Preliminary Interconnection System Impact Study for Generation Interconnection Requests

(PISIS-2011-001)

August 2011

Generation Interconnection

Southwest Power Pool

Revision History

Date or Version Number	Author	Change Description	Comments
8/31/2011	Southwest Power Pool	N/A	Report Issued
09/08/2011	Southwest Power Pool	Report reposted to list GEN-2010-044 in Group 13 of power flow section	Report Posted

Executive Summary

Generation Interconnection customers have requested a Preliminary Interconnection System Impact Study (PISIS) under the Generation Interconnection Procedures (GIP) in the Southwest Power Pool Open Access Transmission Tariff (OATT). The Interconnection Customers' requests have been clustered together for the following Impact Cluster Study. This Impact Study analyzes the interconnecting of multiple generation interconnection requests associated with new generation totaling approximately 479.0 MW of new generation which would be located within the transmission systems of Mid-Kansas Electric Power LLC (MKEC), Missouri Public Service (MIPU), Nebraska Public Power District (NPPD), Midwest Energy Inc. (MIDW), Oklahoma Gas and Electric (OKGE), Omaha Public Power District (OPPD), Southwestern Public Service (SPS), Sunflower Electric Power Corporation (SUNC), Westar Energy (WERE) and Western Farmers Electric Cooperative (WFEC). The various generation interconnection requests have differing proposed in-service dates[1]. The generation interconnection requests included in this Impact Cluster Study are listed in Appendix A by their queue number, amount, requested interconnection service, area, requested interconnection point, proposed interconnection point, and the requested in-service date.

Power flow analysis has indicated that for the power flow cases studied, 479.0 MW of nameplate generation may be interconnected with transmission system reinforcements within the SPP transmission system. Dynamic Stability and power factor analysis has determined the need for reactive compensation in accordance with Order No. 661-A for wind farm interconnection requests and those requirements are listed for each interconnection request within the contents of this report.

Dynamic Stability Analysis has determined that the transmission system will remain stable with the assigned Network Upgrades and necessary reactive compensation requirements.

The total estimated minimum cost for interconnecting the PISIS-2011-001 interconnection customers is $58,450,000. These costs are shown in Appendix E and F. Interconnection Service to PISIS-2011-001 interconnection customers is also contingent upon higher queued customers paying for certain required network upgrades. **The in service date for the PISIS customers will be deferred until the construction of these network upgrades can be completed.**

These costs do not include the Interconnection Customer Interconnection Facilities as defined by the SPP Open Access Transmission Tariff (OATT). This cost does not include additional network constraints in the SPP transmission system that were identified as shown in Appendix H.

[1] The generation interconnection requests in-service dates will need to be deferred based on the required lead time for the Network Upgrades necessary. The Interconnection Customer's that proceed to the Facility Study will be provided a new in-service date based on the competition of the Facility Study. time for the Network Upgrades necessary. The Interconnection Customer's that proceed to the Facility Study will be provided a new in-service date based on the competition of the Facility Study.

Network Constraints listed in Appendix H are in the local area of the new generation when this generation is injected throughout the SPP footprint for the Energy Resource (ER) Interconnection Request. Certain Interconnection Requests were studied for Network Resource Interconnection Service (NR). Those constraints are listed in Appendix H. Additional Network constraints will have to be verified with a Transmission Service Request (TSR) and associated studies. With a defined source and sink in a TSR, this list of Network Constraints will be refined and expanded to account for all Network Upgrade requirements.

The required interconnection costs listed in Appendix E and F do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request through SPP's Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP OATT.

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Introduction

Pursuant to the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT), SPP has conducted this Preliminary Interconnection System Impact Study (PISIS) for certain generation interconnection requests in the SPP Generation Interconnection Queue. These interconnection requests have been clustered together for the following Impact Study. The customers will be referred to in this study as the PISIS-2011-001 Interconnection Customers. This Impact Study analyzes the interconnecting of multiple generation interconnection requests associated with new generation totaling 479.0 MW of new generation which would be located within the transmission systems of American Electric Power (AEPW), Kansas City Power and Light (KCPL), Missouri Public Service (MIPU), Nebraska Public Power District (NPPD), Oklahoma Gas and Electric (OKGE), Southwestern Public Service (SPS), Sunflower Electric Power Corporation (SUNC), and Westar Energy (WERE). The various generation interconnection requests have differing proposed in-service dates[2]. The generation interconnection requests included in this Impact Study are listed in Appendix A by their queue number, amount, requested interconnection service, area, requested interconnection point, proposed interconnection point, and the requested in-service date.

The primary objective of this Preliminary Interconnection System Impact Study is to identify the system constraints associated with connecting the generation to the area transmission system. The Impact and other subsequent Interconnection Studies are designed to identify attachment facilities, Network Upgrades and other Direct Assignment Facilities needed to accept power into the grid at each specific interconnection receipt point.

Model Development

Interconnection Requests Included in the Cluster

SPP has included all interconnection requests that submitted a Preliminary Interconnection System Impact Study request no later than March 31, 2011 and were subsequently accepted by Southwest Power Pool under the terms of the Generator Interconnection Procedures (GIP) that became effective March 30, 2010.

The interconnection requests that are included in this study are listed in Appendix A.

Previous Queued Projects

The previous queued projects included in this study are listed in Appendix B. In addition to the Base Case Upgrades, the previous queued projects and associated upgrades were assumed to be

[2] The generation interconnection requests in-service dates will need to be deferred based on the required lead time for the Network Upgrades necessary. The Interconnection Customer's that proceed to the Facility Study will be provided a new in-service date based on the competition of the Facility Study.

in-service and added to the Base Case models. These projects were dispatched as Energy Resources with equal distribution across the SPP footprint.

Development of Base Cases

Power Flow - The 2010 series Transmission Service Request (TSR) Models 2011 spring, 2012 summer and winter peak, 2016 summer and winter peak, and 2021 summer peak scenario 0 cases were used for this study. After the cases were developed, each of the control areas' resources were then re-dispatched using current dispatch orders.

Stability – The 2010 series SPP Model Development Working Group (MDWG) Models 2011 winter and 2011 summer were used as starting points for this study.

Base Case Upgrades

The following facilities are part of the SPP Transmission Expansion Plan or the Balanced Portfolio or recently approved Priority Projects. These facilities have been approved or are in construction stages and were assumed to be in-service at the time of dispatch and added to the base case models. The PISIS-2011-001 Customers have not been assigned cost for the below listed projects. <u>The PISIS-2011-001 Customers Generation Facilities in service dates may need to be delayed until the completion of the following upgrades.</u> If for some reason, construction on these projects is discontinued, additional restudies will be needed to determine the interconnection needs of the PISIS customers.

- Hitchland 345/230/115kV upgrades to be built by SPS for 2010/2011 in-service[3].
    - Hitchland – Moore County 230kV line
    - Hitchland – Perryton 230kV line
    - Hitchland – Texas County 115kV line
    - Hitchland – Hansford County 115kV line
    - Hitchland – Sherman County Tap 115kV line
- Valliant – Hugo – Sunnyside 345kV – assigned to Aggregate Study AG3-2006 Customers
- Wichita – Reno County – Summit 345kV to be built by WERE[4].
- Rose Hill – Sooner 345kV to be built by WERE/OKGE.
- Knob Hill – Steele City 115kV to be built by NPPD/WERE.
- Balanced Portfolio Projects[5]:
    - Gracemont 345/138/13.2kV Autotransformer
    - Woodward– Tuco 345kV line
    - Iatan– Nashua 345kV line
    - Muskogee– Seminole 345kV line
    - Post Rock– Axtell 345kV line

[3] Approved 230kV upgrades are based on SPP 2007 STEP. Upgrades may need to be re-evaluated in the system impact study.
[4] Approved based on an order of the Kansas Corporation Commission issued in Docket no. 07-WSEE-715-MIS
[5] Notice to Construct (NTC) issued June, 2009

  - Spearville– Post Rock 345kV line
  - Tap Stillwell – Swissvale 345kV line at West Gardner
- Priority Projects[6]:
  - Hitchland - Woodward double circuit 345kV
  - Woodward – Medicine Lodge double circuit 345kV
  - Spearville – Comanche (Clark) double circuit 345kV
  - Comanche (Clark) – Medicine Lodge double circuit 345kV
  - Medicine Lodge – Wichita double circuit 345kV
  - Medicine Lodge 345/138kV autotransformer

Contingent Upgrades

The following facilities do not yet have approval. These facilities have been assigned to higher queued interconnection customers. These facilities have been included in the models for the PISIS-2011-001 study and are assumed to be in service. <u>The PISIS-2011-001 Customers at this time do not have responsibility for these facilities but may later be assigned the cost of these facilities if higher queued customers terminate their GIA or withdraw from the interconnection queue. The PISIS-2011-001 Customer Generation Facilities in service dates may need to be delayed until the completion of the following upgrades.</u>

- Finney – Holcomb 345kV ckt #2 line assigned to GEN-2006-044 interconnection customer. This customer is currently in suspension[7].
- Central Plains – Setab 115kV transmission line assigned to GEN-2007-013 interconnection customer.
- Grassland 230/115kV autotransformer #2 assigned to 1st Cluster Interconnection Customers (100% to GEN-2008-016)
- Judson Large – North Judson Large – Spearville 115kV circuit #2 assigned to DISIS-2009-001-1 Interconnection Customers (100% to GEN-2008-079)
- Hitchland – Wheeler (Border) double circuit 345kV assigned to DISIS-2010-001 Interconnection Customers
- Madison County - Hoskins 230kV Ckt #1 assigned to DISIS-2010-001 Interconnection Customer
- Washita – Gracemont 138kV circuit #2 assigned to DISIS-2010-001 Interconnection Customers
- Post Rock 345/230kV autotransformer #2 assigned to DISIS-2010-001 Interconnection Customers.
- Washita – Weatherford 138kV Ckt #1 assigned to DISIS-2010-001 Interconnection Customers
- GEN-2008-079 Tap – Spearville 115kV circuit #1 assigned to DISIS-2010-001 Interconnection Customers

[6] Notice to Construct (NTC) issued June, 2010. NTC for double circuit lines indicated that NTC may be revised at a later time to be built at a higher voltage.
[7] Based on Facility Study Posting November 2008

- Spearville 345/115kV autotransformer #1 assigned to DISIS-2010-001 Interconnection Customers
- Beaver County – Gray County 345kV Ckt #1 assigned to DISIS-2010-002 Interconnection Customers
- Medicine Lodge 345/115kV autotransformer #2 assigned to DISIS-2010-002 Interconnection Customers
- St. John – St. John 115kV Ckt #1 assigned to DISIS-2010-002 Interconnection Customers
- Northwest 345/138/13.8kV autotransformer circuit #1 assigned to DISIS-2010-002 NRIS Interconnection Customer Gen-2010-040
- Beaver County – Comanche 345kV Ckt #1 assigned to DISIS-2011-001 Interconnection Customers
- Border – Grassland 345kV conversion assigned to DISIS-2011-001 Interconnection Customers
- Circle – Reno double 345kV assigned to DISIS-2011-001 Interconnection Customers
- GEN-2010-047 – Crete 115kV Ckt #1 assigned to DISIS-2011-001 Interconnection Customers
- Grassland – Jones 345kV Ckt #1 assigned to DISIS-2011-001 Interconnection Customers
- Hobart Junction – Snyder 138kV conversion assigned to DISIS-2011-001 Interconnection Customers
- Jones – Tuco 345kV Ckt #1 assigned to DISIS-2011-001 Interconnection Customers
- Lawton Eastside – Oklaunion 345kV Ckt #2 to DISIS-2011-001 Interconnection Customers

Potential Upgrades Not in the Base Case

Any potential upgrades that do not have a Notification to Construct (NTC) have not been included in the base case. These upgrades include any identified in the SPP Extra-High Voltage (EHV) overlay plan, or any other SPP planning study other than the upgrades listed above in the previous section.

Regional Groupings

The interconnection requests listed in Appendix A were grouped together in fifteen different regional groups based on geographical and electrical impacts. These groupings are shown in Appendix C.

To determine interconnection impacts, fifteen different dispatch variations of the spring base case models were developed to accommodate the regional groupings.

Power Flow - For each group, the various wind generating plants were modeled at 80% nameplate of maximum generation. The wind generating plants in the other areas were modeled at 20% nameplate of maximum generation. This process created fifteen different scenarios with each group being studied at 80% nameplate rating. These projects were dispatched as Energy Resources with equal distribution across the SPP footprint. Certain projects that requested Network Resource Interconnection Service were dispatched in an additional analysis into the balancing authority of the interconnecting transmission owner. This method allowed for the identification of network constraints that were common to the regional groupings that could then in turn have the mitigating upgrade cost allocated throughout the entire cluster. Each interconnection request was also modeled separately at 100% nameplate for certain analyses.

Peaking units were not dispatched in the 2011 spring model. To study peaking units' impacts, the 2012 summer and winter, 2016 summer and winter, and 2021 summer peak models were chosen and peaking units were modeled at 100% of the nameplate rating and wind generating facilities were modeled at 10% of the nameplate rating. Each interconnection request was also modeled separately at 100% nameplate for certain analyses.

Stability - For each group, all interconnection requests were studied at 100% nameplate output while the other groups were dispatched at 20% output for wind requests and 100% output for fossil requests.

Identification of Network Constraints

The initial set of network constraints were found by using PTI MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels mentioned above. These constraints were then screened to determine if any of the generation interconnection requests had at least a 20% Distribution Factor (DF) upon the constraint. Constraints that measured at least a 20% DF from at least one interconnection request were considered for mitigation. Interconnection Requests that were being studied for Network Resource Interconnection Service were studied in the additional NRIS analysis to determine if any constraint had at least a 3% DF. If so, these constraints were considered for mitigation.

Determination of Cost Allocated Network Upgrades

Cost Allocated Network Upgrades of wind generation interconnection requests were determined using the 2011 spring model. Cost Allocated Network Upgrades of peaking units was determined using the 2016 summer peak model. A MUST FCITC analysis was performed to determine the Power Transfer Distribution Factors (PTDF), a distribution factor with no contingency that each generation interconnection request had on each new upgrade. The impact each generation interconnection request had on each upgrade project was weighted by the size of each request. Finally the costs due by each request for a particular project were then determined by allocating the portion of each request's impact over the impact of all affecting requests.

For example, assume that there are three Generation Interconnection requests, X, Y, and Z that are responsible for the costs of Upgrade Project '1'. Given that their respective PTDF for the project have been determined, the cost allocation for Generation Interconnection request 'X' for Upgrade Project 1 is found by the following set of steps and formulas:

- Determine an Impact Factor on a given project for all responsible GI requests:

Request X Impact Factor on Upgrade Project 1 = PTDF(%)(X) * MW(X) = X1

Request Y Impact Factor on Upgrade Project 1 = PTDF(%)(Y) * MW(Y) = Y1

Request Z Impact Factor on Upgrade Project 1 = PTDF(%)(Z) * MW(Z) = Z1

- Determine each request's Allocation of Cost for that particular project:

$$\text{Request X's Project 1 Cost Allocation (\$)} = \frac{\text{Network Upgrade Project 1 Cost(\$)} * X1}{X1 + Y1 + Z1}$$

- Repeat previous for each responsible GI request for each Project

The cost allocation of each needed Network Upgrade is determined by the size of each request and its impact on the given project. This allows for the most efficient and reasonable mechanism for sharing the costs of upgrades.

Credits for Amounts Advanced for Network Upgrades

Interconnection Customer shall be entitled to credits in accordance with Attachment Z1 of the SPP Tariff for any Network Upgrades including any tax gross-up or any other tax-related payments associated with the Network Upgrades, and not refunded to the Interconnection Customer.

Interconnection Facilities

The requirement to interconnect the 479.0 MW of generation into the existing and proposed transmission systems in the affected areas of the SPP transmission footprint consist of the necessary cost allocated shared facilities listed in Appendix F by upgrade. The interconnection requirements for the cluster total $58,450,000. Interconnection Facilities specific to each generation interconnection request are listed in Appendix E.

A list of constraints with greater than or equal to a 20% OTDF that were identified and used for mitigation are listed in Appendix G. Other Network Constraints in the MIPU, NPPD, OKGE, SPS, SUNC, and WERE transmission systems that were identified are shown in Appendix H. With a defined source and sink in a TSR, this list of Network Constraints will be refined and expanded to account for all Network Upgrade requirements.

A preliminary one-line drawing for each generation interconnection request are listed in Appendix D. Figure 1 depicts the major transmission line Network Upgrades needed to support the interconnection of the generation amounts requested in this study.

Power Flow

Power Flow Analysis Methodology

The Southwest Power Pool (SPP) Criteria states that:

> "The transmission system of the SPP region shall be planned and constructed so that the contingencies as set forth in the Criteria will meet the applicable *NERC Reliability Standards* for transmission planning. All MDWG power flow models shall be tested to verify compliance with the System Performance Standards from NERC Table 1 – Category A."

The ACCC function of PSS/E was used to simulate single contingencies in portions or all of the modeled control areas of American Electric Power (AEPW), Kansas City Power and Light (KCPL), Missouri Public Service (MIPU), Nebraska Public Power District (NPPD), Oklahoma Gas and Electric (OKGE), Southwestern Public Service (SPS), Sunflower Electric Power Corporation (SUNC), and Westar Energy (WERE) and other control areas were applied and the resulting scenarios analyzed. This satisfies the “more probable” contingency testing criteria mandated by NERC and the SPP criteria.

Power Flow Analysis

A power flow analysis was conducted for each Interconnection Customer’s facility using modified versions of the 2011 spring peak, 2012 summer and winter peak, the 2016 summer and winter peak, and the 2021 summer peak models. The output of the Interconnection Customer’s facility was offset in each model by a reduction in output of existing online SPP generation. This method allows the request to be studied as an Energy Resource (ER) Interconnection Request. The available seasonal models used were through the 2021 Summer Peak. Certain requests that requested Network Resource Interconnection Service (NRIS) had an additional analysis conducted for sinking the energy in the interconnecting Transmission Owner’s balancing authority.

This analysis was conducted assuming that previous queued requests in the immediate area of these interconnect requests were in-service. The analysis of each Customer’s project indicates that additional criteria violations will occur on the MIPU, NPPD, MIDW, OKGE, OPPD, SPS, SUNC, WERE and WFEC transmission systems under steady state and contingency conditions in the peak seasons.

Cluster Group 1 (Woodward Area)

In addition to the 4,742.0 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 2 (Hitchland Area)

In addition to the 4,426.3 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 3 (Spearville Area)

In addition to the 5,390.7 MW of previously queued generation in the area, 180.0 MW of new interconnection service was studied. Constraints were seen in this area around the North Hays – Vine Street 115kV line and the North Hays – Knoll 115kV line. To mitigate this, the lines will need to be rebuilt. A second 230/115kV transformer will also be needed at the South Hays substation. Another constraint was seen on the Smoky Hills – Summit 230kV line, requiring the line to be rebuilt.

