GEN-2007-046 Impact Restudy for Generator Modification (Turbine Change)

February 2014
Generator Interconnection

Executive Summary

The GEN-2007-046 interconnection customer has requested a system impact restudy to determine the effects of changing wind turbine generators from the previously studied GE 1.5MW wind turbine generators to a combination of Vestas V100 VCSS 2.0 MW and V110 VCSS 2.0MW wind turbine generators. Excel Engineering was commissioned by Southwest Power Pool to perform this study. The report is compiled by SPP using Excel's work product where noted.

In this restudy the project uses ninety (90) Vestas V110 VCSS 2.0MW and ten (10) Vestas V100 VCSS 2.0 MW wind turbine generators for an aggregate power of 200.0MW. The point of interconnection (POI) for GEN-2007-046 is at the Southwestern Public Service Company (SPS) Hitchland 115 kV Substation. The interconnection customer has provided documentation that shows the Vestas V100 and V110 VCSS 2.0MW wind turbine generators have a reactive capability of 0.98 lagging (providing VARS) and 0.96 leading (absorbing VARS) power factor.

The restudy showed that, with required capacitor banks, no stability problems were found during the summer and the winter peak conditions as a result of changing to the Vestas V100 and V110 VCSS 2.0MW wind turbine generators. 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.

A power factor analysis was performed in this restudy. The facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VARs) power factor at the point of interconnection. Since the Vestas V100 and V110 VCSS 2.0MW wind turbines have limited reactive capability, SPP determined that a minimum of 30MVAR capacitor bank on the 34.5kV side of the project substation transformer (115kV/34.5kV) will be required.

With the assumptions outlined in this report and with all the required network upgrades from the GEN-2007-046 GIA in place, GEN-2007-046 with the Vestas V100 and V110 VCSS 2.0MW wind turbine generators 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 obtain deliverability to a specific customer, a separate request for transmission service shall be requested on Southwest Power Pool's OASIS by the Customer.

I. Introduction

GEN-2007-046 Impact Restudy is a generation interconnection study performed to study the impacts of interconnecting the project shown in Table I-1. The in-service date assumed for the generation addition was 2015. This restudy is for a change from GE to Vestas wind turbines.

Table I-1: Interconnection Request

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2007-046	200	Vestas 2.0MW (10 x V100 and 90 x V110 for a total of 200MW)	Hitchland 115kV (523093)

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

Table I-2: Prior Queued Interconnection Requests

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2002-008	240	GE 1.5MW	Hitchland 345kV (523097)
GEN-2002-009	79.8	Suzlon S88 2.1MW	Hansford 115kV (523195)
GEN-2003-020	159.1	GE 1.5 MW	Martin 115kV (523928)
GEN-2006-020S	20	DeWind 2.0MW	Tap on the Hitchland – Lasley 115kV (523160)
GEN-2006-044	370	DeWind 2.0MW	Hitchland 345kV (523097)

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 power factor analysis was performed on this project since it is a wind farm. The analyses were performed on three seasonal models, the modified versions of the 2014 winter peak, the 2015 summer peak, and the 2024 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 III-1 were used in the stability analysis.

The power factor analysis determines the power factor at the point of interconnection for the wind interconnection project for pre-contingency and post-contingency conditions. The contingencies used in the power factor analysis were a subset of the stability analysis contingencies shown in Table III-1.

Nothing in this System Impact Study constitutes a request for transmission service or grants the Interconnection Customer any rights to transmission service.

II. Facilities

A one-line drawing for the GEN-2007-046 generation interconnection request is shown in Figure II-1.

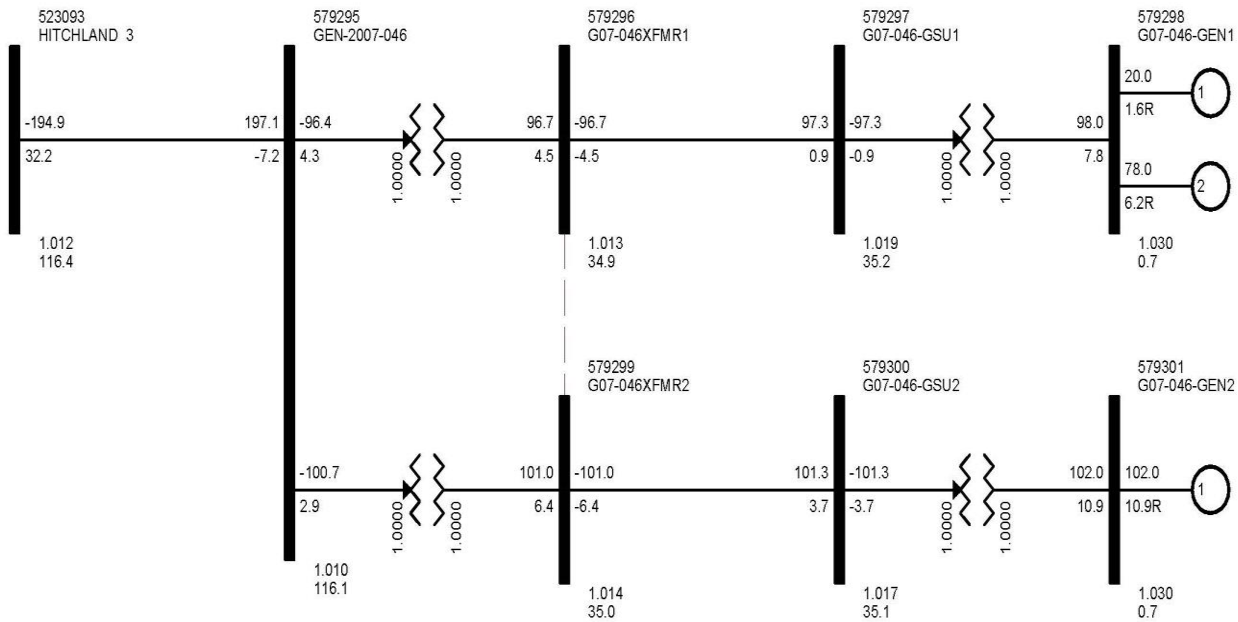

Figure II-1[1]: GEN-2007-046 One-line Diagram

[1] Taken from Excel Engineering Project 130579

III. 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 2013 series of Model Development Working Group (MDWG) dynamic study models including the 2014 winter peak, 2015 summer peak, and the 2024 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.

