Impact Re-Study
For
Generation Interconnection
Request
GEN-2006-044

SPP Generation Interconnection

(#GEN-2006-044)

December 2010

Executive Summary

<OMITTED TEXT> (Customer) has requested an Impact Study for the purpose of interconnecting 370 MW of wind generation within the control area of Southwestern Public Service (SPS) located in Hansford County, Texas. The proposed point of interconnection is the Hitchland 345kV substation owned by Southwestern Public Service (SPS).

The wind farm was studied with DeWind 2.0Mw wind turbines with +/-90% power factor capability. With these turbines, the Customer will not be required to install capacitors within their interconnection facilities.

A stability study was conducted for this generation interconnection request. The stability study showed that due to large amount of prior queued generation on the Potter – Finney 345kV line and in the Texas Panhandle on the 115kV and 230kV system, the interconnection could not be accommodated without the addition of a 2nd Finney – Holcomb 345kV line.

The maximum amount of generation that can be accommodated without the addition of the 2nd Finney – Holcomb 345kV line is 250MW. A total of 370MW can be accommodated if the Finney – Holcomb 345kV line outage is mitigated by the addition of a 2nd 345kV line from Finney – Holcomb. This assumes that the Hitchland 345/230kV upgrades are in service. The Hitchland 345/230kV upgrades are scheduled to be complete by
2011 and include the following facilities

- Hitchland 345/230kV autotransformer
- Hitchland 230/115kV autotransformer
- Hitchland – Moore County 230kV transmission line
- Hitchland – Perryton 230kV transmission line

The Impact Study has also determined that with the DeWind turbines provided with the manufacturer's low voltage ride through package and the 2nd 345kVline from Finney – Holcomb in service, GEN-2006-044 will meet FERC Order #661A low voltage requirements for low voltage ride through.

POWER SYSTEMS DIVISION
GRID SYSTEMS CONSULTING

INTERONNECTION IMPACT RE-STUDY FOR GEN-2006-044

DRAFT REPORT

REPORT NO.: E-00005650-R0
Issued On: December 15, 2010

Prepared for:
Southwest Power Pool, Inc.

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

Legal Notice

Southwest Power Pool, Inc.	**No.** E-00005650-R0	
Interconnection Impact Re-study for GEN-2006-044	Date: 12/15/2010	# Pages 37

Author(s): B Kondala Rao

Reviewed by: Seshadri Subramanian

Approved by: Willie Wong

Executive Summary

Southwest Power Pool, Inc. (SPP) has commissioned ABB Inc. to perform a generator interconnection impact study for a proposed 370 MW wind farm with a Point of Interconnection (POI) at Hitchland 345 kV Switching Station, in Hansford County, Texas, owned by Southwestern Public Service (d/b/a XEL Energy). This proposed generator interconnection, with Queue # GEN-2006-044 comprises of DeWind's 2.0MW wind turbines.

Request	Size	Wind Turbine Model	Point of Interconnection	County
GEN-2006-044	370 MW	DeWind 2.0MW	Hitchland 345kV (bus #523097)	Hansford County, Texas

The main objectives of this study are:

1) To determine the need for added reactive power compensation, if any, to facilitate the interconnection of the proposed wind farm
2) To determine the impact of proposed GEN-2006-044 project on the stability of SPP transmission systems and nearby generating stations.
3) To validate the compliance with FERC LVRT requirement for the subject wind farm interconnection.

To achieve these objectives the following analyses were performed on the 2010-2011 Summer Peak and Winter Peak system conditions with GEN-2006-044 in-service;

- Contingency Analysis (power flow)
- Power factor analysis for selected contingencies.
- Transient stability analysis for several local and regional contingencies.
- LVRT performance evaluation for selected contingencies near the POI.

A steady state contingency analysis was performed prior to determining the power factor at the wind farm POI. This first step is expected to highlight any serious steady state voltage issues (e.g. voltage collapse), especially in the post-project conditions that may require mitigation.

A summary of the study findings is given below:

Contingency Analysis:

All tested contingencies were found to result in acceptable voltages at the wind farm POI. However, the outage of Finney – Holcomb 345 kV line showed non-convergence of power flow for summer and well as winter peak load conditions (with the GEN-2006-044 in service). The power flow non-convergence was identified as the result of a lack of reactive power support in Hitchland vicinity. Two options were tested to mitigate the incremental project impact:

i) Reduce the output from GEN-2006-044 – The steady state issues were found to be addressed with GEN-2006-044 output reduced to 250 MW.
ii) Add a 2nd Finney – Holcomb 345 kV line – Addition of this line ensured the injection of the full output (370 MW) from GEN-2006-044 addressed the steady state issues.

Power factor analysis:

The power factor analysis was performed with mitigating measure(s) (i.e. transmission upgrades or reduction in wind farm output) in place where found necessary.

The power factor analysis showed the wind farm has sufficient reactive power capability to maintain a power factor of at least 0.95 at the POI with acceptable POI voltage.

Stability Analysis

All the tested disturbances were found to be stable except those involving the outage of existing Finney – Holcomb 345 kV line; the faults involving the loss of the above facility (FLT_81_3PH and FLT_82_1PH) showed out of step conditions for the winter peak load conditions. Two mitigation options were tested, - i) addition of a 2nd 345 kV line between Finney and Holcomb substations; ii) operate the wind farm at a reduced output of 250 MW. The voltage recovery was acceptable and no specific damping issues were identified due to the proposed wind farm interconnection, considering the above two mitigation options.

FERC Order 661A Compliance

Selected faults were simulated at the Point of Interconnection (POI) of the proposed GEN-2006-044 wind farm to determine the compliance with FERC 661 – A; post-transition period LVRT standard. The results indicated that the proposed project met the FERC LVRT requirement for wind farm interconnection.

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

Rev #	Revision Desc.	Date	Authored by	Reviewed by	Approved by
0	Draft Report	12/15/2010	B Kondalarao	Subramanian, S	Wong, W
DISTRIBUTION: Juliano Freitas– Southwest Power Pool, Inc.					

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1 INTRODUCTION

Southwest Power Pool, Inc. (SPP) commissioned ABB Inc. to perform a generator interconnection study for a 370 MW wind farm in Hansford County, Texas. This wind farm will be interconnected into the Hitchland 345kV switching station. The substation is owned by Southwestern Public Service (d/b/a XEL Energy). Figure 1-1 shows the POI of the proposed generation project on a Geographical Transmission Map.

This study evaluated the impact of adding the GEN-2006-044 project on the SPP Transmission System. The scope of this study was limited to the power factor evaluation and transient stability analysis.

The main objectives of this study were

1) To determine the need of reactive power compensation, if any, for the proposed wind farm
2) To determine the impact of the proposed Project on the stability of SPP transmission system and nearby generating stations.
3) To validate the compliance with FERC LVRT requirement for the wind farm.

To achieve these objectives the following analyses were performed on the Summer Peak and Winter Peak system.

- Power factor analysis for selected contingencies.
- Transient stability analysis for various local and regional contingencies.
- LVRT performance under selected contingencies near the POI.

The study was performed on 2010-2011 Summer Peak and winter peak cases, provided by SPP. This report documents the methods, analysis and results of the system impact study.

Table 1-1: GEN-2006-044 Project

Project	Size (MW)	Wind Turbine Type	Point of Interconnection	Location
GEN-2006-044	370	DeWind 2.0MW	Hitchland 345kV (bus #523097)	Hansford County, Texas

1.1 REPORT ORGANIZATION

This report is organized as follows:

Section 2: Description of project
Section 3: Study methodology
Section 4: Model Development
Section 5: Contingency Analysis
Section 6: Power Factor Analysis Results
Section 7: Stability Analysis Results
Section 8: Conclusions

The detailed study results are included in separate Appendices.

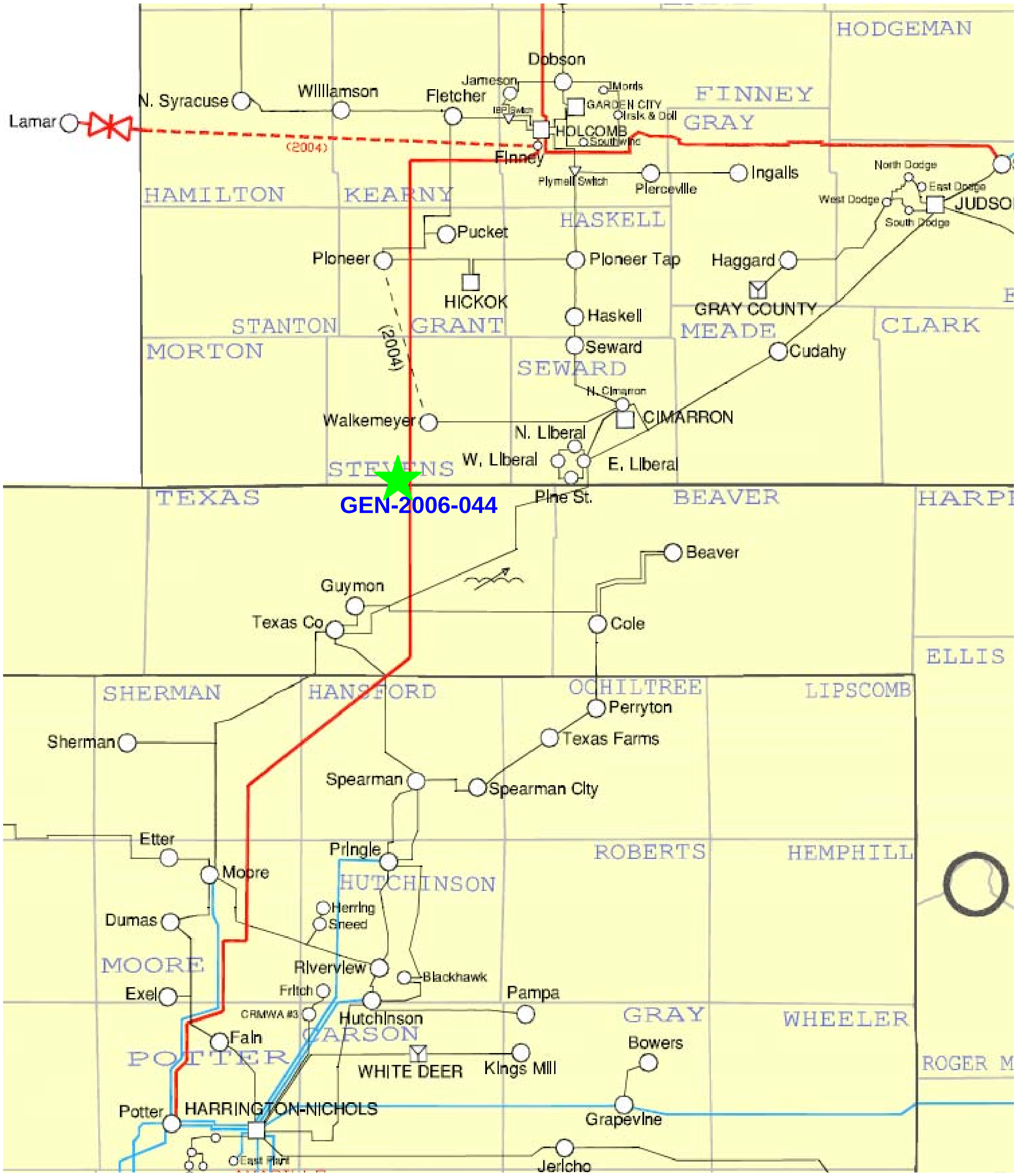

Figure 1-1 Geographical Transmission Map with GEN-2006-044 Project location

2 DESCRIPTION OF THE PROJECT

The details of load flow and dynamic data for the GEN-2006-044 wind farm project is included in Appendix A.

- Wind farm size: 370 MW
- Interconnection:

  Voltage: 345 kV

  POI: Hitchland 345kV switching station. The wind-farm will be connected to the POI via 345 kV line.

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

  MVA: 78 MVA

  Voltage: 345/115 kV

  Z: 8.5 % on 200 MVA; 8.5 % on 250 MVA
- Wind Turbines:

  Number: one Hundred and Eighty Five (185)

  Manufacturer: DeWind

  Type: Permanent Magnet Synchronous Generator

  Machine Terminal voltage: 0.416 kV

  Rated Power: 2.0 MW

  Frequency: 60 Hz

  Generator Step-up Transformer

  MVA: 2.3
  High voltage: 34.5 kV
  Low voltage: 0.416 kV
  Z: 5.75% on 2.3 MVA

  Reactive Power Capability: 0.9 lead/0.9 lag
- Fault Ride-through: Manufacturer's default ride-through capability was modeled
- PSSE Model Used DWD8G1_v1-0_r30-3CVF.OBJ, G59REL_r30-3CVF.OBJ

3 STUDY METHODOLOGY

3.1 POWER FACTOR ANALYSIS

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

The Power Factor Analysis involved the following Steps:

- A generator was represented at the wind farm's substation high voltage bus (Hitchland 345kV) with a MW output of the wind farm (370MW) and an unlimited VAR range. The generator was set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided base case.
- A list of selected contingencies in the vicinity of the subject wind farm was simulated. The results were used to identify the most-limiting contingency from steady state voltage and power factor perspective.
- If the required reactive power support, to maintain an acceptable power factor at the POI, was found to be beyond the capability of proposed wind-farm then the additional reactive power compensation (e.g. static capacitor banks) was considered.

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

3.2 TRANSIENT STABILITY ANALYSIS

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

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

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

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

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

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

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

4 MODEL DEVELOPMENT

SPP provided two power flow cases for this study – i) “MDWG_2010_2011SP.sav” and ii) “MDWG_2010_2011WP.sav” –representing respectively the 2010-2011 Summer Peak and Winter Peak conditions. The study cases included the following prior-queued projects:

#	Prior Queued Generator	Size (MW)	Wind Turbine Model	Point of Interconnection
1	GEN-2002-006	150	GE 1.5MW	Texas Co. 115kV (523090)
2	GEN-2002-008	240	GE 1.5MW	Hitchland 345kV (523097)
3	GEN-2002-009	80	Suzlon 2.1MW	Hansford 115kV (523195)
4	GEN-2003-013	196	GE 1.5 MW	Hitchland – Finney 345kV (560029)
5	GEN-2003-020	160	GE 1.5 MW	Carson Co. 115kV (523924)
6	GEN-2005-017	340	GE 1.5 MW	Hitchland – Potter 345kV 523961
7	GEN-2006-020	19.5	GE 1.5 MW	Hitchland – Sherman Tap 115kV (560200)

4.1 MODEL DEVELOPMENT FOR GEN-2006-044 PROJECT

The GEN-2006-044 wind farm will comprise of total one hundred eighty five (185) DeWind 2.0MW wind turbine generators. The equivalent model network diagram was developed from single line diagram (Novus I SLD - 100928.pdf) given by SPP. These 185 turbines were modeled as four equivalent generators, with equivalent feeders and buses representing the entire collector system in the proposed wind farm. The equivalent generators were connected to a 34.5 kV collector bus through separate generator step-up transformers (4.16/34.5 kV).

The 34.5 kV collector bus was connected to the POI via four 34.5/115 kV to two 115/345 kV station transformers. The equivalent collector system in shown in Figure 4-1.

Figure 4-2 and Figure 4-3 show the power flow in the electrical vicinity of GEN-2006-044 for 2010-2011 summer peak and winter peak conditions.

The pre-project dynamic model setup with the “snapshot” was provided by SPP. Based on the model parameters for DeWind WTG, provided by SPP (ESAC5A_V1.2b_datasheet.xls, EUD8G1_V1.3b_datasheet.xls, G59REL_Input_Data_V1 2b.xls and GENSAL_V1.2b_datasheet.xls), we developed the PSSE dynamic model input in “DYRE” format. This “DYRE” file was read into the PSSE to create a new “snap-shot”. Being a user-written model, the model object files had to be compiled and linked to the PSSE standard library.

We performed a no-disturbance simulation to verify the models initialized correctly. This simulation indicated no “drifts” on the monitored quantities like machine angles, bus voltages etc., implying the models initialized correctly.