Cluster Group 4 (Mingo/NW Kansas Group)

In addition to the 924.2 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 5 (Amarillo Area)

In addition to the 2,132.6 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 6 (South Texas Panhandle/New Mexico)

In addition to the 2,380.7 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 7 (Southwestern Oklahoma)

In addition to the 2,895.8 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 8 (South Central Kansas/North Oklahoma)

In addition to the 3,356.0 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 9 (Northeast Nebraska)

In addition to the 1,009.3 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 10 (North Nebraska)

In addition to the 345.3 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 11 (North Central Kansas)

In addition to the 1,495.1 MW of previously queued generation in the area, 200.0 MW of new interconnection service was studied. A constraint was seen on the Smoky Hills – Summit 230kV line, requiring it to be rebuilt.

Cluster Group 12 (Northwest Arkansas)

In addition to the 0.0 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 13 (Northwest Missouri)

In addition to the 2,872.0 MW of previously queued generation in the area, 99.0 MW of new interconnection service was studied. The Beatrice Power Station – Clatonia 115kV line was seen to be overloading, the line will need to be completely rebuilt.

Cluster Group 14 (South Central Oklahoma)

In addition to the 1051.7 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 15 (Southwest Nebraska)

In addition to the 89.7 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Stability Analysis

A stability analysis was conducted for each Interconnection Customer's facility using modified versions of the 2011 summer and 2011 winter peak models. The stability analysis was conducted with all upgrades in service that were identified in the power flow analysis. For each group, the interconnection requests were studied at 100% nameplate output while the other groups were dispatched at 20% output for wind requests and 100% output for fossil requests. The output of the Interconnection Customer's facility was offset in each model by a reduction in output of existing online SPP generation. The following synopsis is included for each group. The entire stability study for each group can be found in the Appendices.

Cluster Group 1 (Woodward Area)

There was no stability analysis conducted in the Woodward area due to no requests in the area.

Cluster Group 2 (Hitchland Area)

There was no stability analysis conducted in the Hitchland area due to no requests in the area.

Cluster Group 3 (Spearville Area)

The Group 3 stability study was conducted by S&C Electric Company. The stability analysis indicates that requests in Group 3 will be stable for each contingency specified by SPP and the nearby areas will retain angular, frequency and voltage stability.
With the power factor requirements and all network upgrades in service, all interconnection request in Group 3 will meet FERC Order #661A low voltage ride through (LVRT) requirements.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI	
				Lagging (supplying)	Leading (absorbing)
GEN-2010-061	179.4	Siemens 2.3MW	Tap Post Rock – Spearville 345kV	0.95	0.95

*As reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the point of interconnection.

Cluster Group 4 (Mingo Area)

There was no stability analysis conducted in the Mingo area due to no requests in the area.

Cluster Group 5 (Amarillo Area)

There was no stability analysis conducted in the Amarillo area due to no requests in the area.

Cluster Group 6 (South Texas Panhandle/New Mexico)

There was no stability analysis conducted in the South Texas Panhandle/New Mexico area due to no requests in the area.

Cluster Group 7 (Southwest Oklahoma Area)

There was no stability analysis conducted in the Southwest Oklahoma area due to no requests in the area.

Cluster Group 8 (South Central Kansas/North Oklahoma)

There was no stability analysis conducted in the South Central Kansas/North Oklahoma area due to no requests in the area.

Cluster Group 9 (Northeast Nebraska Area)

There was no stability analysis conducted in the Northeast Nebraska area due to no requests in the area.

Cluster Group 10 (North Nebraska Area)

There was no stability analysis conducted in the North Nebraska area due to no requests in the area.

Cluster Group 11 (North Central Kansas Area)

The Group 11 stability analysis was conducted by Pterra Consulting . There are no impacts on the stability performance of the SPP system for the contingencies simulated, the studied request stays on-line and stable. With the power factor requirements and all network upgrades in service, all interconnection request in Group 11 will meet FERC Order #661A low voltage ride through (LVRT) requirements and the transmission system will remain stable.

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI	
				Lagging (supplying)	Leading (absorbing)
GEN-2011-001	200	Siemens 2.3MW	Tap Post Rock – Axtell 345kV	0.97	0.98

Cluster Group 12 (Northwest Arkansas Area)

There was no stability analysis conducted in the Northwest Arkansas area due to no requests in the area.

Cluster Group 13 (Northwest Missouri Area)

The Group 13 stability analysis was conducted by Mitsubishi Electric Power Products, Inc (MEPPI). There are no impacts on the stability performance of the SPP system for the contingencies simulated, the studied request stays on-line and stable. With the power factor requirements and all network upgrades in service, all interconnection request in Group 9 will meet FERC Order #661A low voltage ride through (LVRT) requirements and the transmission system will remain stable.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI	
				Lagging (supplying)	Leading (absorbing)
GEN-2010-044	99	Siemens 2.3MW	Harbine 115kV or Tap Harbine – Beatrice 115kV	1.00	0.95

*As reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the point of interconnection.

Cluster Group 14 (South Central Oklahoma)

There was no stability analysis conducted in the South Central Oklahoma area due to no requests in the area.

Cluster Group 15 (Southwest Nebraska Area)

There was no stability analysis conducted in the Southwest Nebraska area due to no requests in the area.

Conclusion

The minimum cost of interconnecting 479.0 MW of new interconnection requests included in this Preliminary Interconnection System Impact Study is estimated at $58,450,000 for the Allocated Network Upgrades and Transmission Owner Interconnection Facilities are listed in Appendix E and F. These costs do not include the cost of upgrades of other transmission facilities listed in Appendix I which are Network Constraints.

These interconnection costs do not include any cost of Network Upgrades determined to be required by short circuit analysis. These studies will be performed if the Interconnection Customer executes the appropriate Interconnection System Impact Study Agreement and provides the required data along with demonstration of Site Control and the appropriate deposit. At the time of the System Impact Cluster Study, a better determination of the interconnection facilities may be available.

The required interconnection costs listed in Appendices E, and F, and other upgrades associated with Network Constraints do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request (TSR) through SPP’s Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP Open Access Transmission Tariff (OATT).

Appendix

A. Generation Interconnection Requests Considered for Impact Study

Request	Amount	Service	Area	Requested Point of Interconnection	Proposed Point of Interconnection	Requested In-Service Date	In Service Date Delayed Until no earlier than
GEN-2010-044	99.0	ER/NR	NPPD	Harbine 115kV	Tap Harbine – Beatrice 115kV	11/01/2012	12/31/2014
GEN-2010-061	180.0	ER/NR	SUNC	Tap Post Rock – Spearville 345kV	Tap Post Rock – Spearville 345kV	12/31/2012	12/31/2014
GEN-2011-001	200.0	ER/NR	SUNC	Tap Post Rock – Axtell 345kV	GEN-2010-016 Tap 345kV	06/30/2013	12/31/2014
TOTAL	479.0						

B: Prior Queued Interconnection Requests

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2001-014	96.0	WFEC	Fort Supply 138kV	On-Line
GEN-2001-026	74.0	WFEC	Washita 138kV	On-Line
GEN-2001-033	180.0	SPS	San Juan Mesa Tap 230kV	On-Line
GEN-2001-036	80.0	SPS	Caprock Tap 115kV	On-Line
GEN-2001-037	100.0	OKGE	Windfarm Switching 138kV	On-Line
GEN-2001-039A	105.0	MKEC	Tap Greensburg - Judson-Large 115kV	On Schedule for 2011
GEN-2001-039M	100.0	SUNC	Central Plains Tap 115kV	On-Line
GEN-2002-004	200.0	WERE	Latham 345kV	On-Line at 150MW
GEN-2002-005	120.0	WFEC	Red Hills Tap 138kV	On-Line
GEN-2002-008	240.0	SPS	Hitchland 345kV	On-Line at 120MW
GEN-2002-009	80.0	SPS	Hansford County 115kV	On-Line
GEN-2002-022	240.0	SPS	Bushland 230kV	On-Line at 160MW
GEN-2002-025A	150.0	MKEC	Spearville 230kV	On-Line at 100.5MW
GEN-2003-004	100.0	WFEC	Washita 138kV	On-Line
GEN-2003-005	100.0	WFEC	Anadarko - Paradise 138kV	On Line
GEN-2003-006A	200.0	MKEC	Elm Creek 230kV	On-Line
GEN-2003-013	198.0	SPS	Hitchland - Finney 345kV	On Schedule for 2012
GEN-2003-019	250.0	MIDW	Smoky Hills Tap 230kV	On-Line
GEN-2003-020	160.0	SPS	Martin 115kV	On-Line at 80MW
GEN-2003-022	120.0	AEPW	Washita 138kV	On-Line
GEN-2004-023	20.6	WFEC	Washita 138kV	On-Line
GEN-2004-014	154.5	MKEC	Spearville 230kV	On Schedule for 2011
GEN-2004-020	27.0	AEPW	Washita 138kV	On-Line
GEN-2005-003	30.6	WFEC	Washita 138kV	On-Line
GEN-2005-005	18.0	OKGE	Windfarm Tap 138kV	IA Pending
GEN-2005-008	120.0	OKGE	Woodward 138kV	On-Line
GEN-2005-012	250.0	SUNC	Spearville 345kV	On Schedule for 2012
GEN-2005-013	201.0	WERE	Tap Latham - Neosho	On Schedule for 2012
GEN-2005-017	340.0	SPS	Tap Hitchland - Potter County 345kV	On Suspension
GEN-2006-002	101.0	AEPW	Grapevine - Elk City 230kV	On-Line
GEN-2006-006	205.5	MKEC	Spearville 230kV	IA Pending
GEN-2006-014	300.0	MIPU	Tap Maryville – Clarinda and tie Midway (WFARMS) 161kV	On Suspension
GEN-2006-017	300.0	MIPU	Tap Maryville – Clarinda and tie Midway (WFARMS) 161kV	On Suspension
GEN-2006-018	170.0	SPS	Tuco 230kV	On Schedule for 2011
GEN-2006-020S	18.9	SPS	DWS Frisco Tap	On Schedule for 12/31/2011
GEN-2006-020N	42.0	NPPD	Bloomfield 115kV	On-Line
GEN-2006-021	101.0	MKEC	Flat Ridge Tap 138kV	On-Line
GEN-2006-022	150.0	MKEC	Ninnescah Tap 115kV	On Suspension
GEN-2006-024S	19.8	WFEC	South Buffalo Tap 69kV	On-Line
GEN-2006-026	502.0	SPS	Hobbs 230kV	On-Line
GEN-2006-031	75.0	MIDW	Knoll 115kV	On-Line
GEN-2006-032	200.0	MIDW	South Hays 230kV	On Suspension
GEN-2006-034	81.0	SUNC	Tap Kanarado - Sharon Springs 115kV	On Suspension
GEN-2006-035	225.0	AEPW	Tap Grapevine - Elk City 230kV	On Schedule for 2011
GEN-2006-037N1	75.0	NPPD	Broken Bow 115kV	On Suspension
GEN-2006-038N019	80.0	NPPD	Petersburg 115kV	On-Line
GEN-2006-038	750.0	WFEC	Hugo 345kV	On Suspension
GEN-2006-038N005	80.0	NPPD	Broken Bow 115kV	On-Line
GEN-2006-039	400.0	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV	On Suspension
GEN-2006-040	108.0	SUNC	Mingo 115kV	On Schedule for 2010
GEN-2006-043	99.0	AEPW	Grapevine - Elk City 230kV	On Line
GEN-2006-044	370.0	SPS	Hitchland 345kV	On Schedule for 2014
GEN-2006-044N	40.5	NPPD	Tap Neligh – Petersburg 115kV	On Schedule for 12/2011
GEN-2006-044N02	100.5	NPPD	GEN-2008-086N02 230kV	Under Study (DISIS-2010-001)
GEN-2006-045	240.0	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV	On Suspension
GEN-2006-046	131.0	OKGE	Dewey 138kV	On-Line

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2006-047	240.0	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV	On Schedule for 2013
GEN-2006-049	400.0	SPS	Hitchland - Finney 345kV	On Schedule for 2014
GEN-2007-002	160.0	SPS	Grapevine 115kV	On Suspension
GEN-2007-006	160.0	OKGE	Roman Nose 138kV	On Suspension
GEN-2007-011	135.0	SUNC	Syracuse 115kV	On Schedule
GEN-2007-011N08	81.0	NPPD	Bloomfield 115kV	On-Line
GEN-2007-013	99.0	SUNC	Selkirk 115kV	On Suspension
GEN-2007-015	135.0	WERE	Tap Humboldt – Kelly 161kV	On Suspension
GEN-2007-017	100.5	MIPU	Tap Maryville – Clarinda and tie Midway (WFARMS) 161kV	On Suspension
GEN-2007-021	201.0	OKGE	Tatonga 345kV	On Schedule for 2014
GEN-2007-025	300.0	WERE	Tap Woodring – Wichita 345kV	On Suspension
GEN-2007-032	150.0	WFEC	Tap Clinton Junction – Clinton 138kV	OnSchedule for 2012
GEN-2007-038	200.0	SUNC	Spearville 345kV	On Schedule for 2015
GEN-2007-040	200.1	SUNC	Tap Holcomb – Spearville 345kV	On Schedule for 2012
GEN-2007-043	200.0	OKGE	Tap Lawton Eastside – Cimarron 345kV	On-Line (100MW)
GEN-2007-044	300.0	OKGE	Tatonga 345kV	On Schedule for 2014
GEN-2007-046	199.5	SPS	Tap & Tie Texas County – Hitchland & DWS Frisco Tap – Hitchland 115kV	On Schedule for 2014
GEN-2007-048	400.0	SPS	Tap Amarillo South – Swisher 230kV	On Schedule for 2014
GEN-2007-050	170.0	OKGE	Woodward 138kV	On-Line
GEN-2007-051	200.0	WFEC	Mooreland 138kV	On Schedule for 2014
GEN-2007-052	150.0	WFEC	Anadarko 138kV	On-Line
GEN-2007-053	110.0	MIPU	Tap Maryville – Clarinda and tie Midway (WFARMS) 161kV	On Schedule for 2013
GEN-2007-057	34.5	SPS	Moore County East 115kV	On Schedule for 2014
GEN-2007-062	765.0	OKGE	Woodward 345kV	On Schedule for 2014
GEN-2008-003	101.0	OKGE	Woodward EHV 138kV	On-Line
GEN-2008-008	60.0	SPS	Graham 115kV	On Schedule for 2014
GEN-2008-009	60.0	SPS	San Juan Mesa Tap 230kV	On Schedule for 2014
GEN-2008-013	300.0	OKGE	Tap Woodring – Wichita 345kV	On Schedule for 2013
GEN-2008-014	150.0	SPS	Tap Tuco – Oklaunion 345kV	On Schedule for 2014
GEN-2008-016	248.0	SPS	Grassland 230kV	IA Pending
GEN-2008-017	300.0	SUNC	Setab 345kV	On Schedule for 2012
GEN-2008-018	405.0	SPS	Finney 345kV	IA Pending
GEN-2008-019	300.0	OKGE	Tatonga 345kV	On Schedule for 2015
GEN-2008-021	42.0	WERE	Wolf Creek 345kV	IA Pending
GEN-2008-022	300.0	SPS	Tap Eddy – Tolk 345kV	IA Pending
GEN-2008-023	150.0	AEPW	Hobart Junction 138kV	On Schedule for 2012
GEN-2008-025	101.2	SUNC	Ruleton 115kV	On Schedule for 2015
GEN-2008-029	250.5	OKGE	Woodward EHV 138kV	On Schedule for 2014
GEN-2008-037	101.0	WFEC	Tap Washita – Blue Canyon 138kV	IA Pending
GEN-2008-044	197.8	OKGE	Tatonga 345kV	IA Pending
GEN-2008-046	200.0	OKGE	Sunnyside 345kV	IA Pending
GEN-2008-047	300.0	SPS	Tap Hitchland - Woodward 345kV	IA Pending
GEN-2008-051	322.0	SPS	Potter 345kV	On Schedule for 2014
GEN-2008-071	76.8	OKGE	Newkirk 138kV	IA Pending
GEN-2008-079	100.5	MKEC	Tap Judson Large – Cudahy 115kV	On Schedule for 2012
GEN-2008-086N02	200.0	NPPD	Tap Ft. Randall – Columbus 230kV	On Schedule for 2014
GEN-2008-088	50.6	SPS	Vega 69kV	IA Pending
GEN-2008-092	201.0	MIDW	Knoll 115kV	IA Pending
GEN-2008-098	100.8	WERE	Tap Wolf Creek – LaCygne 345kV	IA Pending
GEN-2008-110	299.2	SPS	Hitchland 345kV	IA Pending
GEN-2008-119O	60.0	OPPD	Tap Humboldt – Kelly 161kV	On-Line
GEN-2008-123N	89.7	NPPD	Tap Guide - Pauline 115kV	IA Pending
GEN-2008-124	200.1	SUNC	Spearville 345kV	On Schedule for 2014
GEN-2008-127	200.1	WERE	Tap Sooner – Rose Hill 345kV	On Schedule for 2012
GEN-2008-129	80.0	MIPU	Pleasant Hill 161kV	On-Line
GEN-2009-008	199.5	SUNC	South Hays 230kV	IA Pending
GEN-2009-011	50.0	MKEC	Tap Plainville – Phillipsburg 115kV	On Schedule for 2014
GEN-2009-016	141.0	AEPW	Falcon Road 138kV	On Schedule for 2012
GEN-2009-017	60.0	SPS	Tap Pembrook – Stiles 138kV	Under Study (DISIS-2009-001)
GEN-2009-020	48.6	MIDW	Tap Bazine – Nekoma 69kV	IA Pending
GEN-2009-025	60.0	OKGE	Tap Deer Creek – Sinclair 69kV	On Suspension
GEN-2009-030	100.8	WFEC	Weatherford 138kV	IA Pending