Disturbances

Forty-eight (48) contingencies were identified for use in this study and are listed in Table III-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)

The control areas monitored are 520, 524, 525, 526, 531, 534, and 536.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
1	FLT01-3PH	3 phase fault on the Hitchland (523093) to Texas County (523090) 115 kV line, at Hitchland. a. Apply fault at the Hitchland 115kV 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 Hitchland (523093) to Frisco_wnd (523160) 115 kV line, at Hitchland. a. Apply fault at the Hitchland 115kV 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 Hitchland (523093) to Hansford (523195) 115 kV line, at Hitchland. a. Apply fault at the Hitchland 115kV 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 Texas County (523090) to TC-Whiting (523099) 115 kV line, at Texas County. a. Apply fault at the Texas County 115kV 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 the Texas County (523090) to TC-McMurry (523113) 115 kV line, at Texas County. a. Apply fault at the Texas County 115kV 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	FLT10-3PH	Single phase fault and sequence like previous
11	FLT11-3PH	3 phase fault on the Frisco_wnd (523160) to Lasley (523175) 115 kV line, at Frisco_wnd. a. Apply fault at the Frisco_wnd 115kV 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 the Lasley (523175) to Sherman (523168) 115 kV line, at Lasley. a. Apply fault at the Lasley 115kV 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

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
15	FLT15-3PH	3 phase fault on the Lasley (523175) to RB-Spurlock (523177) 115 kV line, at Lasley. a. Apply fault at the Lasley 115kV 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 the Spearman (523186) to Pringle (523266) 115 kV line, at Spearman. a. Apply fault at the Spearman 115kV 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 the Spearman (523186) to Spearman Sub (523203) 115 kV line, at Spearman. a. Apply fault at the Spearman 115kV 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 the Spearman (523186) to Hansford (523195) 115 kV line, at Spearman. a. Apply fault at the Spearman 115kV 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 Hitchland (523095) to Ochiltree (523155) 230kV line, at Hitchland. a. Apply fault at the Hitchland 230kV 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 the Hitchland (523095) to Moore_cnty (523309) 230kV line, at Hitchland. a. Apply fault at the Hitchland 230kV 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 the Moore_cnty (523309) to Potter Co (523959) 230kV line, at Moore_cnty. a. Apply fault at the Moore_cnty 230kV 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

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
29	FLT29-3PH	3 phase fault on the Hitchland (523097) to Woodward (515375) 345kV line ckt1, at Hitchland. a. Apply fault at the Hitchland 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 the Hitchland (523097) to Finney (523853) 345kV line ckt1, at Hitchland. a. Apply fault at the Hitchland 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.
32	FLT32-1PH	Single phase fault and sequence like previous
33	FLT33-3PH	3 phase fault on the Hitchland (523097) to Potter Co (523961) 345kV line ckt1, at Hitchland. a. Apply fault at the Hitchland 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.
34	FLT34-1PH	Single phase fault and sequence like previous
35	FLT35-3PH	3 phase fault on the Cole (523120) to Ochiltree (523154) 115kV line ckt1, at Cole. a. Apply fault at the Cole 115kV 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 Cole (523120) to TC-Anthony Tap (523012) 115kV line ckt1, at Cole. a. Apply fault at the Cole 115kV 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 Ochiltree (523154) to Texas Farms (523140) 115kV line ckt1, at Ochiltree. a. Apply fault at the Ochiltree 115kV 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 Ochiltree (523154) to Perryton (523158) 115kV line ckt1, at Ochiltree. a. Apply fault at the Ochiltree 115kV 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

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
43	FLT43-3PH	3 phase double circuit fault on the Hitchland (523097) to Woodward (515375) 345kV lines, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted lines.
44	FLT44-3PH	3 phase fault on the Hitchland 115kV (523093) to 230kV (523095)/13.2kV (523092) transformer at the 115kV bus. a. Apply fault at the Hitchland 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer
45	FLT45-3PH	3 phase fault on the Hitchland 230kV (523095) to 345kV (523097)/13.2kV (523094) transformer at the 230kV bus. a. Apply fault at the Hitchland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer
46	FLT46-3PH	3 phase fault on the Moore County 230kV (523309) to 115kV (523308)/13.2kV (523302) transformer at the 230kV bus. a. Apply fault at the Moore County 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer
47	FLT47-3PH	3 phase fault on the Ochiltree 230kV (523155) to 115kV (523154)/13.2kV (523151) transformer at the 230kV bus. a. Apply fault at the Ochiltree 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer
48	FLT48-3PH	3 phase fault on the Texas Co. 115kV phase shifting transformer (523090 to 523106), near the main 115 kV bus. a. Apply fault at the main Texas Co. 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Results

The stability analysis was performed and the results are summarized in Table III-2.

Oscillations were observed for Fault #31, fault on the Hitchland-Finney 345kV line. It was determined that external capacitor banks would alleviate these oscillations.

In determining the required external reactive support, it was noted that an outage of the Hitchland to Finney 345kV line produced voltage oscillations at Hitchland when the Vestas wind turbine generators are used without external capacitor banks (see Figure III-1). As a baseline the GE wind turbine generators (external capacitor banks were turned off) were tested with the same outage. The voltage recovery at Hitchland was well damped and the voltage returned to near pre-fault level (see Figure III-2). With the Vestas wind turbine generators and 30MVARS capacitor bank on the low voltage side (34.5kV) of the project substation transformer and for the same outage, the voltage recovery at Hitchland was well damped and the voltage returned to near pre-fault level (see Figure III-3).

With the required capacitor banks, there were no stability problems found during any of the other simulations. No generators tripped or went unstable, and voltages recovered to acceptable levels.

