar

The results shown are for the 2025 summer case. The other two cases (2016 winter and 2017 summer) were almost identical since the generation plant design is the same in all cases.

SECTION 6: SHORT CIRCUIT ANALYSIS

The short circuit analysis was performed on the 2017 & 2025 Summer Peak power flow cases using the PSS/E ASCC program. Since the power flow model does not contain negative and zero sequence data, only three-phase symmetrical fault current levels were calculated at the point of interconnection up to and including five levels away.

Short Circuit Analysis was conducting using flat conditions with the following PSS/E ASCCC program settings:

- BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
- GENERATOR P=0, Q=0
- TRANSFORMER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
- LINE CHARGING=0.0 IN +/-/0 SEQUENCE
- LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
- LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
- DC LINES AND FACTS DEVICES BLOCKED
- TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

Results
The results of the short circuit analysis are shown in Appendix C.

SECTION 7: CONCLUSION

The SPP GEN-2015-015 Impact Restudy evaluated the impact of interconnecting the project shown below in Table 7-1.

TABLE 7-1: INTERCONNECTION REQUEST

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2015-015	154.6	9 Siemens 2.3MW & 51 Siemens 2.625 generators	Tap on Coyote – Medford Tap 138kV (560031)

With all Base Case Network Upgrades in service, previously assigned Network Upgrades in service, and required capacitor banks in service, the GEN-2015-015 project was found to remain on line, and the transmission system was found to remain stable for all conditions studied. The requested modification is not considered Material.

A low-wind/no-wind condition analysis was performed for this modification request. The project will be required to install a total of approximately 8 Mvar of reactor shunts on its substation 34.5kV buses. This is necessary to offset the capacitive effect on the transmission network cause by the project's transmission line and collector system during low-wind or no-wind conditions.

Low Voltage Ride Through (LVRT) analysis showed the study generators did not trip offline due to low voltage when all Network Upgrades are in service.

Any changes to the assumptions made in this study, for example, one or more of the previously queued requests withdraw, may require a re-study at the expense of the Customer.

Nothing in this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer any right to receive transmission service.

APPENDIX A: PLOTS

Available on request.

APPENDIX B: POWER FACTOR ANALYSIS

GEN 2015-098 Turbine Restudy POI – BEAVERHILL4 230.00 237.444900513 (652616)		2016 Winter Voltage = 1.0 pu				2017 Summer Voltage = 1.00345 pu				2025 Summer Voltage = 1.0 pu			
Cont. No.	Contingency Name	Power at POI	VARS at POI	Power Factor		Power at POI	VARS at POI	Power Factor		Power at POI	VARS at POI	Power Factor	
1	FLT_00_NoFault	154.6	-17.58	0.994	LEAD	154.6	-21.31	0.991	LEAD	154.6	-11.02	0.997	LEAD
2	FLT_01_OpenSky_G15052T_345kV_3PH	154.6	-14.25	0.996	LEAD	154.6	-17.95	0.993	LEAD	154.6	-7.28	0.999	LEAD
3	FLT_02_G15052T_Rosehill_345kV_3PH	154.6	-7.57	0.999	LEAD	154.6	-12.73	0.997	LEAD	154.6	-1.83	1	LEAD
4	FLT_03_RanchRoad_Sooner_345kV_3PH	154.6	-15.31	0.995	LEAD	154.6	-21.57	0.99	LEAD	154.6	-12.07	0.997	LEAD
5	FLT_04_Sooner_SpringCreek_345kV_3PH	154.6	-11.27	0.997	LEAD	154.6	-16.39	0.994	LEAD	154.6	-5.71	0.999	LEAD
6	FLT_05_Sooner_G15066T_345kV_3PH	154.6	-12.98	0.996	LEAD	154.6	-18.64	0.993	LEAD	154.6	-8.72	0.998	LEAD
7	FLT_06_G15066T_Cleveland_345kV_3PH	154.6	-9.36	0.998	LEAD	154.6	-16.37	0.994	LEAD	154.6	-6.54	0.999	LEAD
8	FLT_07_Sooner_G16061T_345kV_3PH	154.6	-17.53	0.994	LEAD	154.6	-21.11	0.991	LEAD	154.6	-10.25	0.998	LEAD
9	FLT_08_G16061T_Woodring_345kV_3PH	154.6	-16.79	0.994	LEAD	154.6	-20.36	0.991	LEAD	154.6	-9.54	0.998	LEAD
10	FLT_09_G15015Tap_MedfordTap_138kV_3PH	154.6	-8.81	0.998	LEAD	154.6	-19	0.993	LEAD	154.6	-10.74	0.998	LEAD
11	FLT_10_G15015Tap_Coyote_138kV_3PH	154.6	-16.91	0.994	LEAD	154.6	-11.54	0.997	LEAD	154.6	-10.17	0.998	LEAD
12	FLT_11_Kildare_NewkirkAT_138kV_3PH	154.6	-27.95	0.984	LEAD	154.6	-25.05	0.987	LEAD	154.6	-13.31	0.996	LEAD