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2009-040	73.8	WERE	Tap Smittyville - Knob Hill 115kV	On Schedule for 2012
GEN-2009-060	84.0	WFEC	Gotebo 69kV	IA Pending
GEN-2009-062	115.0	MKEC	Hugoton 115kV	Under Study (DISIS-2010-001)
GEN-2009-067S	20.0	SPS	7 Rivers 69kV	IA Pending
GEN-2010-001	300.0	OKGE	Tap Hitchland – Woodward 345kV	Under Study (DISIS-2010-002
GEN-2010-003	100.8	WERE	GEN-2008-098 345kV	IA Pending
GEN-2010-005	300.0	WERE	GEN-2007-025 345kV	IA Pending
GEN-2010-006	205.0	SPS	Jones 230kV	On-Line
GEN-2010-007	73.8	SPS	Tap Pringle - Riverview 115kV	IA Pending
GEN-2010-008	64.4	WFEC	Fargo 69kV	IA Pending
GEN-2010-009	165.6	SUNC	Gray County 345kV	IA Pending
GEN-2010-010	100.5	NPPD	Madison County 230kV	IA Pending
GEN-2010-011	29.7	OKGE	Tatonga 345kV	On Schedule for 2011
GEN-2010-014	360.0	SPS	Hitchland 345kV	IA Pending
GEN-2010-015	200.1	SUNC	Spearville 345kV	IA Pending
GEN-2010-016	199.8	SUNC	Tap Spearville - Knoll 345kV	IA Pending
GEN-2010-020	20.0	SPS	Roswell 115kV	Under Study (DISIS-2011-001)
GEN-2010-029	450.0	SUNC	Spearville 345kV	Under Study (DISIS-2011-001)
GEN-2010-036	4.6	WERE	6th Street 115kV	Under Study (DISIS-2010-002)
GEN-2010-040	300.0	OKGE	Cimarron 345kV	Under Study (DISIS-2010-002)
GEN-2010-041	10.5	OPPD	S 1399 161kV	Under Study (DISIS-2010-002)
GEN-2010-043	320.0	WFEC	Mooreland 138kV	Under Study (DISIS-2010-002)
GEN-2010-045	197.8	SUNC	Tap Holcomb – Spearville 345kV	Under Study (DISIS-2010-002)
GEN-2010-046	56.0	SPS	Tuco 230kV	Under Study (DISIS-2010-002)
GEN-2010-047	72.0	NPPD	Tap Beatrice – Harbine 115kV	Under Study (DISIS-2010-002)
GEN-2010-048	70.0	MIDW	Tap Beach Station – Redline 115kV	Under Study (DISIS-2010-002)
GEN-2010-049	49.6	SUNC	Pratt 115kV	Under Study (DISIS-2010-002)
GEN-2010-051	200.0	NPPD	TAP TWIN CHURCH – HOSKINS 230kV	Under Study (DISIS-2010-002)
GEN-2010-052	301.3	SUNC	FINNEY 345kV	Under Study (DISIS-2010-002)
GEN-2010-053	199.8	SUNC	COMANCHE 345kV	Under Study (DISIS-2010-002)
GEN-2010-055	4.5	AEPW	Wekiwa 138kV	Under Study (DISIS-2011-001)
GEN-2010-056	151.2	MIPU	Tap Saint Joseph - Cooper 345kV	Under Study (DISIS-2011-001)
GEN-2010-057	201.0	MIDW	Rice County 230kV	Under Study (DISIS-2011-001)
GEN-2010-058	20.0	SPS	Chaves County 115kV	Under Study (DISIS-2011-001)
GEN-2011-007	250.0	OKGE	Tap Cimarron - Woodring 345kV (Matthewson 345kV)	Under Study (DISIS-2011-001)
GEN-2011-008	600.0	SUNC	Clark County 345kV	Under Study (DISIS-2011-001)
GEN-2011-009	150.4	AEPW	Hobart 138kV	Under Study (DISIS-2011-001)
GEN-2011-010	100.8	OKGE	Minco 345kV	Under Study (DISIS-2011-001)
GEN-2011-011	50.0	KCPL	Iatan 345kV	Under Study (DISIS-2011-001)
GEN-2011-012	104.5	SPS	Tap Moore County - Hitchland 230kV	Under Study (DISIS-2011-001)

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2011-013	101.7	OKGE	Sunnyside 345kV	Under Study (DISIS-2011-001)
GEN-2011-014	201.0	OKGE	Tap Hitchland - Woodward 345kV	Under Study (DISIS-2011-001)
GEN-2011-015	300.6	OKGE	Tap Tatonga – Woodward 345kV	Under Study (DISIS-2011-001)
GEN-2011-016	200.1	SUNC	Spearville 345kV	Under Study (DISIS-2011-001)
GEN-2011-017	299.0	SUNC	Tap Spearville - Knoll 345kV	Under Study (DISIS-2011-001)
GEN-2011-018	73.6	NPPD	Steele City 115kV	Under Study (DISIS-2011-001)
GEN-2011-019	299.0	OKGE	Woodward 345kV	Under Study (DISIS-2011-001)
GEN-2011-020	299.0	OKGE	Woodward 345kV	Under Study (DISIS-2011-001)
GEN-2011-021	299.0	SPS	Tap Hitchland - Woodward 345kV	Under Study (DISIS-2011-001)
GEN-2011-022	299.0	SPS	Hitchland 345kV	Under Study (DISIS-2011-001)
GEN-2011-023	299.0	SUNC	Tap Clark - Spearville 345kV	Under Study (DISIS-2011-001)
GEN-2011-024	299.0	OKGE	Tatonga 345kV	Under Study (DISIS-2011-001)
GEN-2011-025	82.3	SPS	Tap Floyd County - Crosby County 115kV	Under Study (DISIS-2011-001)
GEN-2011-027	120.0	NPPD	Tap Twin Church - Hoskins 230kV	Under Study (DISIS-2011-001)
Broken Bow	8.3	NPPD	Genoa 115kV	On-Line
Ord	10.8	NPPD	Bloomfield 115kV	On-Line
Stuart	2.1	NPPD	Petersburg 115kV	On-Line
Ainsworth	75.0	NPPD	Ainsworth Wind Tap 115kV	On-Line
Rosebud	30.0	NPPD	St. Francis 115kV	On-Line
Wolf Creek	1,170.0	WERE	Wolf Creek 345kV	On-Line
Genoa	4.0	NPPD	Genoa 115kV	On-Line
ASGI-2010-001	400.0	AECI	Tap Cooper – Fairport 345kV	AECI queue Affected Study
ASGI-2010-002	201.0	AECI	Lathrop 161kV	AECI queue Affected Study
ASGI-2010-003	300.0	AECI	Maryville 161kV	AECI queue Affected Study
ASGI-2010-004	50.0	AECI	Tap Queen City – Lancaster 69kV	AECI queue Affected Study
ASGI-2010-005	99.0	AECI	Lathrop 161kV	AECI queue Affected Study
ASGI-2010-006	150.0	AECI	Tap Fairfax – Fairfax Tap 138kV	AECI queue Affected Study
ASGI-2010-007	150.0	AECI	Tap Fairfax – Fairfax Tap 138kV	AECI queue Affected Study
ASGI-2010-008	100.0	AECI	Maryville 161kV	AECI queue Affected Study
ASGI-2010-009	201.0	AECI	Osborn 161kV	AECI queue Affected Study
ASGI-2010-010	42.0	SPS	Lovington 115kV	Affected Study
ASGI-2010-011	48.0	SPS	Texas County 69kV	Affected Study
ASGI-2010-020	50.0	SPS	Tap (LE) Tatum – (LE) Crossroads 69kV	Under Study (DISIS-2010-002)
ASGI-2010-021	36.6	SPS	Tap (LE) Saunders Tap – (LE) Anderson 69kV	Under Study (DISIS-2010-002)
ASGI-2011-001	28.8	SPS	LE-Lovington 115kV	Affected Study
ASGI-2011-002	10.0	SPS	Herring 115kV	Affected Study
ASGI-2011-003	10.0	SPS	Hendricks 115kV	Affected Study
Llano Estacado	80.0	SPS	Llano Wind Farm Tap 115kV	On-Line
SPS DISTRIBUTED	90.0	SPS	Dumas_19ST 115kV	On-Line
			Etter 115kV	On-Line
			Sherman 115kV	On-Line
			Spearman 115kV	On-Line
			Texas County 115kV	On-Line
Montezuma	110.0	MKEC	Haggard 115kV	On-Line
TOTAL	**33,223.1**			

C: Study Groupings

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2001-014	96.0	WFEC	Fort Supply 138kV
	GEN-2001-037	100.0	OKGE	Windfarm Switching 138kV
	GEN-2005-005	18.0	OKGE	Windfarm Tap 138kV
	GEN-2005-008	120.0	OKGE	Woodward 138kV
	GEN-2006-024S	20.0	WFEC	South Buffalo Tap 69kV
	GEN-2006-046	131.0	OKGE	Dewey 138kV
	GEN-2007-006	160.0	OKGE	Roman Nose 138kV
	GEN-2007-021	201.0	OKGE	Tatonga 345kV
	GEN-2007-044	300.0	OKGE	Tatonga 345kV
	GEN-2007-050	170.0	OKGE	Woodward 138kV
	GEN-2007-051	200.0	WFEC	Mooreland 138kV
	GEN-2007-062	765.0	OKGE	Woodward 345kV
	GEN-2008-003	101.0	OKGE	Woodward EHV 138kV
	GEN-2008-019	300.0	OKGE	Tatonga 345kV
	GEN-2008-029	250.5	OKGE	Woodward EHV 138kV
	GEN-2008-044	197.8	OKGE	Tatonga 345kV
	GEN-2010-008	64.4	WFEC	Fargo 69kV
	GEN-2010-011	29.7	OKGE	Tatonga 345kV
	GEN-2010-043	320.0	WFEC	Mooreland 138kV
	GEN-2011-015	300.6	OKGE	Tap Tatonga – Woodward 345kV
	GEN-2011-019	299.0	OKGE	Woodward 345kV
	GEN-2011-020	299.0	OKGE	Woodward 345kV
	GEN-2011-024	299.0	OKGE	Tatonga 345kV
PRIOR QUEUED SUBTOTAL		**4,742.0**		
Group 1 WOODWARD SUBTOTAL		**0.0**		
AREA TOTAL		**4,742.0**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	SPS Distribution	90.0	SPS	Various
	ASGI-2010-011	48.0	SPS	Texas County 69kV
	ASGI-2011-002	10.0	SPS	Herring 115kV
	GEN-2002-008	240.0	SPS	Hitchland 345kV
	GEN-2002-009	80.0	SPS	Hansford County 115kV
	GEN-2003-013	198.0	SPS	Tap Hitchland - Finney 345kV
	GEN-2003-020	160.0	SPS	Martin 115kV
	GEN-2005-017	340.0	SPS	Tap Hitchland - Potter County 345kV
	GEN-2006-020S	20.0	SPS	DWS Frisco Tap
	GEN-2006-044	370.0	SPS	Hitchland 345kV
	GEN-2006-049	400.0	SPS	Tap Hitchland - Finney 345kV
	GEN-2007-046	200.0	SPS	Tap & Tie Texas County – Hitchland & DWS Frisco Tap – Hitchland 115kV
	GEN-2007-057	35.0	SPS	Moore County East 115kV
	GEN-2008-047	300.0	SPS	Tap Hitchland - Woodward 345kV
	GEN-2008-110	299.2	SPS	Hitchland 345kV
	GEN-2010-001	300.0	WFEC	GEN-2008-047 Tap 345kV
	GEN-2010-007	73.8	SPS	Tap Pringle – Riverview 115kV
	GEN-2010-014	358.8	SPS	Hitchland 345kV
	GEN-2011-012	104.5	SPS	Tap Moore County - Hitchland 230kV
	GEN-2011-014	201.0	SPS	Tap Hitchland - Woodward 345kV
	GEN-2011-021	299.0	SPS	Tap Hitchland - Woodward 345kV
	GEN-2011-022	299.0	SPS	Hitchland 345kV
PRIOR QUEUED SUBTOTAL		**4,426.3**		
Group 2 HITCHLAND SUBTOTAL		**0.0**		
AREA TOTAL		**4,426.3**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	Montezuma	110.0	MKEC	Haggard 115kV
	GEN-2001-039A	105.0	MKEC	Tap Greensburg - Judson-Large 115kV
	GEN-2002-025A	150.0	MKEC	Spearville 230kV
	GEN-2004-014	154.5	MKEC	Spearville 230kV
	GEN-2005-012	250.0	SUNC	Spearville 345kV
	GEN-2006-006	205.5	MKEC	Spearville 230kV
	GEN-2006-021	101.0	MKEC	Flat Ridge Tap 138kV
	GEN-2006-022	150.0	MKEC	Ninnescah Tap 115kV
	GEN-2007-038	200.0	SUNC	Spearville 345kV
	GEN-2007-040	200.0	SUNC	Tap Holcomb – Spearville 345kV
	GEN-2008-018	405.0	SUNC	Finney 345kV
	GEN-2008-079	100.5	MKEC	Tap Fort Dodge – Cudahy 115kV
	GEN-2008-124	200.1	SUNC	Spearville 345kV
	GEN-2009-062	115.0	SUNC	Hugoton 115kV
	GEN-2010-009	165.6	SUNC	Gray County 345kV
	GEN-2010-015	200.1	SUNC	Spearville 345kV
	GEN-2010-016	199.8	SUNC	Tap Spearville – Knoll 345kV
	GEN-2010-029	450.0	SUNC	Spearville 345kV
	GEN-2010-045	197.8	SUNC	Tap Holcomb – Spearville 345kV
	GEN-2010-049	49.6	MKEC	Pratt 115kV
	GEN-2010-052	301.3	SPS	Finney 345kV
	GEN-2010-053	199.8	SUNC	Comanche 345kV
	GEN-2010-061	180	SUNC	Tap Post Rock – Spearville 345kV
	GEN-2011-001	200	SUNC	Tap Post Rock – Axtell 345kV
	GEN-2011-008	600.0	WFEC	Clark County 345kV
	GEN-2011-016	200.1	SUNC	Spearville 345kV
	GEN-2011-017	299.0	SUNC	Tap Spearville - Knoll 345kV
	GEN-2011-023	299.0	SUNC	Tap Clark - Spearville 345kV
	PRIOR QUEUED SUBTOTAL	**5,988.7**		
Cluster	**Request**	**Amount**	**Area**	**Proposed Point of Interconnection**
Spearville	GEN-2010-061	180.0	SUNC	GEN-2010-016 Tap 345kV
	Group 3 SPEARVILLE SUBTOTAL	**180.0**		
	AREA TOTAL	**6,168.7**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2001-039M	100.0	SUNC	Central Plains Tap 115kV
	GEN-2006-034	81.0	SUNC	Tap Kanarado - Sharon Springs 115kV
	GEN-2006-040	108.0	SUNC	Mingo 115kV
	GEN-2007-011	135.0	SUNC	Syracuse 115kV
	GEN-2007-013	99.0	SUNC	Selkirk 115kV
	GEN-2008-017	300.0	SUNC	Setab 345kV
	GEN-2008-025	101.2	SUNC	Ruleton 115kV
	PRIOR QUEUED SUBTOTAL	**924.2**		
	Group 4 MINGO/NW KANSAS SUBTOTAL	**0.0**		
	AREA TOTAL	**924.2**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	Llano Estacado	80.0	SPS	Llano Estacado Tap 115kV
	GEN-2002-022	240.0	SPS	Bushland 230kV
	GEN-2006-039	400.0	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV
	GEN-2006-045	240.0	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV
	GEN-2006-047	240.0	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV
	GEN-2007-002	160.0	SPS	Grapevine 115kV
	GEN-2007-048	400.0	SPS	Tap Amarillo South – Swisher 230kV
	GEN-2008-051	322.0	SPS	Potter 345kV
	GEN-2008-088	50.6	SPS	Vega 69kV
	PRIOR QUEUED SUBTOTAL	**2,132.6**		
	Group 5 AMARILLO SUBTOTAL	**0.0**		
	AREA TOTAL	**2,132.6**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	ASGI-2010-010	42.0	SPS	Lovington 115kV
	ASGI-2010-020	50.0	SPS	Tap (LE) Tatum – (LE) Crossroads 69kV
	ASGI-2010-021	36.6	SPS	Tap (LE) Saunders Tap – (LE) Anderson 69kV
	ASGI-2011-001	28.8	SPS	LE-Lovington 115kV
	ASGI-2011-003	10.0	SPS	Hendricks 115kV
	GEN-2001-033	180.0	SPS	San Juan Mesa Tap 230kV
	GEN-2001-036	80.0	SPS	Caprock Tap 115kV
	GEN-2006-018	170.0	SPS	Tuco 230kV
	GEN-2006-026	502.0	SPS	Hobbs 230kV
	GEN-2008-008	60.0	SPS	Graham 115kV
	GEN-2008-009	60.0	SPS	San Juan Mesa Tap 230kV
	GEN-2008-014	150.0	SPS	Tap Tuco – Oklaunion 345kV
	GEN-2008-016	248.0	SPS	Grassland 230kV
	GEN-2008-022	300.0	SPS	Tap Eddy – Tolk 345kV
	GEN-2009-017	60.0	SPS	Tap Pembrook – Stiles 138kV
	GEN-2009-067S	20.0	SPS	7 Rivers 69kV
	GEN-2010-006	205.0	SPS	Jones 230kV
	GEN-2010-020	20.0	SPS	Roswell 115kV
	GEN-2010-046	56.0	SPS	Tuco 230kV
	GEN-2010-058	20.0	SPS	Chaves County 115kV
	GEN-2011-025	82.3	SPS	Tap Floyd County - Crosby County 115kV
	PRIOR QUEUED SUBTOTAL	**2,380.7**		
	Group 6 S-TX Panhandle/NM SUBTOTAL	**0.0**		
	AREA TOTAL	**2,380.7**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2001-026	74.0	WFEC	Washita 138kV
	GEN-2002-005	120.0	WFEC	Red Hills Tap 138kV
	GEN-2003-004	101.0	WFEC	Washita 138kV
	GEN-2003-005	100.0	WFEC	Anadarko - Paradise 138kV
	GEN-2003-022	120.0	AEPW	Washita 138kV
	GEN-2004-020	27.0	AEPW	Washita 138kV
	GEN-2004-023	21.0	WFEC	Washita 138kV
	GEN-2005-003	31.0	WFEC	Washita 138kV
	GEN-2006-002	101.0	AEPW	Grapevine - Elk City 230kV
	GEN-2006-035	225.0	AEPW	Grapevine - Elk City 230kV
	GEN-2006-043	99.0	AEPW	Grapevine - Elk City 230kV
	GEN-2007-032	150.0	WFEC	Tap Clinton Junction – Clinton 138kV
	GEN-2007-043	200.0	OKGE	Tap Lawton Eastside – Cimarron 345kV
	GEN-2007-052	150.0	WFEC	Anadarko 138kV
	GEN-2008-023	150.0	AEPW	Hobart Junction 138kV
	GEN-2008-037	100.8	WFEC	Tap Washita – Blue Canyon 138kV
	GEN-2009-016	140.0	AEPW	Falcon Road 138kV
	GEN-2009-030	100.8	WFEC	Weatherford 138kV
	GEN-2009-060	84.0	WFEC	Gotebo 69kV
	GEN-2010-040	300.0	OKGE	Cimarron 345kV
	GEN-2011-007	250.0	OKGE	Tap Cimarron - Woodring 345kV (Matthewson 345kV)
	GEN-2011-009	150.4	AEPW	Hobart 138kV
	GEN-2011-010	100.8	OKGE	Minco 345kV
	PRIOR QUEUED SUBTOTAL	**2,895.8**		
	Group 7 SW OKLAHOMA SUBTOTAL	**0.0**		
	AREA TOTAL	**2,895.8**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	Wolf Creek	1,170.0	WERE	Wolf Creek 345kV
	ASGI-2010-006	150.0	AECI	Tap Fairfax – Fairfax Tap 138kV
	ASGI-2010-007	150.0	AECI	Tap Fairfax – Fairfax Tap 138kV
	GEN-2002-004	200.0	WERE	Latham 345kV
	GEN-2005-013	201.0	WERE	Tap Latham - Neosho
	GEN-2007-025	300.0	WERE	Tap Woodring – Wichita 345kV
	GEN-2008-013	300.0	OKGE	Tap Woodring – Wichita 345kV
	GEN-2008-021	42.0	WERE	Wolf Creek 25kV
	GEN-2008-071	76.8	OKGE	Newkirk 138kV
	GEN-2008-098	100.8	WERE	Tap Wolf Creek – LaCygne 345kV
	GEN-2008-127	200.1	WERE	Tap Sooner – Rose Hill 345kV
	GEN-2009-025	60.0	OKGE	Tap Deer Creek – Sinclair 69kV
	GEN-2010-003	100.8	WERE	GEN-2008-098 345kV
	GEN-2010-005	300.0	WERE	GEN-2007-025 345kV
	GEN-2010-055	4.5	AEPW	Wekiwa 138kV
PRIOR QUEUED SUBTOTAL		**3,356.0**		
Group 8 N-OK/S-KS SUBTOTAL		**0.0**		
AREA TOTAL		**3,356.0**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	Genoa	4.0	NPPD	Genoa 115kV
	Ainsworth	75.0	NPPD	Ainsworth Wind Tap 115kV
	Rosebud Project	30.0	NPPD	St. Francis 115kV
	Broken Bow	8.3	NPPD	Genoa 115kV
	Ord	10.8	NPPD	Bloomfield 115kV
	Stuart	2.1	NPPD	Petersburg 115kV
	GEN-2006-020N	42.0	NPPD	Bloomfield 115kV
	GEN-2006-037N1	75.0	NPPD	Broken Bow 115kV
	GEN-2006-038N005	80.0	NPPD	Broken Bow 115kV
	GEN-2006-038N019	80.0	NPPD	Petersburg 115kV
	GEN-2006-044N	40.5	NPPD	Tap Neligh – Petersburg 115kV
	GEN-2006-044N02	100.5	NPPD	GEN-2008-086N02 230kV
	GEN-2007-011N08	81.0	NPPD	Bloomfield 115kV
	GEN-2008-086N02	200.0	NPPD	Tap Ft. Randall – Columbus 230kV
	GEN-2010-010	100.5	NPPD	Madison County 230kV
	GEN-2010-051	200.0	NPPD	Tap Twin Church – Hoskins 230kV
	GEN-2011-027	120.0	NPPD	Tap Twin Church - Hoskins 230kV
PRIOR QUEUED SUBTOTAL		**1,249.7**		
Group 9/10 N NEBRASKA SUBTOTAL		**0.0**		
AREA TOTAL		**1,249.7**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2003-006A	200.0	MKEC	Elm Creek 230kV
	GEN-2003-019	250.0	MIDW	Smoky Hills Tap 230kV
	GEN-2006-031	75.0	MIDW	Knoll 115kV
	GEN-2006-032	200.0	MIDW	South Hays 230kV
	GEN-2008-092	201.0	MIDW	Knoll 115kV
	GEN-2009-008	199.5	SUNC	South Hays 230kV
	GEN-2009-011	50.0	MKEC	Tap Plainville – Phillipsburg 115kV
	GEN-2009-020	48.6	MIDW	Tap Bazine – Nekoma 69kV
	GEN-2010-048	70.0	MIDW	Tap Beach Station – Redline 115kV
	GEN-2010-057	201.0	MIDW	Rice County 230kV
PRIOR QUEUED SUBTOTAL		**1,495.1**		
Cluster	**Request**	**Amount**	**Area**	**Proposed Point of Interconnection**
North Kansas	GEN-2011-001	200.0	SUNC	Tap Post Rock – Axtell 345kV
Group 11 NORTH KANSAS SUBTOTAL		**200.0**		
AREA TOTAL		**1,695.1**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
	PRIOR QUEUED SUBTOTAL	**0.0**		
	Group 12 NW AR SUBTOTAL	**0.0**		
	AREA TOTAL	**0.0**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	ASGI-2010-001	400.0	AECI	Tap Cooper – Fairport 345kV
	ASGI-2010-002	201.0	AECI	Lathrop 161kV
	ASGI-2010-003	300.0	AECI	Maryville 161kV
	ASGI-2010-004	50.0	AECI	Tap Queen City – Lancaster 69kV
	ASGI-2010-005	99.0	AECI	Lathrop 161kV
	ASGI-2010-008	100.0	AECI	Maryville 161kV
	ASGI-2010-009	201.0	AECI	Osborn 161kV
	GEN-2006-014	300.0	MIPU	Tap Maryville – Clarinda 161kV & Tie to Midway 161kV
	GEN-2006-017	300.0	MIPU	Tap Maryville – Clarinda 161kV & Tie to Midway 161kV
	GEN-2007-015	135.0	WERE	Tap Humboldt – Kelly 161kV
	GEN-2007-017	100.5	MIPU	Tap Maryville – Clarinda 161kV & Tie to Midway 161kV
	GEN-2007-053	110.0	MIPU	Tap Maryville – Clarinda 161kV & Tie to Midway 161kV
	GEN-2008-119O	60.0	OPPD	Tap Humboldt – Kelly 161kV
	GEN-2008-129	80.0	MIPU	Pleasant Hill 161kV
	GEN-2009-040	73.8	WERE	Tap Smittyville – Knob Hill 115kV
	GEN-2010-036	4.6	WERE	6th Street 115kV
	GEN-2010-041	10.5	OPPD	S 1399 161kV
	GEN-2010-047	72.0	NPPD	Tap Beatrice – Harbine 115kV
	GEN-2010-056	151.0	MIPU	Tap Saint Joseph - Cooper 345kV
	GEN-2011-011	50.0	KCPL	Iatan 345kV
	GEN-2011-018	73.6	NPPD	Steele City 115kV
	PRIOR QUEUED SUBTOTAL	**2,872.0**		
Cluster	**Request**	**Amount**	**Area**	**Proposed Point of Interconnection**
NW Missouri	GEN-2011-001	99.0	NPPD	Harbine 115kV/Tap Harbine – Beatrice 115kV
	Group 13 NORTHWEST MISSOURI SUBTOTAL	**99.0**		
	AREA TOTAL	**2,971.0**		