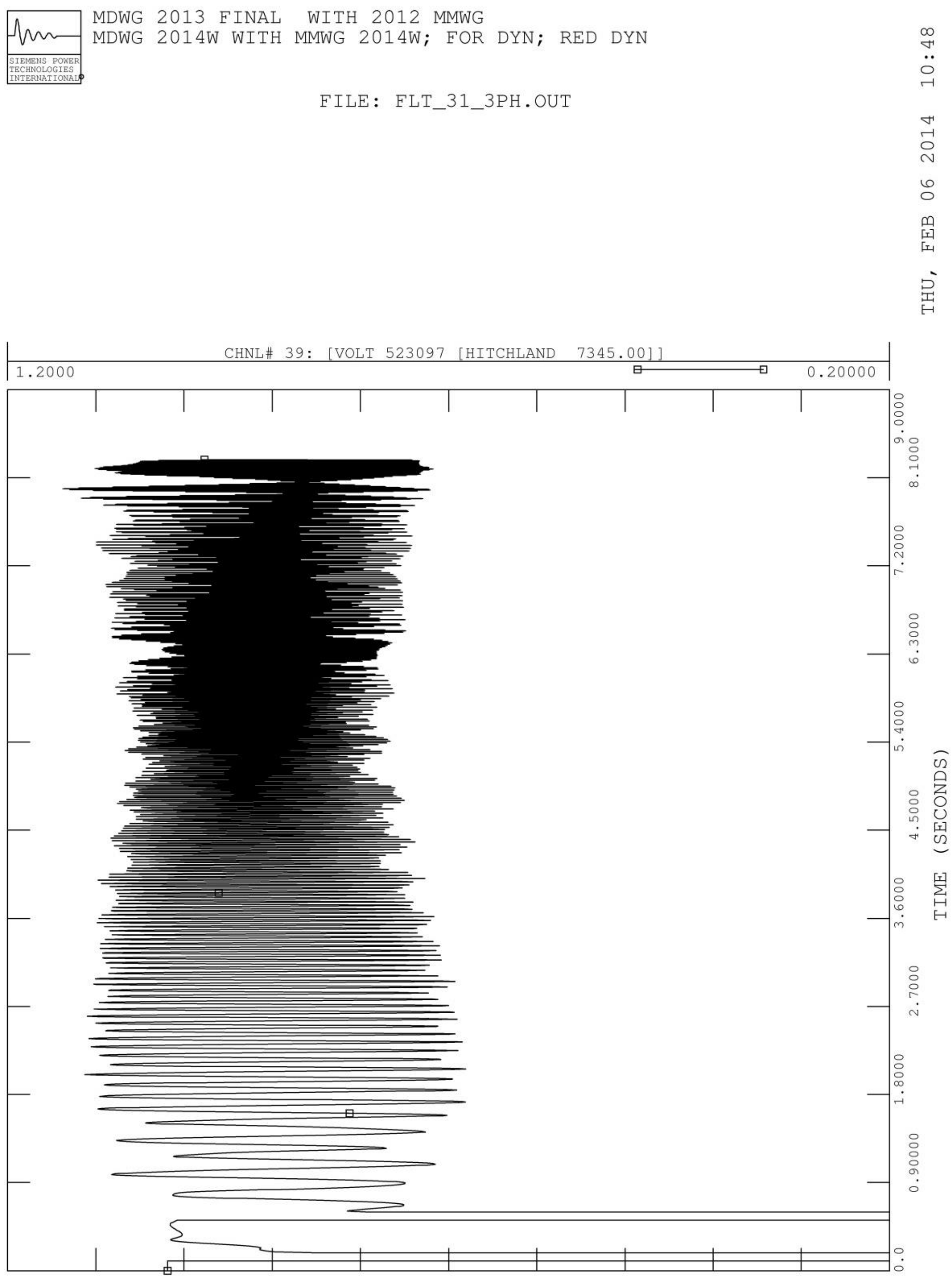

Figure III-1: Voltage at Hitchland 345kV bus using Vestas wind turbines and no capacitor banks

