GEN-2009-040 Impact Restudy for Generator Modification (Turbine Change)

August 2014
Generator Interconnection

Southwest Power Pool

Executive Summary

The GEN-2009-040 interconnection customer has requested a system impact restudy to determine the effects of changing wind turbine generators from the previously studied Nordex 2.5MW wind turbine generators and the Siemens 2.3MW wind turbine generators to Vestas VCSS V100/V110 2.0MW wind turbine generators.

In this restudy the project uses thirty-six (36) Vestas VCSS V100/V110 2.0MW wind turbine generators for an aggregate power of 72.0MW. The point of interconnection (POI) for GEN-2009-040 is at the Westar Energy (Westar) Marshall 115kV substation. The interconnection customer has provided documentation that shows the Vestas VCSS V100 2.0MW and the Vestas VCSS V110 2.0MW wind turbine generators are essentially the same machines with the exception of the rotor diameters (mechanical responses differ due to different inertias and masses of the rotors). Both models have a reactive capability of 0.98 lagging (providing VARS) and 0.96 leading (absorbing VARS) power factor. In this restudy, both Vestas wind turbine generator models were analyzed.

The findings of this restudy show that no stability problems were found during the 2015 summer peak and the 2024 summer peak conditions due to the use of the Vestas V100 2.0MW or the Vestas V110 2.0MW wind turbine generators. However, for the 2014 winter peak case, instability was seen for both Vestas wind turbine generator models for a prior outage of the Marshall to Smittyville 115kV line. For this contingency GEN-2009-040 became unstable which affected the voltage on the nearby 115kV busses. Because the condition that causes the potential instability is a prior outage condition (n-1-1 condition), the mitigation can be accomplished without the addition of transmission reinforcements. This instability can be mitigated by the reduction of the power output of both GEN-2009-040 and GEN-2011-018 when the Marshall to Smittyville 115kV line is out of service. By reducing each generation facility to 80% of maximum power, any potential instability was alleviated for the subsequent outage.

A power factor analysis was 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. Since the Vestas VCSS V100 2.0MW and the Vestas VCSS V110 2.0MW wind turbines have a limited power factor range, GEN-2009-040 will need external capacitor banks or other reactive equipment to meet the power factor requirements at the POI.

With the assumptions outlined in this report and with all the required network upgrades from the GEN-2009-040 GIA in place, GEN-2009-040 with the Vestas VCSS V100 2.0MW or the Vestas VCSS V110 2.0MW wind turbine generators should be able to interconnect reliably to the SPP transmission grid. 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.

It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, 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.

I. Introduction

GEN-2009-040 Impact Restudy is a generation interconnection study performed to study the impacts of interconnecting the project shown in Table I-1. This restudy analyzed both the Vestas VCSS V100 2.0MW and the Vestas VCSS V110 2.0MW wind turbine generators. The in-service date assumed for the generation addition is December 31, 2014.

Table I-1: Interconnection Request

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2009-040	72.0	Vestas VCSS V100 2.0MW or Vestas VCSS V110 2.0MW (36 total generators)	Tap on the Knob Hill – Smittyville 115kV line. Marshall 115kV (533349)

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

Table I-2: Prior Queued Interconnection Requests

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2003-021N	75	GE 1.5MW	Tap on the Ainsworth – Calamus 115kV line (640050)
GEN-2004-023N	75	GENROU	Columbus 115kV (640119)
GEN-2006-020N	42	Vestas 3.0MW	Bloomfield 115kV (640084)
GEN-2006-037N1	75	GE 1.5MW	Broken Bow 115kV (640089)
GEN-2006-038N005	79.5	GE 1.5MW	Broken Bow 115kV (640089)
GEN-2006-038N019	79.5	GE 1.5MW	Petersburg 115kV (640444)
GEN-2006-044N	40.5	GE 1.5MW	Petersburg 115kV (640444)
GEN-2007-011N08	81	Vestas 3.0MW	Bloomfield 115kV (640084)
GEN-2008-086N02	199.5	GE 1.5MW	Tap on the Columbus – Ft Randall 230kV line (560006)
GEN-2008-119O	60	GE 1.5MW	S1399 161kV (646399)
GEN-2008-123N	89.7	SMK203 2.3MW	Tap on the Pauline – Guide Rock 115kV (560137)
GEN-2010-041	10.5 expansion to GEN-2008-119O	GE 1.5MW	S1399 161kV (646399)
GEN-2010-051	198.9	GE 1.85MW	Tap Twin Church-Hoskins 230kV (560347)

Table I-2: Prior Queued Interconnection Requests

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2011-018	73.6	GE 1.7MW	Steele City 345kV (640426)
GEN-2011-027	120.3	GE 1.85MW	Tap Twin Church-Hoskins 230kV (560347)

The study cases also include several adjacent generating units in the Western Area Power Administration (WAPA) system at 100% of PMAX. These generating units are listed are listed in Table I-3 below:

Table I-3 – WAPA Generators

Bus #	**Bus Name**	**Pmax (MW)**	**kV**	**Unit ID**
652546	FTRDL12G	43.0	13.800	1
652546	FTRDL12G	43.0	13.800	2
652547	FTRDL34G	43.0	13.800	3
652547	FTRDL34G	43.0	13.800	4
652548	FTRDL56G	43.0	13.800	5
652548	FTRDL56G	44.0	13.800	6
652549	FTRDL78G	44.0	13.800	7
652549	FTRDL78G	44.0	13.800	8
652575	GAVINS1G	31.0	13.800	1
652576	GAVINS2G	31.0	13.800	2
652577	GAVINS3G	30.0	13.800	3
659116	SPIRI71G	52.0	13.800	1
659117	SPIRI72G	52.0	13.800	2

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 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 contingencies used in the stability analysis are listed in Table III-1.

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

It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, 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.

II. Facilities

A one-line drawing for the GEN-2009-040 generation interconnection request is shown in Figure II-1. The POI is the Westar Energy (Westar) Marshall 115kV substation.