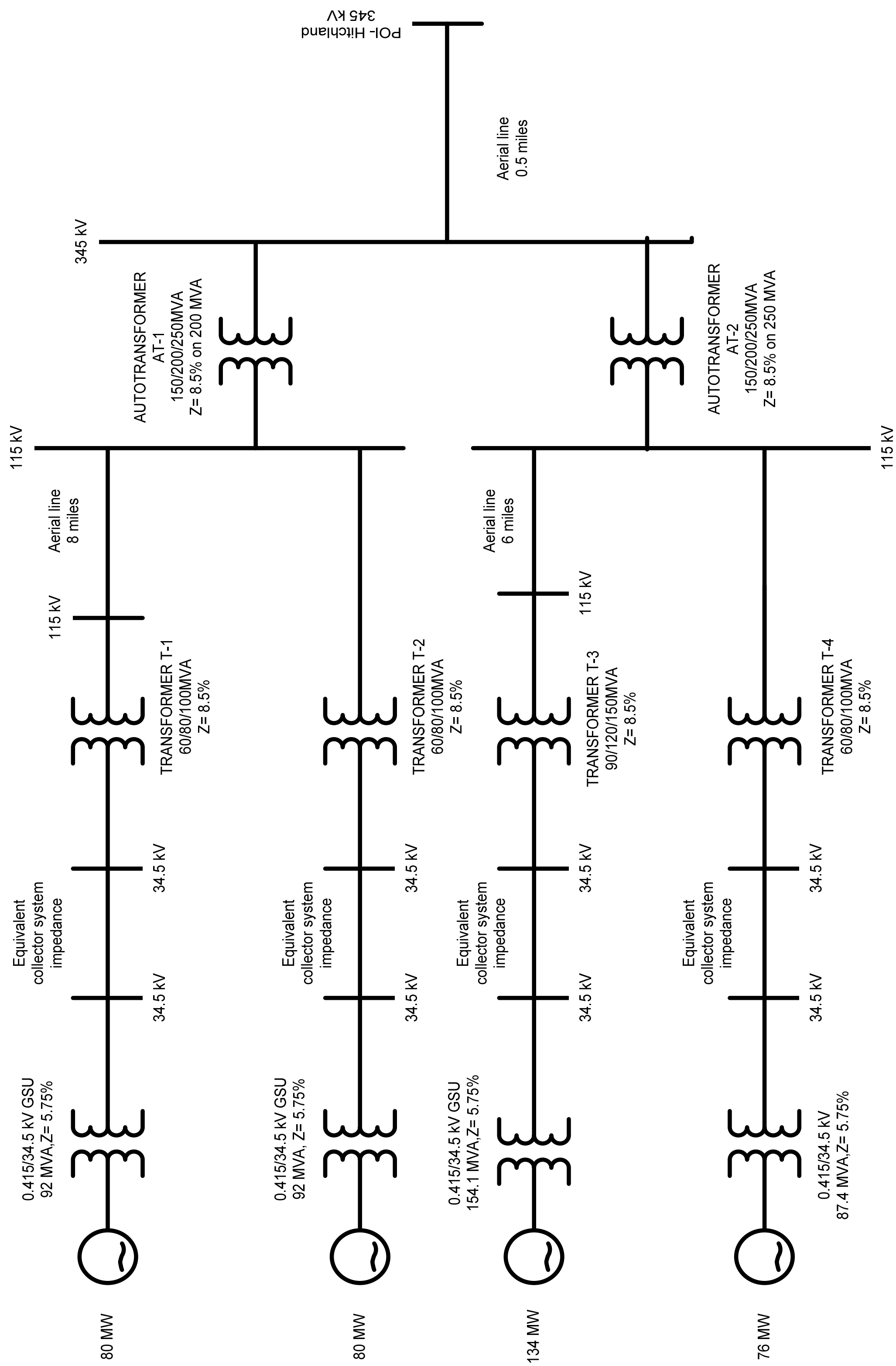

Figure 4-1 GEN-2006-044 Equivalent collector system

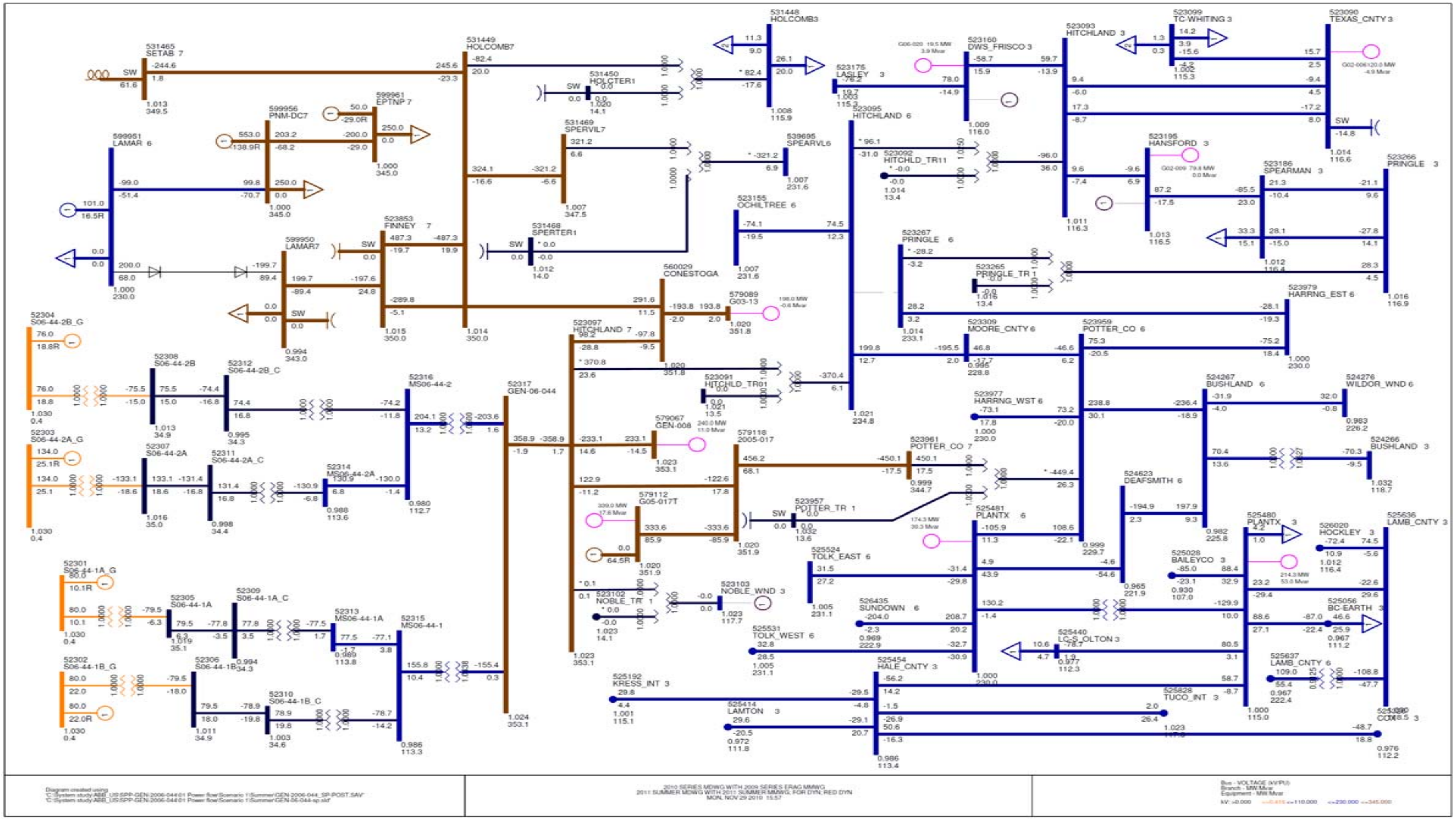

Figure 4-2 Power Flow Diagram of the local area of GEN-2006-044 (Summer Peak)

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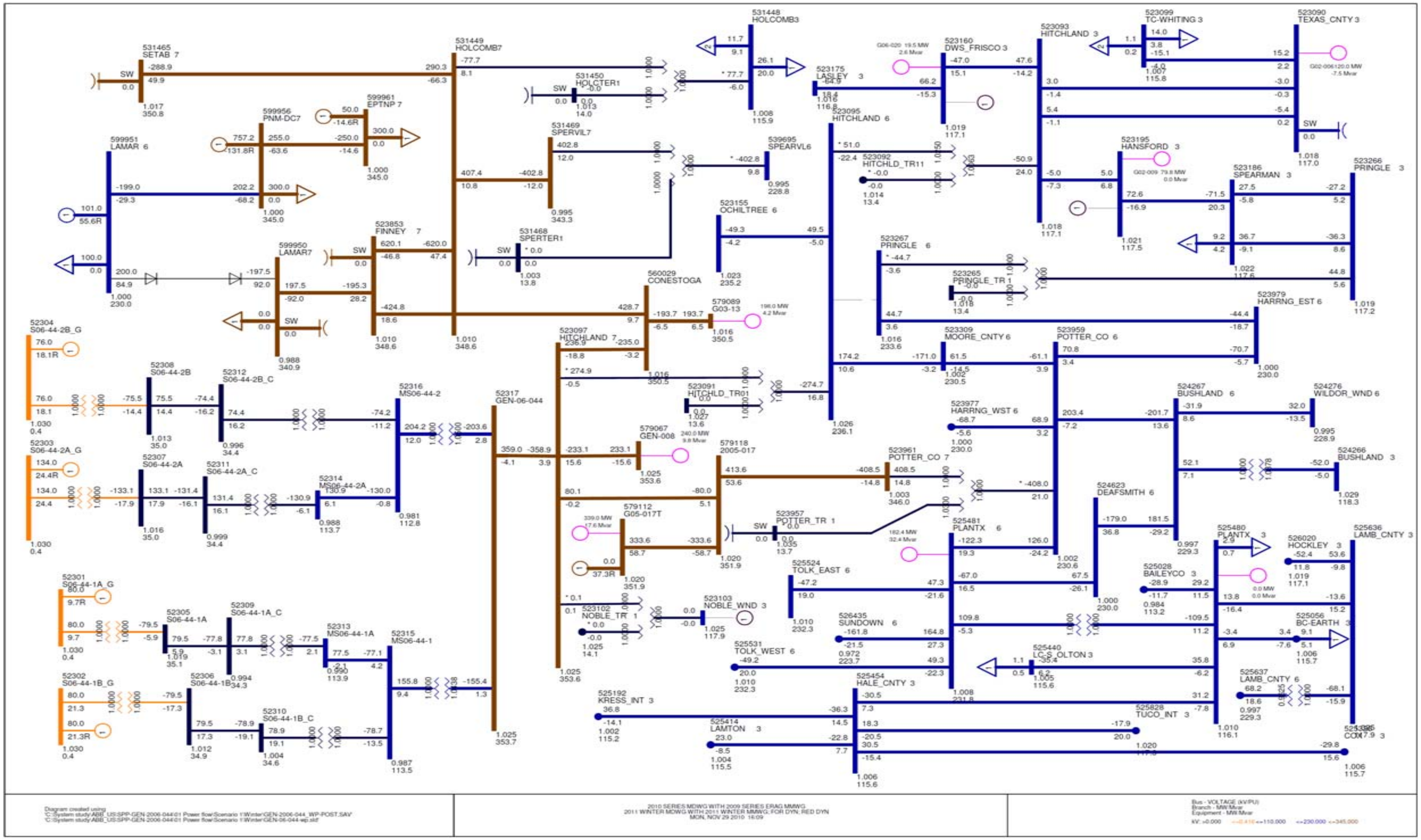

Figure 4-3 Power Flow Diagram of the local area of GEN-2006-044 (Winter Peak)

5 CONTINGENCY ANALYSIS

We started the analysis by first running a power flow contingency analysis. Such an approach (i.e. contingency analysis) is expected to highlight any serious steady state issues (thermal overloads, voltage collapse etc.) which might need mitigation. Table 5-1 lists the contingencies simulated for Contingency analysis. The simulation was performed on both summer and winter peak load conditions.

The results from this simulation did not indicate any voltage problems except for CONT-29 [Loss of Holcomb (531449) to Finney (523853) 345kV line]. The outage of Holcomb – Finney 345 kV resulted in non-convergence of power flow, most likely due to a lack of reactive power support, for both the winter and summer peak load conditions, with the 370 MW of proposed wind farm in service. The same contingency however provided a power flow solution for pre-project conditions, with acceptable post-contingency voltages. Therefore, this collapse condition may be attributed to the incremental impact of adding GEN-2006-044 (total 370 MW). There are only two 345 kV transmission outlets for all the power that is injected at Hitchland (GEN-2006-044, Conestoga and Finney). With the outage of Finney-Holcomb, one of the two outlets, then all this power (~430 MW) has to flow towards Hitchland and then to Potter Co. 345 kV substation. The resolution of the problem calls for either a reduction in the MW generation from the GEN-2006-044 or addition of a new transmission, say a 2nd Finney – Holcomb 345 kV line.

As a sensitivity case, we evaluated the maximum MW injection at the GEN-2006-044 location that would result in a secure system condition, i.e. with no potential collapse. For the summer conditions, the maximum injection was found to be 360 MW whereas for the winter conditions, only 250 MW could be injected without any added reactive power support or transmission upgrades. Based on the evaluation of summer and winter conditions, then the maximum wind farm capability that can be accommodated without any added reactive power support or transmission upgrades, is 250 MW.

SPP suggested the addition of a new, second line between Finney – Holcomb to mitigate the problems associated with the outage of the existing Holcomb – Finney 345 kV line. The addition of the second, Finney-Holcomb 345 kV line was found to resolve the power flow convergence problems and accommodate the full output (i.e. 370 MW) from the proposed GEN-2006-044 wind farm.

A Q-V analysis was performed to verify that both the above alternatives (i.e. reduced wind farm output of 250 MW or adding a 2nd Finney – Holcomb 345 kV line) have indeed sufficient reactive power margin in the post-contingency conditions. Figure 5-1 and Figure 5-2 show the Q-V curves for both the above alternatives for summer and winter peak cases respectively. From these QV curves, it may be noted that i) there is sufficient reactive power margin and ii) the post-contingency voltage is acceptable (>0.95 p.u.).

Table 5-1: List of Contingencies

Contingency Name	Contingency Description
CONT_00	BASECASE
CONT_01	Loss of Hitchland (523097) to GEN-2003-013 (560029) 345kV line
CONT_02	Loss of Hitchland (523097) to GEN-2005-017 (579118) 345kV line
CONT_03	Loss of Hitchland (523097) to GEN-008 (579067) 345kV lines
CONT_04	Loss of Hitchland 230kV (523095) to 345kV (523097) transformer
CONT_05	Loss of Hitchland (523095) to Moore Co (523309) 230kV line
CONT_06	Loss of GEN-2005-017 (579118) to Potter Co. (523961) 345kV line
CONT_07	Loss of Moore Co. (523309) to Potter Co (523959) 230kV line
CONT_08	Loss of Pringle (523267) to Harrington (523979) 230kV line
CONT_09	Loss of GEN-2003-013 (560029) to Finney (523853) 345kV line
CONT_10	Loss of Holcomb (531449) to Setab (531465) 345kV line
CONT_11	Loss of Holcomb (531449) to Spearville (531469) 345kV line
CONT_12	Loss of Woodward (515375) to Tatonga (515407) 345kV line
CONT_13	Loss of Hitchland (523093) to GEN-2006-020 (523160) to Sherman Tap (523175) to Moore Co. East (523308) and to Sherman (523168) 115kV line
CONT_14	Loss of Hitchland (523093) to Hansford (523195) 115kV line
CONT_15	Loss of Hitchland 115kV (523093) to 230kV (523095) transformer
CONT_16	Loss of Pringle (523266) to Spearman (523186) 115kV line
CONT_17	Loss of Moore Co. East (523308) to RB Hogu (523216) 115kV line
CONT_18	Loss of Moore Co. West (523304) to Dumas (523318) 115kV line
CONT_19	Loss of Moore Co. West (523304) to RB Sneed (523366) 115kV line
CONT_20	Loss of Moore Co. East 115kV (523308) to 230kV (523309) transformer
CONT_21	Loss of Spearman (523186) to Spearman Sub (523203) 115kV line
CONT_22	Loss of Texas Co. 115kV phase shifting transformer (523090 to 523106)
CONT_23	Loss of Riverview(523377) to Pringle (523266) 115kV line
CONT_24	Loss of Pringle 115kV (523266) to Pringle 230kV (523267) transformer
CONT_25	Loss of Riverview (523377) to Harrington Tap (523352) 115kV line
CONT_26	Loss of Riverview (523377) to CRMWA#1 (523403) 115kV line
CONT_27	Loss of Hutchison 115kV (523546) to the Hutchison 230kV (523551) transformer
CONT_28	Loss of Pringle (523266) to Q_RYTON_TP (523478) 115kV line
CONT_29	Loss of Finney (523853) to Holcomb (531449) 345kV line