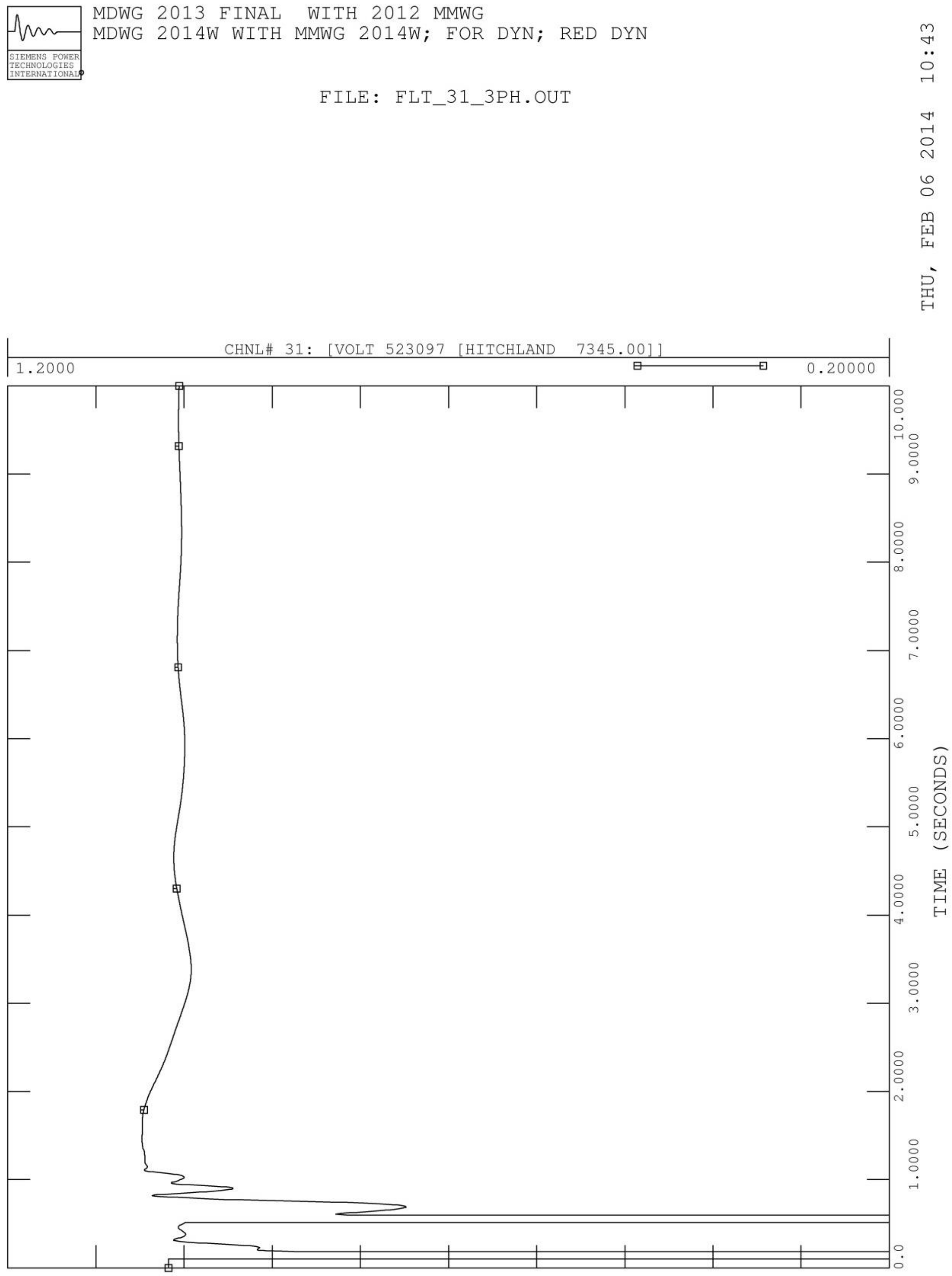

Figure III-2: Voltage at Hitchland 345kV bus using GE wind turbines and external reactive equipment turned off to show baseline response

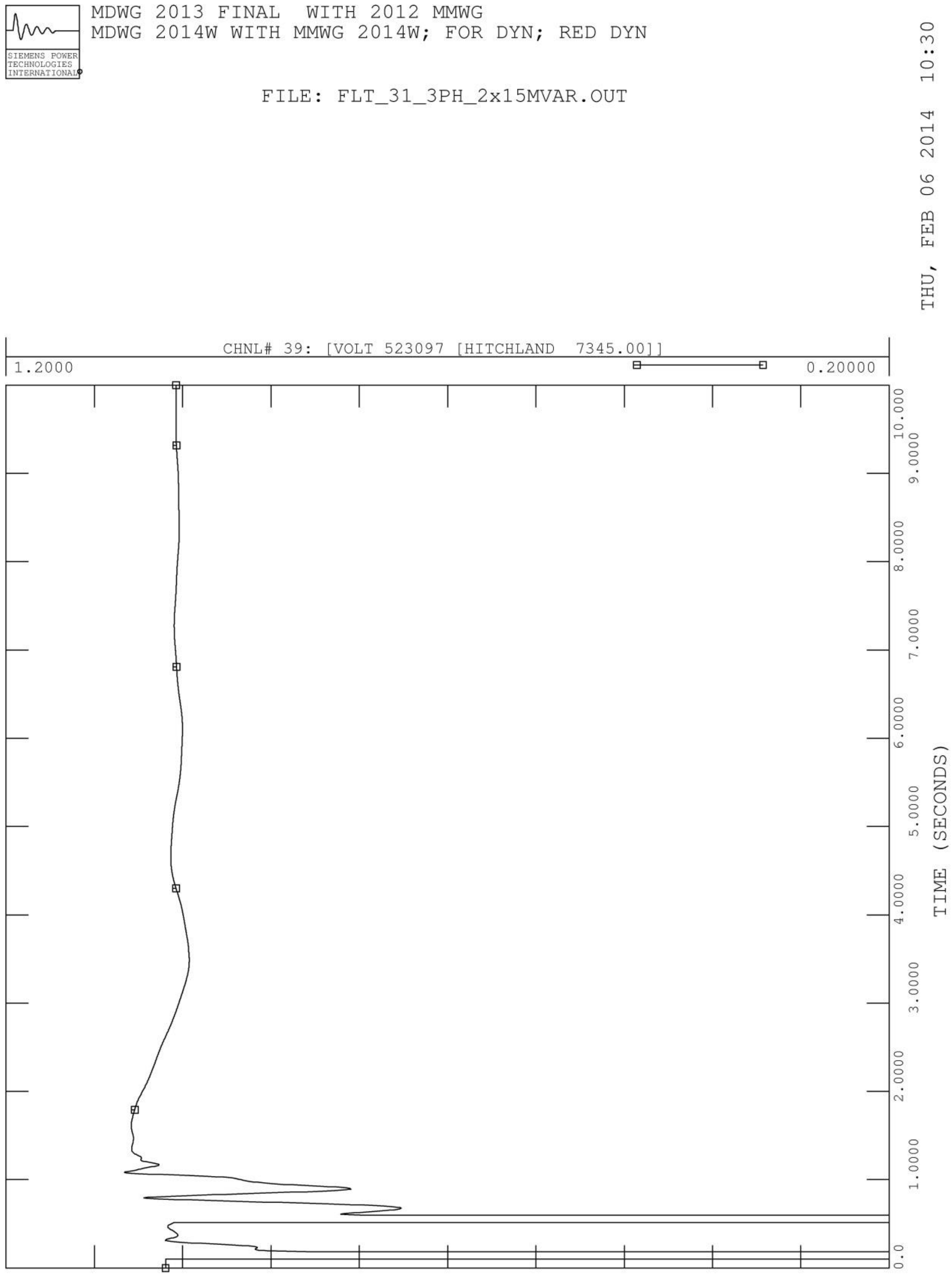

Figure III-3: Voltage at Hitchland 345kV bus using Vestas wind turbines and with 30MVAR capacitor bank turned on