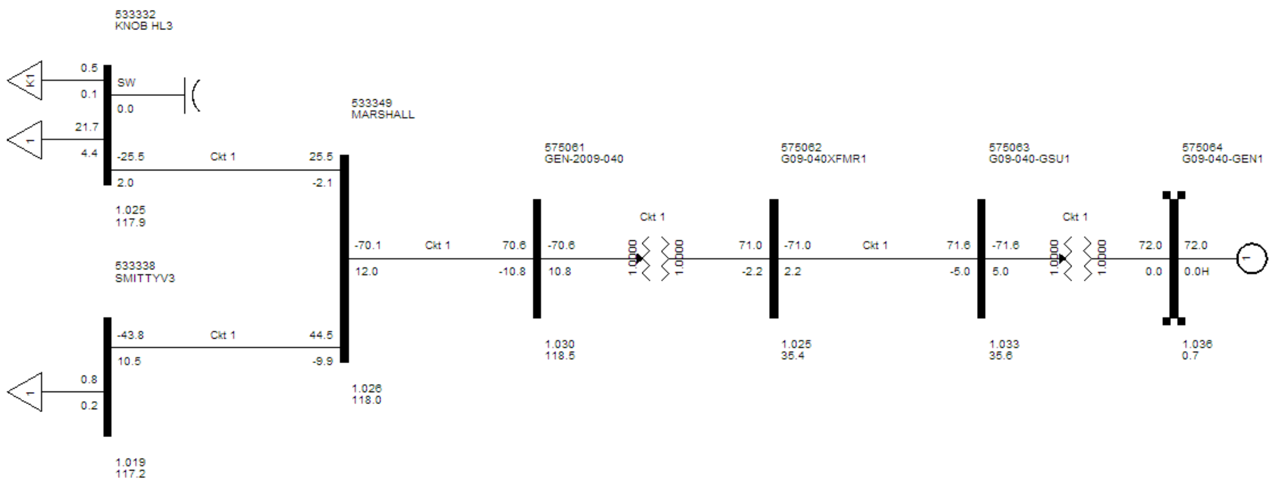

Figure II-1: GEN-2009-040 One-line Diagram

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

The 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, the 2015 summer peak, and the 2024 summer peak seasonal models. The cases are loaded with prior queued interconnection requests and network upgrades assigned to those interconnection requests. The prior queued and study generation are dispatched into the SPP footprint. Initial simulations were carried out for a no-disturbance run of twenty (20) seconds to verify the numerical stability of the model.

Disturbances

Forty-four (44) contingencies were identified for use in this study and are listed in Table III-1.

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

1. apply fault at particular location
2. continue fault for the number of cycles specified in the fault table
3. clear the fault by tripping the faulted facility

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 (5.5) 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 531, 534, 536, 540, 541, 640, 645, 650, and 652.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
1	FLT01-3PH	3 phase fault on the Marshall (533349) to Smittyville (533338) 115kV near Marshall. a. Apply fault at Marshall 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
2	FLT02-3PH	3 phase fault on the Kelly (533217) to Seneca (533337) 115kV near Kelly. a. Apply fault at Kelly 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
3	FLT03-3PH	3 phase fault on the Sheldon (640278) to BPS Sub (640088) 115kV near Sheldon. a. Apply fault at Sheldon 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
4	FLT04-3PH	3 phase fault on the Sheldon (640278) to Clatonia (640153) 115kV near Sheldon. a. Apply fault at Sheldon 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
5	FLT05-3PH	3 phase fault on the Sheldon (640278) to Crete (640111) 115kV near Sheldon. a. Apply fault at Sheldon 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
6	FLT06-3PH	3 phase fault on the Sheldon (640278) to Firth (640171) 115kV near Sheldon. a. Apply fault at Sheldon 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
7	FLT07-3PH	3 phase fault on the Folsom (650242) to Pioneers (650238) 115kV near Folsom. a. Apply fault at Folsom 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
8	FLT08-3PH	3 phase fault on the Folsom (650242) to Rokeby (650290) 115kV near Folsom. a. Apply fault at Folsom 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
9	FLT09-3PH	3 phase fault on the Beatrice (640076) to BPS Sub (640088) 115kV near Beatrice, ckt2. a. Apply fault at Beatrice 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
10	FLT10-3PH	3 phase fault on the Beatrice (640076) to Harbine (640208) 115kV near Beatrice. a. Apply fault at Beatrice 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
11	FLT11-3PH	3 phase fault on the Beatrice (640076) to Steiner (640361) 115kV near Beatrice. a. Apply fault at Beatrice 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
12	FLT12-3PH	3 phase fault on the Humboldt (640235) to Steiner (640361) 115kV near Humboldt. a. Apply fault at Humboldt 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
13	FLT13-3PH	3 phase fault on the Harbine (640208) to Fairbury (640169) 115kV near Harbine. a. Apply fault at Harbine 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
14	FLT14-3PH	3 phase fault on the Steele City (640426) to Harbine (640208) 115kV near Harbine. a. Apply fault at Harbine 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
15	FLT15-3PH	3 phase fault on the Steele City (640426) to Knob Hill (533332) 115kV near Harbine. a. Apply fault at Harbine 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
16	FLT16-3PH	3 phase fault on the Knob Hill (533332) to Green Leaf (539665) 115kV near Knob Hill. a. Apply fault at Knob Hill 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
17	FLT17-3PH	3 phase fault on the Knob Hill (533332) to Marshall (533349) 115kV near Knob Hill. a. Apply fault at Knob Hill 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
18	FLT18-3PH	3 phase fault on the Kelly (533217) to King Hill (533331) 115kV near Kelly. a. Apply fault at Kelly 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
19	FLT19-3PH	3 phase fault on the Clifton (539656) to Concordia (539657) 115kV near Clifton. a. Apply fault at Clifton 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
20	FLT20-3PH	3 phase fault on the Concordia (539657) to Beloit (539650) 115kV near Concordia. a. Apply fault at Concordia 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
21	FLT21-3PH	3 phase fault on the Concordia (539657) to Jewell (539669) 115kV near Concordia. a. Apply fault at Concordia 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
22	FLT22-3PH	3 phase fault on the Moore (640277) to Cooper (640139) 345kV line, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
23	FLT23-3PH	3 phase fault on the Moore (640277) to McCool (640271) 345kV line, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
24	FLT24-3PH	3 phase fault on the Moore (640277) to Pauline (640312) 345kV line, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
25	FLT25-3PH	3 phase fault on the Moore (640277) to NW68Holdrg (650114) 345kV line, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
26	FLT26-3PH	3 phase fault on the Moore (640277) to 103&Rokeby (650189) 345kV line, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
27	FLT27-3PH	3 phase fault on the Hebron North (640218) to Fairbury (640169) 115kV near Hebron North. a. Apply fault at Hebron North 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
28	FLT28-3PH	3 phase fault on the Hebron North (640218) to Carlton Jct (640105) 115kV near Hebron North. a. Apply fault at Hebron North 115kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
29	FLT29-3PH	3 phase fault on the Elm Creek (539639) to Concordia (539658) 230kV near Elm Creek. a. Apply fault at Elm Creek 230kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.
30	FLT30-3PH	3 phase fault on the Elm Creek (539639) to N. Manhattan (532865) 230kV near Elm Creek. a. Apply fault at Elm Creek 230kV bus. b. Clear fault after 6.5 cycles by tripping faulted line.