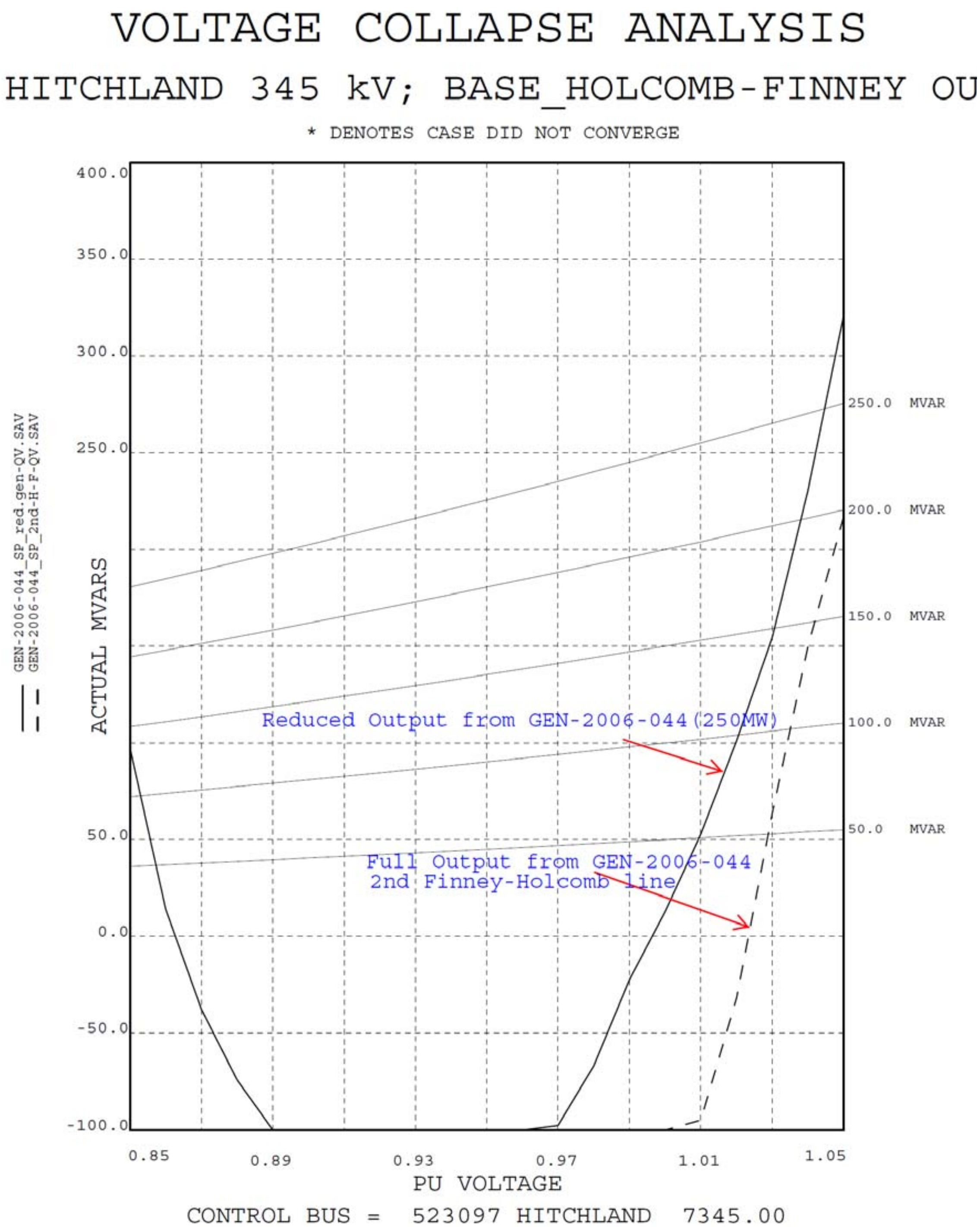

Figure 5-1 Q-V curve at Hitchland 345 kV for CONT-29 (summer peak)

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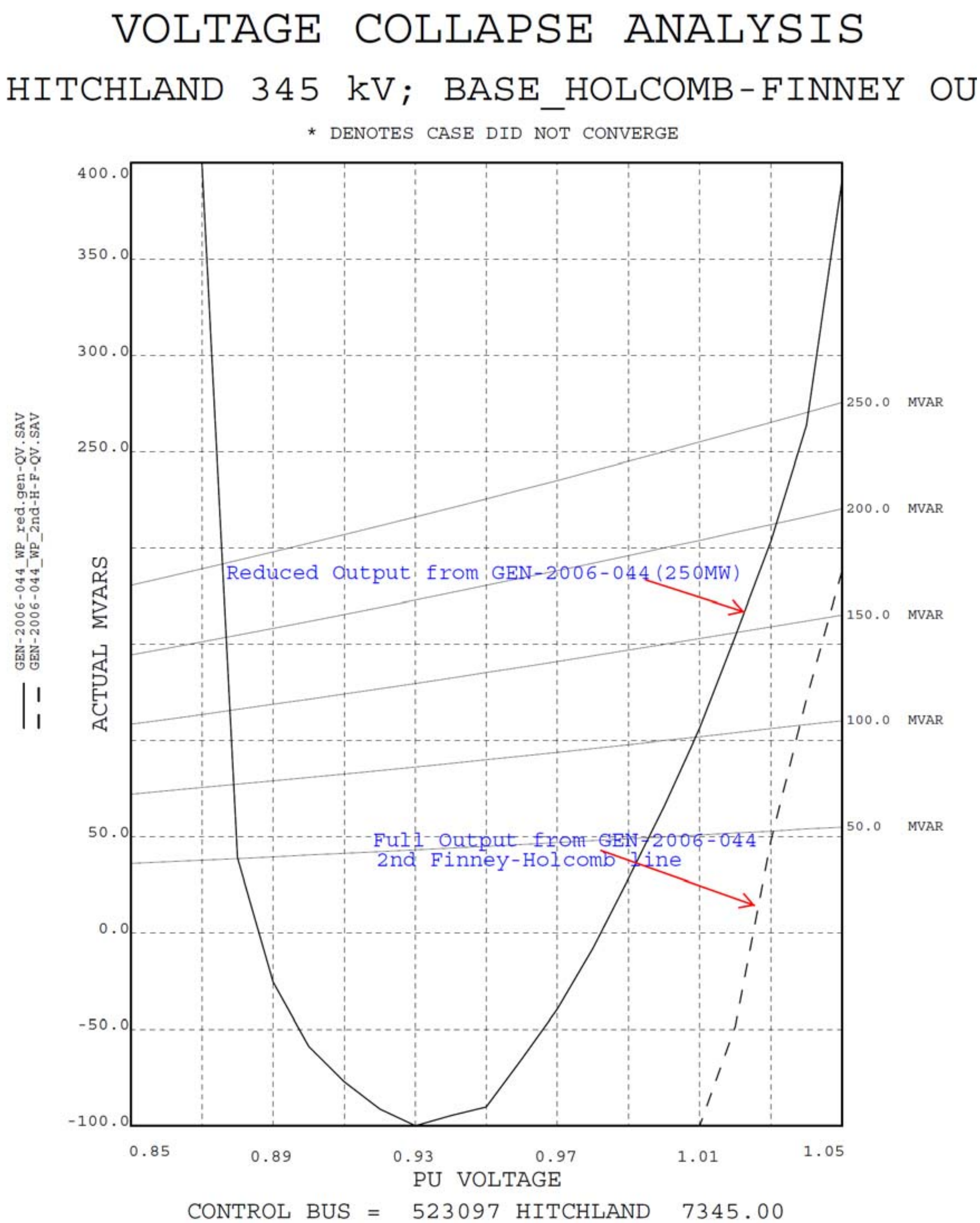

Figure 5-2 Q-V curve at Hitchland 345 kV for CONT-29 (winter peak)

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6 POWER FACTOR ANALYSIS

A Power Factor analysis was performed to verify that the wind-farm interconnection met SPP's standard in terms of power factor and voltage requirements at the POI. Table 5-1 lists the contingencies simulated for Power Factor analysis.

As described in section 3.1, a VAR generator was modeled at POI. The VAR generator was set to hold the 345 kV POI voltage equal to the pre-project, system intact voltage (1.025 p.u.), which is a conservative assumption.

The contingencies shown in Table 5-1 were simulated on summer peak and winter peak load conditions for the two alternatives described in Section 5.

Reduced Output from GEN-2006-044 (250 MW): For both summer peak and winter peak load conditions, CONT_29 (loss of Finney – Holcomb 345 kV line) showed maximum reactive power output from the VAR generator at POI (202 MVAR for Winter peak load conditions, Table 6-1). This implies that this contingency requires the highest amount of reactive power to meet the, pre-project, pre-contingency voltage schedule of 1.025 p.u. However, if one were to compute the VAR requirements to maintain the pre-project, post-contingency voltage (1.0 p.u), that amounts to 133 MVAR of reactive power requirement at the POI, thereby requiring some VAR support (~15 MVAR) from the grid to maintain 1.0 pu. voltage at the POI.

Next, the same contingencies (Table 5-1) were re-simulated, but without the VAR generator at the POI, to verify the power factor at the POI. This analysis considered the detailed representation of the wind farm collector system and equivalent wind generators. The results for system intact condition and the most restrictive contingency (from a reactive power requirement perspective, winter peak load conditions) are shown in Table 6-2. The power factor at the POI was computed [the wind farm was found to be injecting 65 MVAR (winter peak load conditions) into the grid after satisfying the collector system requirements of roughly 55 MVAR]. The voltage at the POI was 0.985 p.u. for the winter peak load condition. In order to hold 1.0 p.u. voltage at the POI (pre-project, post-contingency voltage), an additional 45 MVAR from the grid was required (Grid power factor of 0.96 lag). The power factor as well as the bus voltage is therefore acceptable.

Full Output from GEN-2006-044, 2nd Finney-Holcomb 345 kV: For both summer peak and winter peak load conditions in this option-2 (Addition of new second line between Finney – Holcomb for full GEN-2006-044), CONT_06 (loss of GEN-2005-017 – Potter Co. 345 kV line) showed maximum reactive power output from the VAR generator at POI following interconnection of GEN-2006-044 project (Table 6-3). This implies that this contingency requires the highest amount of reactive power to meet the pre-project, pre-contingency voltage schedule. Considering 0.9 power factor capability for the subject wind farm, its reactive power capability will be 160 MVAR.

However, if the pre-project, post-contingency voltage is considered (Hitchland 345 kV voltage = 1.01 p.u) in place of the system intact voltage, the MVAR requirement is only 115 MVAR. This requirement can be met from the subject wind farm with little reactive power support from the grid.

Next, the same contingencies (Table 5-1) were re-simulated, but without the VAR generator at the POI, to verify the power factor at the POI. This analysis considered the detailed representation of the wind farm collector system and equivalent wind generators. The results for system intact condition and the most restrictive contingency (from a reactive power requirement perspective) are shown in Table 6-4. The power factor at the POI was computed, which was close to unity. The voltage at the POI was close to 1.0 p.u. The power factor as well as the bus voltage was found to be acceptable for all the tested conditions.

The complete results from the above analyses are included in Appendix B.

Table 6-1 Results of Power Factor Analysis for 250 MW of GEN-06-044 Generation

Contingency Name	Contingency Description	Summer Peak	Winter Peak
CONT_00	BASECASE	1.4	8.7
CONT_01	Loss of Hitchland (523097) to GEN-2003-013 (560029) 345kV line	31	38.7
CONT_02	Loss of Hitchland (523097) to GEN-2005-017 (579118) 345kV line	17.2	-0.4
CONT_03	Loss of Hitchland (523097) to GEN-008 (579067) 345kV lines	15.9	16.8
CONT_04	Loss of Hitchland 230kV (523095) to 345kV (523097) transformer	11.8	7.1
CONT_05	Loss of Hitchland (523095) to Moore Co (523309) 230kV line	22.7	11.5
CONT_06	Loss of GEN-2005-017 (579118) to Potter Co. (523961) 345kV line	131.8	98
CONT_07	Loss of Moore Co. (523309) to Potter Co (523959) 230kV line	0.9	8.1
CONT_08	Loss of Pringle (523267) to Harrington (523979) 230kV line	4	5.4
CONT_09	Loss of GEN-2003-013 (560029) to Finney (523853) 345kV line	39.5	45.9
CONT_10	Loss of Holcomb (531449) to Setab (531465) 345kV line	13	30.5
CONT_11	Loss of Holcomb (531449) to Spearville (531469) 345kV line	19.8	20.9
CONT_12	Loss of Woodward (515375) to Tatonga (515407) 345kV line	1.3	8.9
CONT_13	Loss of Hitchland (523093) to GEN-2006-020 (523160) to Sherman Tap (523175) to Moore Co. East (523308) and to Sherman (523168) 115kV line	3.3	12.6
CONT_14	Loss of Hitchland (523093) to Hansford (523195) 115kV line	0.5	11.4
CONT_15	Loss of Hitchland 115kV (523093) to 230kV (523095) transformer	12.8	20.4
CONT_16	Loss of Pringle (523266) to Spearman (523186) 115kV line	0.2	8.9
CONT_17	Loss of Moore Co. East (523308) to RB Hogu (523216) 115kV line	0.8	9.2
CONT_18	Loss of Moore Co. West (523304) to Dumas (523318) 115kV line	4.8	5.8
CONT_19	Loss of Moore Co. West (523304) to RB Sneed (523366) 115kV line	-0.3	8
CONT_20	Loss of Moore Co. East 115kV (523308) to 230kV (523309) transformer	9.1	1.1
CONT_21	Loss of Spearman (523186) to Spearman Sub (523203) 115kV line	6.5	8.1
CONT_22	Loss of Texas Co. 115kV phase shifting transformer (523090 to 523106)	4.2	11.9
CONT_23	Loss of Riverview (523377) to Pringle (523266) 115kV line	0.8	10.3
CONT_24	Loss of Pringle 115kV (523266) to Pringle 230kV (523267) transformer	4.2	5.2
CONT_25	Loss of Riverview (523377) to Harrington Tap (523352) 115kV line	4.2	10.8
CONT_26	Loss of Riverview (523377) to CRMWA#1 (523403) 115kV line	1.7	8.6
CONT_27	Loss of Hutchison 115kV (523546) to the Hutchison 230kV (523551) transformer	-0.7	9.2
CONT_28	Loss of Pringle (523266) to Q_RYTON_TP (523478) 115kV line	0.2	9.8
CONT_29	Loss of Holcomb (531449) to Finney (523853) 345kV line	**163.6**	**202**

Table 6-2: Voltage & p.f. at POI without VAR generator – GEN0-2006-044 at 250 MW

System condition		Voltage (in p.u.)	P.F.
summer peak	System Intact	1.028	0.99
	Post-contingency (1)	0.995	0.96
winter peak	System Intact	1.03	0.99
	Post-contingency (1)	0.985	0.96

(1) *CONT_29*: Loss of Holcomb – Finney 345 kV line

Table 6-3 Results of Power Factor Analysis with 2nd Finney – Holcomb line

Contingency Name	Contingency Description	Summer Peak	Winter Peak
CONT_00	BASECASE	3.9	18.4
CONT_01	Loss of Hitchland (523097) to GEN-2003-013 (560029) 345kV line	40.4	49.9
CONT_02	Loss of Hitchland (523097) to GEN-2005-017 (579118) 345kV line	34.3	18.6
CONT_03	Loss of Hitchland (523097) to GEN-008 (579067) 345kV lines	18	14.5
CONT_04	Loss of Hitchland 230kV (523095) to 345kV (523097) transformer	36.6	26.9
CONT_05	Loss of Hitchland (523095) to Moore Co (523309) 230kV line	8.2	2.3
CONT_06	Loss of GEN-2005-017 (579118) to Potter Co. (523961) 345kV line	**174.1**	**137.7**
CONT_07	Loss of Moore Co. (523309) to Potter Co (523959) 230kV line	5.9	17.5
CONT_08	Loss of Pringle (523267) to Harrington (523979) 230kV line	1	14.9
CONT_09	Loss of GEN-2003-013 (560029) to Finney (523853) 345kV line	74.5	86.9
CONT_10	Loss of Holcomb (531449) to Setab (531465) 345kV line	19.9	41.8
CONT_11	Loss of Holcomb (531449) to Spearville (531469) 345kV line	25.6	29.6
CONT_12	Loss of Woodw ard (515375) to Tatonga (515407) 345kV line	3.9	18.6
CONT_13	Loss of Hitchland (523093) to GEN-2006-020 (523160) to Sherman Tap (523175) to Moore Co. East (523308) and to Sherman (523168) 115kV line	8.4	22.1
CONT_14	Loss of Hitchland (523093) to Hansford (523195) 115kV line	5.6	21
CONT_15	Loss of Hitchland 115kV (523093) to 230kV (523095) transformer	18.7	30.3
CONT_16	Loss of Pringle (523266) to Spearman (523186) 115kV line	5.4	18.5
CONT_17	Loss of Moore Co. East (523308) to RB Hogu (523216) 115kV line	4.5	18.8
CONT_18	Loss of Moore Co. West (523304) to Dumas (523318) 115kV line	0.4	15.4
CONT_19	Loss of Moore Co. West (523304) to RB Sneed (523366) 115kV line	4.9	17.6
CONT_20	Loss of Moore Co. East 115kV (523308) to 230kV (523309) transformer	3.6	11
CONT_21	Loss of Spearman (523186) to Spearman Sub (523203) 115kV line	1.4	17.7
CONT_22	Loss of Texas Co. 115kV phase shifting transformer (523090 to 523106)	1.7	22.7
CONT_23	Loss of Riverview (523377) to Pringle (523266) 115kV line	6	20
CONT_24	Loss of Pringle 115kV (523266) to Pringle 230kV (523267) transformer	0.9	14.8
CONT_25	Loss of Riverview (523377) to Harrington Tap (523352) 115kV line	9.4	20.4
CONT_26	Loss of Riverview (523377) to CRMWA#1 (523403) 115kV line	3.5	18.2
CONT_27	Loss of Hutchison 115kV (523546) to the Hutchison 230kV (523551) transformer	4.5	18.8
CONT_28	Loss of Pringle (523266) to Q_RYTON_TP (523478) 115kV line	5.6	19.6
CONT_29	Loss of Holcomb (531449) to Finney (523853) 345kV line	4	18.6

Table 6-4: Voltage & p.f. at POI without VAR generator – GEN-2006-044 at full output, Add 2nd Finney – Holcomb 345 kV

System condition		Voltage (in p.u.)	P.F.
summer peak	System Intact	1.023	1.00
	Post-contingency (1)	0.999	0.996
winter peak	System Intact	1.025	1.00
	Post-contingency (1)	1.000	0.998

(1) *CONT_06*: Loss of GEN-2005-017 – Potter Co. 345 kV line

7 STABILITY ANALYSIS

Stability simulations were performed to examine the transient behavior of GEN-2006-044 project and its impact on the SPP system. Several faults, both three-phase and single phase faults (with re-closing where applicable) were simulated. The fault clearing times and re-closing times used for the simulations are shown in Table 7-1.