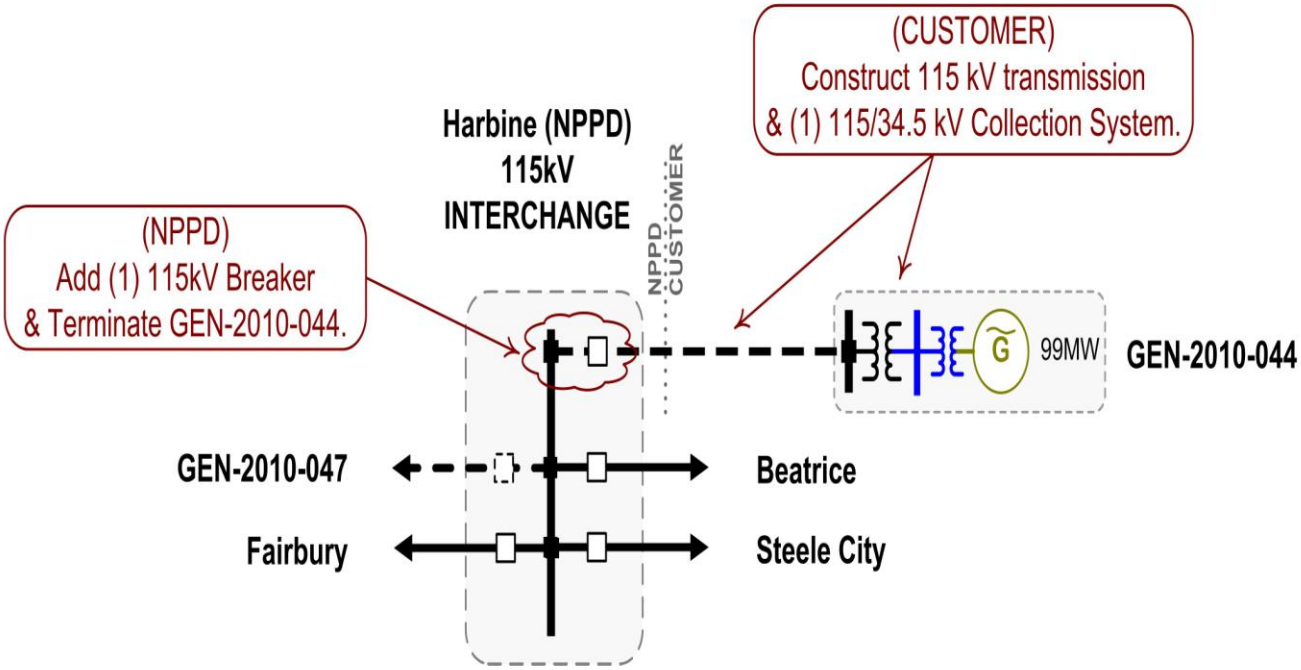
Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2006-038	750.0	WFEC	Hugo 345kV
	GEN-2008-046	200.0	OKGE	Sunnyside 345kV
	GEN-2011-013	101.7	OKGE	Sunnyside 345kV
	PRIOR QUEUED SUBTOTAL	**1,051.7**		
	Group 14 SOUTH OKLAHOMA SUBTOTAL	**0.0**		
	AREA TOTAL	**1,051.7**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2008-123N	89.7	NPPD	Tap Guide – Pauline 115kV
	PRIOR QUEUED SUBTOTAL	**89.7**		
	Group 15 SOUTH NEBRASKA	**0.0**		
	AREA TOTAL	**89.7**		

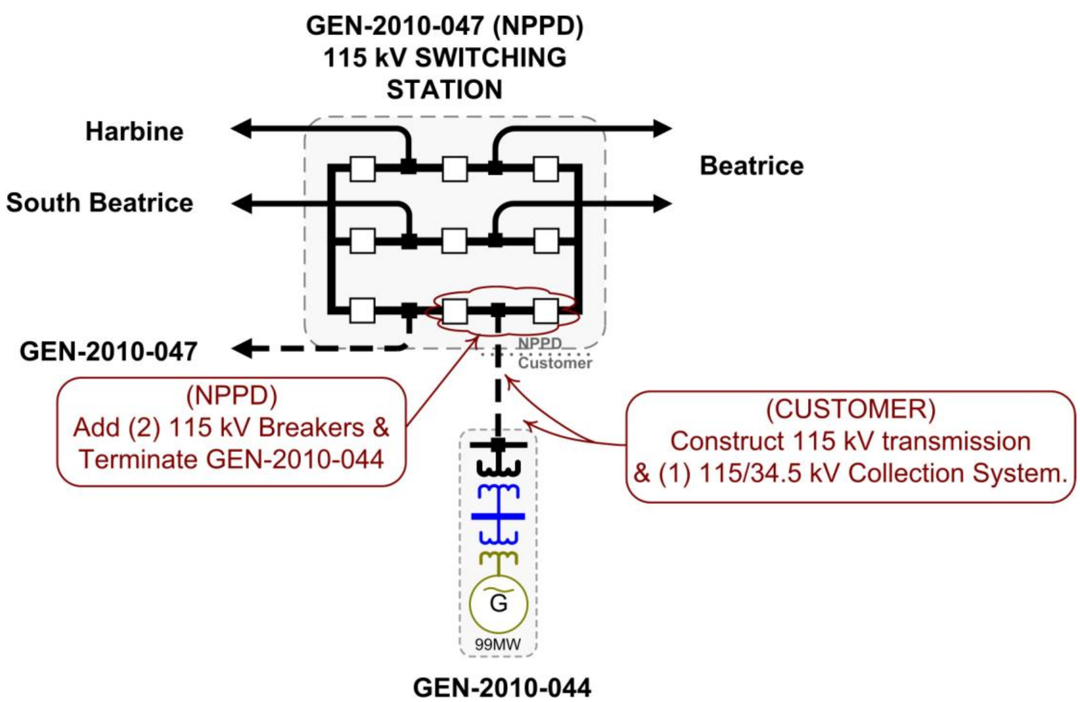
CLUSTER TOTAL (CURRENT STUDY)	**479MW**
CLUSTER TOTAL (INCLUDING PRIOR QUEUED)	**33,702.1MW**

D: Proposed Point of Interconnection One line Diagrams

GEN-2010-044 (Option A)

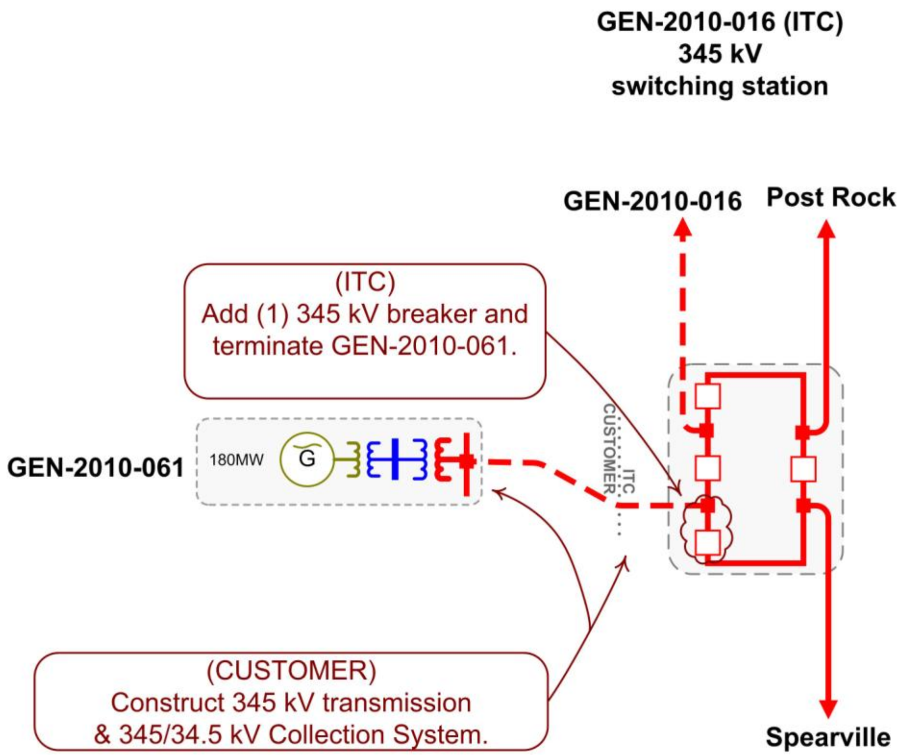


GEN-2010-044 (Option B)

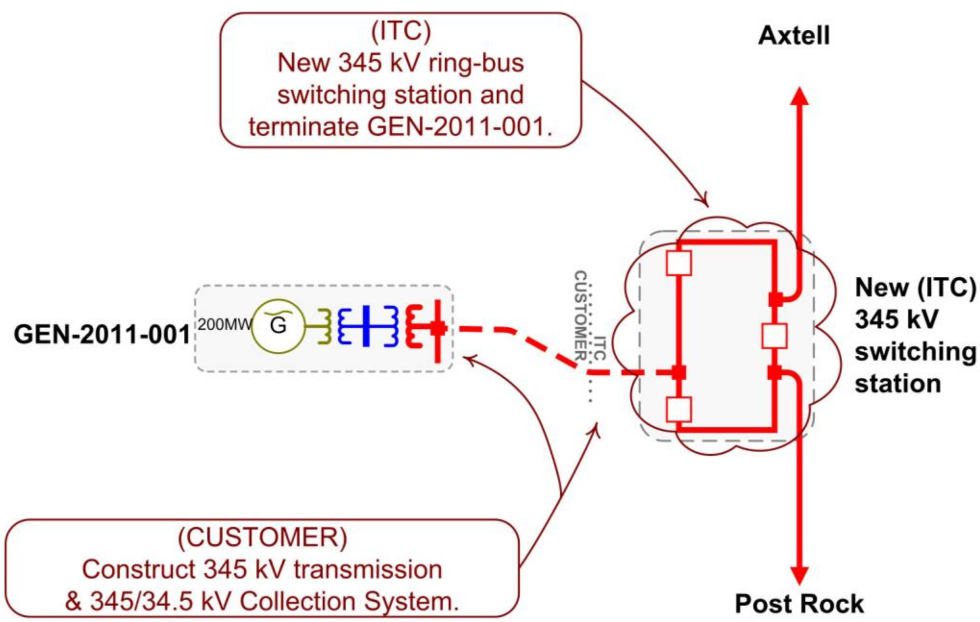


* Planned ^ Proposed

GEN-2010-061



GEN-2011-001



E: Cost Allocation per Interconnection Request (Including Prior Queued Upgrades)

*Important Note:

****WITHDRAWAL OF HIGHER QUEUED PROJECTS WILL CAUSE A RESTUDY AND MAY RESULT IN HIGHER INTERCONNECTION COSTS****

This section shows each Generation Interconnection Request Customer, their current study impacted Network Upgrades, and the previously allocated upgrades upon which they rely to accommodate their interconnection to the transmission system.

The costs associated with the current study Network Upgrades are allocated to the Customers shown in this report.

In addition should a higher queued request, defined as one this study includes as a prior queued request, withdraw, the Network Upgrades assigned to the withdrawn request may be reallocated to the remaining requests that have an impact on the Network Upgrade under a restudy. Also, should a Interconnection Request choose to go into service prior to the operation date of any necessary Network Upgrades, the costs associated with those upgrades may be reallocated to the impacted Interconnection Request. The actual costs allocated to each Generation Interconnection Request Customer will be determined at the time of a restudy.

The required interconnection costs listed do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request through SPP's Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP OATT. In addition, costs associated with a short circuit analysis will be allocated should the Interconnection Request Customer choose to execute a Facility Study Agreement.