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
31	FLT31-3PH	3 phase fault on the JEC N (532766) to Hoyt (532765) 345kV line, near JEC N. a. Apply fault at the JEC N 345kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
32	FLT32-3PH	3 phase fault on the JEC N (532766) to Morris (532770) 345kV line, near JEC N. a. Apply fault at the JEC N 345kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
33	FLT33-3PH (2014WP & 2015SP only)	3 phase fault on the JEC N (532766) to Summit (532773) 345kV line, near JEC N. a. Apply fault at the JEC N 345kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
34	FLT34-3PH	3 phase fault on the Hoyt (533163) 115kV to Hoyt (532765) 345kV/(532804) 14.4kV transformer at the 115kV bus, ckt1. a. Apply fault at the Hoyt 115kV bus. b. Clear fault after 5.5 cycles by tripping the transformer
35	FLT35-3PH	3 phase fault on the Moore (640277) 345kV to Sheldon (640278) 115kV/(640280) 13.8kV transformer at the 345kV bus, ckt1. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5.5 cycles by tripping the transformer
36	FLT36-3PH	3 phase fault on the Humboldt (640235) 115kV to Humboldt (640234) 161kV/(643087) 13.8kV transformer at the 115kV bus, ckt1. a. Apply fault at the Humboldt 115kV bus. b. Clear fault after 5.5 cycles by tripping the transformer
37	FLT37-3PH	3 phase fault on the Kelly (533217) 115kV to Kelly (532913) 161kV/(532942) 13.8kV transformer at the 115kV bus, ckt1. a. Apply fault at the Kelly 115kV bus. b. Clear fault after 5.5 cycles by tripping the transformer
38	FLT38-3PH	3 phase fault on the Concordia (539657) 115kV to Concordia (539658) 230kV/(539904) 13.8kV transformer at the 115kV bus, ckt1. a. Apply fault at the Concordia 115kV bus. b. Clear fault after 5.5 cycles by tripping the transformer
39	FLT39-3PH (2024SP only)	3 phase fault on the Elm Creek (539639)230kV to Elm Creek (539805) 345kV/(539806) 13.8kV transformer at the 345kV bus, ckt1. a. Apply fault at the Pauline 345kV bus. b. Clear fault after 5.5 cycles by tripping the transformer
40	FLT40-3PH (2024SP only)	3 phase fault on the JEC N (532766) to Cleary (532767) 345kV line, near JEC N. a. Apply fault at the JEC N 345kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
41	FLT41-3PH	**Prior outage of the Knob Hill (533332) to Greenleaf (539665) 115kV line.** 3 phase fault on the Steele City (640426) to Harbine (640208) 115kV line, near Steele City. a. Apply fault at Steele City 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line
42	FLT42-3PH	**Prior outage of the Marshall (533349) to Smittyville (533338) 115kV line.** 3 phase fault on the Steele City (640426) to Harbine (640208) 115kV line, near Steele City. a. Apply fault at Steele City 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line

Table III-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
43	FLT43-3PH	**Prior outage of the Harbine (640208) to Fairbury (640169) 115kV line.** 3 phase fault on the Steele City (640426) to Knob Hill (533332) 115kV line, near Steele City. a. Apply fault at Steele City 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line
44	FLT44-3PH	**Prior outage of the Harbine (640208) to Beatrice (640076) 115kV line.** 3 phase fault on the Steele City (640426) to Knob Hill (533332) 115kV line, near Steele City. a. Apply fault at Steele City 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line

Results

A separate stability analysis was performed for the Vestas VCSS V100 2.0MW and for the Vestas VCSS V110 2.0MW wind turbine generators. The results of each stability analysis are summarized in Table III-2. For the 2014 summer and the 2024 summer conditions with all network upgrades in service, GEN-2009-040 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.

However, for the 2014 winter conditions both the Vestas V100 and the Vestas V110 were unstable for a prior outage of the Marshall to Smittyvile 115kV line with a subsequent outage of the Steele City to Harbine 115kV line (contingency FLT42-3PH). GEN-2009-040 became unstable which affected the voltage on the nearby 115kV busses (see Figure III-1 and Figure III-2). Because the condition that caused the potential instability is a prior outage condition (n-1-1 condition), the mitigation can be accomplished without the addition of transmission reinforcements. This instability can be mitigated by the reduction of the power output of both GEN-2009-040 and GEN-2011-018 when the Marshall to Smittyville 115kV line is out of service. By reducing each generation facility to 80% of maximum power, any potential instability was alleviated for the subsequent outage (see Figure III-3 and Figure III-4).