Table 7-1 Fault Clearing Times

Faulted bus kV level	Normal Clearing	Time before re-closing
69	5 cycles	20 cycles
138	5 cycles	20 cycles
230	5 cycles	20 cycles
345	5 cycles	20 cycles

Twenty eight (28) three phase and twenty (20) single-line-to-ground faults (with re-closing where applicable) were simulated. For all tested cases the initial disturbance was applied at t = 0.1 seconds. The breaker clearing was initiated at the appropriate time following the fault inception (see Table 7-1). Table 7-2 lists all the faults simulated for transient stability analysis.

The system was stable for all the simulated 3-Phase and single-phase faults except FLT_81_3PH and FLT_82_1PH. The proposed GEN-2006-044 wind farm stayed on-line throughout the duration of the faults and thereof, the voltage recovery was acceptable. The stability plots showed that any post-contingency oscillations were damped out for all but one fault case - FLT_26_3PH.Tripping of some prior queued projects was indicated for FLT-22 and FLT-31, 32.The above cases were then evaluated further, results of which are discussed in the subsequent paragraphs.

FLT_81_3PH and FLT_82_1PH: These two faults involved the tripping of Finney – Holcomb 345 kV line upon fault clearing. A steady state voltage collapse was noted in Section 5 for full wind farm output of 370 MW for the outage of this line. As a next step, to verify any dynamic voltage issues we simulated the tripping of this line (without any fault). The results from this simulation did not indicate any dynamic voltage recovery issues (Fig. 7-1). Next, a 3-PH fault and SLG fault at Finney with outage of Holcomb – Finney 345 kV (FLT_81_3PH and FLT_82_1PH) were simulated. No stability issues were noted for summer peak loading condition. Figure 7-2 and Figure 7-3 show the voltage recovery for the outage of Holcomb – Finney 345 kV, fault FLT_81_3PH and fault FLT_82_3PH for summer peak load condition.

However, in winter peak case out of step conditions were observed. The corresponding pre-project case did not show any such problems. This implies that additional transmission upgrade(s) may be required to support the full wind farm output of 370 MW. Without any transmission upgrades, a reduced MW injection at the GEN-2006-044 location may still be viable. The steady state analysis had shown that a 250 MW output from this wind farm is technically viable from a steady state perspective.

Next, we performed the fault simulations (3-PH fault and SLG fault) with a reduced output level of 250 MW. The stability results indicated stable system performance with acceptable voltage recovery and damping. Fig. 7-4 and Fig. 7-5 show the voltage recovery for and fault FLT_81_3PH and fault FLT_82_1PH.

Another option to mitigate the stability problem described in the previous paragraph is to add a 2^{nd} line between Finney and Holcomb 345 kV substations. This option ensured stable system performance even with full output of 370 MW from GEN-2006-044 wind farm.

FLT_26_3PH: Fig. 7-6 shows oscillations in the voltage at Holcomb 345 kV for a 3-phase fault (normally cleared) with subsequent tripping of Holcomb – Spearville 345 kV (for winter peak condition). These oscillations seemed typical of an out-of-step condition in the system. Further investigations identified the machine that was out-of-step with rest of the system. The machine (19MVA) at Colby (bus #530555) was dispatched at -54 MW in the winter peak case, and without any flux dynamics representation (in the dynamic model, this machine is represented with a GENCLS model). Fig. 7-7 shows that this machine is out of step with other machines in the system.

Next, we "netted" out this generation (i.e. represented as a load) without any dynamic representation to see if the oscillations in the voltage is really due to the modeling of Colby machine and due to it going out of step. The repeat simulation of the same fault with the machine in question "netted" out (i.e. replaced with an equivalent negative load) did not show any oscillations (see Fig. 7.8). For this study purpose, we believe the netting of the 19 MVA Colby machine is acceptable, in the absence of a detailed model and the fact that it is electrically not very close to the study vicinity. However, it is suggested that SPP review the dispatch on this machine, and if available, replace the GENCLS model with a more detailed one.

FLT_22_3PH: The tripping of prior queued project(s) was observed for the faults FLT_22_3PH in summer and winter peak pre- and post-project cases. The GEN-2003-013 wind farm tripped subsequent to the outage of the outlet to Finney (leaving a single, transmission outlet to Hitchland 345 kV). We repeated the simulation after disabling the WTG trip. The results from this repeat simulation showed acceptable voltage recovery.

FLT_31-3PH, FLT_32-1PH: The tripping of GEN-2006-020 wind farm was indicated. The WTG trip (GEN-2006-020) associated with these fault events are the result of the above wind farm getting isolated from the grid.

Table 7-3 summarizes the stability analysis results for summer and winter peak load conditions. The plots from stability analysis are included in Appendix C.

Table 7-2 List of Simulated Faults for GEN-2006-044 SIS

Cont. No.	Cont. Name	Description
1.	FLT01-3PH	3 phase fault on the Hitchland (523097) to GEN-2003-013 (560029) 345kV line, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
2.	FLT02-1PH	Single phase fault on the line in previous 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.	FLT03-3PH	3 phase fault on the Hitchland (523097) to GEN-2005-017 (579118) 345kV line, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
4.	FLT04-1PH	Single phase fault on the line in previous 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.	FLT05-3PH[1]	3 phase 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 line.
6.	FLT06-1PH	Single phase fault on the line in previous 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.
7.	FLT08-3PH	3 phase fault on the Hitchland 230kV (523095) to 345kV (523097) transformer, near the 230kV bus. a. Apply fault at the Hitchland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
8.	FLT10-3PH	3 phase fault on the Hitchland (523095) to Moore Co (523309) 230kV near Moore Co. a. Apply fault at the Moore Co 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.
9.	FLT14-3PH	3 phase fault on the GEN-2005-017 (579118) to Potter Co. (523961) 345kV line, near GEN-2005-017. a. Apply fault at the GEN-2005-017 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
10.	FLT15-1PH	Single phase fault on the line in previous 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.	FLT16-3PH	3 phase fault on the Moore Co. (523309) to Potter Co (523959) 230kV line, near Potter Co. a. Apply fault at the Potter Co. 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.
12.	FLT20-3PH	3 phase fault on the Pringle (523267) to Harrington (523979) 230kV line, near Pringle. a. Apply fault at the Pringle 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.

[1] FLT05-3PH and FLT06-1PH fault definition is not valid

Cont. No.	Cont. Name	Description
13.	FLT21-1PH	*Single phase fault and sequence like previous*
14.	FLT22-3PH	3 phase fault on the GEN-2003-013 (560029) to Finney (523853) 345kV line, near GEN-2003-013. a. Apply fault at the GEN-2003-013 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line
15.	FLT23-1PH	Single phase fault on the line in previous 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.	FLT24-3PH	3 phase fault on the Holcomb (531449) to Setab (531465) 345kV line, near Holcomb. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
17.	FLT25-1PH	*Single phase fault and sequence like previous*
18.	FLT26-3PH	3 phase fault on the Holcomb (531449) to Spearville (531469) 345kV line, near Holcomb. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
19.	FLT27-1PH	*Single phase fault and sequence like previous*
20.	FLT28-3PH	3 phase fault on the Woodward (515375) to Tatonga (515407) 345kV line, near Woodward. a. Apply fault at the Woodward 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.
21.	FLT31-3PH	3 phase fault on the Hitchland (523093) to GEN-2006-020 (523160) to Sherman Tap (523175) to Moore Co. East (523308) and to Sherman (523168) 115kV line, near Hitchland. a. Apply fault at the Hitchland 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line (all segments listed above). 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.	FLT32-1PH	*Single phase fault and sequence like previous*
23.	FLT33-3PH	3 phase fault on the Hitchland (523093) to Hansford (523195) 115kV line, near 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.
24.	FLT34-1PH	*Single phase fault and sequence like previous*
25.	FLT35-3PH	3 phase fault on the Hitchland 115kV (523093) to 230kV (523095) transformer, near the 115 kV bus. a. Apply fault at the Hitchland 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
26.	FLT36-3PH	3 phase fault on the Pringle (523266) to Spearman (523186) 115kV line #1, near Pringle. a. Apply fault at the Pringle 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.
27.	FLT37-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
28.	FLT40-3PH	3 phase fault on the Moore Co. East (523308) to RB Hogu (523216) 115kV line, near Moore Co. East. a. Apply fault at the Moore Co. East 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.
29.	FLT41-1PH	*Single phase fault and sequence like previous*
30.	FLT42-3PH	3 phase fault on the Moore Co. West (523304) to Dumas (523318) 115kV line, near Moore Co. West. a. Apply fault at the Moore Co. West 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.
31.	FLT43-1PH	*Single phase fault and sequence like previous*
32.	FLT44-3PH	3 phase fault on the Moore Co. West (523304) to RB Sneed (523366) 115kV line, near Moore Co. West. a. Apply fault at the Moore Co. West 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.
33.	FLT45-1PH	*Single phase fault and sequence like previous*
34.	FLT46-3PH	3 phase fault on the Moore Co. East 115kV (523308) to 230kV (523309) transformer, near the 115 kV bus. a. Apply fault at the Moore Co. East 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
35.	FLT47-1PH	*Single phase fault and sequence like previous*
36.	FLT52-3PH	3 phase fault on the Spearman (523186) to Spearman Sub (523203) 115kV line, near 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.
37.	FLT53-1PH	*Single phase fault and sequence like previous*
38.	FLT57-3PH	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.
39.	FLT69-3PH	3 phase fault on the Riverview(523377) to Pringle (523266) 115kV line, near Riverview. a. Apply fault at the Riverview 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.	FLT70-1PH	*Single phase fault and sequence like previous*
41.	FLT73-3PH	3 phase fault on the Pringle 115kV (523266) to Pringle 230kV (523267) transformer near the 115 kV bus. a. Apply fault at the Pringle 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Cont. No.	Cont. Name	Description
42.	FLT74-3PH	3 phase fault on the Riverview (523377) to Harrington Tap (523352) 115kV line, near Riverview. a. Apply fault at the Riverview 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.
43.	FLT75-1PH	*Single phase fault and sequence like previous*
44.	FLT76_3PH	3 phase fault on the Riverview (523377) to CRMWA#1 (523403) 115kV line, near Riverview. a. Apply fault at the Riverview 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.
45.	FLT77_1PH	*Single phase fault and sequence like previous*
46.	FLT78_3PH	3 phase fault on the Hutchison 115kV (523546) to the Hutchison 230kV (523551) transformer near the 115 kV bus. a. Apply fault at the Hutchison 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
47.	FLT79-3PH	3 phase fault on the Pringle (523266) to Q_RYTON_TP (523478) 115kV line #1, near Pringle. a. Apply fault at the Pringle 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.
48.	FLT_80-1PH	*Single phase fault and sequence like previous*
49.	FLT81-3PH	3 phase fault on the Finney (523853) to Holcomb (531449) 345kV line, near Finney. a. Apply fault at the Finney 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
50.	FLT_82-1PH	*Single phase fault and sequence like previous*

Table 7-3 Results of stability analysis

FAULT	Summer Peak			Winter Peak		
		Post-Project			Post-Project	
	Pre-Project	Stable?	Acceptable Voltages?	Pre-Project	Stable?	Acceptable Voltages?
FLT_01_3PH	---	STABLE	YES	---	STABLE	YES
FLT_02_1PH	---	STABLE	YES	---	STABLE	YES
FLT_03_3PH	---	STABLE	YES	---	STABLE	YES
FLT_04_1PH	---	STABLE	YES	---	STABLE	YES
FLT_08_3PH	---	STABLE	YES	---	STABLE	YES
FLT_10_3PH	---	STABLE	YES	---	STABLE	YES
FLT_14_3PH	---	STABLE	YES	---	STABLE	YES
FLT_15_1PH	---	STABLE	YES	---	STABLE	YES
FLT_16_3PH	---	STABLE	YES	---	STABLE	YES
FLT_20_3PH	---	STABLE	YES	---	STABLE	YES
FLT_21_1PH	---	STABLE	YES	---	STABLE	YES
FLT_22_3PH	MACHINE 1 AT BUS 579091 [CLR_1 0.5750] TRIPPED					
FLT_22_3PH-NT	---	STABLE	YES	---	STABLE	YES
FLT_23_1PH	---	STABLE	YES	---	STABLE	YES
FLT_24_3PH	---	STABLE	YES	---	STABLE	YES
FLT_25_1PH	---	STABLE	YES	---	STABLE	YES
FLT_26_3PH	---	STABLE	YES	---	STABLE	YES
FLT_27_1PH	---	STABLE	YES	---	STABLE	YES
FLT_28_3PH	---	STABLE	YES	---	STABLE	YES
FLT_31_3PH[2]	MACHINE 1 AT BUS 90201 [CLR_1 0.5750] TRIPPED					
FLT_31_3PH-NT	---	STABLE	YES	---	STABLE	YES
FLT_32_1PH	MACHINE 1 AT BUS 90201 [CLR_1 0.5750] TRIPPED					
FLT_32_1PH-NT	---	STABLE	YES	---	STABLE	YES
FLT_33_3PH	---	STABLE	YES	---	STABLE	YES
FLT_34_1PH	---	STABLE	YES	---	STABLE	YES
FLT_35_3PH	---	STABLE	YES	---	STABLE	YES
FLT_36_3PH	---	STABLE	YES	---	STABLE	YES
FLT_37_1PH	---	STABLE	YES	---	STABLE	YES
FLT_40_3PH	---	STABLE	YES	---	STABLE	YES
FLT_41_1PH	---	STABLE	YES	---	STABLE	YES
FLT_42_3PH	---	STABLE	YES	---	STABLE	YES

[2] Tripping is due to the isolation of the subject wind farms from rest of the system

FAULT	Summer Peak			Winter Peak		
	Pre-Project	Post-Project		Pre-Project	Post-Project	
		Stable?	Acceptable Voltages?		Stable?	Acceptable Voltages?
FLT_43_1PH	---	STABLE	YES	---	STABLE	YES
FLT_44_3PH	---	STABLE	YES	---	STABLE	YES
FLT_45_1PH	---	STABLE	YES	---	STABLE	YES
FLT_46_3PH	---	STABLE	YES	---	STABLE	YES
FLT_47_1PH	---	STABLE	YES	---	STABLE	YES
FLT_52_3PH	---	STABLE	YES	---	STABLE	YES
FLT_53_1PH	---	STABLE	YES	---	STABLE	YES
FLT_57_3PH	---	STABLE	YES	---	STABLE	YES
FLT_69_3PH	---	STABLE	YES	---	STABLE	YES
FLT_70_1PH	---	STABLE	YES	---	STABLE	YES
FLT_73_3PH	---	STABLE	YES	---	STABLE	YES
FLT_74_3PH	---	STABLE	YES	---	STABLE	YES
FLT_75_1PH	---	STABLE	YES	---	STABLE	YES
FLT_76_3PH	---	STABLE	YES	---	STABLE	YES
FLT_77_1PH	---	STABLE	YES	---	STABLE	YES
FLT_78_3PH	---	STABLE	YES	---	STABLE	YES
FLT_79_3PH	---	STABLE	YES	---	STABLE	YES
FLT_80_1PH	---	STABLE	YES	---	STABLE	YES
FLT_81_3PH	---	STABLE	YES	---		
FLT_82_1PH	---	STABLE	YES	---		