E. Cost Allocation Per Request

(Including Perviously Allocated Network Upgrades*)

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN 2010-044			
Beatrice - Clatonia 115kV line Rebuild approximately 9 miles of 115kV line	Current Study	$5,250,000.00	$5,250,000.00
GEN 2010-044 Interconnection Costs See Oneline Diagram.	Current Study	$4,000,000.00	$4,000,000.00
GEN 2010-047 - Harbine 115kV Rebuild approximately 6 miles of 115kV from Harbine - GEN 2010-047 Tap	Previously Allocated		$3,500,000.00
GEN 2010-047 Tap - Crete 115kV CKT 1 Build approximately 35 miles of new 115kV line	Previously Allocated		$20,800,000.00
	Current Study Total	$9,250,000.00	
GEN 2010-061			
GEN 2010-061 Interconnection Costs See Oneline Diagram.	Current Study	$9,000,000.00	$9,000,000.00
Knoll - North Hays 115kV NRIS upgrade: Rebuild approximately 2 miles of 115kV line	Current Study	$1,500,000.00	$1,500,000.00
North Hays - Vine Street 115kV NRIS upgrade: Rebuild approximately 4 miles of 115kV line	Current Study	$3,000,000.00	$3,000,000.00
Smoky Hill - Summit 230kV NRIS upgrade: Rebuild approximately 40 miles of 230kV line	Current Study	$14,519,815.75	$23,700,000.00
South Hays 230/115/12.5kV transformer CKT 2 NRIS upgrade: Install 2nd 230/115/12.5kV transformer at South Hays	Current Study	$3,000,000.00	$3,000,000.00
Beaver County - Gray County 345kV Build approximately 90 miles of 345kV from Beaver County - Gray County	Previously Allocated		$90,000,000.00
Border - Tuco Interchange 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV (Total Project E&C Cost Shown)	Previously Allocated		$148,727,500.00
Matthewson - Cimarron 345kV CKT 2 Build second 345kV circuit from Matthewson - Cimarron	Previously Allocated		$15,000,000.00
Medicine Lodge - Wichita 345KV Dbl CKT Priority Project: Spearville - Comanche - Med Lodge - Wichita Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$356,300,000.00
Medicine Lodge - Woodward 345KV Dbl CKT Priority Project: Med Lodge - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$194,972,759.00

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Medicine Lodge 345/115kV transformer Install new 345/115kV transformer at Medicine Lodge	Previously Allocated		$10,000,000.00
Mullegreen - Circle 345kV Dbl CKT Build new 345kV line from Mullergreen - Circle	Previously Allocated		$132,000,000.00
Post Rock 345/230/13.8KV Autotransformer CKT 1 Balanced Portfolio: Spearville - PostRock - Axtell 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$112,700,000.00
Post Rock 345/230/13.8kV Autotransformer CKT 2 DISIS-2010-001 Restudy	Previously Allocated		$13,749,527.00
PostRock - GEN-2010-016 Tap 345KV CKT 1 Balanced Portfolio: Spearville - PostRock - Axtell 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$112,700,000.00
Spearville - Mullergreen 345kV Dbl CKT Build new 345kV line from Spearville - Mullergreen	Previously Allocated		$124,000,000.00
Tatonga - Matthewson 345kV CKT 2 Build second 345kV circuit from Tatonga - Matthewson	Previously Allocated		$60,000,000.00
Tuco Interchange 345/230/13.2KV Autotransformer CKT 2 Balanced Portfolio: Tuco 345/230 kV Transformer CKT 2 (Total Project E&C Cost Shown)	Previously Allocated		$11,250,000.00
	Current Study Total	$31,019,815.75	

GEN 2011-001

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN 2011-001 Interconnection Costs See Oneline Diagram.	Current Study	$4,500,000.00	$9,000,000.00
Smoky Hill - Summit 230kV NRIS upgrade: Rebuild approximately 40 miles of 230kV line	Current Study	$9,180,184.25	$23,700,000.00
Beaver - Woodward 345kV Dbl CKT Priority Project: Hitchland - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$247,005,793.00
Medicine Lodge - Wichita 345KV Dbl CKT Priority Project: Spearville - Comanche - Med Lodge - Wichita Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$356,300,000.00
Post Rock 345/230/13.8KV Autotransformer CKT 1 Balanced Portfolio: Spearville - PostRock - Axtell 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$112,700,000.00
Post Rock 345/230/13.8kV Autotransformer CKT 2 DISIS-2010-001 Restudy	Previously Allocated		$13,749,527.00
PostRock - GEN-2010-016 Tap 345KV CKT 1 Balanced Portfolio: Spearville - PostRock - Axtell 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$112,700,000.00

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
South Hays - Hays Plant - Vine Street 115kV CKT 1 Rebuild approximately 4 miles of 115kV.	Previously Allocated		$3,000,000.00
Spearville - GEN-2010-016 Tap 345KV CKT 1 Balanced Portfolio: Spearville - PostRock - Axtell 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$112,700,000.00
	Current Study Total	$18,180,184.25	

TOTAL CURRENT STUDY COSTS: $58,450,000.00

F: Cost Allocation per Proposed Study Network Upgrade

*Important Note:

****WITHDRAWAL OF HIGHER QUEUED PROJECTS WILL CAUSE A RESTUDY AND MAY RESULT IN HIGHER INTERCONNECTION COSTS****

This section shows each Direct Assigned Facility and Network Upgrade and the Generation Interconnection Request Customer(s) which have an impact in this study assuming all higher queued projects remain in the queue and achieve commercial operation.

The required interconnection costs listed do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request through SPP's Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP OATT. In addition, costs associated with a short circuit analysis will be allocated should the Interconnection Request Customer choose to execute a Facility Study Agreement.

There may be additional costs allocated to each Customer. See Appendix E for more details.

Appendix F. Cost Allocation by Upgrade

Upgrade			Cost
Beatrice - Clatonia 115kV line			**$5,250,000.00**
Rebuild approximately 9 miles of 115kV line			
	GEN 2010-044	$5,250,000.00	
	Total Allocated Costs	**$5,250,000.00**	
GEN 2010-044 Interconnection Costs			**$4,000,000.00**
See Oneline Diagram.			
	GEN 2010-044	$4,000,000.00	
	Total Allocated Costs	**$4,000,000.00**	
GEN 2010-061 Interconnection Costs			**$9,000,000.00**
See Oneline Diagram.			
	GEN 2010-061	$9,000,000.00	
	Total Allocated Costs	**$9,000,000.00**	
GEN 2011-001 Interconnection Costs			**$9,000,000.00**
See Oneline Diagram.			
	GEN 2011-001	$4,500,000.00	
	Total Allocated Costs	**$18,000,000.00**	
Knoll - North Hays 115kV			**$1,500,000.00**
NRIS upgrade: Rebuild approximately 2 miles of 115kV line			
	GEN 2010-061	$1,500,000.00	
	Total Allocated Costs	**$1,500,000.00**	
North Hays - Vine Street 115kV			**$3,000,000.00**
NRIS upgrade: Rebuild approximately 4 miles of 115kV line			
	GEN 2010-061	$3,000,000.00	
	Total Allocated Costs	**$3,000,000.00**	
Smoky Hill - Summit 230kV			**$23,700,000.00**
NRIS upgrade: Rebuild approximately 40 miles of 230kV line			
	GEN 2010-061	$14,519,815.75	
	GEN 2011-001	$9,180,184.25	
	Total Allocated Costs	**$23,700,000.00**	
South Hays 230/115/12.5kV transformer CKT 2			**$3,000,000.00**
NRIS upgrade: Install 2nd 230/115/12.5kV transformer at South Hays			
	GEN 2010-061	$3,000,000.00	

Total Allocated Costs	**$3,000,000.00**

G: Power Flow Analysis (Constraints 20% TDF and above)

SOLUTIONTYPE	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONTCOMMONNAME	RATEB	TDF	TC%LOADING	CONTNAME
FDNS	00G10_044NR	0	16WP	G10_044	'FROM->TO'	'BEATRICE POWER STATION - CLATONIA 115KV CKT 1'	137	0.21064	105.6526	'BEATRICE POWER STATION - SHELDON 115KV CKT 1'

H: Power Flow Analysis (Constraints Between 3% and 20% TDF)

SOLUTIONTYPE	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONTCOMMONNAME	RATEB	TDF	TC%LOADIN	CONTNAME
FNSL-Iteration limit ex	3	0	11G	G10_044		Non Converged Contingency	0	0.05138	9999	'050 1'
FNSL-Iteration limit ex	3	0	11G	G10_044		Non Converged Contingency	0	0.04793	9999	'050 2'
FNSL-Iteration limit ex	3	0	11G	G10_044		Non Converged Contingency	0	0.04957	9999	'ATC_B2_8E2'
FNSL-Iteration limit ex	3	0	11G	G10_044		Non Converged Contingency	0	0.05354	9999	'ATC_B2_8E2_G'
FDNS	3	0	11G	G10_061	'TO->FROM'	'KNOLL - N HAYS3 115.00 115KV CKT 1'	99	0.04525	112.2759	'KNOLL 230 - POSTROCK6 230.00 230KV CKT 1'
FDNS	3	0	11G	G10_061	'TO->FROM'	'N HAYS3 115.00 - VINE STREET 115KV CKT 1	99	0.04525	118.7945	'KNOLL 230 - POSTROCK6 230.00 230KV CKT 1'
FDNS	3	0	11G	G10_061	'TO->FROM'	'MULLERGREN - SPEARVILLE 230KV CKT 1'	355.3	0.07794	106.8894	'G10-16T 345.00 - POSTROCK7 345.00 345KV CKT 1'
FDNS	3	0	11G	G10_061	'FROM->TO'	'WICHITA (WICHT12X) 345/138/13.8KV TRANS	440	0.03898	111.607	'BENTON - WICHITA 345KV CKT 1'
FDNS	3	0	11G	G10_061	'FROM->TO'	'WICHITA (WICHT12X) 345/138/13.8KV TRANS	440	0.03898	111.277	'BENTON - WICHITA 345KV CKT 1'
FDNS	3	0	11G	G11_001	'TO->FROM'	'KNOLL - N HAYS3 115.00 115KV CKT 1'	99	0.04831	112.2759	'KNOLL 230 - POSTROCK6 230.00 230KV CKT 1'
FDNS	3	0	11G	G11_001	'TO->FROM'	'N HAYS3 115.00 - VINE STREET 115KV CKT 1	99	0.04831	118.7945	'KNOLL 230 - POSTROCK6 230.00 230KV CKT 1'
FNSL-Iteration limit ex	3	0	11G	G11_001		Non Converged Contingency	0	0.03964	9999	'050 1'
FNSL-Iteration limit ex	3	0	11G	G11_001		Non Converged Contingency	0	0.03721	9999	'050 2'
FNSL-Iteration limit ex	3	0	11G	G11_001		Non Converged Contingency	0	0.03824	9999	'ATC_B2_8E2'
FNSL-Iteration limit ex	3	0	11G	G11_001		Non Converged Contingency	0	0.04105	9999	'ATC_B2_8E2_G'
FNSL-Iteration limit ex	11	0	11G	G10_044		Non Converged Contingency	2598	0.03468	19.7803	'LAKEOVER - MCADAMS 500KV CKT 1'
FNSL-Iteration limit ex	11	0	11G	G10_044		Non Converged Contingency	0	0.05073	9999	'050 1'
FNSL-Iteration limit ex	11	0	11G	G10_044		Non Converged Contingency	0	0.04733	9999	'050 2'
FNSL-Iteration limit ex	11	0	11G	G10_044		Non Converged Contingency	0	0.05286	9999	'ATC_B2_8E2_G'
FNSL-Iteration limit ex	11	0	11G	G11_001		Non Converged Contingency	0	0.04393	9999	'TRF-STEGALL'
FNSL-Iteration limit ex	11	0	11G	G11_001		Non Converged Contingency	0	0.03899	9999	'050 1'
FNSL-Iteration limit ex	11	0	11G	G11_001		Non Converged Contingency	0	0.03661	9999	'050 2'
FNSL-Iteration limit ex	11	0	11G	G11_001		Non Converged Contingency	0	0.04037	9999	'ATC_B2_8E2_G'
FNSL-Iteration limit ex	13	0	11G	G10_044		Non Converged Contingency	0	0.05073	9999	'050 1'
FNSL-Iteration limit ex	13	0	11G	G10_044		Non Converged Contingency	0	0.04733	9999	'050 2'
FNSL-Iteration limit ex	13	0	11G	G10_044		Non Converged Contingency	0	0.04895	9999	'ATC_B2_8E2'
FNSL-Iteration limit ex	13	0	11G	G10_044		Non Converged Contingency	0	0.05286	9999	'ATC_B2_8E2_G'
FNSL-Iteration limit ex	13	0	11G	G11_001		Non Converged Contingency	0	0.04396	9999	'TRF-STEGALL'
FNSL-Iteration limit ex	13	0	11G	G11_001		Non Converged Contingency	0	0.03899	9999	'050 1'
FNSL-Iteration limit ex	13	0	11G	G11_001		Non Converged Contingency	0	0.03661	9999	'050 2'
FNSL-Iteration limit ex	13	0	11G	G11_001		Non Converged Contingency	0	0.03761	9999	'ATC_B2_8E2'
FNSL-Iteration limit ex	13	0	11G	G11_001		Non Converged Contingency	0	0.04036	9999	'ATC_B2_8E2_G'
FNSL-Iteration limit ex	00G10_044	0	11WP	G10_044		Non Converged Contingency	0	0.04653	9999	'ATC_B2_8E2'
FNSL-Iteration limit ex	00G10_044	0	11WP	G10_044		Non Converged Contingency	0	0.05024	9999	'ATC_B2_8E2_G'
FNSL-Iteration limit ex	00G10_044	0	11WP	G10_044		Non Converged Contingency	1793	0.03458	20.95449	'GEN300015 1-1SGPDEL 18.000'
FNSL-Iteration limit ex	00G10_044	0	11WP	G10_044		Non Converged Contingency	1793	0.03458	20.95449	'GEN300016 1-1G1GPDEL 18.000'
FNSL-Iteration limit ex	00G10_044	0	11WP	G10_044		Non Converged Contingency	1793	0.03458	20.95449	'GEN300017 1-1G2GPDEL 18.000'
FNSL-Iteration limit ex	00G10_044N	0	11SP	G10_044		Non Converged Contingency	0	0.03151	9999	'DAK07WAPAB2'
FNSL-Iteration limit ex	00G10_044N	0	16SP	G10_044		Non Converged Contingency	0	0.03105	9999	'DAK07WAPAB2'
FNSL-Iteration limit ex	00G11_001	0	11WP	G11_001		Non Converged Contingency	0	0.04043	9999	'TRF-STEGALL'
FNSL-Iteration limit ex	00G11_001	0	11WP	G11_001		Non Converged Contingency	0	0.03503	9999	'ATC_B2_8E2'
FNSL-Iteration limit ex	00G11_001	0	11WP	G11_001		Non Converged Contingency	0	0.03758	9999	'ATC_B2_8E2_G'
FNSL-Iteration limit ex	00G11_001N	0	11SP	G11_001		Non Converged Contingency	1792	0.03036	52.25013	'G11-015T 345.00 - TATONGA7 345.00 345KV CKT 1'
FNSL-Iteration limit ex	00G11_001N	0	16SP	G11_001		Non Converged Contingency	1076	0.06011	60.78535	'HOYT - JEFFERY ENERGY CENTER 345KV CKT 1'
FDNS	03G10_061	0	11G	G10_061	'TO->FROM'	'KNOLL - N HAYS3 115.00 115KV CKT 1'	99	0.04525	117.8355	'KNOLL 230 - POSTROCK6 230.00 230KV CKT 1'
FDNS	03G10_061	0	11G	G10_061	'TO->FROM'	'N HAYS3 115.00 - VINE STREET 115KV CKT 1	99	0.04525	124.2462	'KNOLL 230 - POSTROCK6 230.00 230KV CKT 1'
FDNS	03G10_061	0	11G	G10_061	'FROM->TO'	'SMOKYHL6 230.00 - SUMMIT 230KV CKT 1'	319	0.10228	101.9702	'G11_001T 345.00 - POSTROCK7 345.00 345KV CKT 1'
FDNS	03G10_061	0	11G	G10_061	'FROM->TO'	'SMOKYHL6 230.00 - SUMMIT 230KV CKT 1'	319	0.10228	104.2442	'AXTELL - G11_001T 345.00 345KV CKT 1'
FDNS	03G10_061N	0	11G	G10_061	'TO->FROM'	'KNOLL 230 - POSTROCK6 230.00 230KV CKT	398	0.11337	100.9985	'G11_001T 345.00 - POSTROCK7 345.00 345KV CKT 1'
FDNS	03G10_061N	0	11G	G10_061	'FROM->TO'	'SMOKYHL6 230.00 - SUMMIT 230KV CKT 1'	319	0.06938	104.7272	'G11_001T 345.00 - POSTROCK7 345.00 345KV CKT 1'
FDNS	03G10_061N	0	11G	G10_061	'TO->FROM'	'KNOLL 230 - POSTROCK6 230.00 230KV CKT	398	0.11337	103.3799	'AXTELL - G11_001T 345.00 345KV CKT 1'
FDNS	03G10_061N	0	11G	G10_061	'FROM->TO'	'SMOKYHL6 230.00 - SUMMIT 230KV CKT 1'	319	0.06938	107.0685	'AXTELL - G11_001T 345.00 345KV CKT 1'
FDNS	03G10_061N	0	11G	G10_061	'FROM->TO'	'SMOKYHL6 230.00 - SUMMIT 230KV CKT 1'	319	0.04612	100	'DBL-MEDLO-WI'
FDNS	03G10_061N	0	11G	G10_061	'TO->FROM'	'KNOLL - N HAYS3 115.00 115KV CKT 1'	99	0.03998	132.5128	'KNOLL 230 - POSTROCK6 230.00 230KV CKT 1'

FDNS	03G10_061N	0	11G	G10_061	'TO->FROM'	'N HAYS3 115.00 - VINE STREET 115KV CKT 1	99	0.03998	138.9491	'KNOLL 230 - POSTROCK6 230.00 230KV CKT 1'
FDNS	03G10_061N	0	11G	G10_061	'FROM->TO'	'S HAYS6 230.00 (S HAYS T1) 230/115/12.47	166.7	0.03998	101.2194	'KNOLL 230 - POSTROCK6 230.00 230KV CKT 1'
FDNS	03G10_061N	0	11G	G10_061	'FROM->TO'	'S HAYS6 230.00 (S HAYS T1) 230/115/12.47	166.7	0.03998	100.9208	'KNOLL 230 - POSTROCK6 230.00 230KV CKT 1'
FNSL-Iteration limit ex	11G11_001	0	11G	G11_001		Non Converged Contingency	0	0.04393	9999	'TRF-STEGALL'
FNSL-Iteration limit ex	11G11_001	0	11G	G11_001		Non Converged Contingency	0	0.039	9999	'050 1'
FNSL-Iteration limit ex	11G11_001	0	11G	G11_001		Non Converged Contingency	0	0.03661	9999	'050 2'
FNSL-Iteration limit ex	11G11_001	0	11G	G11_001		Non Converged Contingency	0	0.04037	9999	'ATC_B2_8E2_G'
FDNS	11G11_001N	0	11G	G11_001	'FROM->TO'	'SMOKYHL6 230.00 - SUMMIT 230KV CKT 1'	319	0.16802	100.067	'AXTELL - G11_001T 345.00 345KV CKT 1'
FNSL-Iteration limit ex	13G10_044	0	11G	G10_044		Non Converged Contingency	0	0.05073	9999	'050 1'
FNSL-Iteration limit ex	13G10_044	0	11G	G10_044		Non Converged Contingency	0	0.04733	9999	'050 2'
FNSL-Iteration limit ex	13G10_044	0	11G	G10_044		Non Converged Contingency	0	0.04895	9999	'ATC_B2_8E2'
FNSL-Iteration limit ex	13G10_044	0	11G	G10_044		Non Converged Contingency	0	0.05286	9999	'ATC_B2_8E2_G'

I: Stability Study for Group 1

- No requests were located in the cluster group

J: Stability Study for Group 2

- No requests were located in the cluster group

K: Stability Study for Group 3

- See report below

Final Report

For

Southwest Power Pool

From

S&C Electric Company

PRELIMINARY INTERCONNECTION IMPACT STUDY PISIS-2011-001 (Group 3)

S&C Project No. 5652

August 30, 2011

S&C Electric Company

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Report Revision History:

Date of Report	Issue	Comments
August, 29 2011	Rev. A	Preliminary report issued for review and approval
August, 30 2011	Rev. 0	Final report issued

Prepared by: _____________________________________ Shay Bahramirad Project Engineer S&C Electric Company	Reviewed by: _______________________________________ George S. Tsai Li Senior Engineer S&C Electric Company
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Executive Summary

S&C Electric Company has performed an interconnection impact study for the Definitive Impact Study PISIS-2011-001 (Group 3) in response to a request through the Southwest Power Pool (SPP) Tariff studies. The interconnection request for Group 3 consists of GEN-2010-061.