Table III-2: Stability Analysis Results

Contingency Number and Name		Vestas VCSS V100 2.0MW			Vestas VCSS V110 2.0MW		
		2014WP	2015SP	2024SP	2014WP	2015SP	2024SP
1	FLT_01_MARSHALL_SMITTYVILLE_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
2	FLT_02_KELLY_SENECA_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
3	FLT_03_SHELDON_BPSSUB_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
4	FLT_04_SHELDON_CLATONA_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
5	FLT_05_SHELDON_CRETE_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
6	FLT_06_SHELDON_FIRTH_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
7	FLT_07_FOLSOM_PIONEERS_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
8	FLT_08_FOLSOM_ROKEBY_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
9	FLT_09_BEATRICE_BPSSUB_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
10	FLT_10_BEATRICE_HARBINE_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
11	FLT_11_BEATRICE_STEINER_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
12	FLT_12_HUMBOLDT_STEINER_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
13	FLT_13_HARBINE_FAIRBURY_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
14	FLT_14_STEELECITY_HARBINE_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
15	FLT_15_STEELECITY_KNOBHILL_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
16	FLT_16_KNOBHILL_GREENLEAF_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
17	FLT_17_KNOBHILL_MARSHALL_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
18	FLT_18_KELLY_KINGHILL_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
19	FLT_19_CLIFTON_CONCORDIA_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
20	FLT_20_CONCORDIA_BELOIT_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
21	FLT_21_CONCORDIA_JEWELL_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
22	FLT_22_MOORE_COOPER_345kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
23	FLT_23_MOORE_McCOOL_345kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
24	FLT_24_MOORE_PAULINE_345kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
25	FLT_25_MOORE_NW68HOLDRG_345kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
26	FLT_26_MOORE_103_ROKEBY_345kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
27	FLT_27_HEBRONNORTH_FAIRBURY_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
28	FLT_28_HEBRONNORTH_CARLTONJCT_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
29	FLT_29_ELMCREEK_CONCORDIA_230_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
30	FLT_30_ELMCREEK_NMANHATTAN_230kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable

Table III-2: Stability Analysis Results

Contingency Number and Name		Vestas VCSS V100 2.0MW			Vestas VCSS V110 2.0MW		
		2014WP	2015SP	2024SP	2014WP	2015SP	2024SP
31	FLT_31_JECN_HOYT_345kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
32	FLT_32_JECN_MORRIS_345kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
33	FLT_33_JECN_SUMMIT_345kV_3PH	Stable	Stable	NA	Stable	Stable	NA
34	FLT_34_HOYT_HOYT_115_345kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
35	FLT_35_MOORE_SHELDON_345_115kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
36	FLT_36_HUMBLDT_HUMBOLDT_115_161kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
37	FLT_37_KELLY_KELLY_115_161kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
38	FLT_38_CONCORDIA_CONCORDIA_115_230kV_3PH	Stable	Stable	Stable	Stable	Stable	Stable
39	FLT_39_ELMCREEK_ELMCREEK_230_345kV_3PH	NA	NA	Stable	NA	NA	Stable
40	FLT_40_JECN_CLEARY_345kV_3PH	NA	NA	Stable	NA	NA	Stable
41	FLT_41_3PH (Prior outage Knob Hill – Greenleaf 115kV; outage at Steele City – Harbine 115kV)	Stable	Stable	Stable	Stable	Stable	Stable
42	FLT_42_3PH (Prior outage Marshall – Smittyville 115kV; outage at Steele City – Harbine 115kV)	Stable[1]	Stable	Stable	Stable[1]	Stable	Stable
43	FLT_43_3PH (Prior outage Harbine – Fairbury 115kV; outage at Steele City – Knob Hill 115kV)	Stable	Stable	Stable	Stable	Stable	Stable
44	FLT_44_3PH (Prior outage Harbine – Beatrice 115kV; outage at Steele City – Knob Hill 115kV)	Stable	Stable	Stable	Stable	Stable	Stable

[1]FLT_42_3PH required power at GEN-2009-040 and GEN-2011-018 to be reduced to 80% maximum for stability.