Table III-2: Stability Analysis Results

	Contingency Number and Name	2014SP	2014WP	2023SP
1	3 phase fault on the Hitchland (523093) to Texas County (523090) 115 kV line, at Hitchland.	OK	OK	OK
2	Single phase fault and sequence like previous	OK	OK	OK
3	3 phase fault on the Hitchland (523093) to Frisco_wnd (523160) 115 kV line, at Hitchland.	OK	OK	OK
4	Single phase fault and sequence like previous	OK	OK	OK
5	3 phase fault on the Hitchland (523093) to Hansford (523195) 115 kV line, at Hitchland.	OK	OK	OK
6	Single phase fault and sequence like previous	OK	OK	OK
7	3 phase fault on the Texas County (523090) to TC-Whiting (523099) 115 kV line, at Texas County.	OK	OK	OK
8	Single phase fault and sequence like previous	OK	OK	OK
9	3 phase fault on the Texas County (523090) to TC-McMurry (523113) 115 kV line, at Texas County.	OK	OK	OK
10	Single phase fault and sequence like previous	OK	OK	OK
11	3 phase fault on the Frisco_wnd (523160) to Lasley (523175) 115 kV line, at Frisco_wnd.	OK	OK	OK
12	Single phase fault and sequence like previous	OK	OK	OK
13	3 phase fault on the Lasley (523175) to Sherman (523168) 115 kV line, at Lasley.	OK	OK	OK
14	Single phase fault and sequence like previous	OK	OK	OK
15	3 phase fault on the Lasley (523175) to RB-Spurlock (523177) 115 kV line, at Lasley.	OK	OK	OK
16	Single phase fault and sequence like previous	OK	OK	OK
17	3 phase fault on the Spearman (523186) to Pringle (523266) 115 kV line, at Spearman.	OK	OK	OK
18	Single phase fault and sequence like previous	OK	OK	OK
19	3 phase fault on the Spearman (523186) to Spearman Sub (523203) 115 kV line, at Spearman.	OK	OK	OK
20	Single phase fault and sequence like previous	OK	OK	OK
21	3 phase fault on the Spearman (523186) to Hansford (523195) 115 kV line, at Spearman.	OK	OK	OK
22	Single phase fault and sequence like previous	OK	OK	OK
23	3 phase fault on the Hitchland (523095) to Ochiltree (523155) 230kV line, at Hitchland.	OK	OK	OK
24	Single phase fault and sequence like previous	OK	OK	OK
25	3 phase fault on the Hitchland (523095) to Moore_cnty (523309) 230kV line, at Hitchland.	OK	OK	OK
26	Single phase fault and sequence like previous	OK	OK	OK
27	3 phase fault on the Moore_cnty (523309) to Potter Co (523959) 230kV line, at Moore_cnty.	OK	OK	OK
28	Single phase fault and sequence like previous	OK	OK	OK
29	3 phase fault on the Hitchland (523097) to Woodward (515375) 345kV line ckt1, at Hitchland.	OK	OK	OK
30	Single phase fault and sequence like previous	OK	OK	OK
31	3 phase fault on the Hitchland (523097) to Finney (523853) 345kV line ckt1, at Hitchland.	Undamped Oscillations	Undamped Oscillations	Undamped Oscillations
31A	3 phase fault on the Hitchland (523097) to Finney (523853) 345kV line ckt1, at Hitchland with 30Mvar capacitor banks at GEN-2007-046.	OK	OK	OK

Table III-2: Stability Analysis Results

Contingency Number and Name		2014SP	2014WP	2023SP
32	Single phase fault and sequence like previous	OK	OK	OK
33	3 phase fault on the Hitchland (523097) to Potter Co (523961) 345kV line ckt1, at Hitchland.	OK	OK	OK
34	Single phase fault and sequence like previous	OK	OK	OK
35	3 phase fault on the Cole (523120) to Ochiltree (523154) 115kV line ckt1, at Cole.	OK	OK	OK
36	Single phase fault and sequence like previous	OK	OK	OK
37	3 phase fault on the Cole (523120) to TC-Anthony Tap (523012) 115kV line ckt1, at Cole.	OK	OK	OK
38	Single phase fault and sequence like previous	OK	OK	OK
39	3 phase fault on the Ochiltree (523154) to Texas Farms (523140) 115kV line ckt1, at Ochiltree.	OK	OK	OK
40	Single phase fault and sequence like previous	OK	OK	OK
41	3 phase fault on the Ochiltree (523154) to Perryton (523158) 115kV line ckt1, at Ochiltree.	OK	OK	OK
42	Single phase fault and sequence like previous	OK	OK	OK
43	3 phase double circuit fault on the Hitchland (523097) to Woodward (515375) 345kV lines, near Hitchland.	OK	OK	OK
44	3 phase fault on the Hitchland 115kV (523093) to 230kV (523095)/13.2kV (523092) transformer at the 115kV bus.	OK	OK	OK
45	3 phase fault on the Hitchland 230kV (523095) to 345kV (523097)/13.2kV (523094) transformer at the 230kV bus.	OK	OK	OK
46	3 phase fault on the Moore County 230kV (523309) to 115kV (523308)/13.2kV (523302) transformer at the 230kV bus.	OK	OK	OK
47	3 phase fault on the Ochiltree 230kV (523155) to 115kV (523154)/13.2kV (523151) transformer at the 230kV bus.	OK	OK	OK
48	3 phase fault on the Texas Co. 115kV phase shifting transformer (523090 to 523106), near the main 115 kV bus.	OK	OK	OK

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 1, 3, and 5 in Table III-2 simulated the LVRT contingencies. GEN-2007-046 met the LVRT requirements by staying on line and the transmission system remained stable.

IV. Power Factor Analysis[2]

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 point of interconnection (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 POIs 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.

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 final power factor requirements are shown in Table IV-1 below. These are only the minimum power factor ranges based on steady-state analysis.

Table IV-1: Power Factor Requirements [a]

Request	Size (MW)	Generator Model	Point of Interconnection	Final PF Requirement	
				Lagging [b]	Leading [c]
GEN-2007-046	200	Vestas V100 and V110 2.0MW	Hitchland 115kV (523093)	1.000	0.982

Notes:

a. 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 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.

[2] Power Factor Analysis performed by Excel Engineering

V. Conclusion

The SPP GEN-2007-046 Impact Restudy evaluated the impact of interconnecting the project shown below.

Request	Size	Generator Type	Point of Interconnection	Gen Buses
GEN-2007-046	200	Vestas 2.0MW (10 x V100 and 90 x V110 for a total of 200MW)	Hitchland 115kV (523093)	579298 579301

With all Base Case Network Upgrades in service, previously assigned Network Upgrades in service, and required capacitor banks in service, the GEN-2007-046 project was found to remain on line, and the transmission system was found to remain stable for all conditions studied.