The interconnection request project and prior queued projects were studied at 100% output power using 2010/2011 summer and winter peak loading cases provided by SPP.

SPP requires that the interconnection request project meet a voltage schedule at the point of interconnection (POI) consistent with the voltage in the SPP base case or nominal voltage, whichever is higher. The base case voltage at the POI location was lower than nominal and power flow results indicated that the power factor required at the POI for the majority of N-1 outage contingencies in the summer and winter cases exceed 95% lagging (capacitive). Per FERC 661-A, it is sufficient for Group 3 to deliver ±95% power factor at the POI for each of the outage contingencies specified by SPP.

The interconnection request project and prior queued project are able to ride through the fault contingencies specified by SPP and that nearby areas would retain angular, frequency and voltage stability in each case. But the prior queued project; GEN-2011-016, Siemens 2.3MW at Spearville 345kV (531469), was tripping off in winter peak due at contingencies 28 and 30. The problem is solved by adjusting the transformer tap at the collector bus and the project is able to ride through the fault contingencies. Reactive power capability beyond the +/-95% power factor range is not necessary for low voltage ride through or for transient stability of Group 3. The interconnection request project in Group 3 can successfully interconnect into the transmission system at the desired location without reduction in output power.

1. Introduction

S&C Electric Company has performed an interconnection impact study for the preliminary Impact Study PISIS-2011-001 (Group 3) in response to a request through the Southwest Power Pool (SPP) Tariff studies. The interconnection request project in Group 3 is listed in Table 1.1.

Table 1.1: Study Project in Group 3

Project	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2010-061	179.4	Siemens 2.3MW	Tap on Spearville – Post Rock 345kV line

Group 3 and prior queued projects were studied at 100% output power using 2010/2011 summer and winter peak loading cases provided by SPP.

2 Transmission System and Study Area

The wind generation project in Group 3, were monitored in the following areas:

AEP West (AEPW)

Oklahoma Gas and Electric (OKGE)

Western Farmers Electric Cooperative (WFEC)

Southwestern Public Service (SPS)

Midwest Energy, Inc. (MIDW)

Westar Energy, Inc (WERE)

Nebraska Public Power District (NPPD)

Omaha Public Power District (OPPD)

Lincoln Electric System (LES)

Western Area Power Administration (WAPA)

Sunflower Electric Power Corporation (SUNC)

3. Power Flow Base Cases

The following power flow base cases were provided by SPP:

MDWG_2010_2011SP_PISIS-2011-001-G3.sav – Summer peak 2010/2011, which includes aggregate representation of wind turbine generator for Preliminary Impact Study PISIS-2011-001 (Group 3) and prior queued projects at 100% output power. Other study Groups were also included in the base case with wind farms dispatched at 20% of rated output power.

MDWG_2010_2011WP_PISIS-2011-001-G3.sav– Winter peak 2010/2011, which includes aggregate representation of generation interconnect projects for Preliminary Impact Study PISIS-2011-001 (Group 3) and prior queued projects at 100% output power. Other study Groups were also included in the base case with wind farms dispatched at 20% of rated output power.

4 Power Flow Model

Preliminary Impact Study PISIS-2011-001 (Group 3) and prior queued projects were modeled as aggregates of wind turbine generators. The aggregate models were part of the base case supplied by SPP. Single-line diagrams and other information corresponding to the Group 1 project can be found in Appendix A.

4.1 <u>Siemens SWT 2.3 MW / 60 Hz Wind Turbine Generator</u>

The SWT WTG consists of a rotor, gearbox, induction generator, machine bridge, DC link, and network bridge. The machine bridge and network bridge decouple the generator from the power system and allows the WTG to operate at a definite power factor setpoint. The power factor range of operation in steady-state and dynamically is variable and is a function of the voltage at the generator terminals and the active power output of the generator. At rated output power and at nominal terminal voltage, the output power factor range varies from 90% leading (inductive) to 90% lagging (capacitive) power factor. The lagging power factor range is reduced if the terminal voltage is higher than nominal. The leading power factor range is reduced if the terminal voltage is less than nominal and increased if the terminal voltage is greater than nominal.

5. Power Factor Requirements at the Point of Interconnection

SPP has specific voltage requirements for interconnecting wind farm requests. Such projects are required to meet a voltage schedule at the POI consistent with the voltage in the SPP base case or nominal voltage, whichever is higher, for transmission facility outage contingencies specified by SPP. The base case voltages at the point of interconnection for summer and winter are listed in Table 5.1.

Table 5.1: Base Case Voltage at the Point of Interconnection

Point of Interconnection	Summer Peak 2010/2011 (pu)	Winter Peak 2010/2011 (pu)
Spearville – 345kV (576704)	0.985	0.982

5.1 *Facility Outage Contingencies*

Single transmission facility outage contingencies specified by SPP are listed in Table 5.2.

Table 5.2: List of Power Flow Contingencies

Cont. No.	Description
0	System Intact
1	Outage of the Spearville (531469) to GEN-2007-040 Tap (531000) 345kV line
2	Outage of the GEN-2010-016 Tap (576704) to Spearville (531469) 345kV line
3	Outage of the Spearville (531469) to Comanche (765341) 345kV lines Ckt 2
4	Outage of the Spearville 345kV (531469) to 230kV (539695) transformer
5	Outage of the Spearville 230kV (539695) to 115kV (539694) transformer
6	Outage of the Spearville 345kV (531469) to 115kV (539694) transformer
7	Outage of the Spearville (539695) to Mullergren (539679) 230kV line
8	Outage of the Comanche (765341) to Medicine Lodge (765342) 345kV line Ckt1
9	Outage of the GEN-2010-016 Tap (576704) to Post Rock (530583) 345kV line
10	Outage of the Finney (523853) to Conestoga (560029) 345kV line
11	Outage of the Finney (523853) to Holcomb (531449) 345kV lines
12	Outage of the GEN-2008-018 Tap (531010) to Holcomb (531449) 345kV line
13	Outage of the Holcomb 345kV (531449) to 115kV (531448) transformer
14	Outage of the Woodward (515375) to GEN-2008-047 Tap 345kV lines Ckt 1 & 2
15	Outage of the Knoll (530558) to Post Rock (530584) 230kV line
16	Outage of the Post Rock (530583) to GEN-2011-001 (580129) 345kV line
17	Outage of the Post Rock 345kV (530583) to 230kV (530584) transformer
18	Outage of the GEN-2008-047 (580500) to GEN-2007-040 Tap (531000) 345kV line
19	Outage of the Spearville (531469) to Mullergren (100312) 345kV lines ckt 1 & 2
20	Outage of the Medicine Lodge (765342) to Wichita (532796) 345kV lines ckt 1 & 2
21	Outage of the Medicine Lodge (765342) to Wichita (532796) 345kV lines ckt 1
22	Outage of the GEN-2011-023 (582023) to Comanche (765341) 345kV line

Table 5.3 lists the power factor required of GEN-2010-011 for outage contingencies in Table 5.1 in order to maintain nominal voltage at the POI. The cases for which the 95% power factor requirements are exceeded have been highlighted. The worse cases for lagging and leading power factor are highlighted in yellow. The worst case contingency is the outage of Comanche (765341) to Medicine Lodge (765342) 345kV line Ckt1. The voltage drops to 0.97 in order to keep the power factor equal to 0.95%.

Table 5.3: Power Factor Requirement at the POI for Power Flow Contingencies in Table 5.1 for GEN-2010-061

Cont. No.	Summer				Winter			
	P (MW)	Q (MVAR)	Power Factor		P (MW)	Q (MVAR)	Power Factor	
0	-176.2	-62.5	94.25%	lagging	-176.2	-74.6	92.09%	lagging

1	-176.2	-93.4	88.35%	lagging	-176.2	-105.3	85.84%	lagging
2	-176.6	53	95.78%	leading	-176.5	-58	95.00%	lagging
3	-176.2	-74.5	92.11%	lagging	-176.2	-86	89.87%	lagging
4	-176.2	-64.5	93.91%	lagging	-176.2	-76.4	91.75%	lagging
5	-176.2	-62.5	94.25%	lagging	-176.2	-74.6	92.09%	lagging
6	-176.2	-62.1	94.31%	lagging	-176.2	-75.2	91.97%	lagging
7	-176.2	-126.2	81.30%	lagging	-176.2	-136.7	79.01%	lagging
8	-176.2	-155.4	75.00%	lagging	-176.2	-175.2	70.91%	lagging
9	-176.6	53	95.78%	leading	-176.5	58	95.00%	leading
10	-176.2	-101.8	86.59%	lagging	-176.2	-111.1	84.59%	lagging
11	-176.2	-62.5	94.25%	lagging	-176.2	74.6	92.09%	leading
12	-176.2	-118.2	83.05%	lagging	-176.2	-143.5	77.54%	lagging
13	-176.2	-59.1	94.81%	lagging	-176.2	-71.1	92.73%	lagging
14	-176.2	-76.1	91.80%	lagging	-176.2	-91.1	88.83%	lagging
15	-176.2	-58.7	94.87%	lagging	-176.2	-70.4	92.86%	lagging
16	-176.2	-62.5	94.25%	lagging	-176.2	-74.6	92.09%	lagging
17	-176.2	-68.6	93.19%	lagging	-176.2	-80.2	91.02%	lagging
18	-155	-62.2	92.81%	lagging	-176.2	-172.7	71.42%	lagging
19	-176.2	-124.8	81.60%	lagging	-176.2	-144.7	77.28%	lagging
20	-176.2	-134.8	79.42%	lagging	-176.2	-161	73.82%	lagging
21	-176.2	-134.8	79.42%	lagging	-176.2	-161	73.82%	lagging
22	-176.2	-85.6	89.95%	lagging	-176.2	-97.9	87.41%	lagging

Wind farms are not required by FERC 661-A to operate at the POI beyond a power factor range of ±95% for voltages from 95% to 105% of nominal unless additional reactive power is necessary to prevent voltage collapse or operation of the voltage ride through protection in wind turbine generators.

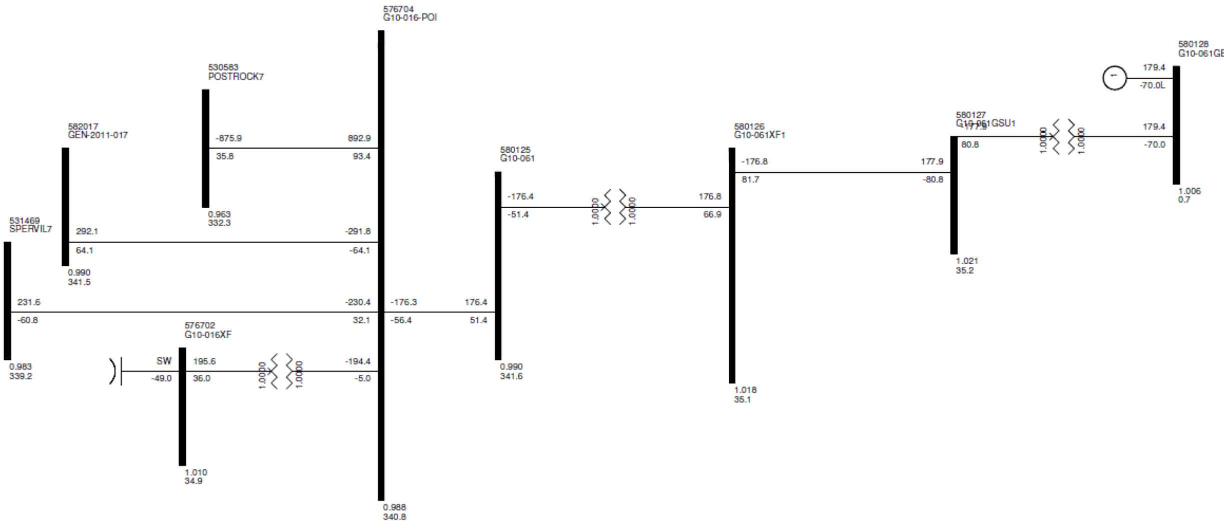

Figure 5.1: Power flow diagram

6. Transient Stability Analysis

Transient stability analysis was performed for the fault contingencies in Table 6.1, which were specified by SPP. For the purpose of the transient stability analysis, each of the interconnection request projects was studied with 95% power factor at the POIs.

Table 6.1: SPP Fault Contingencies

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Spearville (531469) to GEN-2007-040 Tap (531000) 345kV line, near Spearville. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
2	FLT02-1PH	Single phase fault on the line in previous a. Apply single phase fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
3	FLT03-3PH	3 phase fault on the GEN-2010-016 Tap (576704) to Spearville (531469) 345kV line, near GEN-2010-016 Tap. a. Apply fault at GEN-2010-016 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
4	FLT04-1PH	Single phase fault on the line in previous a. Apply single phase fault at GEN-2010-016 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
5	FLT05-3PH	3 phase fault on one of the Spearville (531469) to Comanche (765341) 345kV line Ckt 2, near Spearville. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
6	FLT06-1PH	Single phase fault on the line in previous a. Apply single phase fault at the Spearville 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.
7	FLT07-3PH	3 phase fault on the Spearville 345kV (531469) to 230kV (539695) transformer, near the 345kV bus. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Cont. No.	Cont. Name	Description
8	FLT08-3PH	3 phase fault on the Spearville 230kV (539695) to 115kV (539694) transformer , near the 230kV bus. a. Apply fault at the Spearville 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
9	FLT09-3PH	3 phase fault on the Spearville 345kV (531469) to 115kV (539694) transformer, near the 345kV bus. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
10	FLT10-3PH	3 phase fault on the Spearville (539695) to Mullergren (539679) 230kV line, near Spearville. a. Apply fault at the Spearville 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.
11	FLT11-1PH	Single phase fault and sequence like previous
12	FLT12-3PH	3 phase fault on the Comanche (765341) to Medicine Lodge (765342) 345kV line Ckt1, near Comanche. a. Apply fault at the Comanche 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
13	FLT13-1PH	Single phase fault on the line in previous a. Apply single phase fault at the Comanche 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
14	FLT14-3PH	3 phase fault on the GEN-2010-016 Tap (576704) to Post Rock (531469) 345kV line, near GEN-2010-016 Tap. a. Apply fault at GEN-2010-016 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
15	FLT15-1PH	Single phase fault on the line in previous a. Apply single phase fault at GEN-2010-016 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
16	FLT16-3PH	3 phase fault on the Finney (523853) to Conestoga (560029) 345kV line, near Finney. a. Apply fault at the Finney 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
17	FLT17-1PH	Single phase fault on the line in previous a. Apply single phase fault at the Finney 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT18-3PH	3 phase fault on one of the Finney (523853) to Holcomb (531449) 345kV lines, near Finney. a. Apply fault at the Finney 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
19	FLT19-1PH	Single phase fault on the line in previous a. Apply single phase fault at the Finney 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT20-3PH	3 phase fault on the GEN-2008-018 Tap (531010) to Holcomb (531449) 345kV line, near GEN-2008-018 Tap. a. Apply fault at the GEN-2008-018 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
21	FLT21-1PH	Single phase fault on the line in previous a. Apply single phase fault at the GEN-2008-018 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT22-3PH	3 phase fault on the Holcomb 345kV (531449) to 115kV (531448) transformer, near the 345 kV bus. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Cont. No.	Cont. Name	Description
23	FLT23-3PH	3 phase fault on the Woodward (515375) to GEN-2008-047 Tap 345kV lines Ckt 1 & 2, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
24	FLT24-1PH	Single phase fault on the line in previous a. Apply single phase fault. 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.
25	FLT25-3PH	3 phase fault on the Knoll (530558) to Post Rock (530584) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT26-1PH	Single phase fault and sequence like previous
27	FLT27-3PH	3 phase fault on the Post Rock (530583) to Axtell (640065) 345kV line, near Post Rock. a. Apply fault at the Post Rock 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
28	FLT28-1PH	Single phase fault on the line in previous a. Apply single phase fault at the Post Rock 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.
29	FLT29-3PH	3 phase fault on the Post Rock 345kV (530583) to 230kV (530584) transformer, near the 345 kV bus. a. Apply fault at the Post Rock 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
30	FLT30-3PH	3 phase fault on the GEN-2008-047 (580500) to GEN-2007-040 Tap (531000) 345kV line, near GEN-2007-040 Tap. a. Apply fault at the GEN-2007-040 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

Cont. No.	Cont. Name	Description
31	FLT31-1PH	Single phase fault and sequence like previous
32	FLT32-3PH	3 phase fault on the Spearville (531469) to Mullergren (100312) 345kV lines ckt 1 & 2, near Spearville. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
33	FLT33-3PH	3 phase fault on the Medicine Lodge (765342) to Wichita (532796) 345kV lines ckt 1 & 2, near Medicine Lodge. a. Apply fault at the Medicine Lodge 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT34-3PH	3 phase fault on the Medicine Lodge (765342) to Wichita (532796) 345kV lines ckt 1, near Medicine Lodge. a. Apply fault at the Medicine Lodge 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.
35	FLT35-3PH	3 phase fault on one of the GEN-2011-023 (582023) to Comanche (765341) 345kV line, near GEN-2011-023. a. Apply fault at the GEN-2011-023 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
36	FLT36-1PH	Single phase fault and sequence like previous

Single line-to-ground faults were simulated in a manner consistent with currently accepted practices that is to assume that a single line-to-ground fault will cause a voltage drop at the fault location to 60% of nominal.