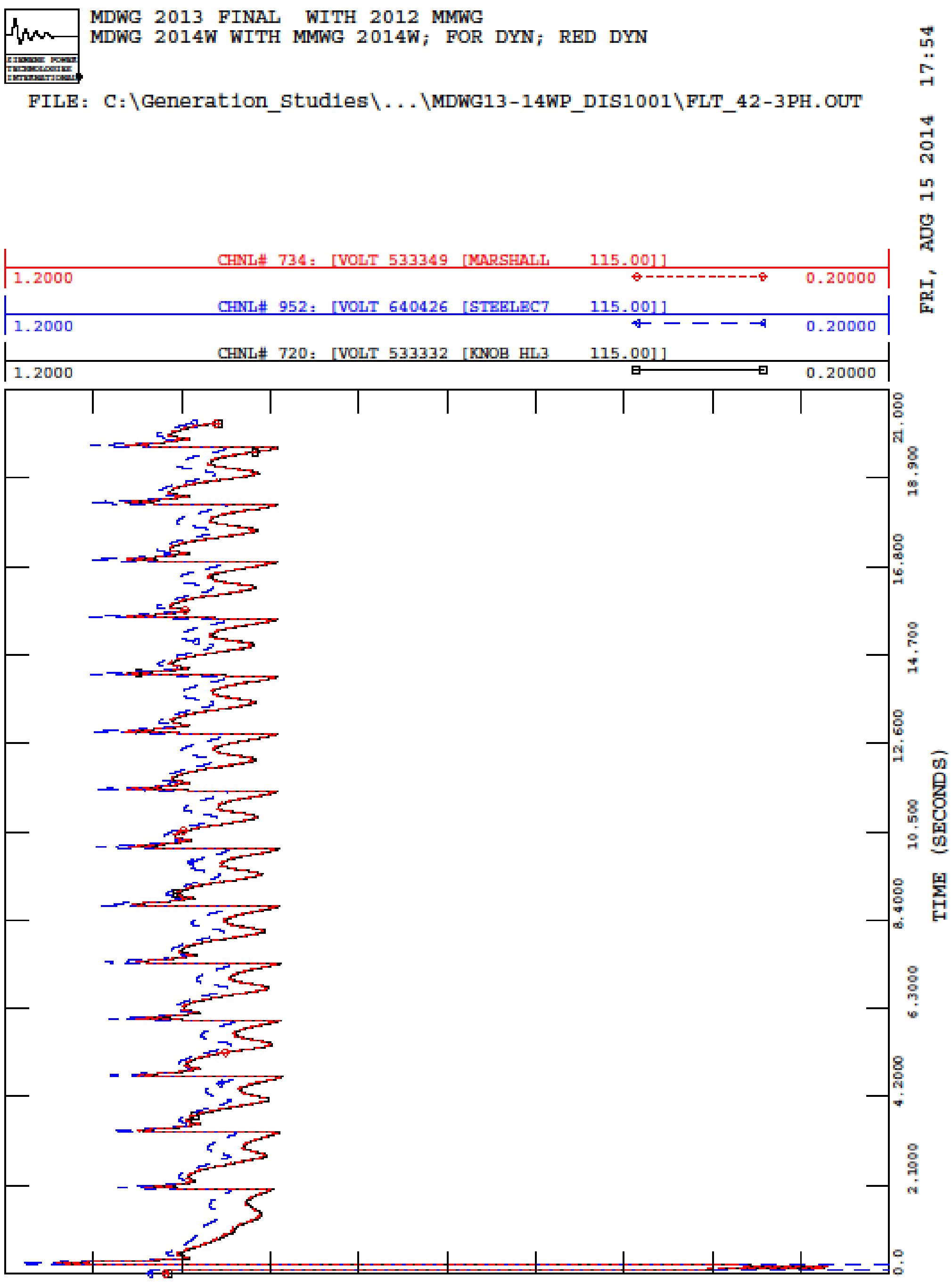

Figure III-1: Plot of bus voltages for the 2014 Winter Peak case for FLT42-3PH contingency

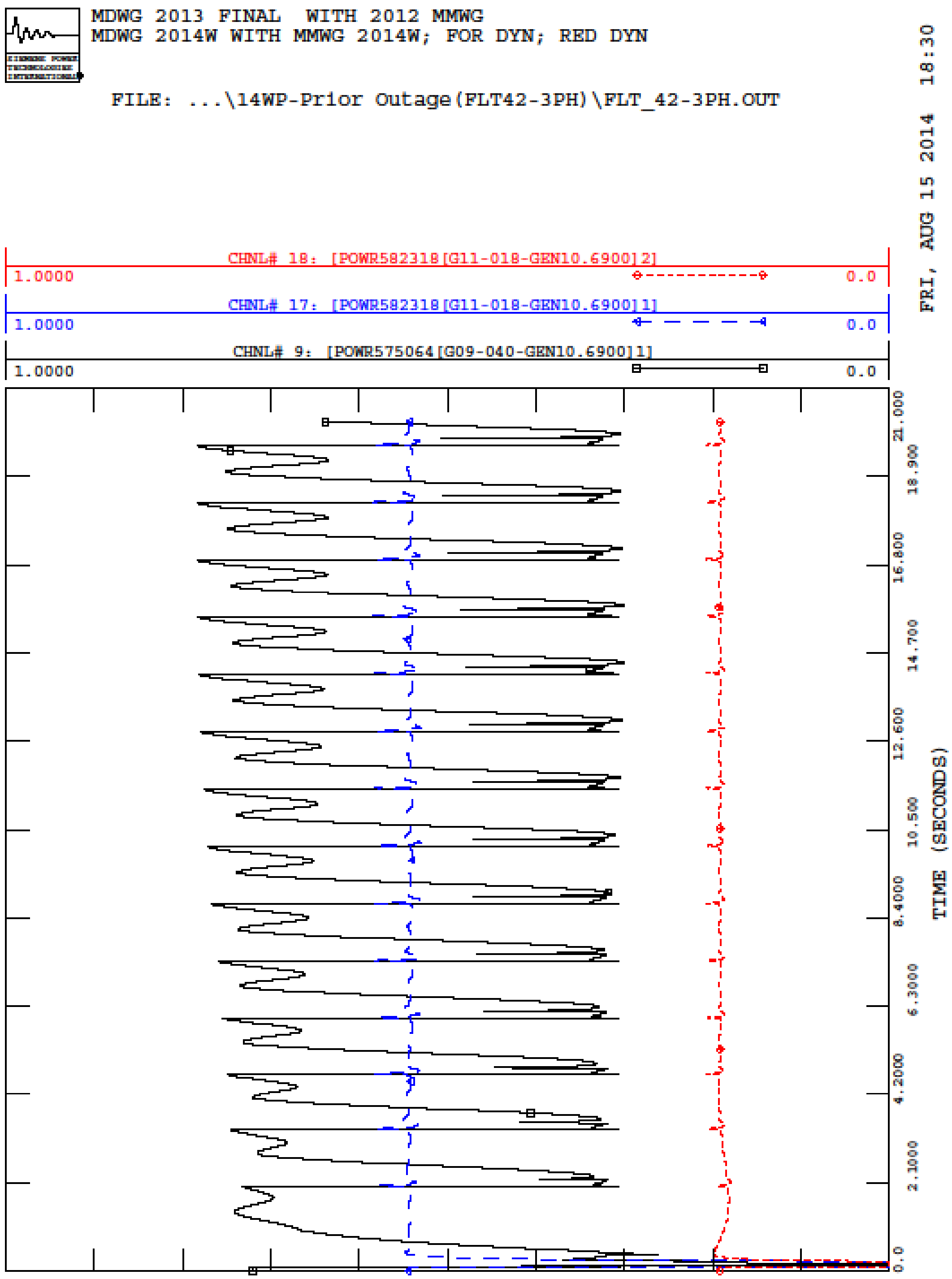

Figure III-2: Plot of real power response of GEN-2009-040 and GEN-2011-018 for the 2014 Winter Peak case for FLT42-3PH contingency