The power factor analysis of the study cases showed that the GEN-2007-046 project is required to maintain a power factor requirement of the pro-forma standard 0.95 leading (absorbing) to 0.95 lagging (supplying) at the Point of Interconnection.

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.

All generators in the monitored areas remained stable for all of the modeled disturbances.

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 upon request)

APPENDIX B

TRANSIENT VOLTAGE DETAILS
(Available upon request)

APPENDIX C

POWER FACTOR ANALYSIS

		2014 Winter Peak					2015 Summer Peak					2024 Summer Peak				
		MW	Mvar	PF		Vsch	MW	Mvar	PF		Vsch	MW	Mvar	PF		Vsch
System Intact	0	194.88	-15.1	0.997	leading	1.0196	194.91	-19.24	0.995	leading	1.0292	194.91	-20.59	0.994	leading	1.0289
Contingency	1	194.88	-7.17	0.999	leading	1.0196	194.91	-8.66	0.999	leading	1.0292	194.91	-9.78	0.999	leading	1.0289
Contingency	2	194.88	-7.17	0.999	leading	1.0196	194.91	-8.66	0.999	leading	1.0292	194.91	-9.78	0.999	leading	1.0289
Contingency	3	194.88	-8.65	0.999	leading	1.0196	194.91	-15.04	0.997	leading	1.0292	194.91	-14.42	0.997	leading	1.0289
Contingency	4	194.88	-8.65	0.999	leading	1.0196	194.91	-15.04	0.997	leading	1.0292	194.91	-14.42	0.997	leading	1.0289
Contingency	5	194.88	-10.6	0.999	leading	1.0196	194.91	-29.96	0.988	leading	1.0292	194.91	-37.09	0.982	leading	1.0289
Contingency	6	194.88	-10.6	0.999	leading	1.0196	194.91	-29.96	0.988	leading	1.0292	194.91	-37.09	0.982	leading	1.0289
Contingency	7	194.88	-26.29	0.991	leading	1.0196	194.91	-31.85	0.987	leading	1.0292	194.91	-34	0.985	leading	1.0289
Contingency	8	194.88	-26.29	0.991	leading	1.0196	194.91	-31.85	0.987	leading	1.0292	194.91	-34	0.985	leading	1.0289
Contingency	9	194.88	-8.92	0.999	leading	1.0196	194.91	-14.49	0.997	leading	1.0292	194.91	-15.18	0.997	leading	1.0289
Contingency	10	194.88	-8.92	0.999	leading	1.0196	194.91	-14.49	0.997	leading	1.0292	194.91	-15.18	0.997	leading	1.0289
Contingency	11	194.88	-7.84	0.999	leading	1.0196	194.91	-13.12	0.998	leading	1.0292	194.91	-12.99	0.998	leading	1.0289
Contingency	12	194.88	-7.84	0.999	leading	1.0196	194.91	-13.12	0.998	leading	1.0292	194.91	-12.99	0.998	leading	1.0289
Contingency	13	194.88	-15.01	0.997	leading	1.0196	194.91	-20.93	0.994	leading	1.0292	194.91	-22.23	0.994	leading	1.0289

	2014 Winter Peak					2015 Summer Peak					2024 Summer Peak				
	MW	Mvar	PF		Vsch	MW	Mvar	PF		Vsch	MW	Mvar	PF		Vsch
Contingency 14	194.88	-15.01	0.997	leading	1.0196	194.91	-20.93	0.994	leading	1.0292	194.91	-22.23	0.994	leading	1.0289
Contingency 15	194.88	-11.83	0.998	leading	1.0196	194.91	-14.05	0.997	leading	1.0292	194.91	-14.54	0.997	leading	1.0289
Contingency 16	194.88	-11.83	0.998	leading	1.0196	194.91	-14.05	0.997	leading	1.0292	194.91	-14.54	0.997	leading	1.0289
Contingency 17	194.88	-14.75	0.997	leading	1.0196	194.91	-15.47	0.997	leading	1.0292	194.91	-13.97	0.997	leading	1.0289
Contingency 18	194.88	-14.75	0.997	leading	1.0196	194.91	-15.47	0.997	leading	1.0292	194.91	-13.97	0.997	leading	1.0289
Contingency 19	194.88	-14.44	0.997	leading	1.0196	194.91	-18.91	0.995	leading	1.0292	194.91	-18.52	0.996	leading	1.0289
Contingency 20	194.88	-14.44	0.997	leading	1.0196	194.91	-18.91	0.995	leading	1.0292	194.91	-18.52	0.996	leading	1.0289
Contingency 21	194.88	-7.6	0.999	leading	1.0196	194.91	-24.53	0.992	leading	1.0292	194.91	-18.12	0.996	leading	1.0289
Contingency 22	194.88	-7.6	0.999	leading	1.0196	194.91	-24.53	0.992	leading	1.0292	194.91	-18.12	0.996	leading	1.0289
Contingency 23	194.88	-7.1	0.999	leading	1.0196	194.91	-1.83	1	leading	1.0292	194.91	3.11	1	lagging	1.0289
Contingency 24	194.88	-7.1	0.999	leading	1.0196	194.91	-1.83	1	leading	1.0292	194.91	3.11	1	lagging	1.0289
Contingency 25	194.88	-14.76	0.997	leading	1.0196	194.91	-22.87	0.993	leading	1.0292	194.91	-20.84	0.994	leading	1.0289
Contingency 26	194.88	-14.76	0.997	leading	1.0196	194.91	-22.87	0.993	leading	1.0292	194.91	-20.84	0.994	leading	1.0289
Contingency 27	194.88	-14.86	0.997	leading	1.0196	194.91	-8.82	0.999	leading	1.0292	194.91	-14.7	0.997	leading	1.0289
Contingency 28	194.88	-14.86	0.997	leading	1.0196	194.91	-8.82	0.999	leading	1.0292	194.91	-14.7	0.997	leading	1.0289
Contingency 29	194.88	-14.35	0.997	leading	1.0196	194.91	-16.01	0.997	leading	1.0292	194.91	-17.16	0.996	leading	1.0289