ABB

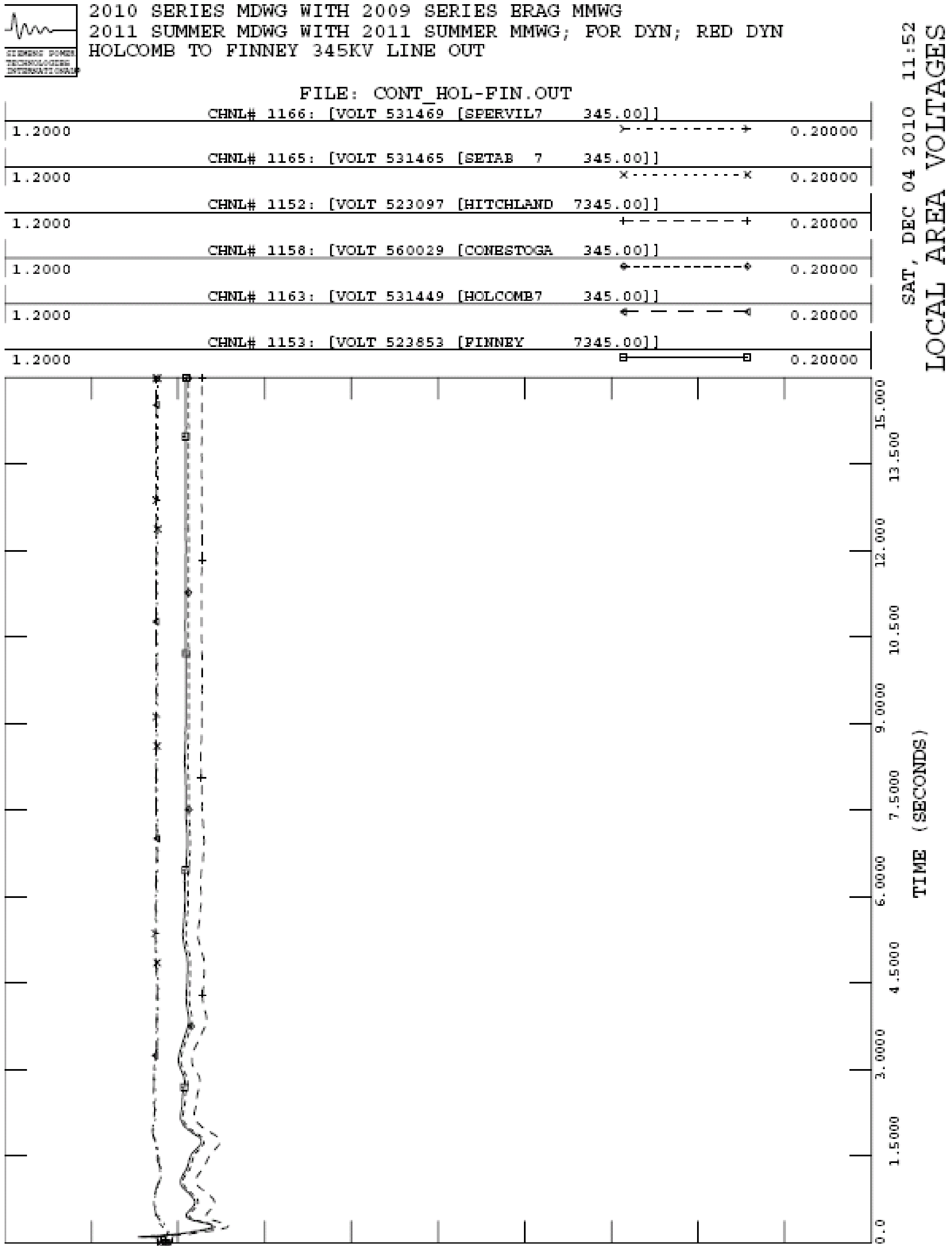

Figure 7-1 Voltage plot for the Outage of Holcomb – Finney 345 kV line (summer peak)

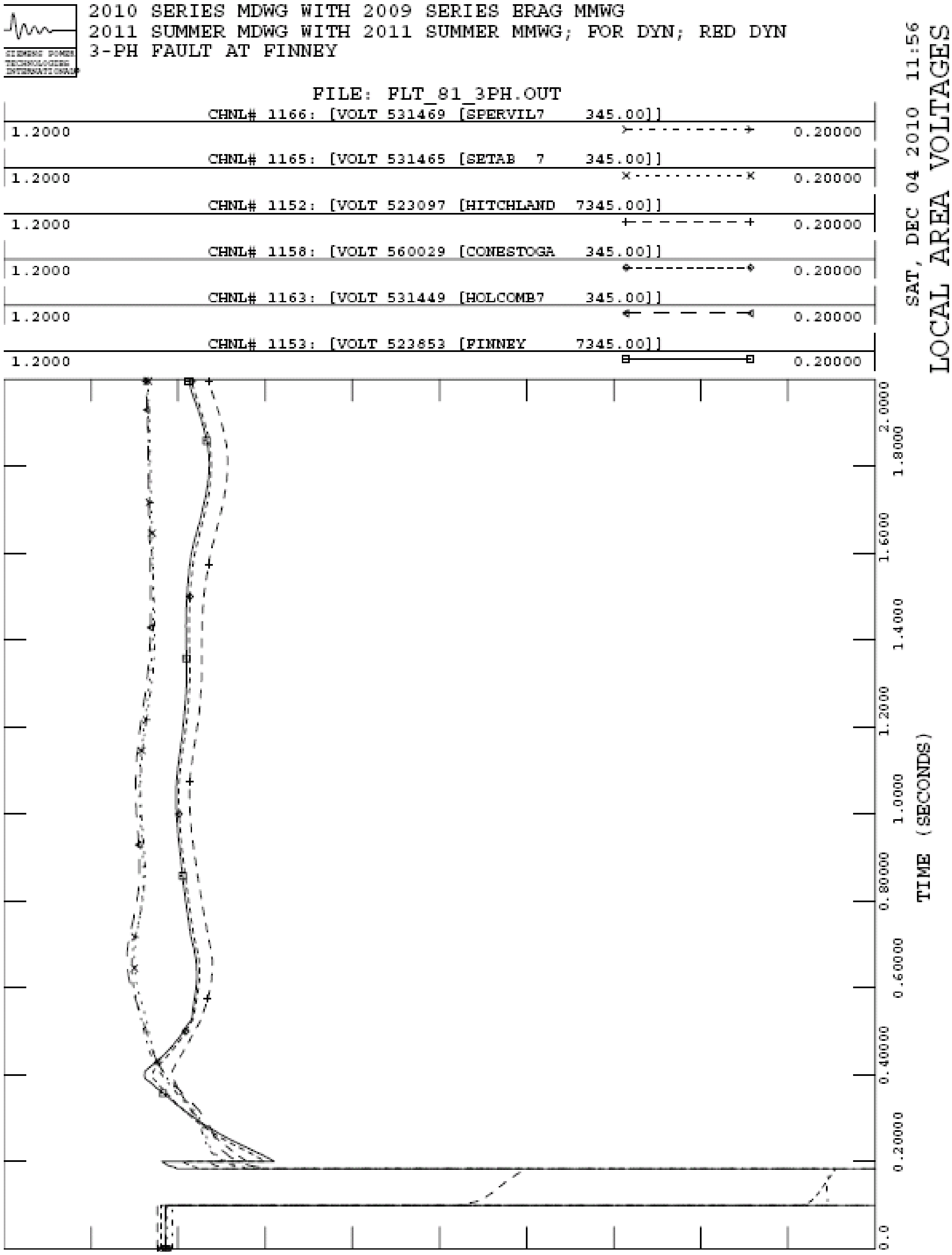

Figure 7-2 Voltage plot for 3-phase fault at Finney 345 kV (FLT_81_3PH) summer peak

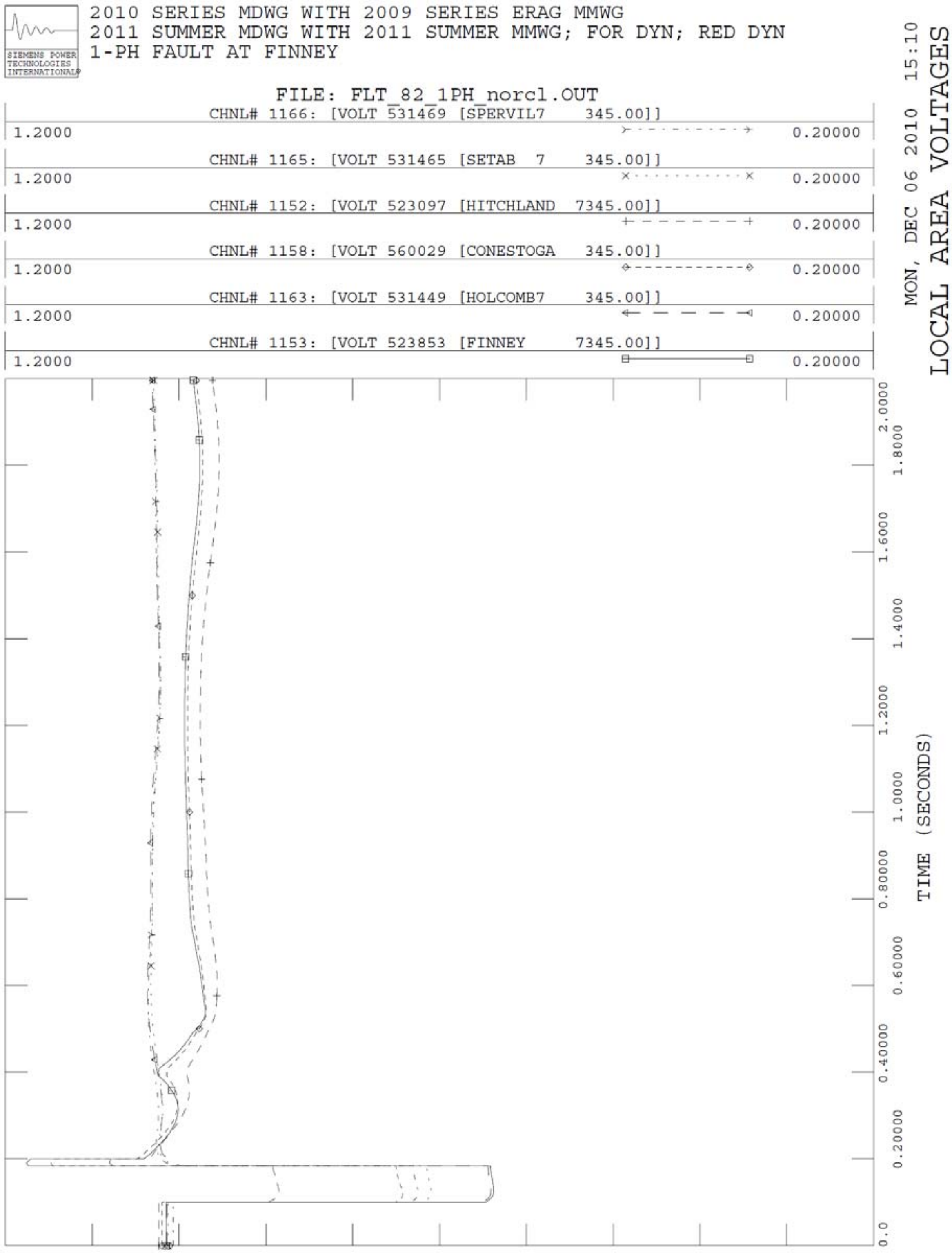

Figure 7-3 Voltage plot for 1-phase fault at Finney 345 kV (FLT_82_1PH) summer peak

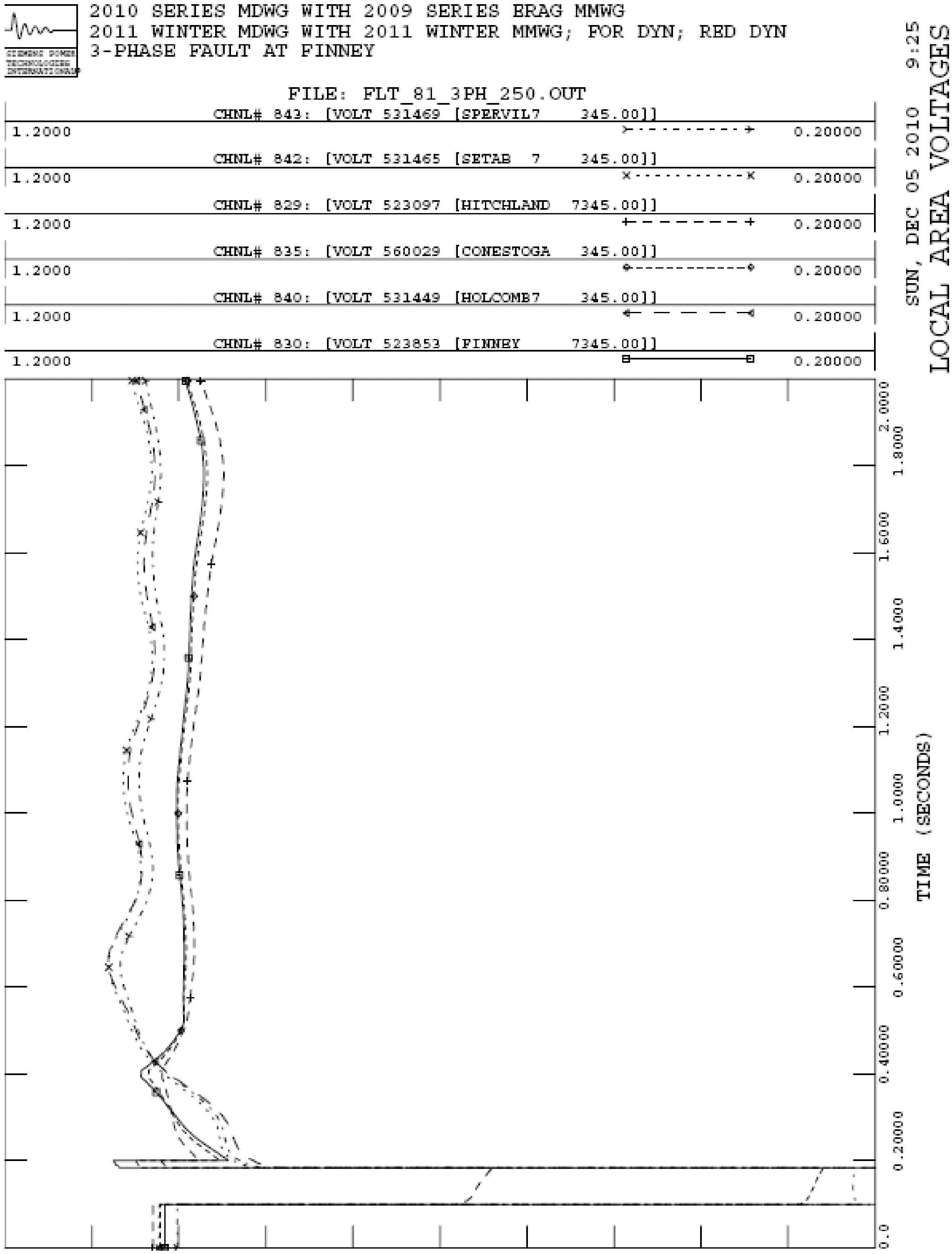

Figure 7-4 Voltage plot for 3-phase fault at Finney 345 kV (FLT_82_3PH) with reduced generation – Winter Peak Load Conditions