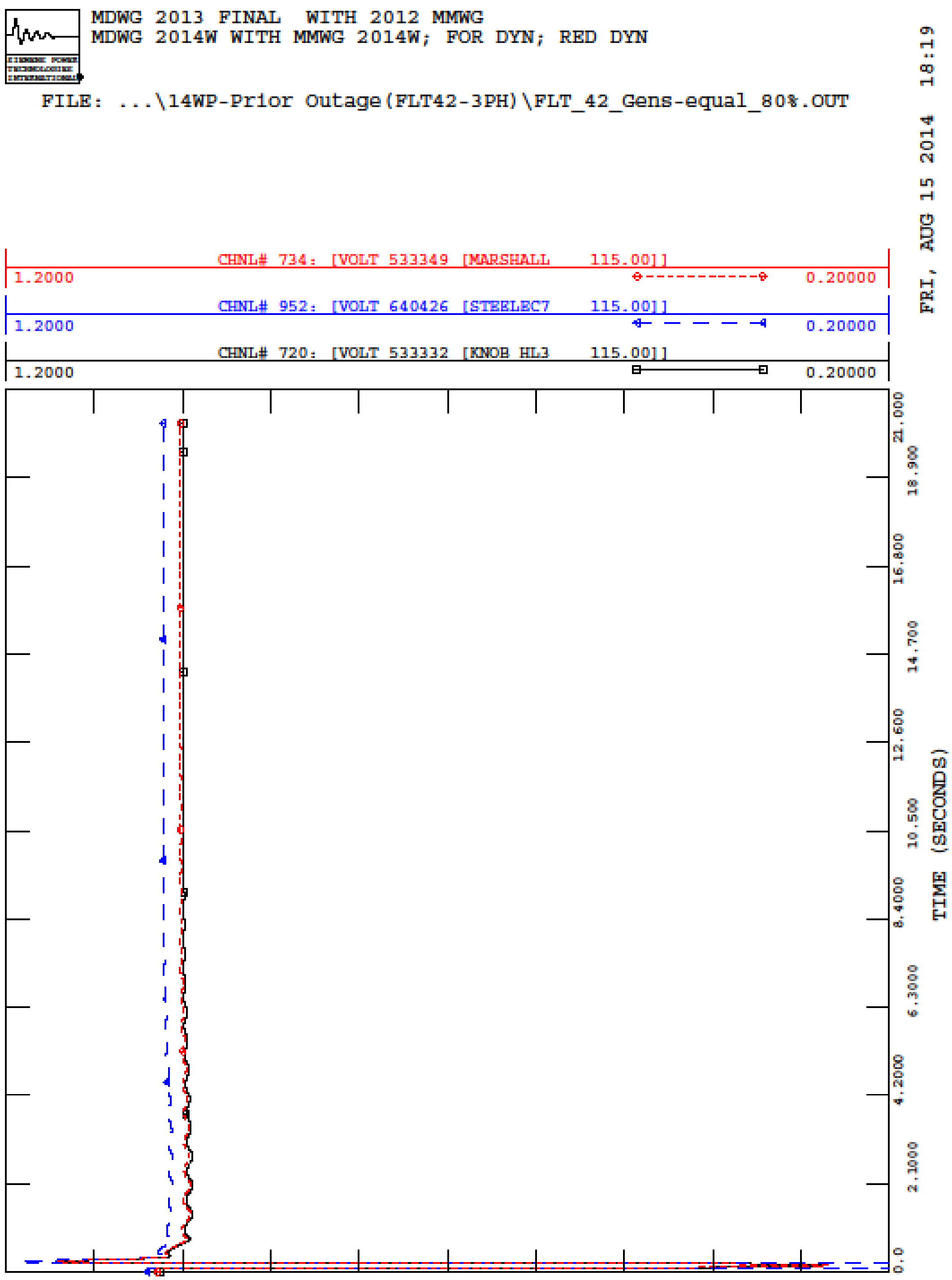

Figure III-3: Plot of bus voltages for the 2014 Winter Peak case for FLT42-3PH contingency with mitigation