	2014 Winter Peak					2015 Summer Peak					2024 Summer Peak				
	MW	Mvar	PF		Vsch	MW	Mvar	PF		Vsch	MW	Mvar	PF		Vsch
Contingency 30	194.88	-14.35	0.997	leading	1.0196	194.91	-16.01	0.997	leading	1.0292	194.91	-17.16	0.996	leading	1.0289
Contingency 31	194.88	1.19	1	lagging	1.0196	194.91	-1.82	1	leading	1.0292	194.91	-2.96	1	leading	1.0289
Contingency 32	194.88	1.19	1	lagging	1.0196	194.91	-1.82	1	leading	1.0292	194.91	-2.96	1	leading	1.0289
Contingency 33	194.88	-11.69	0.998	leading	1.0196	194.91	-15.27	0.997	leading	1.0292	194.91	-14.37	0.997	leading	1.0289
Contingency 34	194.88	-11.69	0.998	leading	1.0196	194.91	-15.27	0.997	leading	1.0292	194.91	-14.37	0.997	leading	1.0289
Contingency 35	194.88	-13.94	0.997	leading	1.0196	194.91	-12.67	0.998	leading	1.0292	194.91	-7.06	0.999	leading	1.0289
Contingency 36	194.88	-13.94	0.997	leading	1.0196	194.91	-12.67	0.998	leading	1.0292	194.91	-7.06	0.999	leading	1.0289
Contingency 37	194.88	-15.75	0.997	leading	1.0196	194.91	-21.04	0.994	leading	1.0292	194.91	-22.92	0.993	leading	1.0289
Contingency 38	194.9	-15.8	0.997	leading	1.0196	194.9	-21.0	0.994	leading	1.0292	194.9	-22.9	0.993	leading	1.0289
Contingency 39	194.9	-14.9	0.997	leading	1.0196	194.9	-18.9	0.995	leading	1.0292	194.9	-18.6	0.995	leading	1.0289
Contingency 40	194.9	-14.9	0.997	leading	1.0196	194.9	-18.9	0.995	leading	1.0292	194.9	-18.6	0.995	leading	1.0289
Contingency 41	194.9	-15.1	0.997	leading	1.0196	194.9	-19.2	0.995	leading	1.0292	194.9	-20.5	0.994	leading	1.0289
Contingency 42	194.9	-15.1	0.997	leading	1.0196	194.9	-19.2	0.995	leading	1.0292	194.9	-20.5	0.994	leading	1.0289
Contingency 43	194.9	-16.5	0.996	leading	1.0196	194.9	-11.1	0.998	leading	1.0292	194.9	-15.2	0.997	leading	1.0289
Contingency 44	194.9	-28.9	0.989	leading	1.0196	194.9	-9.8	0.999	leading	1.0292	194.9	-1.4	1.000	leading	1.0289
Contingency 45	194.9	-16.2	0.997	leading	1.0196	194.9	-13.9	0.997	leading	1.0292	194.9	-13.9	0.997	leading	1.0289

	2014 Winter Peak					2015 Summer Peak					2024 Summer Peak				
	MW	Mvar	PF		Vsch	MW	Mvar	PF		Vsch	MW	Mvar	PF		Vsch
Contingency 46	194.9	-11.5	0.998	leading	1.0196	194.9	-16.8	0.996	leading	1.0292	194.9	-10.9	0.998	leading	1.0289
Contingency 47	194.9	-10.9	0.998	leading	1.0196	194.9	-5.6	1.000	leading	1.0292	194.9	-0.5	1.000	leading	1.0289
Contingency 48	194.9	-16.3	0.997	leading	1.0196	194.9	-21.2	0.994	leading	1.0292	194.9	-24.4	0.992	leading	1.0289

APPENDIX D

PROJECT MODELS

GEN-2007-046 (Vestas V100 and V110 2.0 MW)

PSS/E 32 Power Flow Data

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579297,'G07-046-GSU1',  34.5000,1, 526,1502, 526,1.01940,  30.5609
579298,'G07-046-GEN1',   0.6900,2, 526,1502, 526,1.03000,  34.5636
579299,'G07-046XFMR2',  34.5000,1, 526,1502, 526,1.01438,  29.7771
579300,'G07-046-GSU2',  34.5000,1, 526,1502, 526,1.01743,  30.1170
579301,'G07-046-GEN2',   0.6900,2, 526,1502, 526,1.03000,  34.1159
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0 / END OF LOAD DATA, BEGIN FIXED SHUNT DATA
0 / END OF FIXED SHUNT DATA, BEGIN GENERATOR DATA
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0.00000E+0,1.00000,1,   78.0,    20.000,     0.000, 526,1.0000
579298,'2 ',    78.000,     6.173,    15.800,   -22.700,1.03000,     0,    78.000, 5.00000E-3, 1.99100E-1, 0.00000E+0,
0.00000E+0,1.00000,1,   78.0,    78.000,     0.000, 526,1.0000
579301,'1 ',   102.000,    10.869,    20.700,   -29.700,1.03000,     0,   102.000, 5.00000E-3, 1.99100E-1, 0.00000E+0,
0.00000E+0,1.00000,1,  102.0,   102.000,     0.000, 526,1.0000
0 / END OF GENERATOR DATA, BEGIN BRANCH DATA
523093,579295,'1 ', 5.93000E-3, 6.96200E-2,   0.01553,    0.00,    0.00,    0.00,  0.00000,  0.00000,  0.00000,  0.00000,1,1,  17.50,
526,1.0000
579296,579297,'1 ', 6.44000E-3, 1.45000E-2,   0.04800,    0.00,    0.00,    0.00,  0.00000,  0.00000,  0.00000,  0.00000,1,1,   0.00,
526,1.0000
579296,579299,'1 ', 0.00000E+0, 1.00000E-4,   0.00000,    0.00,    0.00,    0.00,  0.00000,  0.00000,  0.00000,  0.00000,0,1,   0.00,
526,1.0000
579299,579300,'1 ', 2.75000E-3, 6.19000E-3,   0.03199,    0.00,    0.00,    0.00,  0.00000,  0.00000,  0.00000,  0.00000,1,1,   0.00,
526,1.0000
0 / END OF BRANCH DATA, BEGIN TRANSFORMER DATA
579295,579296,     0,'1 ',1,2,1, 0.00000E+0, 0.00000E+0,2,'            ',1, 526,1.0000
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1.00000,   0.000
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1.00000,   0.000
579297,579298,     0,'1 ',1,2,1, 0.00000E+0, 0.00000E+0,2,'            ',1, 526,1.0000
 8.01000E-3, 7.75900E-2,   102.90
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PSS/E 32 Dynamics Data