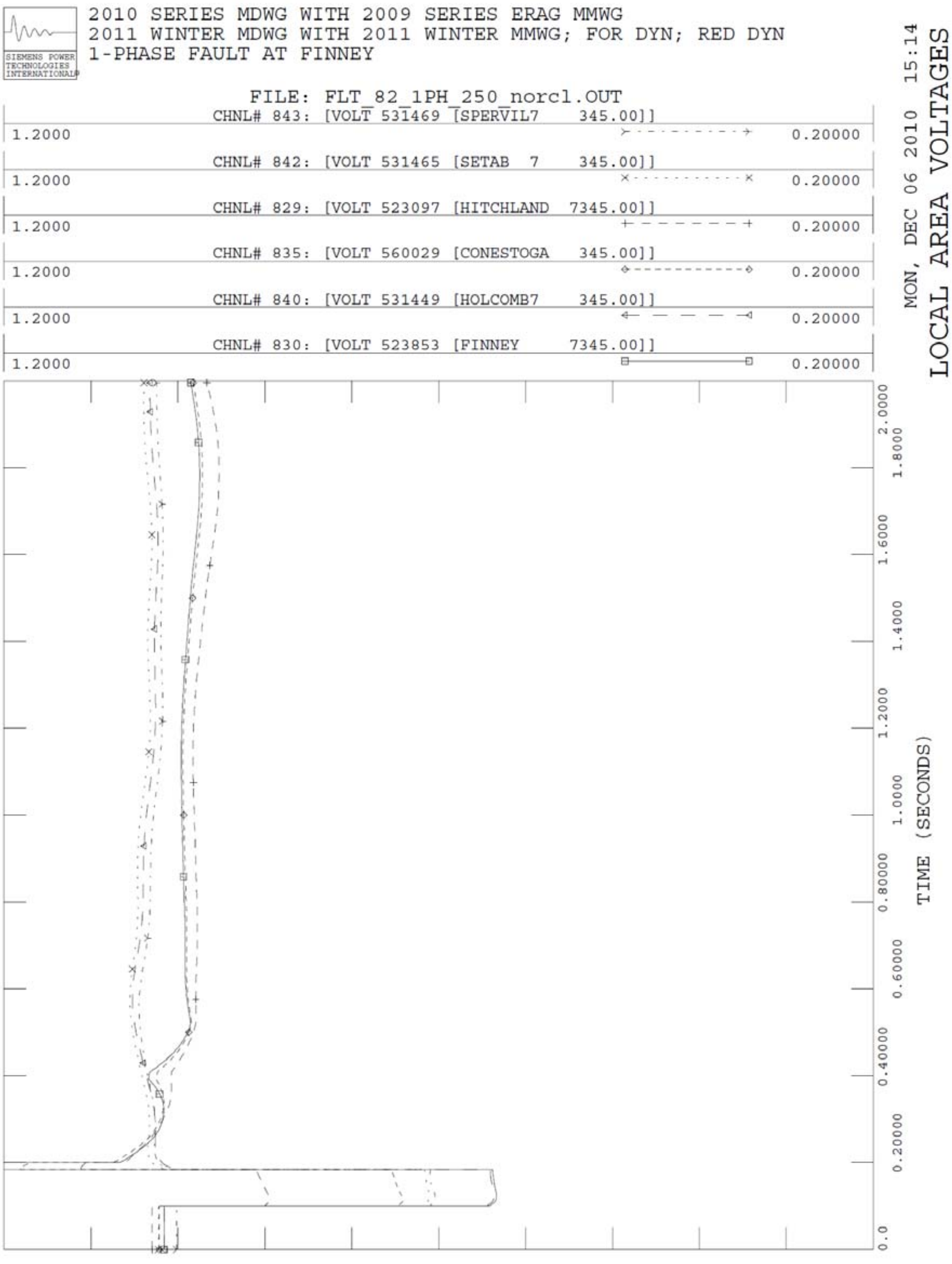

Figure 7-5 Voltage plot for 1-phase fault at Finney 345 kV (FLT_82_1PH) with reduced generation – Winter Peak Load Conditions

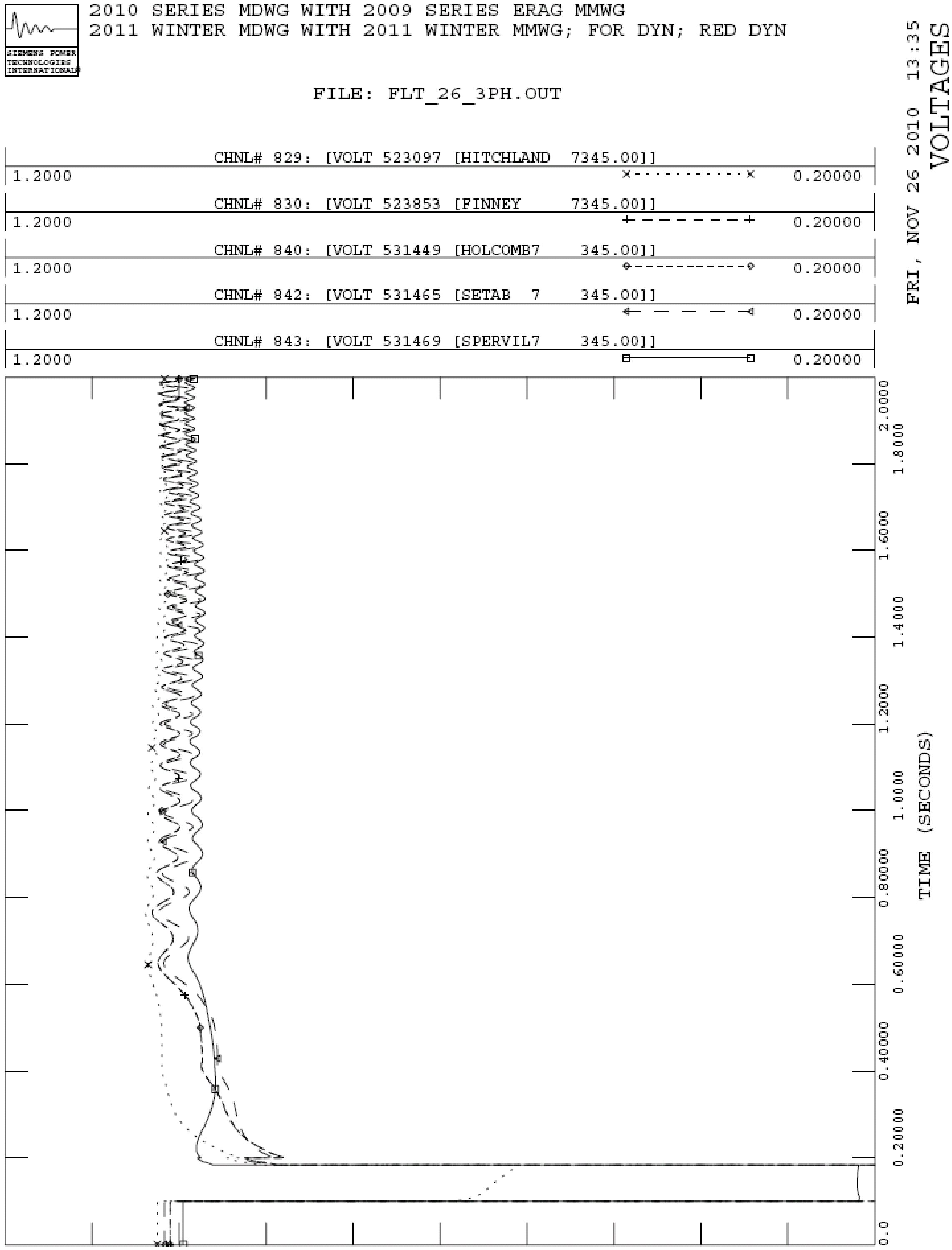

Figure 7-6 Voltage plot oscillations for a 3-phase fault at Holcomb 345 kV (FLT_26_3PH) winter peak

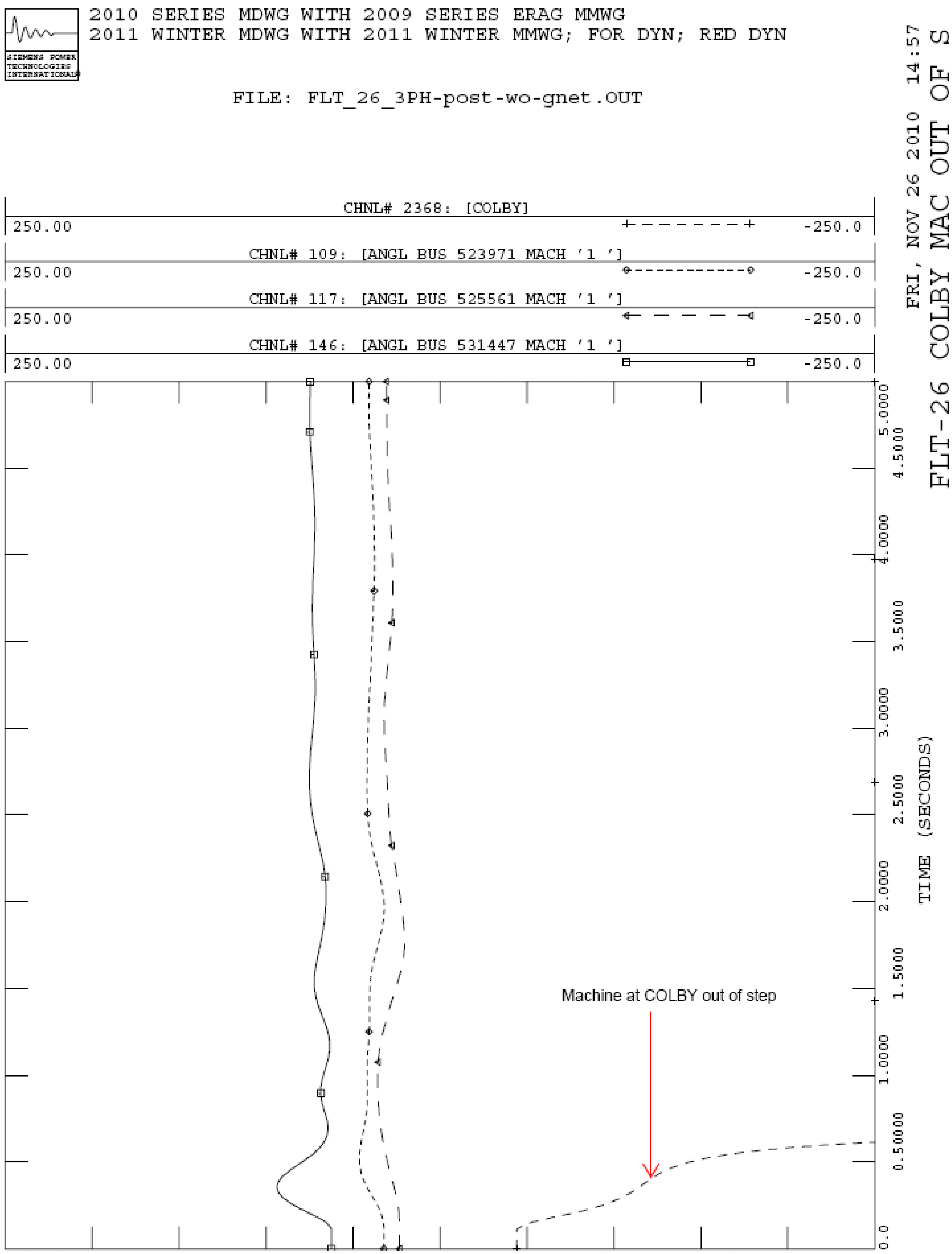

Figure 7-7 Machine at COLBY out of step for a 3-phase fault at Holcomb 345 kV (FLT_26_3PH) winter peak

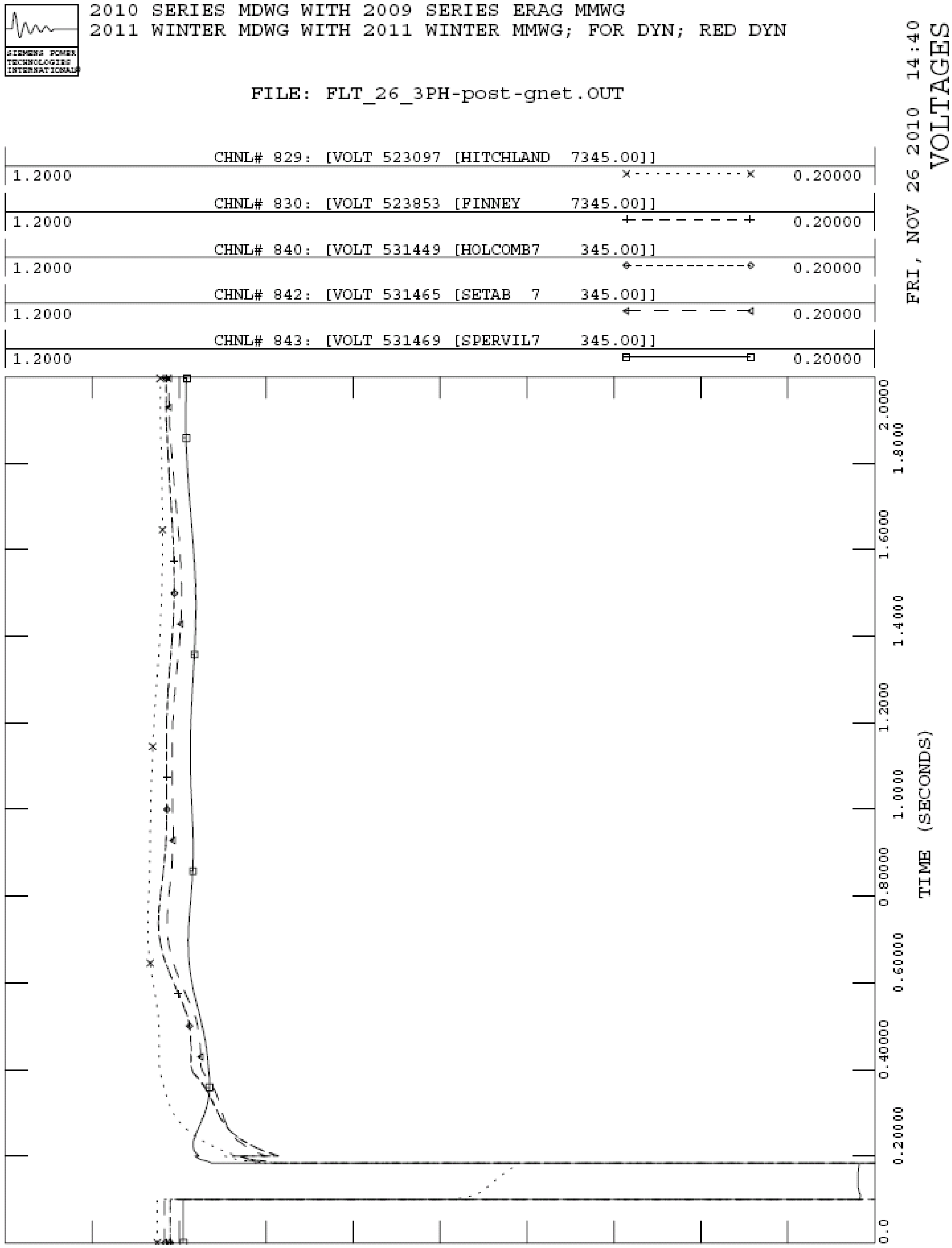

Figure 7-8 Voltage plot after "netted" out the generation at Colby for a 3-phase fault at Holcomb 345 kV (FLT_26_3PH) winter peak

7.1 FERC LVRT COMPLIANCE

This section discusses the FERC mandated LVRT compliance verification for GEN-2006-044 project. As explained in section 2, the proposed project was modeled with manufacturer's default settings. To determine the compliance of the subject wind farm project four (4) faults were simulated. These faults were simulated at the POI of wind farm project and cleared after 9 cycles for 3-phase and 15 cycles for 1-phase faults (i.e. 9 cycle primary clearing followed by a 6 cycle back-up clearing due to a breaker stuck event). Table 7-4 gives the description of faults simulated for LVRT analysis.

Table 7-4: List of faults for FERC LVRT compliance

Fault Name	Description
FLT_01_LVRT_3PH	3 phase fault on the Hitchland (523097) to GEN-2003-013 (560029) 345kV line, near Hitchland
	a. Apply fault at the Hitchland 345kV bus.
	b. Clear fault after 9.0 cycles by tripping the faulted line.
FLT_02_LVRT_1PH	*Single Phase fault Delayed Clearing (9 Cycles + 6 Cycles) and sequence like previous*
FLT_03_LVRT_3PH	3 phase fault on the Hitchland (523097) to GEN-2005-017 (579118) 345kV line, near Hitchland.
	a. Apply fault at the Hitchland 345kV bus.
	b. Clear fault after 9.0 cycles by tripping the faulted line.
FLT_04_LVRT_1PH	*Single Phase fault Delayed Clearing (9 Cycles + 6 Cycles) and sequence like previous*

The results of the simulations indicated that the GEN-2006-044 wind farm project stayed online through the fault duration and recovered to acceptable speed and voltage post-fault clearing. Therefore the subject wind farm meets the FERC LVRT criteria for the interconnection (FERC Order 661 – A). The sample response of GEN-2006-044 project for FLT_01_LVRT_3PH is given in Figure 7-9. This fault is a 3 Phase fault at the POI.