(fault near GEN-2009-040 Tap) – 2015 Summer

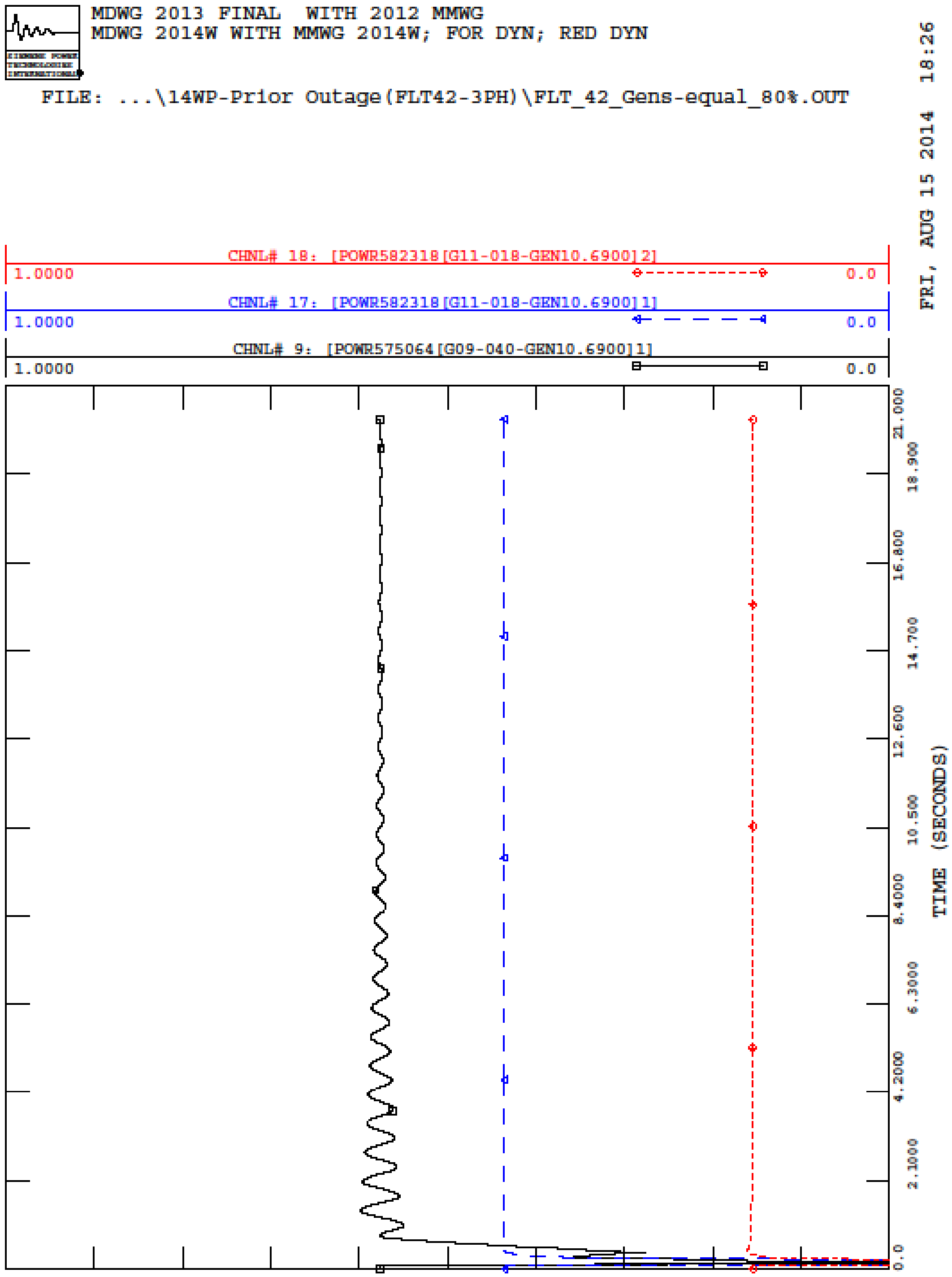

Figure III-4: Plot of real power response of GEN-2009-040 and GEN-2011-018 for the 2014 Winter Peak case for FLT42-3PH contingency with mitigation

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.

Contingency 1 in Table III-2 simulated the LVRT contingencies. GEN-2009-040 met the LVRT requirements by staying on line and the transmission system remaining stable.

IV. Power Factor Analysis

A subset of the stability faults was used as power flow contingencies to analyze the power factor requirements for the wind farm to maintain scheduled voltage at the POI. The voltage schedule was set equal to the voltage at the POI before the project is added with a minimum being 1.00 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.

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 IV-1. The detailed power factor analysis tables are in Appendix B. Since the Vestas VCSS V100 2.0MW and the Vestas VCSS V110 2.0MW wind turbines have limited reactive capability (0.98 lagging and 0.96 leading), the generation facility will require external capacitor banks or other reactive equipment to meet the power factor requirement at the POI.

Table IV-1: Power Factor Requirements [a]

Request	Size (MW)	Generator Model	Point of Interconnection	Final PF Requirement at POI	
				Lagging [b]	Leading [c]
GEN-2009-040	72.0	Vestas VCSS V100 2.0MW or Vestas VCSS V110 2.0MW	Tap on the Knob Hill – Smittyville 115kV line. Marshall 115kV (533349)	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. The most lagging power factor determined through analysis was 1.00.

e. The most leading power factor determined through analysis was 0.97.

V. Conclusion

The SPP GEN-2009-040 Impact Restudy evaluated the impact of interconnecting the project shown below.

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2009-040	72.0	Vestas VCSS V100 2.0MW or Vestas VCSS V110 2.0MW (36 total generators)	Tap on the Knob Hill – Smittyville 115kV line. Marshall 115kV (533349)

With all Base Case Network Upgrades in service, previously assigned Network Upgrades in service, and any required capacitor banks in service, the GEN-2009-040 project was found to remain on line, and the transmission system was found to remain stable for the 2014 summer and the 2024 summer conditions. All generators in the monitored areas remained stable for all of the modeled disturbances.

However, for the 2014 winter peak case, instability was seen for both Vestas wind turbine generator models for a prior outage of the Marshall to Smittyville 115kV line. Because the condition that causes the potential instability is a prior outage condition (n-1-1 condition), the mitigation can be accomplished without the addition of transmission reinforcements. This instability can be mitigated by the reduction of the power output of both GEN-2009-040 and GEN-2011-018 when the Marshall to Smittyville 115kV line is out of service.

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.

A power factor analysis was performed for this modification request. 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. Since the Vestas VCSS V100 2.0MW and the Vestas VCSS V110 2.0MW wind turbine generators have limited reactive capability (0.98 lagging and 0.96 leading), the generation facility will require external capacitor banks or other reactive equipment to meet the power factor requirement at the POI.

Any changes to the assumptions made in this study, for example, one or more of the previously queued requests withdraw, may require a restudy 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

(Plots available on request)