GEN 2015-098 Turbine Restudy POI – BEAVERHILL4 230.00 237.444900513 (652616)		2016 Winter Voltage = 1.0 pu				2017 Summer Voltage = 1.00345 pu				2025 Summer Voltage = 1.0 pu			
Cont. No.	Contingency Name	Power at POI	VARS at POI	Power Factor		Power at POI	VARS at POI	Power Factor		Power at POI	VARS at POI	Power Factor	
13	FLT_12_Kildare_WhiteEagle_138kV_3PH	154.6	5.53	0.999	LAG	154.6	-10.32	0.998	LEAD	154.6	1.96	1	LAG
14	FLT_13_Renfrow_RenfrowWFEC_138kV_3PH	154.6	-14.18	0.996	LEAD	154.6	-21.73	0.99	LEAD	154.6	-14.4	0.996	LEAD

APPENDIX C: SHORT CIRCUIT ANALYSIS

17SP

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                             PSS®E-32.2.0 ASCC SHORT CIRCUIT CURRENTS          MON, SEP 11
2017  16:09

2015 MDWG FINAL WITH 2013 MMWG, UPDATED WITH 2014 SERC & MRO

MDWG 17S WITH MMWG 15S, MRO 16W TOPO/16S PROF, SERC 16S


OPTIONS USED:

    - FLAT CONDITIONS

         - BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE

         - GENERATOR P=0, Q=0

         - TRANSFOMRER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0

         - LINE CHARGING=0.0 IN +/-/0 SEQUENCE

         - LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE

         - LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE

         - DC LINES AND FACTS DEVICES BLOCKED

         - TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED


                                  THREE PHASE FAULT

X---------- BUS ----------X          /I+/    AN(I+)

560031 [G15-015-TAP 138.00] AMP     8063.6   -81.07

515569 [MDFRDTP4    138.00] AMP    10864.0   -83.45

515581 [COYOTE 4    138.00] AMP     8026.3   -80.46

584570 [GEN-2015-015138.00] AMP     5692.0   -81.69

514757 [CHIKASI4    138.00] AMP     8695.7   -79.33

515544 [RENFROW4    138.00] AMP    13402.8   -84.84

522397 [MDFRDJCT    138.00] AMP     7157.4   -82.24
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514756	[CHIKASI2	69.000]	AMP	9693.3	-79.33
514760	[KILDARE4	138.00]	AMP	10174.6	-79.50
515543	[RENFROW7	345.00]	AMP	11222.1	-84.65
515546	[GRANTCO4	138.00]	AMP	6233.9	-81.17
520409	[RENFROW4	138.00]	AMP	9947.0	-83.13
522398	[PONDCREEK	138.00]	AMP	5335.8	-81.65
514750	[BRMAN 2	69.000]	AMP	8550.9	-77.50
514755	[BLACKWL2	69.000]	AMP	8152.9	-77.32
514761	[WHEAGLE4	138.00]	AMP	14993.2	-81.75
514764	[NWKRKAT4	138.00]	AMP	9853.0	-79.41
515476	[HUNTERS7	345.00]	AMP	12083.3	-84.69
515509	[SNCBLKT2	69.000]	AMP	6771.9	-75.58
515547	[GRANTCO2	69.000]	AMP	7142.5	-80.44
520205	[WAKITAS4	138.00]	AMP	5633.6	-80.51
529255	[OMBLKWL2	69.000]	AMP	7883.9	-79.42
532798	[VIOLA 7	345.00]	AMP	11406.9	-85.09
583750	[GEN-2013-029345.00]		AMP	10000.6	-84.60
514715	[WOODRNG7	345.00]	AMP	16949.5	-84.81
514719	[CLYDE 2	69.000]	AMP	4318.2	-73.61
514728	[SINCBLK2	69.000]	AMP	6756.8	-75.56
514739	[MEDFORD2	69.000]	AMP	5231.5	-76.49
514743	[OSAGE 4	138.00]	AMP	15716.2	-81.70
514748	[CONTEMP4	138.00]	AMP	12938.6	-81.64
514751	[NEWKRKT2	69.000]	AMP	5413.1	-66.31
514754	[KAYCOOP2	69.000]	AMP	5653.5	-72.98
514759	[NEWKIRK4	138.00]	AMP	8351.4	-79.18
515412	[DMNCRKT4	138.00]	AMP	13501.0	-84.32
515477	[CHSHLMV7	345.00]	AMP	12067.3	-84.69