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/ MODULE: Vestas Generic Model Dynamic Data Template for PSS/E
/ Model revision: 7.6
/ WTG type: V100 VCSS 2.0 MW 60 Hz Mk7H
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1.9807 8.3333 1.9807 8.3333 30.0000 0.2000 1.2000
0.1000 0.0012 0.9925 0.0474 1.6118 0.0000 351.8584
313.4245 0.0300 0.0000 0.0300 0.3000 0.0000 1.0000
0.3183 4.9736 2812227.1900 43.2960 90.0120 600000.0000 3.0000
0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
0.0000 0.0000 0.0000/
0 'USRMDL' 0 'VWVAR6' 8 0 2 0 0 30 579298 '1' /
0 'USRMDL' 0 'VWLVR6' 8 0 3 65 10 35 579298 '1' 1
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0.5000 1.0000 1.5625 0.9676 1.2000 0.5000 690.0000
1514.6603 0.3500 0.0500 0.2500 0.0200 3.0000 4.0000
9999.0000 0.0232 0.9000 0.9000 0.0500 0.0000 0.0100
0.0000 2.0000 0.0000 1.0000 0.0000 0.0000 0.0000
0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
0.0000 0.0000 /
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0.2000 0.2000 1.3000 0.0500 0.5000 0.5000 0.1000
0.1000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
0.0000 0.0000 /
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0.0000 0.0000 0.0000 /
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0.0000 0.0000 0.0000/
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60.0000 1.1500 2.0000 1.2000 0.0800 1.2500 0.0050
1.2500 0.0050 0.0000 0.0000 0.0000 0.0000 0.0000
0.0000 0.0000 0.1500 0.8000 2.7000 0.8500 3.5000
0.9000 5.0000 /
0 'USRMDL' 0 'VWFPR6' 0 2 3 12 0 7 579298 '1' 0
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0.2000 63.6000 0.2000 63.6000 0.2000 /
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/ MODULE: Vestas Generic Model Dynamic Data Template for PSS/E
/ Model revision: 7.6
/ WTG type: V110 VCSS 2.0 MW 60 Hz Mk10
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 0.1000 0.0012 0.9925 0.0474 1.6118 0.0000 351.8584
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 0.0000 0.0000 0.0000/
0 'USRMDL' 0 'VWVAR6' 8 0 2 0 0 30 579298 '2'  /
0 'USRMDL' 0 'VWLVR6' 8 0 3 65 10 35 579298 '2' 1
 0.9000 0.0010 0.1500 18.6316 74.5430 74.5430 74.5430
 0.5000 1.0000 2.6200 0.9676 1.2000 0.5000 690.0000
 903.3041 0.3500 0.0500 0.2500 0.0200 3.0000 4.0000
 9999.0000 0.0232 0.9000 0.9000 0.0500 0.0000 0.0100
 0.0000 2.0000 0.0000 1.0000 0.0000 0.0000 0.0000
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 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
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 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 /
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 0.2000 0.2000 1.0000 1.0000 0.0000 0.0000 0.1000
 0.1000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 /
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 0.0000 0.0000 0.0000/
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 60.0000 1.1500 2.0000 1.2000 0.0800 1.2500 0.0050
 1.2500 0.0050 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.1500 0.8000 2.7000 0.8500 3.5000
 0.9000 5.0000 /
0 'USRMDL' 0 'VWFPR6' 0 2 3 12 0 7 579298 '2'  0
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/ MODULE: Vestas Generic Model Dynamic Data Template for PSS/E
/ Model revision: 7.6
/ WTG type: V110 VCSS 2.0 MW 60 Hz Mk10
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 0.1000 0.0012 0.9925 0.0474 1.6118 0.0000 351.8584
 161.5343 0.0300 0.0000 0.0300 0.3000 0.0000 1.0000
 0.3183 4.9736 2812227.1900 43.2960 90.0120 600000.0000 3.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000/
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0 'USRMDL' 0 'VWLVR6' 8 0 3 65 10 35 579301 '1' 1
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 0.5000 1.0000 2.6200 0.9676 1.2000 0.5000 690.0000
 903.3041 0.3500 0.0500 0.2500 0.0200 3.0000 4.0000
 9999.0000 0.0232 0.9000 0.9000 0.0500 0.0000 0.0100
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 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 /
0 'USRMDL' 0 'VWPWR6' 8 0 3 30 7 10 579301 '1' 1
 1.0000 0.5000 -0.5000 0.6988 0.8844 0.9800 0.9600
 0.2000 0.2000 1.0000 1.0000 0.0000 0.0000 0.1000
 0.1000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 /
0 'USRMDL' 0 'VWMEC6' 8 0 2 10 8 0 579301 '1'
 2000.0000 422.2301 4736.7543 420.7500 83.5000 6188.8071 39.3992
 0.0000 0.0000 0.0000 /
0 'USRMDL' 0 'VWMEA6' 8 0 2 10 8 5 579301 '1'
 0.1000 0.1000 0.1000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000/
0 'USRMDL' 0 'VWVPR6' 0 2 7 30 0 18 579301 '1'  1 1 0 0 0
 0.8500 11.0000 0.8500 11.0000 0.9000 60.0000 1.1000
 60.0000 1.1500 2.0000 1.2000 0.0800 1.2500 0.0050
 1.2500 0.0050 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.1500 0.8000 2.7000 0.8500 3.5000
 0.9000 5.0000 /
0 'USRMDL' 0 'VWFPR6' 0 2 3 12 0 7 579301 '1'  0
 56.4000 0.2000 56.4000 0.2000 56.4000 0.2000 63.6000
 0.2000 63.6000 0.2000 63.6000 0.2000 /
/********************************************************************************
```

APPENDIX E

TRANSMISSION ONE-LINES
(Available upon request)