The prior queued projects monitored are listed in Table 6.2.

Table 6.2: Prior Queued Wind Farm Projects Monitored

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2001-039A	105	Clipper 2.5MW	Tap on Judson Large – Greensburg 115kV line (579025)
GEN-2002-025A	150	GE 1.5 MW	Spearville 230kV (539695)
GEN-2004-014	154.5	GE 1.5 MW	Spearville 230kV (539695)
GEN-2005-012	250.7	Siemens 2.3MW	Spearville 345kV (531469)
GEN-2006-006	205.5	GE 1.5 MW	Spearville 345kV (531469)
GEN-2006-021	100	Clipper 2.5MW	Tap on Harper – Medicine Lodge 138kV line (539638)
GEN-2006-022	150	Clipper 2.5MW	Pratt 115kV (539687)
GEN-2007-038	200	Clipper 2.5MW	Spearville 345kV (531469)
GEN-2008-018	405	GE 1.5 MW	Finney 345kV (523853)
GEN-2007-040	200.1	Siemens 2.3MW	Tap on Holcomb – Spearville 345kV line (531000)
GEN-2008-079	99.5	G.E. 1.5 MW & 1.6MW	Tap on Cudahy – Judson Large 115kV line (573029)
GEN-2008-124	200.1	Siemens 2.3MW	Spearville 345kV (531469)
GEN-2009-062	115	Genrou	Hugoton 115kV (531481)
GEN-2010-009	165.6	Siemens SWT 2.3MW	Tap on Holcomb – Spearville 345kV line (531000)
GEN-2010-015	200.1	Siemens SWT 2.3MW	Spearville 345kV (531469)
GEN-2010-016	199.8	Vestas V90 1.8MW	Tap on Spearville – Post Rock 345kV line (576704)
GEN-2010-027	900	GE 2.5 MW	Comanche 345kV (765341) *not included in the study since the project was canceled
GEN-2010-029	450	Vestas V90 1.8MW	Spearville 345kV (531469)
GEN-2010-045	197.8	Siemens 2.3MW	Tap on Holcomb – Spearville 345kV line (531000)
GEN-2010-049	49.6	GE 1.6MW	Pratt 115kV (539687)
GEN-2010-052	301.3	Siemens 2.3MW	Finney 345kV (523853)
GEN-2010-053	199.8	Vestas V90 1.8MW	Comanche 345kV (765341)
GEN-2011-008	600	GE 1.6MW	Comanche 345kV (765341)
GEN-2011-016	200.1	Siemens 2.3MW	Spearville 345kV (531469)

GEN-2011-017	299	Siemens 2.3MW	Tap on Spearville – Post Rock 345kV line (576704)
GEN-2011-023	299	Siemens 2.3MW	Tap on Comanche - Spearville 345kV (582023)

Table 6.3 listed voltage and frequency relay settings were used to evaluate fault ride-through capability of WTGs in transient stability analysis.

Table 6.3: Siemens SWT 2.3 MW Protection Settings (PSS/E Model Version 1.3)

Relay Type	Trip Setting	Time Setting (sec)
Undervoltage	0.85 (pu)	3.0
Undervoltage	0.40 (pu)	1.6
Undervoltage	0.15 (pu)	0.85
Overvoltage	1.2 (pu)	0.15
Overvoltage	1.10 (pu)	1.0
Underfrequency	57.0 (Hz)	10
Underfrequency	56.4 (Hz)	0.1
Overfrequency	62.4 (Hz)	0.1

6.1 Stability Criteria

Disturbances including three-phase and single-phase to ground faults should not cause synchronous and asynchronous plants to become unstable or disconnect from the transmission grid.

The criterion for synchronous generator stability as defined by NERC is:

"Power system stability is defined as that condition in which the difference of the angular positions of synchronous machine rotor becomes constant following an aperiodic system disturbance."

Voltage magnitudes and frequencies at terminals of asynchronous generators should not exceed magnitudes and durations that will cause protection elements to operate. Furthermore, the response after the disturbance needs to be studied at the terminals of the machine to insure that there are no sustained oscillations in power output, speed, frequency, etc.

Voltage magnitudes and angles after the disturbance should settle to a constant and reasonable operating level. Frequencies should settle to the nominal 60 Hz power frequency.

6.2 Transient Stability Results

Undisturbed runs of 20 seconds were performed with the summer and winter peak cases to verify proper initialization of dynamic models.

Group 3 will survive each fault disturbance in Table 6.1. Voltage, frequency and angular stability will be retained. Transient stability plots of the undisturbed runs and #1 through #36 fault contingencies for summer and winter can be found in the Appendix (B and C) section of this report. GEN-2011-016, Siemens 2.3MW at Spearville 345kV (531469), was tripping off at contingencies 28 and 30 in winter peak. The problem is solved by adjusting the transformer tap at the collector bus and the project is able to ride through the fault contingencies. The result for after transformer tap adjustment is attached in Appendix D.

Table 6.6: Summary of Transient Stability Results

Cont. No.	Cont. Name	Summer Peak 2010/2011	Winter Peak 2010/2011
1	FLT01-3PH	STABLE	STABLE
2	FLT02-1PH	STABLE	STABLE
3	FLT03-3PH	STABLE	STABLE
4	FLT04-1PH	STABLE	STABLE
5	FLT05-3PH	STABLE	STABLE
6	FLT06-1PH	STABLE	STABLE
7	FLT07-3PH	STABLE	STABLE
8	FLT08-3PH	STABLE	STABLE
9	FLT09-3PH	STABLE	STABLE

Cont. No.	Cont. Name	Summer Peak 2010/2011	Winter Peak 2010/2011
10	FLT10-3PH	STABLE	STABLE
11	FLT11-1PH	STABLE	STABLE
12	FLT12-3PH	STABLE	STABLE
13	FLT13-1PH	STABLE	STABLE
14	FLT14-3PH	STABLE	STABLE
15	FLT15-1PH	STABLE	STABLE
16	FLT16-3PH	STABLE	STABLE
17	FLT17-1PH	STABLE	STABLE
18	FLT18-3PH	STABLE	STABLE
19	FLT19-1PH	STABLE	STABLE
20	FLT20-3PH	STABLE	STABLE
21	FLT21-1PH	STABLE	STABLE
22	FLT22-3PH	STABLE	STABLE
23	FLT23-3PH	STABLE	STABLE
24	FLT24-1PH	STABLE	STABLE
25	FLT25-3PH	STABLE	STABLE
26	FLT26-1PH	STABLE	STABLE
27	FLT27-3PH	STABLE	STABLE
28	FLT28-1PH	STABLE	STABLE
29	FLT29-3PH	STABLE	STABLE
30	FLT30-3PH	STABLE	STABLE
31	FLT31-1PH	STABLE	STABLE
32	FLT32-3PH	STABLE	STABLE
33	FLT33-3PH	STABLE	STABLE
34	FLT34-3PH	STABLE	STABLE
35	FLT35-3PH	STABLE	STABLE
36	FLT36-1PH	STABLE	STABLE

7. Conclusions and Recommendations

Transient analysis results indicate that Preliminary Impact Study PISIS-2011-001 (Group 3) can successfully interconnect into the transmission system at 100% output power and at the desired location. Per FERC 661-A, it is sufficient for Group 3 to deliver ±95% power factor at the POI for each of the outage contingencies specified by SPP.

L: Stability Study for Group 4

- No requests were located in the cluster group

M: Stability Study for Group 5

- No requests were located in the cluster group

N: Stability Study for Group 6

- No requests were located in the cluster group

O: Stability Study for Group 7

- No requests were located in the cluster group

P: Stability Study for Group 8

- No requests were located in the cluster group

Q: Stability Study for Group 9

- No requests were located in the cluster group

R: Stability Study for Group 10

- No requests were located in the cluster group

Southwest Power Pool, Inc. (SPP)

Preliminary Impact Study PISIS-2011-001: Group 13

Final Report

PXE-0500
Revision #01

August 2011

Submitted By:
Mitsubishi Electric Power Products, Inc. (MEPPI)
Power Systems Engineering Services Department
Warrendale, PA

Title: **Preliminary Impact Study PISIS-2011-001: Group 13: Final Report PXE-0500**
Date: August 2011
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EXECUTIVE SUMMARY

SPP requested an Interconnection System Impact Study for PISIS-2011-001: Group 13. The Interconnection System Impact Study required a Power Factor Analysis and a Stability Analysis detailing the impacts of the study interconnecting project as shown in Table ES-1.

Table ES-1
Interconnection Project Evaluated

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2010-044	99	Siemens 2.3 MW	Tap on the Harbine to Beatrice 115 kV line (580056)

SUMMARY OF POWER FACTOR ANALYSIS

Power Factor Analysis shows that GEN-2010-044 has a power factor range of 0.9098 to 0.9993 leading (absorbing).

SUMMARY OF STABILITY ANALYSIS

The Stability Analysis determined that no wind turbine tripping or system instability occurs from interconnecting GEN-2010-044 at 100% output.

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SECTION 1: OBJECTIVES

The objective of this report is to provide Southwest Power Pool, Inc. (SPP) with the deliverables for the "Preliminary Impact Study PISIS-2011-001: Group 13." SPP requested an Interconnection System Impact Study for GEN-2010-044, which requires a Power Factor Analysis, a Stability Analysis, and an Impact Study Report.

SECTION 2: BACKGROUND

The Siemens Power Technologies, Inc. PSS/E power system simulation program Version 30.3.3 was used for this study. SPP provided the stability database cases for both summer peak[8] and winter peak[9] seasons and a list of contingencies to be examined. The model includes the study project and the previously queued projects as listed in Table 2-1 and Table 2-2, respectively. Refer to Appendix A for the steady-state and dynamic model data for the study project. A power flow one-line diagram of GEN-2010-044 interconnection project is shown in Figure 2-1.

The Power Factor analysis will determine the power factor at the point of interconnection for the wind interconnection project for pre-contingency and post-contingency conditions. Table 2-3 lists the contingencies developed from the three-phase fault definitions provided in the Group's interconnection impact study request.

The Stability Analysis will determine the impacts of the new interconnecting project on the stability and voltage recovery of the nearby system 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 will be investigated. Three-phase and single-phase faults will be examined as listed in Table 2-3.

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[8] *MDWG_2010_2011SP_PISIS-2010-044.sav – summer peak filename.*
[9] *MDWG_2010_2011WP_PISIS-2010-044.sav – winter peak filename.*

Table 2-1
Interconnection Project Evaluated

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2010-044	99	Siemens 2.3 MW	Tap on the Harbine to Beatrice 115 kV line (580056)

Table 2-2
Previously Queued Nearby Interconnection Projects Included

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2006-014	300	G.E. 1.5 MW	WFarms 161 kV (89572)
GEN-2006-017	300	Clipper 2.5 MW	WFarms 161 kV (89572)
GEN-2007-015	135	G.E. 1.5 MW	Tap on the Humboldt to Kelley 161 kV line (579244)
GEN-2007-017	99	G.E. 1.5 MW	WFarms 161 kV (89572)
GEN-2007-053	110	Gamesa 2.0 MW	WFarms 161 kV (89572)
GEN-2008-119O	60	G.E. 1.5 MW	S1399 161 kV (646399)
GEN-2008-129	641/675 MW	Combined Cycle	Pleasant Hill 161 kV (541225)
GEN-2009-040	73.8	Vestas V90 1.8 MW	Tap on Smittyville Coop to Knob Hill 115 kV line (560287)
GEN-2010-036	4.6	GENROU	6th Street 115 kV (533264)
GEN-2010-041	10.5	G.E. 1.5 MW	S1399 161 kV (646399)
GEN-2010-047	72	G.E. 1.6 MW	Tap on the Beatrice to Harbine 115 kV line (580056)
GEN-2010-056	151	Vestas V90 1.8 MW	Tap on Saint Joseph to Cooper 345 kV line (582056)
GEN-2011-011	50	GENROU	Iatan 345 kV (542982)
GEN-2011-018	73.6	Siemens 2.3 MW	Steele City 115 kV (640246)

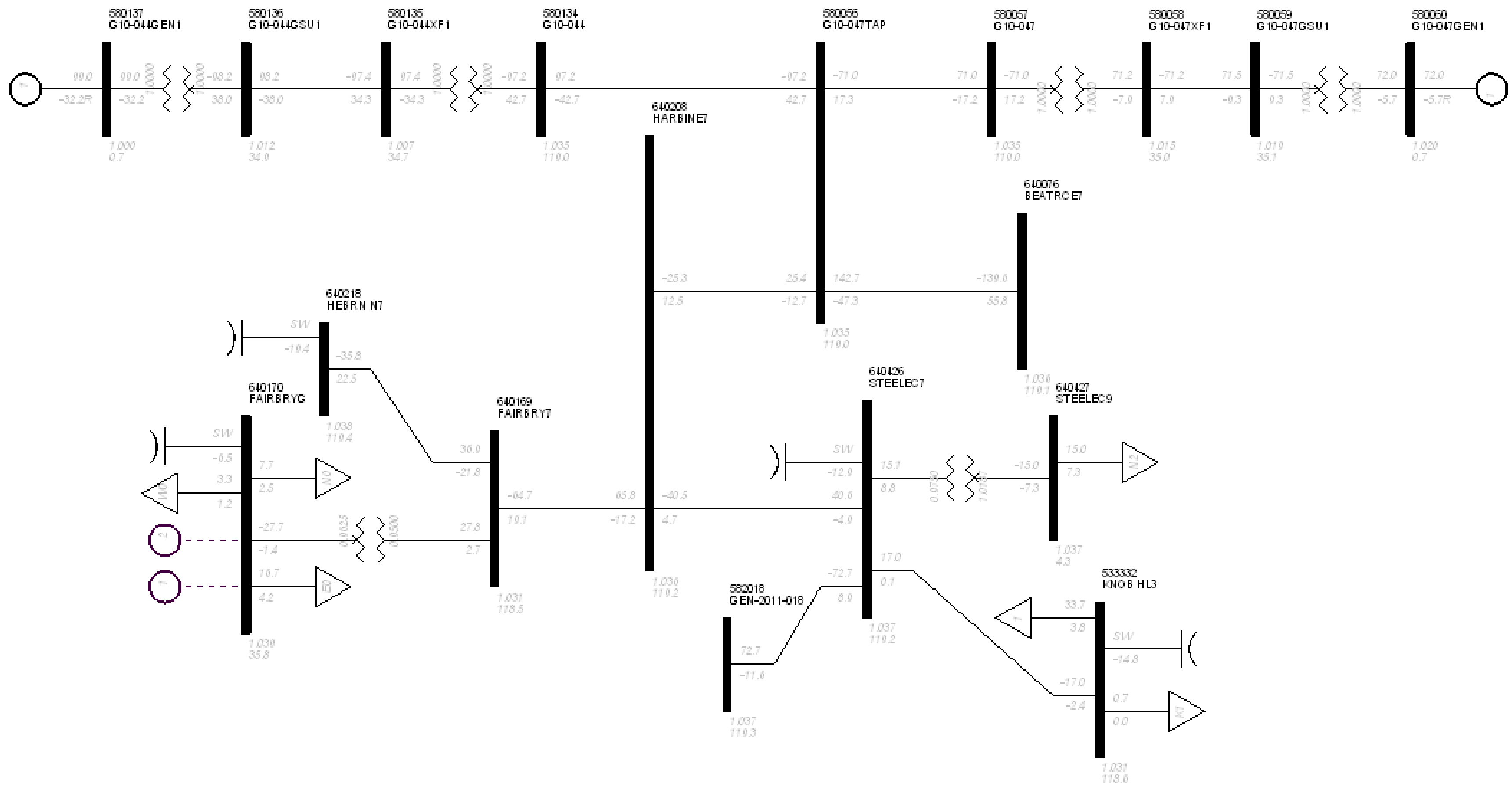

Figure 2-1. Power flow one-line diagram for interconnection project GEN-2010-044.

Table 2-3
Case List with Contingency Description

Ref. No.	Case Name	Description
1	FLT01-3PH	3 phase fault on the Fairport (300039) to Cooper (640139) 345 kV line, near Fairport. a. Apply fault at Fairport 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
2	FLT02-1PH	*Single phase fault and sequence like previous*
3	FLT03-3PH	3 phase fault on the Cooper (640139) to Atchison (635017) 345 kV line, near Cooper. a. Apply fault at Cooper 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
4	FLT04-1PH	*Single phase fault and sequence like previous*
5	FLT05-3PH	3 phase fault on the Moore (640277) to Cooper (640139) 345 kV line, near Moore. a. Apply fault at Moore 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
6	FLT06-1PH	*Single phase fault and sequence like previous*
7	FLT07-3PH	3 phase fault on the Nebraska City (645458) to Cooper (640139) 345 kV line, near Cooper. a. Apply fault at Cooper 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on the Cooper (640139) to 161 kV transformer on the 345 kV bus. a. Apply fault at Cooper 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
10	FLT10-3PH	3 phase fault on the Steele City (640426) to Harbine (640208) 115kV line, near Harbine. a. Apply fault at Harbine 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
11	FLT11-1PH	*Single phase fault and sequence like previous*
12	FLT12-3PH	3 phase fault on the Steele City (640426) to Knob Hill (533332) 115kV line, near Steele City. a. Apply fault at Steele City 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
13	FLT13-1PH	*Single phase fault and sequence like previous*
14	FLT14-3PH	3 phase fault on the Knob Hill (533332) to Greenleaf (539665) 115kV line, near Knob Hill. a. Apply fault at Knob Hill 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
15	FLT15-1PH	*Single phase fault and sequence like previous*
16	FLT16-3PH	3 phase fault on the Knob Hill (533332) to GEN-2009-040 Tap (560287) 115kV line, near Knob Hill. a. Apply fault at Knob Hill 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
17	FLT17-1PH	*Single phase fault and sequence like previous*

Table 2-3 (continued)

Case List with Contingency Description

Ref. No.	Case Name	Description
18	FLT18-3PH	3 phase fault on the Harbine (640208) to Fairbury (640169) 115kV line, near Harbine. a. Apply fault at Harbine 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
19	FLT19-1PH	*Single phase fault and sequence like previous*
20	FLT20-3PH	3 phase fault on the GEN-2010-047 Tap (580056) to Harbine (640208) 115kV line, near GEN-2010-047 Tap. a. Apply fault at GEN-2010-047 Tap 115 kV 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	FLT21-1PH	*Single phase fault and sequence like previous*
22	FLT22-3PH	3 phase fault on the GEN-2010-047 Tap (580056) to Beatrice (640076) 115kV line, near GEN-2010-047 Tap. a. Apply fault at GEN-2010-047 Tap 115 kV 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.
23	FLT23-1PH	*Single phase fault and sequence like previous*
24	FLT24-3PH	3 phase fault on the Beatrice (640076) to Beatrice Power Station (640088) 115kV line, near Beatrice. a. Apply fault at Beatrice 115 kV 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.
25	FLT25-1PH	*Single phase fault and sequence like previous*
26	FLT26-3PH	3 phase fault on the Beatrice (640076) to Steiner (640361) 115kV line, near Beatrice. a. Apply fault at Beatrice 115 kV 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	FLT27-1PH	*Single phase fault and sequence like previous*
28	FLT28-3PH	3 phase fault on the Beatrice Power Station (640088) to Clatonia (640111) 115kV line, near Beatrice Power Station. a. Apply fault at Beatrice Power Station 115 kV 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	FLT29-1PH	*Single phase fault and sequence like previous*
30	FLT30-3PH	3 phase fault on the Sheldon 115 kV (640278) to Moore 345 kV (640277) transformer on the 345 kV bus. a. Apply fault at Moore 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

SECTION 3: POWER FACTOR ANALYSIS

Task Objective

The objective of this task is to quantify the power factor at the point of interconnection for the wind farm during base case and system contingencies. SPP transmission planning practice requires interconnecting generation projects to maintain the power factor (pf) at the Point of Interconnection (POI) near unity for system intact conditions and within +/- 0.95 pf for post-contingency conditions.