515528	[NARDINS2	69.000]	AMP	5042.1	-73.44
520212	[WAKITA4	138.00]	AMP	5595.7	-80.49
520871	[BRAMAN 2	69.000]	AMP	7040.8	-77.00
521012	[NEWKIRK4	138.00]	AMP	9853.0	-79.41
521085	[WAKITA 2	69.000]	AMP	4807.4	-84.85
532792	[FR2EAST7	345.00]	AMP	6213.5	-85.59
532796	[WICHITA7	345.00]	AMP	23680.8	-86.10

25SP

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                             PSS®E-32.2.0 ASCC SHORT CIRCUIT CURRENTS          MON, SEP 11
2017  16:10

2015 MDWG FINAL WITH 2013 MMWG, UPDATED WITH 2014 SERC & MRO

MDWG 2025S WITH MMWG 2024S, MRO & SERC 2025 SUMMER


OPTIONS USED:

    - FLAT CONDITIONS

         - BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE

         - GENERATOR P=0, Q=0

         - TRANSFOMRER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0

         - LINE CHARGING=0.0 IN +/-/0 SEQUENCE

         - LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE

         - LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE

         - DC LINES AND FACTS DEVICES BLOCKED

         - TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED


                                  THREE PHASE FAULT

X---------- BUS ----------X          /I+/    AN(I+)

560031 [G15-015-TAP 138.00] AMP     8168.8   -80.98

515569 [MDFRDTP4    138.00] AMP    11004.6   -83.46

515581 [COYOTE 4    138.00] AMP     8151.7   -80.35

584570 [GEN-2015-015138.00] AMP     5739.3   -81.63

514757 [CHIKASI4    138.00] AMP     8901.3   -79.15

515544 [RENFROW4    138.00] AMP    13627.4   -84.90

522397 [MDFRDJCT    138.00] AMP     7218.2   -82.24

514756 [CHIKASI2    69.000] AMP     9891.8   -78.99

514760 [KILDARE4    138.00] AMP    10545.4   -79.40
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515543 [RENFROW7    345.00] AMP    11854.3   -84.75