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

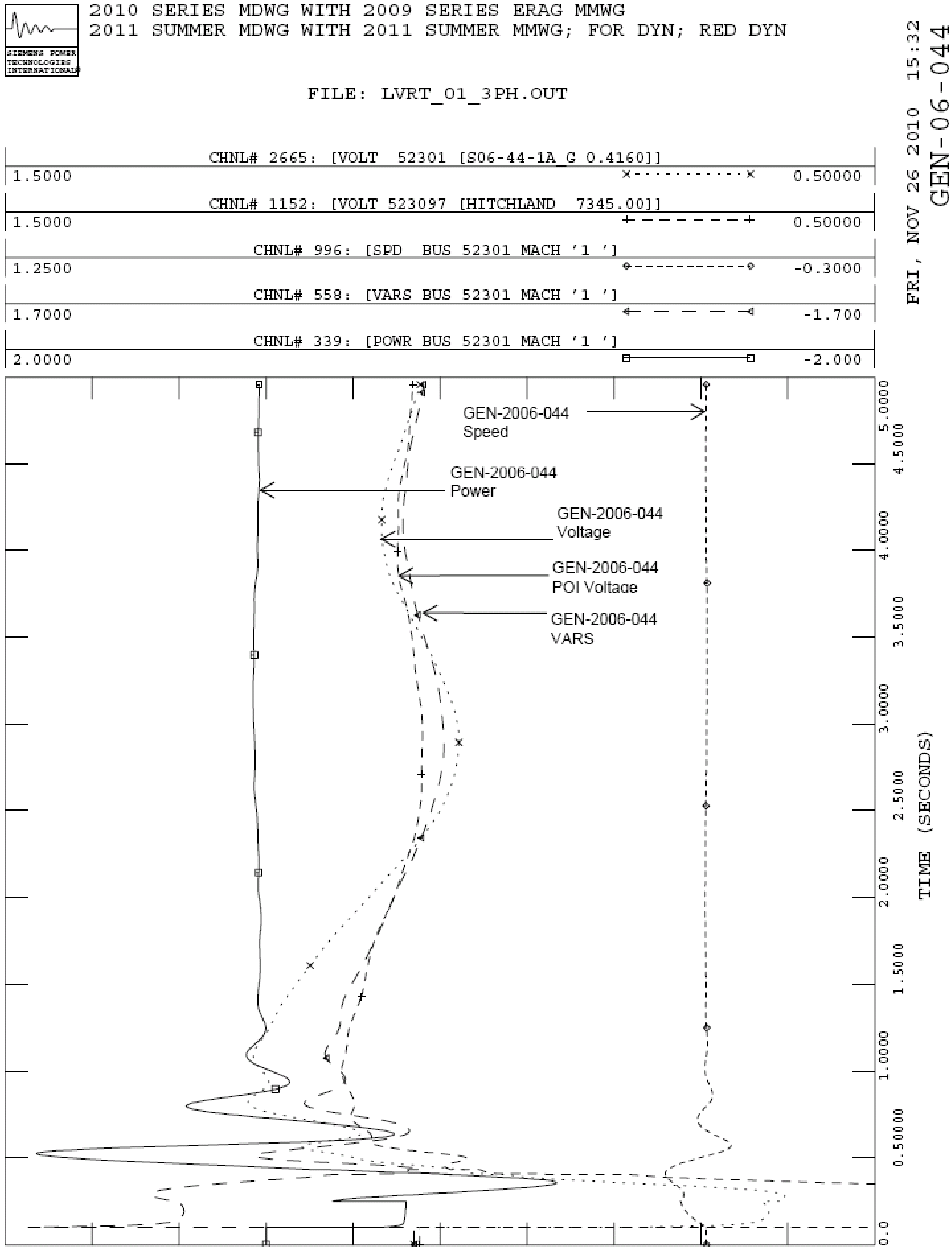

Figure 7-9 GEN-2006-044 response for FLT_01_LVRT_3PH (Summer Peak)

8 CONCLUSIONS

A technical study was performed to evaluate the impact of interconnecting a 370 MW wind based generation to Hitchland 345 kV switching station, in Hansford County, TX. The wind farm consisted of 185 wind turbines, of DeWind make each with a output capability of 2 MW. The detailed wind farm collector system was modeled, along with equivalent wind farm generation. The analysis included a Power Factor analysis and a Stability evaluation. We performed a contingency analysis first, to identify any potential voltage collapse issues. The study outcome and conclusions are given below:

Contingency Analysis:

All tested contingencies were found to result in acceptable voltages at the wind farm POI. However, the outage of Finney – Holcomb 345 kV line showed non-convergence of power flow for summer and well as winter peak load conditions (with the GEN-2006-044 in service). The power flow non-convergence was identified as the result of a lack of reactive power support in Hitchland vicinity. Two options were tested to mitigate the incremental project impact:

i) Reduce the output from GEN-2006-044 – The steady state issues were found to be addressed with GEN-2006-044 output reduced to 250 MW.
ii) Add a 2nd Finney – Holcomb 345 kV line – Addition of this line ensured the injection of the full output (370 MW) from GEN-2006-044 addressed the steady state issues.

Power factor analysis:

The power factor analysis was performed with mitigating measure(s) (i.e. transmission upgrades or reduction in wind farm output) in place where found necessary.

The power factor analysis showed the wind farm has sufficient reactive power capability to maintain a power factor of at least 0.95 at the POI with acceptable POI voltage.

Stability Analysis

All the tested disturbances were found to be stable except those involving the outage of existing Finney – Holcomb 345 kV line; the faults involving the loss of the above facility (FLT_81_3PH and FLT_82_1PH) showed out of step conditions for the winter peak load conditions. Two mitigation options were tested, - i) addition of a 2nd 345 kV line between Finney and Holcomb substations; ii) operate the wind farm at a reduced output of 250 MW. The voltage recovery was acceptable and no specific damping issues were identified due to the proposed wind farm interconnection, considering the above two mitigation options.

FERC Order 661A Compliance

Selected faults were simulated at the Point of Interconnection (POI) of the proposed GEN-2006-044 wind farm to determine the compliance with FERC 661 – A; post-transition period LVRT standard. The results indicated that the proposed project met the FERC LVRT requirement for wind farm interconnection.