APPENDIX B

POWER FACTOR ANALYSIS

GEN-2009-040 POI - MARSHALL 115.00kV (533349)	2014 Winter Peak POI Voltage = 1.022 pu				2015 Summer Peak POI Voltage = 1.024 pu				2024 Summer Peak POI Voltage = 1.034 pu			
	MW	Mvar	PF		MW	Mvar	PF		MW	Mvar	PF	
FLT_00_NoFault	72	-16.324	0.975	LEAD	72	-15.867	0.977	LEAD	72	-16.480	0.975	LEAD
FLT_01_MARSHALL_SMITTYVILLE_115kV	72	-11.024	0.988	LEAD	72	-8.990	0.992	LEAD	72	-15.274	0.978	LEAD
FLT_02_KELLY_SENECA_115kV	72	-3.982[2]	0.998	LEAD	72	-11.013	0.989	LEAD	72	-15.129	0.979	LEAD
FLT_03_SHELDON_BPSSUB_115kV	72	-15.213	0.978	LEAD	72	-14.604	0.980	LEAD	72	-15.605	0.977	LEAD
FLT_04_SHELDON_CLATONA_115kV	72	-15.806	0.977	LEAD	72	-15.248	0.978	LEAD	72	-16.093	0.976	LEAD
FLT_05_SHELDON_CRETE_115kV	72	-15.813	0.977	LEAD	72	-15.564	0.977	LEAD	72	-16.263	0.975	LEAD
FLT_06_SHELDON_FIRTH_115kV	72	-15.209	0.978	LEAD	72	-14.809	0.979	LEAD	72	-15.164	0.979	LEAD
FLT_07_FOLSOM_PIONEERS_115kV	72	-16.196	0.976	LEAD	72	-15.678	0.977	LEAD	72	-16.314	0.975	LEAD
FLT_08_FOLSOM_ROKEBY_115kV	72	-16.293	0.975	LEAD	72	-15.868	0.977	LEAD	72	-16.488	0.975	LEAD
FLT_09_BEATRICE_BPSSUB_115kV	72	-16.078	0.976	LEAD	72	-15.674	0.977	LEAD	72	-16.244	0.975	LEAD
FLT_10_BEATRICE_HARBINE_115kV	72	-15.465	0.978	LEAD	72	-13.750	0.982	LEAD	72	-15.477	0.978	LEAD
FLT_11_BEATRICE_STEINER_115kV	72	-16.399	0.975	LEAD	72	-15.952	0.976	LEAD	72	-16.614	0.974	LEAD
FLT_12_HUMBOLDT_STEINER_115kV	72	-16.446	0.975	LEAD	72	-15.983	0.976	LEAD	72	-16.634	0.974	LEAD
FLT_13_HARBINE_FAIRBURY_115kV	72	-16.910	0.974	LEAD	72	-17.397	0.972	LEAD	72	-17.115	0.973	LEAD
FLT_14_STEELECITY_HARBINE_115kV	72	-10.467	0.990	LEAD	72	-11.771	0.987	LEAD	72	-13.403	0.983	LEAD
FLT_15_STEELECITY_KNOBHILL_115kV	72	-5.455	0.997	LEAD	72	-8.769	0.993	LEAD	72	-14.415	0.981	LEAD
FLT_16_KNOBHILL_GREENLEAF_115kV	72	-18.352[1]	0.969	LEAD	72	-12.704	0.985	LEAD	72	-14.924	0.979	LEAD
FLT_17_KNOBHILL_MARSHALL_115kV	72	-15.287	0.978	LEAD	72	-16.969	0.973	LEAD	72	-11.983	0.986	LEAD
FLT_18_KELLY_KINGHILL_115kV	72	-16.059	0.976	LEAD	72	-15.582	0.977	LEAD	72	-16.827	0.974	LEAD
FLT_19_CLIFTON_CONCORDIA_115kV	72	-16.697	0.974	LEAD	72	-14.888	0.979	LEAD	72	-14.934	0.979	LEAD
FLT_20_CONCORDIA_BELOIT_115kV	72	-15.761	0.977	LEAD	72	-15.847	0.977	LEAD	72	-16.424	0.975	LEAD
FLT_21_CONCORDIA_JEWELL_115kV	72	-15.477	0.978	LEAD	72	-15.388	0.978	LEAD	72	-16.186	0.976	LEAD
FLT_22_MOORE_COOPER_345kV	72	-16.377	0.975	LEAD	72	-15.950	0.976	LEAD	72	-16.748	0.974	LEAD
FLT_23_MOORE_McCOOL_345kV	72	-16.132	0.976	LEAD	72	-15.859	0.977	LEAD	72	-16.480	0.975	LEAD
FLT_24_MOORE_PAULINE_345kV	72	-15.898	0.976	LEAD	72	-15.708	0.977	LEAD	72	-16.338	0.975	LEAD

GEN-2009-040 POI - MARSHALL 115.00kV (533349)	2014 Winter Peak POI Voltage = 1.022 pu				2015 Summer Peak POI Voltage = 1.024 pu				2024 Summer Peak POI Voltage = 1.034 pu			
	MW	Mvar	PF		MW	Mvar	PF		MW	Mvar	PF	
FLT_25_MOORE_NW68HOLDRG_345kV	72	-16.229	0.976	LEAD	72	-15.822	0.977	LEAD	72	-16.434	0.975	LEAD
FLT_26_MOORE_103ROKEBY_345kV	72	-16.211	0.976	LEAD	72	-15.834	0.977	LEAD	72	-16.437	0.975	LEAD
FLT_27_HEBRONNORTH_FAIRBURY_115kV	72	-15.890	0.977	LEAD	72	-15.720	0.977	LEAD	72	-15.782	0.977	LEAD
FLT_28_HEBRONNORTH_CARLTONJCT_115kV	72	-16.063	0.976	LEAD	72	-16.524	0.975	LEAD	72	-17.105	0.973	LEAD
FLT_29_ELMCREEK_CONCORDIA_230_115kV	72	-9.796	0.991	LEAD	72	-11.361	0.988	LEAD	72	-11.564	0.987	LEAD
FLT_30_ELMCREEK_NMANHATTAN_230kV	72	-17.855	0.971	LEAD	72	-16.851	0.974	LEAD	72	-16.934	0.973	LEAD
FLT_31_JECN_HOYT_345kV	72	-14.567	0.980	LEAD	72	-14.739	0.980	LEAD	72	-15.109	0.979	LEAD
FLT_32_JECN_MORRIS_345kV	72	-15.203	0.978	LEAD	72	-15.401	0.978	LEAD	72	-16.079	0.976	LEAD
FLT_33_JECN_SUMMIT_345kV	72	-15.206	0.978	LEAD	72	-15.245	0.978	LEAD	NA[3]	NA[3]	NA[3]	NA[3]
FLT_34_HOYT_HOYT_115_345kV	72	-14.977	0.979	LEAD	72	-12.161	0.986	LEAD	72	-12.008	0.986	LEAD
FLT_35_MOORE_SHELDON_345_115kV	72	-16.621	0.974	LEAD	72	-16.094	0.976	LEAD	72	-16.557	0.975	LEAD
FLT_36_HUMBLDT_HUMBOLDT_115_161kV	72	-16.785	0.974	LEAD	72	-16.240	0.975	LEAD	72	-16.901	0.974	LEAD
FLT_37_KELLY_KELLY_115_161kV	72	-7.052	0.995	LEAD	72	-8.019	0.994	LEAD	72	-10.018	0.990	LEAD
FLT_38_CONCORDIA_CONCORDIA_115_230kV	72	-9.803	0.991	LEAD	72	-11.366	0.988	LEAD	72	-11.568	0.987	LEAD
FLT_39_ELMCREEK_ELMCREEK_230_345kV	NA[3]	NA[3]	NA[3]	NA[3]	NA[3]	NA[3]	NA[3]	NA[3]	72	-15.473	0.978	LEAD
FLT_40_JECN_CLEARY_345kV	NA[3]	NA[3]	NA[3]	NA[3]	NA[3]	NA[3]	NA[3]	NA[3]	72	-15.101	0.979	LEAD

NOTE:

1. Lowest leading (absorbing vars) power factor requirement for all three seasons
2. Lowest lagging (supplying vars) power factor requirement for all three seasons
3. NA—Contingency not applicable to this season's case

APPENDIX C

PROJECT MODELS

(Power flow and dynamic models available on request)