515546 [GRANTCO4    138.00] AMP     6280.0   -81.16

520409 [RENFROW4    138.00] AMP    10059.6   -83.15

522398 [PONDCREEK   138.00] AMP     5369.5   -81.64

514750 [BRMAN  2    69.000] AMP     8716.4   -77.14

514755 [BLACKWL2    69.000] AMP     8305.2   -77.00

514761 [WHEAGLE4    138.00] AMP    15730.4   -81.85

514764 [NWKRKAT4    138.00] AMP    10214.2   -79.32

515476 [HUNTERS7    345.00] AMP    12441.5   -84.73

515509 [SNCBLKT2    69.000] AMP     6854.6   -75.33

515547 [GRANTCO2    69.000] AMP     7171.5   -80.41

520205 [WAKITAS4    138.00] AMP     5657.1   -80.50

529255 [OMBLKWL2    69.000] AMP     8014.8   -79.15

532798 [VIOLA   7   345.00] AMP    13506.2   -85.45

583750 [GEN-2013-029345.00] AMP    10492.4   -84.69

514715 [WOODRNG7    345.00] AMP    17294.9   -84.83

514719 [CLYDE  2    69.000] AMP     4326.8   -73.59

514728 [SINCBLK2    69.000] AMP     6839.1   -75.31

514739 [MEDFORD2    69.000] AMP     5249.5   -76.44

514743 [OSAGE  4    138.00] AMP    16707.2   -81.98

514748 [CONTEMP4    138.00] AMP    13539.7   -81.79

514751 [NEWKRKT2    69.000] AMP     5536.3   -65.85

514754 [KAYCOOP2    69.000] AMP     5751.2   -72.67

514759 [NEWKIRK4    138.00] AMP     8696.0   -79.16

515412 [DMNCRKT4    138.00] AMP    13762.8   -84.38

515477 [CHSHLMV7    345.00] AMP    12424.5   -84.73

515528 [NARDINS2    69.000] AMP     5078.5   -73.27

520212 [WAKITA4     138.00] AMP     5618.7   -80.49
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520871 [BRAMAN 2    69.000] AMP     7152.3   -76.70

521012 [NEWKIRK4    138.00] AMP    10214.2   -79.32

521085 [WAKITA 2    69.000] AMP     4815.0   -84.86

532792 [FR2EAST7    345.00] AMP     6648.8   -85.72

532796 [WICHITA7    345.00] AMP    24652.1   -86.24

533075 [VIOLA  4    138.00] AMP    22049.2   -86.03
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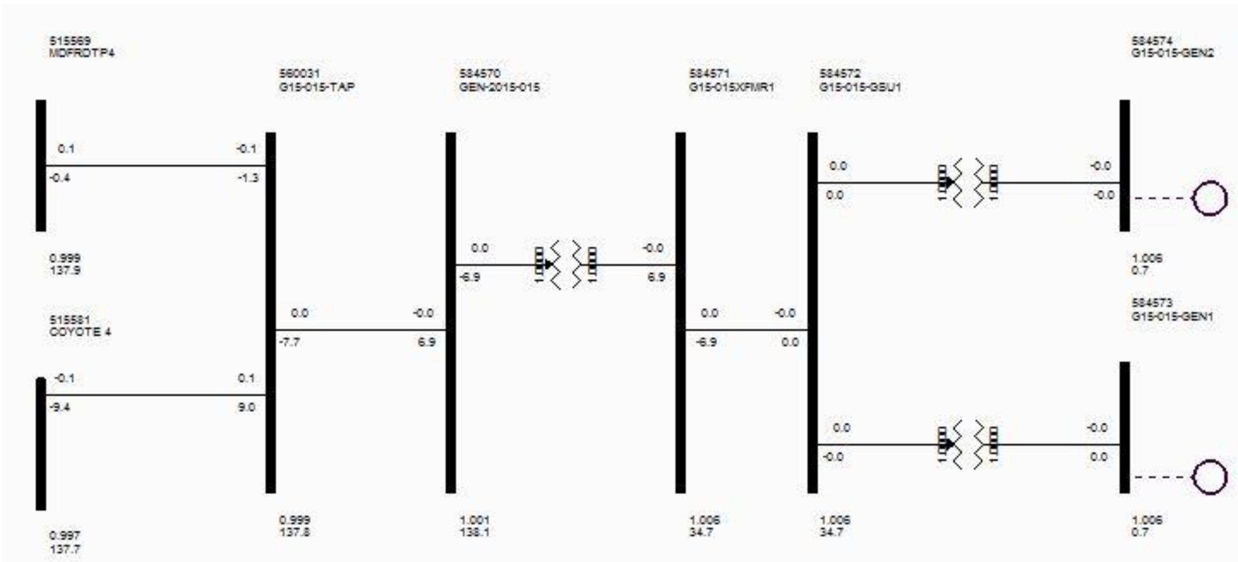
APPENDIX D: LOW WIND ANALYSIS

FIIGURE D-1: GEN-2015-015 WITH GENERATION OFF AND NO SHUNT REACTOR



FIIGURE D-1: GEN-2015-015 WITH GENERATION OFF AND SHUNT REACTOR