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

APPENDIX A LOAD FLOW AND STABILITY DATA IN PSSE FORMAT FOR GEN-06-044 WIND FARM

Loadflow Data

```
2010 SERIES MDWG WITH 2009 SERIES ERAG MMWG
2011 SUMMER MDWG WITH 2011 SUMMER MMWG; FOR DYN; RED DYN
 52301,'S06-44-1A_G ',   0.4160,2,     0.000,     0.000, 526,1502,1.03000, -25.3951,   1
 52302,'S06-44-1B_G ',   0.4160,2,     0.000,     0.000, 526,1502,1.03000, -30.2257,   1
 52303,'S06-44-2A_G ',   0.4160,2,     0.000,     0.000, 526,1502,1.03000, -25.5400,   1
 52304,'S06-44-2B_G ',   0.4160,2,     0.000,     0.000, 526,1502,1.03000, -29.6705,   1
 52305,'S06-44-1A   ',  34.5000,1,     0.000,     0.000, 526,1502,1.01858, -28.0572,   1
 52306,'S06-44-1B   ',  34.5000,1,     0.000,     0.000, 526,1502,1.01142, -32.8528,   1
 52307,'S06-44-2A   ',  34.5000,1,     0.000,     0.000, 526,1502,1.01567, -28.1879,   1
 52308,'S06-44-2B   ',  34.5000,1,     0.000,     0.000, 526,1502,1.01277, -32.3042,   1
 52309,'S06-44-1A_C ',  34.5000,1,     0.000,     0.000, 526,1502,0.99359, -31.1612,   1
 52310,'S06-44-1B_C ',  34.5000,1,     0.000,     0.000, 526,1502,1.00339, -33.1683,   1
 52311,'S06-44-2A_C ',  34.5000,1,     0.000,     0.000, 526,1502,0.99808, -29.9381,   1
 52312,'S06-44-2B_C ',  34.5000,1,     0.000,     0.000, 526,1502,0.99515, -33.0940,   1
 52313,'MS06-44-1A  ', 115.0000,1,     0.000,     0.000, 526,1502,0.98949, -35.0096,   1
 52314,'MS06-44-2A  ', 115.0000,1,     0.000,     0.000, 526,1502,0.98763, -34.2415,   1
 52315,'MS06-44-1   ', 115.0000,1,     0.000,     0.000, 526,1502,0.98553, -37.0103,   1
 52316,'MS06-44-2   ', 115.0000,1,     0.000,     0.000, 526,1502,0.97967, -36.7714,   1
 52317,'GEN-06-044  ', 345.0000,1,     0.000,     0.000, 526,1502,1.02356, -40.9237,   1
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0 / END OF LOAD DATA, BEGIN GENERATOR DATA
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0.00500,   0.11700,   0.00000,   0.00000,1.00000,1,  100.0,    80.000,     0.000,
1,1.0000
 52302,'1 ',    80.000,    21.989,    38.740,   -38.740,1.03000,     0,    88.880,
0.00500,   0.11700,   0.00000,   0.00000,1.00000,1,  100.0,    80.000,     0.000,
1,1.0000
 52303,'1 ',   134.000,    25.069,    64.890,   -64.890,1.03000,     0,   148.870,
0.00500,   0.11700,   0.00000,   0.00000,1.00000,1,  100.0,   134.000,     0.000,
1,1.0000
 52304,'1 ',    76.000,    18.767,    36.800,   -36.800,1.03000,     0,    84.440,
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1,1.0000
0 / END OF GENERATOR DATA, BEGIN BRANCH DATA
 52305,  52309,'1 ',   0.02747,   0.07141,   0.01542,    0.00,    0.00,    0.00,
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 52307,  52311,'1 ',   0.01008,   0.02476,   0.02478,    0.00,    0.00,    0.00,
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 52308,  52312,'1 ',   0.01882,   0.02253,   0.03060,    0.00,    0.00,    0.00,
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 52313,  52315,'1 ',   0.00661,   0.04378,   0.00622,    0.00,    0.00,    0.00,
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 52314,  52316,'1 ',   0.00497,   0.03290,   0.00468,    0.00,    0.00,    0.00,
0.00000,  0.00000,  0.00000,  0.00000,1,   0.00,   1,1.0000
 52317, 523097,'1 ',   0.00003,   0.00024,   0.00472,    0.00,    0.00,    0.00,
0.00000,  0.00000,  0.00000,  0.00000,1,   0.00,   1,1.0000
0 / END OF BRANCH DATA, BEGIN TRANSFORMER DATA
 52305, 52301,     0,'1 ',1,2,1,   0.00000,   0.00000,2,'WTG-TR1A    ',1,   1,1.0000
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1.00000,   0.000,   0.000,    92.00,     0.00,     0.00, 0,      0, 1.10000, 0.90000,
1.10000, 0.90000,  33, 0, 0.00000, 0.00000
1.00000,   0.000
 52306, 52302,     0,'1 ',1,2,1,   0.00000,   0.00000,2,'WTG-TR1A    ',1,   1,1.0000
   0.00760,   0.05700,   92.00
1.00000,   0.000,   0.000,    92.00,     0.00,     0.00, 0,      0, 1.10000, 0.90000,
1.10000, 0.90000,  33, 0, 0.00000, 0.00000
1.00000,   0.000
 52307, 52303,     0,'1 ',1,2,1,   0.00000,   0.00000,2,'WTG-TR2A    ',1,   1,1.0000
   0.00760,   0.05700,   154.10
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1.00000,   0.000,   0.000,   154.10,     0.00,     0.00, 0,      0, 1.10000, 0.90000,
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1.00000,   0.000
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1.00000,   0.000
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1.00000,   0.000
 52315, 52310,     0,'1 ',1,2,1,   0.00000,   0.00000,2,'T2          ',1,   1,1.0000
   0.00424,   0.08500,   100.00
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1.10000, 0.90000,  33, 0, 0.00000, 0.00000
1.00000,   0.000
 52314, 52311,     0,'1 ',1,2,1,   0.00000,   0.00000,2,'T3          ',1,   1,1.0000
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 52316, 52312,     0,'1 ',1,2,1,   0.00000,   0.00000,2,'T4          ',1,   1,1.0000
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1.00000,   0.000
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1.10000, 0.90000,  33, 0, 0.00000, 0.00000
1.00000,   0.000
 52317, 52316,     0,'1 ',1,2,1,   0.00000,   0.00000,2,'MAIN-TR1    ',1,   1,1.0000
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1.10000, 0.90000,  33, 0, 0.00000, 0.00000
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0 / END OF SWITCHED SHUNT DATA, BEGIN IMPEDANCE CORRECTION DATA
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0 / END OF OWNER DATA, BEGIN FACTS DEVICE DATA
0 / END OF FACTS DEVICE DATA
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Dynamics Data

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2010 SERIES MDWG WITH 2009 SERIES ERAG MMWG
2011 SUMMER MDWG WITH 2011 SUMMER MMWG; FOR DYN; RED DYN

PLANT MODELS

REPORT FOR ALL MODELS                     BUS 52301 [S06-44-1A_G 0.4160] MODELS


** GENSAL **  BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S
             52301 S06-44-1A_G  0.4160 1  123036-123047  44403-44407

             MBASE     Z S O R C E         X T R A N       GENTAP
              88.9  0.00500+J 0.11700  0.00000+J 0.00000  1.00000

  T'D0   T''D0   T''Q0     H    DAMP    XD      XQ      X'D    X''D     XL
 2.850   0.018   0.050   0.66   0.00  1.3000  1.1700  0.1300  0.1170  0.0780

                              S(1.0)  S(1.2)
                              0.1000  0.4000


** ESAC5A **  BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S     VAR
             52301 S06-44-1A_G  0.4160 1  123084-123098  44423-44427   16629

   TR      KA     TA   VRMAX   VRMIN     KE     TE     KF     TF1    TF2    TF3
 0.010  500.00  0.100 15.600   0.000   1.000  0.910  0.020  0.100  0.700  0.000

                  E1     S(E1)    E2     S(E2)       KE VAR
                0.0000  1.1000  8.9000  1.9000       0.0000


 ** DWD8G1 **  BUS MACH     C O N S     S T A T E S     V A R S    I C O N S
             52301   1    *****-*****   44443-44447   16633-16644   15870-15870

    PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E     FRI, NOV 26 2010  18:58
2010 SERIES MDWG WITH 2009 SERIES ERAG MMWG
2011 SUMMER MDWG WITH 2011 SUMMER MMWG; FOR DYN; RED DYN

PLANT MODELS

REPORT FOR ALL MODELS                     BUS 52302 [S06-44-1B_G 0.4160] MODELS


** GENSAL **  BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S
             52302 S06-44-1B_G  0.4160 1  123048-123059  44408-44412

             MBASE     Z S O R C E         X T R A N       GENTAP
              88.9  0.00500+J 0.11700  0.00000+J 0.00000  1.00000

  T'D0   T''D0   T''Q0     H    DAMP    XD      XQ      X'D    X''D     XL
 2.850   0.018   0.050   0.66   0.00  1.3000  1.1700  0.1300  0.1170  0.0780

                              S(1.0)  S(1.2)
                              0.1000  0.4000


** ESAC5A **  BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S     VAR
             52302 S06-44-1B_G  0.4160 1  123099-123113  44428-44432   16630

   TR      KA     TA   VRMAX   VRMIN     KE     TE     KF     TF1    TF2    TF3
 0.010  500.00  0.100 15.600   0.000   1.000  0.910  0.020  0.100  0.700  0.000

                  E1     S(E1)    E2     S(E2)       KE VAR
                0.0000  1.1000  8.9000  1.9000       0.0000


 ** DWD8G1 **  BUS MACH     C O N S     S T A T E S     V A R S    I C O N S
             52302   1    *****-*****   44448-44452   16645-16656   15871-15871
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    PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E     FRI, NOV 26 2010  18:58
2010 SERIES MDWG WITH 2009 SERIES ERAG MMWG
2011 SUMMER MDWG WITH 2011 SUMMER MMWG; FOR DYN; RED DYN

PLANT MODELS

REPORT FOR ALL MODELS                    BUS 52303 [S06-44-2A_G 0.4160] MODELS


** GENSAL **  BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S
            52303 S06-44-2A_G  0.4160 1  123060-123071  44413-44417

            MBASE     Z S O R C E        X T R A N      GENTAP
            148.9  0.00500+J 0.11700  0.00000+J 0.00000  1.00000

  T'D0   T''D0   T''Q0     H    DAMP    XD      XQ      X'D    X''D     XL
 2.850   0.018   0.050   0.66   0.00  1.3000  1.1700  0.1300  0.1170  0.0780

                              S(1.0)  S(1.2)
                              0.1000  0.4000


** ESAC5A **  BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S     VAR
            52303 S06-44-2A_G  0.4160 1  123114-123128  44433-44437   16631

   TR      KA     TA   VRMAX   VRMIN     KE     TE     KF     TF1    TF2    TF3
 0.010  500.00  0.100 15.600   0.000   1.000  0.910  0.020  0.100  0.700  0.000

                 E1     S(E1)    E2     S(E2)       KE VAR
               0.0000  1.1000  8.9000  1.9000       0.0000


 ** DWD8G1 **  BUS MACH     C O N S     S T A T E S     V A R S    I C O N S
            52303   1    *****-*****   44453-44457   16657-16668   15872-15872

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2011 SUMMER MDWG WITH 2011 SUMMER MMWG; FOR DYN; RED DYN

PLANT MODELS

REPORT FOR ALL MODELS                    BUS 52304 [S06-44-2B_G 0.4160] MODELS


** GENSAL **  BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S
            52304 S06-44-2B_G  0.4160 1  123072-123083  44418-44422

            MBASE     Z S O R C E        X T R A N      GENTAP
             84.4  0.00500+J 0.11700  0.00000+J 0.00000  1.00000

  T'D0   T''D0   T''Q0     H    DAMP    XD      XQ      X'D    X''D     XL
 2.850   0.018   0.050   0.66   0.00  1.3000  1.1700  0.1300  0.1170  0.0780

                              S(1.0)  S(1.2)
                              0.1000  0.4000


** ESAC5A **  BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S     VAR
            52304 S06-44-2B_G  0.4160 1  123129-123143  44438-44442   16632

   TR      KA     TA   VRMAX   VRMIN     KE     TE     KF     TF1    TF2    TF3
 0.010  500.00  0.100 15.600   0.000   1.000  0.910  0.020  0.100  0.700  0.000

                 E1     S(E1)    E2     S(E2)       KE VAR
               0.0000  1.1000  8.9000  1.9000       0.0000


 ** DWD8G1 **  BUS MACH     C O N S     S T A T E S     V A R S    I C O N S
            52304   1    *****-*****   44458-44462   16669-16680   15873-15873
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APPENDIX B Results from Power Factor Analysis - Gen-06-044 POI voltages without VAR generator

GEN-2006-044 generation with reduced output of 250 MW

Contingency	Contingency Description	POI VOLTAGES		GEN-2006-044 POI power factor					
		Summer Peak	Winter Peak	Summer Peak			Winter Peak		
		(#523097)		Q (MVAR)	P (MW)	p.f	Q (MVAR)	P (MW)	p.f
CONT_00	BASECASE	1.028	1.030	-29.8	-245.0	0.993	-27.0	-244.9	0.994
CONT_01	BUS 523097 [HITCHLAND 7345.00] TO BUS 560029 [CONESTOGA 345.00] CKT 1	1.025	1.026	-34.4	-245.0	0.990	-31.7	-244.8	0.992
CONT_02	BUS 523097 [HITCHLAND 7345.00] TO BUS 579118 [2005-017 345.00] CKT 1	1.028	1.034	-30.1	-245.0	0.993	-20.8	-244.9	0.996
CONT_03	BUS 523097 [HITCHLAND 7345.00] TO BUS 579067 [GEN-008 345.00] CKT 1	1.030	1.036	-27.2	-244.9	0.994	-18.8	-244.9	0.997
CONT_04	BUS 523095 [HITCHLAND 6230.00] TO BUS 523097 [HITCHLAND 7345.00] TO BUS	1.028	1.030	-31.8	-245.0	0.992	-26.1	-244.9	0.994
CONT_05	BUS 523095 [HITCHLAND 6230.00] TO BUS 523309 [MOORE_CNTY 6230.00] CKT 1	1.031	1.032	-25.8	-245.0	0.995	-23.7	-244.9	0.995
CONT_06	BUS 579118 [2005-017 345.00] TO BUS 523961 [POTTER_CO 7345.00] CKT 1	1.009	1.015	-56.3	-244.5	0.974	-47.8	-244.6	0.981
CONT_07	BUS 523309 [MOORE_CNTY 6230.00] TO BUS 523959 [POTTER_CO 6230.00] CKT 1	1.028	1.030	-30.0	-244.8	0.993	-26.7	-244.9	0.994
CONT_08	BUS 523267 [PRINGLE 6230.00] TO BUS 523979 [HARRNG_EST 6230.00] CKT 1	1.028	1.030	-29.3	-244.8	0.993	-26.5	-244.9	0.994
CONT_09	BUS 560029 [CONESTOGA 345.00] TO BUS 523853 [FINNEY 7345.00] CKT 1	1.024	1.025	-35.8	-244.8	0.989	-33.6	-244.8	0.991
CONT_10	BUS 531449 [HOLCOMB7 345.00] TO BUS 531465 [SETAB 7 345.00] CKT 1	1.026	1.028	-31.9	-244.8	0.992	-30.2	-244.8	0.992
CONT_11	BUS 531449 [HOLCOMB7 345.00] TO BUS 531469 [SPERVIL7 345.00] CKT 1	1.025	1.029	-33.1	-244.8	0.991	-28.8	-244.8	0.993
CONT_12	BUS 515375 [WWRDEHV7 345.00] TO BUS 515407 [TATONGA7 345.00] CKT 1	1.028	1.030	-29.8	-244.8	0.993	-27.0	-244.9	0.994
CONT_13	BUS 523093 [HITCHLAND 3115.00] TO BUS 523160 [DWS_FRISCO 3115.00] CKT 1	1.027	1.029	-29.8	-244.8	0.993	-27.5	-244.9	0.994
	BUS 523160 [DWS_FRISCO 3115.00] TO BUS 523175 [LASLEY 3115.00] CKT 1								
	BUS 523175 [LASLEY 3115.00] TO BUS 523168 [SHERMAN 3115.00] CKT 1								
	BUS 523175 [LASLEY 3115.00] TO BUS 523177 [RB-SPURLOCK3115.00] CKT 1								

Contingency	Contingency Description	POI VOLTAGES		GEN-2006-044 POI power factor					
		Summer Peak	Winter Peak	Summer Peak			Winter Peak		
		(#523097)		Q (MVAR)	P (MW)	p.f	Q (MVAR)	P (MW)	p.f
	BUS 523177 [RB-SPURLOCK3115.00] TO BUS 523308 [MOORE_E 3115.00] CKT 1								
CONT_14	BUS 523093 [HITCHLAND 3115.00] TO BUS 523195 [HANSFORD 3115.00] CKT 1	1.028	1.030	-29.9	-244.8	0.993	-27.3	-244.9	0.994
CONT_15	BUS 523093 [HITCHLAND 3115.00] TO BUS 523095 [HITCHLAND 6230.00] TO BU	1.026	1.029	-31.8	-244.8	0.992	-28.6	-244.8	0.993
CONT_16	BUS 523266 [PRINGLE 3115.00] TO BUS 523186 [SPEARMAN 3115.00] CKT 1	1.028	1.030	-29.9	-244.8	0.993	-27.0	-244.9	0.994
CONT_17	BUS 523308 [MOORE_E 3115.00] TO BUS 523216 [RB-HOGUE 3115.00] CKT 1	1.028	1.030	-29.9	-244.8	0.993	-27.0	-244.9	0.994
CONT_18	BUS 523304 [MOORE_W 3115.00] TO BUS 523318 [DUMAS_19ST 3115.00] CKT 1	1.028	1.030	-29.1	-244.8	0.993	-26.5	-244.9	0.994
CONT_19	BUS 523304 [MOORE_W 3115.00] TO BUS 523366 [RB-SNEED 3115.00] CKT 1	1.028	1.030	-30.0	-244.8	0.993	-26.5	-244.9	0.994
CONT_20	BUS 523308 [MOORE_E 3115.00] TO BUS 523309 [MOORE_CNTY 6230.00] CKT 1	1.029	1.031	-28.5	-244.8	0.993	-25.8	-244.9	0.994
CONT_21	BUS 523186 [SPEARMAN 3115.00] TO BUS 523203 [SPEARMNSUB 3115.00] CKT 1	1.028	1.030	-28.9	-244.8	0.993	-26.8	-244.9	0.994
CONT_22	BUS 523090 [TEXAS_CNTY 3115.00] TO BUS 523106 [TXPHSF 3115.00] CKT 1	1.028	1.030	-29.4	-244.8	0.993	-27.4	-244.9	0.994
CONT_23	BUS 523377 [RIVERVIEW 3115.00] TO BUS 523266 [PRINGLE 3115.00] CKT 1	1.028	1.030	-30.1	-244.8	0.993	-27.2	-244.9	0.994
CONT_24	BUS 523266 [PRINGLE 3115.00] TO BUS 523267 [PRINGLE 6230.00] TO BU	1.028	1.030	-29.2	-244.8	0.993	-26.4	-244.9	0.994
CONT_25	BUS 523377 [RIVERVIEW 3115.00] TO BUS 523352 [HERRING_TP 3115.00] CKT 1	1.027	1.030	-30.6	-244.8	0.992	-27.3	-244.9	0.994
CONT_26	BUS 523377 [RIVERVIEW 3115.00] TO BUS 523403 [CRMWA_#1 3115.00] CKT 1	1.028	1.030	-29.8	-244.8	0.993	-26.9	-244.9	0.994
CONT_27	BUS 523546 [HUTCH_S 3115.00] TO BUS 523551 [HUTCHISON 6230.00] CKT 1	1.028	1.030	-29.9	-244.8	0.993	-27.0	-244.9	0.994
CONT_28	BUS 523266 [PRINGLE 3115.00] TO BUS 523478 [Q_RYTON_TP 3115.00] CKT 1	1.028	1.030	-30.1	-244.8	0.993	-27.1	-244.9	0.994
CONT_29	BUS 523853 [FINNEY 345.00] TO BUS 531449 [HOLCOMB 345.00] CKT 1	0.995	0.983	-71.9	-244.1	0.959	-73.9	-244.1	0.957

Addition of new second line between Finney – Holcomb for full GEN-2006-044 output of 370 MW

Contingency	Contingency Description	POI VOLTAGES		GEN-2006-044 POI power factor					
		Summer Peak	Winter Peak	Summer Peak			Winter Peak		
		(#523097)		Q (MVAR)	P (MW)	p.f	Q (MVAR)	P (MW)	p.f
CONT_00	BASECASE	1.023	1.025	1.7	-358.9	1.000	3.9	-358.9	1.000
CONT_01	BUS 523097 [HITCHLAND 7345.00] TO BUS 560029 [CONESTOGA 345.00] CKT 1	1.016	1.018	-9.1	-358.7	1.000	-6.2	-358.8	1.000
CONT_02	BUS 523097 [HITCHLAND 7345.00] TO BUS 579118 [2005-017 345.00] CKT 1	1.016	1.022	-8.4	-358.7	1.000	0.2	-358.9	1.000
CONT_03	BUS 523097 [HITCHLAND 7345.00] TO BUS 579067 [GEN-008 345.00] CKT 1	1.026	1.028	4.8	-358.9	1.000	8.5	-358.9	1.000
CONT_04	BUS 523095 [HITCHLAND 6230.00] TO BUS 523097 [HITCHLAND 7345.00] TO BUS	1.017	1.021	-7.7	-358.8	1.000	-1.2	-358.9	1.000
CONT_05	BUS 523095 [HITCHLAND 6230.00] TO BUS 523309 [MOORE_CNTY 6230.00] CKT 1	1.025	1.027	3.8	-358.9	1.000	6.9	-358.9	1.000
CONT_06	BUS 579118 [2005-017 345.00] TO BUS 523961 [POTTER_CO 7345.00] CKT 1		1.006	-31.4	-358.3	0.996	-22.1	-358.9	0.998
CONT_07	BUS 523309 [MOORE_CNTY 6230.00] TO BUS 523959 [POTTER_CO 6230.00] CKT 1	1.023	1.025	1.4	-358.9	1.000	3.9	-358.9	1.000
CONT_08	BUS 523267 [PRINGLE 6230.00] TO BUS 523979 [HARRNG_EST 6230.00] CKT 1	1.024	1.025	2.1	-358.9	1.000	4.4	-358.9	1.000
CONT_09	BUS 560029 [CONESTOGA 345.00] TO BUS 523853 [FINNEY 7345.00] CKT 1	1.009	1.009	-17.8	-358.6	0.999	-18.8	-358.6	0.999
CONT_10	BUS 531449 [HOLCOMB7 345.00] TO BUS 531465 [SETAB 7 345.00] CKT 1	1.021	1.023	-1.3	-358.9	1.000	0.4	-358.9	1.000
CONT_11	BUS 531449 [HOLCOMB7 345.00] TO BUS 531469 [SPERVIL7 345.00] CKT 1	1.020	1.024	-3.4	-358.8	1.000	2.2	-358.9	1.000
CONT_12	BUS 515375 [WWRDEHV7 345.00] TO BUS 515407 [TATONGA7 345.00] CKT 1	1.023	1.025	1.7	-358.9	1.000	3.8	-358.9	1.000
CONT_13	BUS 523093 [HITCHLAND 3115.00] TO BUS 523160 [DWS_FRISCO 3115.00] CKT 1								
	BUS 523160 [DWS_FRISCO 3115.00] TO BUS 523175 [LASLEY 3115.00] CKT 1								
	BUS 523175 [LASLEY 3115.00] TO BUS 523168 [SHERMAN 3115.00] CKT 1								
	BUS 523175 [LASLEY 3115.00] TO BUS 523177 [RB-SPURLOCK3115.00] CKT 1								
	BUS 523177 [RB-SPURLOCK3115.00] TO BUS 523308 [MOORE_E 3115.00] CKT 1	1.023	1.025	1.0	-358.9	1.000	3.3	-358.9	1.000
CONT_14	BUS 523093 [HITCHLAND 3115.00] TO BUS 523195 [HANSFORD 3115.00] CKT 1	1.023	1.025	1.4	-358.9	1.000	3.5	-358.9	1.000
CONT_15	BUS 523093 [HITCHLAND 3115.00] TO BUS 523095 [HITCHLAND 6230.00] TO BU	1.022	1.024	-1.0	-358.9	1.000	2.0	-358.9	1.000

Contingency	Contingency Description	POI VOLTAGES		GEN-2006-044 POI power factor					
		Summer Peak	Winter Peak	Summer Peak			Winter Peak		
		(#523097)		Q (MVAR)	P (MW)	p.f	Q (MVAR)	P (MW)	p.f
CONT_16	BUS 523266 [PRINGLE 3115.00] TO BUS 523186 [SPEARMAN 3115.00] CKT 1	1.023	1.025	1.6	-358.9	1.000	3.9	-358.9	1.000
CONT_17	BUS 523308 [MOORE_E 3115.00] TO BUS 523216 [RB-HOGUE 3115.00] CKT 1	1.023	1.025	1.6	-358.9	1.000	3.8	-358.9	1.000
CONT_18	BUS 523304 [MOORE_W 3115.00] TO BUS 523318 [DUMAS_19ST 3115.00] CKT 1	1.024	1.025	2.2	-358.9	1.000	4.3	-358.9	1.000
CONT_19	BUS 523304 [MOORE_W 3115.00] TO BUS 523366 [RB-SNEED 3115.00] CKT 1	1.023	1.025	1.5	-358.9	1.000	4.0	-358.9	1.000
CONT_20	BUS 523308 [MOORE_E 3115.00] TO BUS 523309 [MOORE_CNTY 6230.00] CKT 1	1.024	1.026	2.8	-358.9	1.000	4.9	-358.9	1.000
CONT_21	BUS 523186 [SPEARMAN 3115.00] TO BUS 523203 [SPEARMNSUB 3115.00] CKT 1	1.024	1.025	2.4	-358.9	1.000	3.9	-358.9	1.000
CONT_22	BUS 523090 [TEXAS_CNTY 3115.00] TO BUS 523106 [TXPHSF 3115.00] CKT 1	1.024	1.025	2.0	-358.9	1.000	3.3	-358.9	1.000
CONT_23	BUS 523377 [RIVERVIEW 3115.00] TO BUS 523266 [PRINGLE 3115.00] CKT 1	1.023	1.025	1.4	-358.9	1.000	3.6	-358.9	1.000
CONT_24	BUS 523266 [PRINGLE 3115.00] TO BUS 523267 [PRINGLE 6230.00] TO BU	1.024	1.025	2.1	-358.9	1.000	4.4	-358.9	1.000
CONT_25	BUS 523377 [RIVERVIEW 3115.00] TO BUS 523352 [HERRING_TP 3115.00] CKT 1	1.023	1.025	0.9	-358.9	1.000	3.6	-358.9	1.000
CONT_26	BUS 523377 [RIVERVIEW 3115.00] TO BUS 523403 [CRMWA_#1 3115.00] CKT 1	1.024	1.025	1.7	-358.9	1.000	3.9	-358.9	1.000
CONT_27	BUS 523546 [HUTCH_S 3115.00] TO BUS 523551 [HUTCHISON 6230.00] CKT 1	1.023	1.025	1.6	-358.9	1.000	3.8	-358.9	1.000
CONT_28	BUS 523266 [PRINGLE 3115.00] TO BUS 523478 [Q_RYTON_TP 3115.00] CKT 1	1.023	1.025	1.4	-358.9	1.000	3.7	-358.9	1.000
CONT_29	BUS 523853 [FINNEY 345.00] TO BUS 531449 [HOLCOMB 345.00] CKT 1	1.023	1.025	13.1	-359.0	0.999	3.9	-358.9	0.957

APPENDIX C Plots from Stability Simulations

APPENDIX D PLOTS FROM LVRT SIMULATIONS