Approach

Both winter peak and summer peak power flows provided by SPP were examined prior to the Power Factor Analysis to ensure they contained the proposed study project modeled at 100% of the nameplate rating and any previously queued projects listed in Table 2-2. There was no suspect power flow data in the study area. The proposed study project at the point of interconnection was turned off during the power factor analysis. The wind farm was then replaced by a generator modeled at the point of interconnection bus with the same real power (MW) capability as the wind farm and open limits for the reactive power set points (Mvar). The generator was set to hold the POI scheduled bus voltage. Contingencies from the three-phase fault definitions provided in Table 2-3 were then applied and the reactive power required to maintain the bus voltage was recorded.

For request GEN-2010-044, the interconnecting wind farm was disabled at bus 580137 and a generator was placed at the high side bus (Bus 580134). The generator was modeled with P_{GEN} = 99 MW, Q_{Min} = -9999 Mvar, and Q_{Max} = 9999 Mvar. All buses and transformers connected between bus 580134 and 580137 were disabled. The scheduled voltage for the POI (GEN-2010-047 Tap) was 1.0347 p.u. for summer peak and 1.0246 for winter peak conditions.

Results

The power factor was calculated for summer and winter peak conditions. Table 3-1 shows the power factor results for GEN-2010-044 (99 MW). Note that a positive Q (Mvar) output illustrates that the generator is absorbing reactive power from the system, implying a leading power factor; a negative Q (Mvar) illustrates that the generator is supplying reactive power to the system, implying a lagging power factor.

Table 3-1
Power Factor Analysis - GEN-2010-044 (99 MW)*

Ref. No.	Summer Peak			Winter Peak		
	Power Factor		Q** (MVAR)	Power Factor		Q** (MVAR)
Base	0.9163	Leading	43.28	0.9417	Leading	35.38
1	0.9161	Leading	43.34	0.9425	Leading	35.10
3	0.9168	Leading	43.11	0.9456	Leading	34.05
5	0.9181	Leading	42.75	0.9515	Leading	32.02
7	0.9162	Leading	43.29	0.9438	Leading	34.66
9	0.9187	Leading	42.55	0.9500	Leading	32.53
10	0.9333	Leading	38.10	0.9520	Leading	31.82
12	0.9098	Leading	45.15	0.9367	Leading	37.00
14	0.9126	Leading	44.36	0.9471	Leading	33.56
16	0.9297	Leading	39.21	0.9380	Leading	36.57
18	0.9406	Leading	35.73	0.9642	Leading	27.24
20	0.9383	Leading	36.50	0.9655	Leading	26.70
22	0.9993	Leading	3.66	0.9968	Leading	7.95
24	0.9469	Leading	33.60	0.9467	Leading	33.67
26	0.9272	Leading	39.99	0.9482	Leading	33.17
28	0.9285	Leading	39.58	0.9577	Leading	29.74
30	0.9281	Leading	39.71	0.9766	Leading	21.82

*The scheduled voltage for the POI (GEN-2010-047 Tap) was 1.0347 p.u. for summer peak and 1.0246 p.u. for winter peak conditions
**A positive Q (Mvar) output illustrates the generator is absorbing Mvars from the system, which implies a leading power factor; negative Q (Mvar) output shows the generator is supplying Mvars to the system implying a lagging power factor.

Summary

Power Factor Analysis shows that GEN-2010-044 has a power factor range of 0.9098 to 0.9993 leading (absorbing).

SECTION 4: STABILITY ANALYSIS

Objective

The objective of the stability analysis was to determine the impacts of the new wind farm at the GEN-2010-047 Tap point along the Harbine to Beatrice 115 kV line on the stability and voltage recovery of the nearby system. If problems with stability or voltage recovery were identified the need for reactive compensation or system upgrades were investigated.

Approach

Both winter peak and summer peak power flows provided by SPP were examined prior to the Stability Analysis to ensure they contained the proposed study project modeled at 100% of the nameplate rating and previously queued projects listed in Table 2-2. There was no suspect power flow data in the study area. The dynamic datasets were also verified and stable initial system conditions (i.e., “flat lines”) were achieved. Three-phase and single line-to-ground faults listed in Table 2-3 were examined. Single-phase fault impedances were calculated to result in a voltage of approximately 60% of the pre-fault voltage. Refer to Table 4-1 for a list of the calculated single-phase fault impedances used for the analysis.

Table 4-1
Calculated Single-Phase Fault Impedances

Ref. No.	Casename	Single-Phase Fault Impedance (MVA)	
		Summer Peak	Winter Peak
2	FLT02-1PH	-5000	-5000
4	FLT04-1PH	-9750	-9500
6	FLT06-1PH	-8000	-7500
8	FLT08-1PH	-9750	-9500
11	FLT11-1PH	-1000	-937.5
13	FLT13-1PH	-687.5	-687.5
15	FLT15-1PH	-687.5	-656.3
17	FLT17-1PH	-687.5	-656.3
19	FLT19-1PH	-1000	-937.5
21	FLT21-1PH	-1000	-937.5
23	FLT23-1PH	-1125	-1000
25	FLT25-1PH	-1625	-1250
27	FLT27-1PH	-1625	-1250
29	FLT29-1PH	-1875	-1312.5

Bus voltages and previously queued generation in the study area were monitored in addition to the bus voltages in the following areas:

- 531 MIDW
- 534 SUNC
- 536 WERE
- 540 MIPU
- 541 KACP

- 640 NPPD
- 645 OPPD

The results of the analysis determined if reactive compensation or system upgrades were required to obtain acceptable system performance. If additional reactive compensation was required, the size, type, and location were determined. The proposed reactive reinforcements would ensure the wind farm meets FERC Order 661A low voltage requirements and return the wind farm to its pre-disturbance operating voltage. If the results indicated the need for fast responding reactive support, dynamic support such as an SVC or STATCOM was investigated. If tripping of the prior queued projects was observed during the stability analysis (for under/over voltage or under/over frequency) the simulations were re-ran with the prior queued project's voltage and frequency tripping disabled. If stability problems were identified, the maximum acceptable generation level for the GEN-2010-044 to operate without causing any stability problems was quantified. Stability analysis results indicated that GEN-2010-044 can interconnect at 100% output for all contingencies.

Results

Refer to Table 4-2 for a summary of the Stability Analysis results. The initial simulations were run for summer and winter peak conditions and all contingencies remained stable. Figure 4-1 shows the response of the GEN-2010-044 generator during a three-phase fault on the GEN-2010-047 Tap to Beatrice 115 kV line (FLT22-3PH) during summer peak conditions. Figure 4-2 shows selected bus voltages in the study area during FLT22-3PH which is a representative case for the “worst” delayed voltage recovery and “most severe” voltage dip.

Table 4-2
Stability Analysis Summary of Results

Ref. No.	Casename	Summer		Winter	
		Stable?	Acceptable Voltages?	Stable?	Acceptable Voltages?
1	FLT01-3PH	Stable	Yes	Stable	Yes
2	FLT02-1PH	Stable	Yes	Stable	Yes
3	FLT03-3PH	Stable	Yes	Stable	Yes
4	FLT04-1PH	Stable	Yes	Stable	Yes
5	FLT05-3PH	Stable	Yes	Stable	Yes
6	FLT06-1PH	Stable	Yes	Stable	Yes
7	FLT07-3PH	Stable	Yes	Stable	Yes
8	FLT08-1PH	Stable	Yes	Stable	Yes
9	FLT09-3PH	Stable	Yes	Stable	Yes
10	FLT10-3PH	Stable	Yes	Stable	Yes
11	FLT11-1PH	Stable	Yes	Stable	Yes
12	FLT12-3PH	Stable	Yes	Stable	Yes
13	FLT13-1PH	Stable	Yes	Stable	Yes
14	FLT14-3PH	Stable	Yes	Stable	Yes
15	FLT15-1PH	Stable	Yes	Stable	Yes
16	FLT16-3PH	Stable	Yes	Stable	Yes
17	FLT17-1PH	Stable	Yes	Stable	Yes
18	FLT18-3PH	Stable	Yes	Stable	Yes
19	FLT19-1PH	Stable	Yes	Stable	Yes
20	FLT20-3PH	Stable	Yes	Stable	Yes
21	FLT21-1PH	Stable	Yes	Stable	Yes
22	FLT22-3PH	Stable	Yes	Stable	Yes
23	FLT23-1PH	Stable	Yes	Stable	Yes
24	FLT24-3PH	Stable	Yes	Stable	Yes
25	FLT25-1PH	Stable	Yes	Stable	Yes
26	FLT26-3PH	Stable	Yes	Stable	Yes
27	FLT27-1PH	Stable	Yes	Stable	Yes
28	FLT28-3PH	Stable	Yes	Stable	Yes
29	FLT29-1PH	Stable	Yes	Stable	Yes
30	FLT30-3PH	Stable	Yes	Stable	Yes

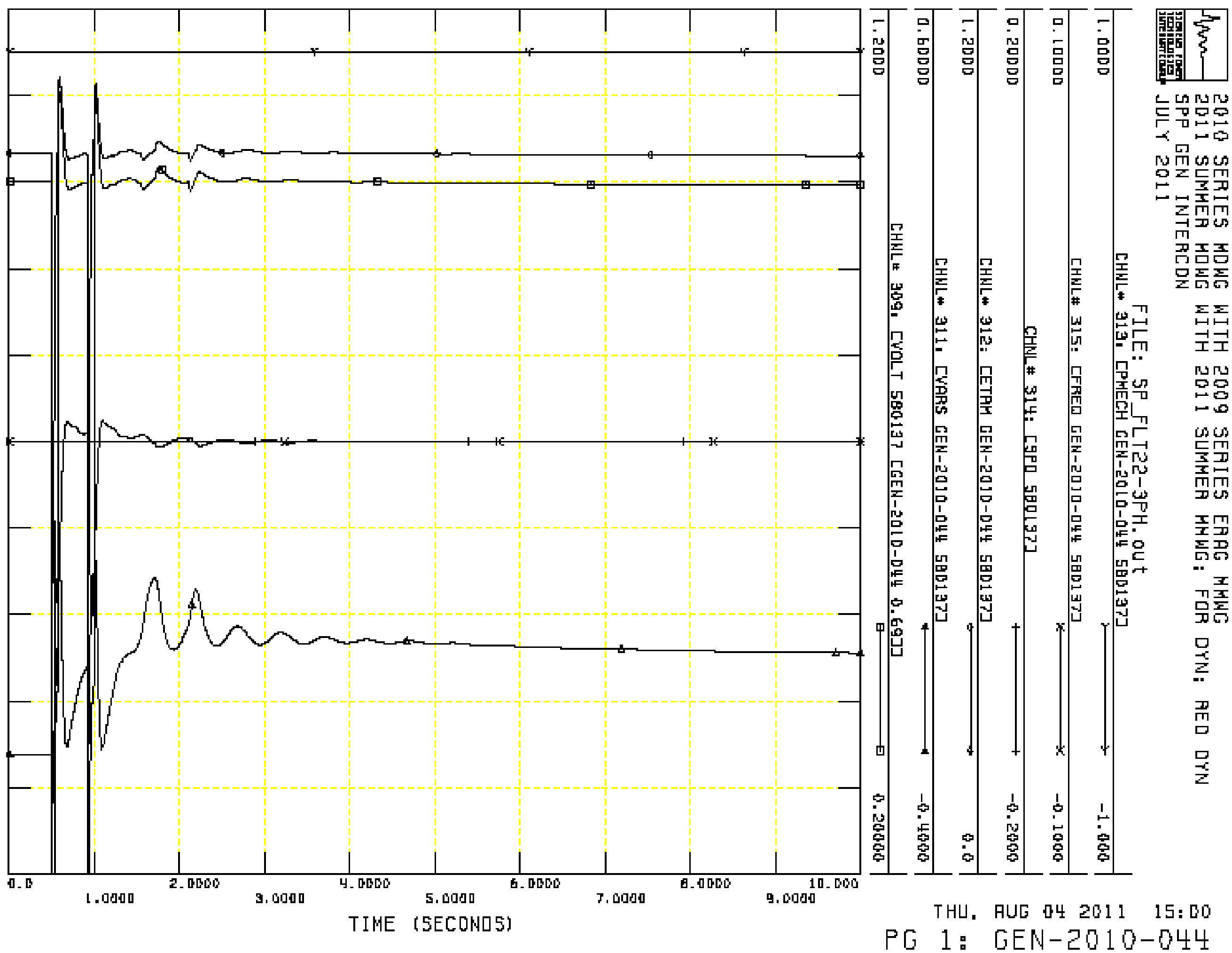

Figure 4-1. Response of GEN-2010-044 project during case FLT22-3PH for summer peak conditions.

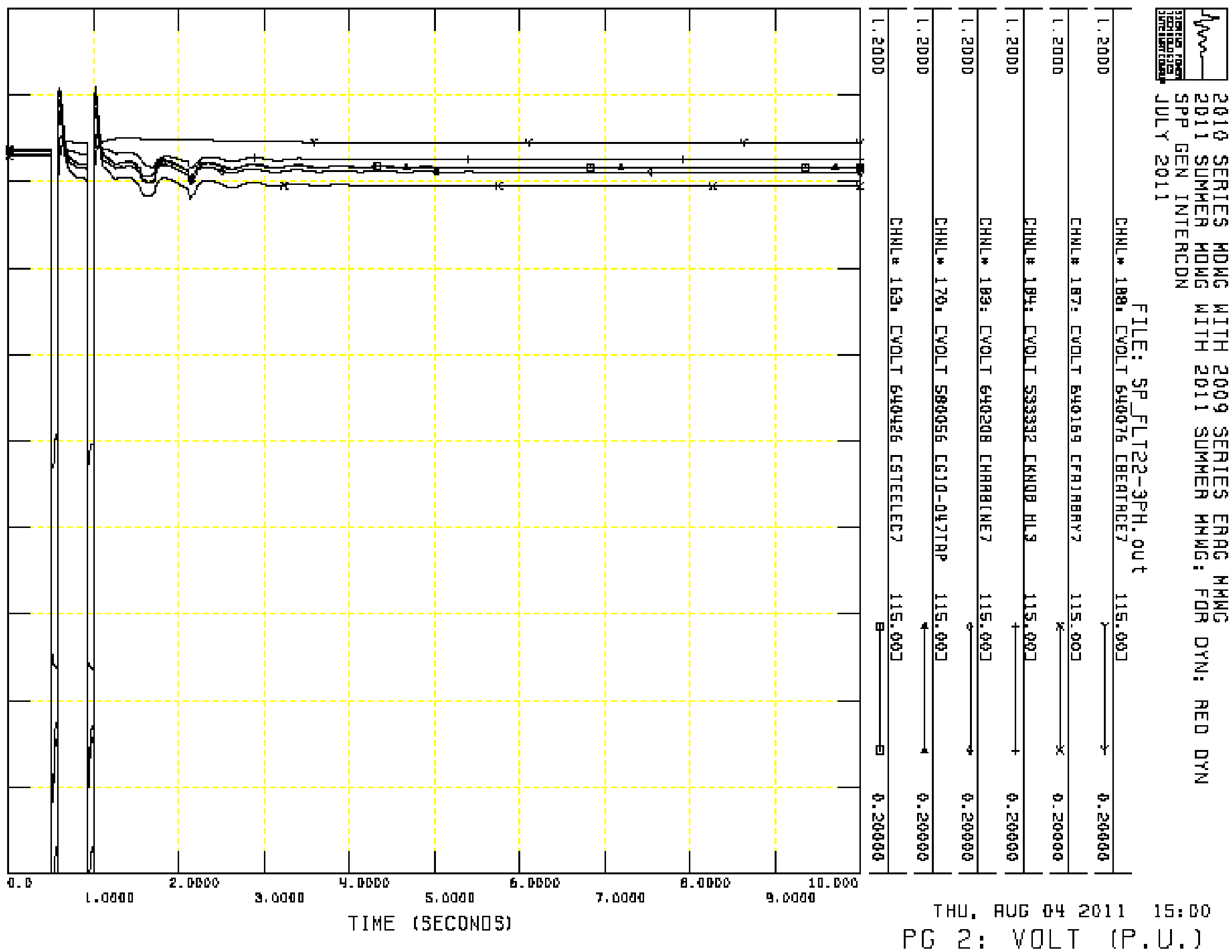

Figure 4-2. Response of selected area bus voltages for case FLT22-3PH for summer peak conditions.

Summary

The stability analysis determined that no wind generator tripping or system instability occurs by interconnecting the Group 13 project at 100% output. Refer to Appendix B and Appendix C for the stability plots of the study area and nearby system's bus voltage and generator's response during the disturbance for the summer peak and winter peak conditions, respectively.

SECTION 5: CONCLUSIONS

Power Factor Analysis

Power Factor Analysis shows that GEN-2010-044 has a power factor range of 0.9098 to 0.9993 leading (absorbing).

Stability Analysis

The Stability Analysis determined that no wind turbine tripping or system instability occurs from interconnecting GEN-2010-044 at 100% output.

S: Stability Study for Group 11

- See report below

Pterra Consulting

Technical Report R132-11

Impact Study for Generation Interconnection Request PISIS-2011-001 Group 11

Submitted to

Southwest Power Pool

August 15, 2011

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Contents

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Executive Summary

This report presents the results of the Prerliminary Impact Study Interconnection Request PISIS-2011-001 (group 11) which includes GEN-2011-001 (the "Project"). The rsults of the impact study comprising of power factor and stability analyses. The Project has a nominal 200.1 MW maximum rating studied using Siemens 2.3 MW wind turbine generators ("WTGs"). The Point of Interconnection ("POI") is a new 345 kV tap on the existing Post Rock-Axtell 345 kV line.

The analysis was conducted through the Southwest Power Pool ("SPP") Tariff. Power factor analysis and transient stability simulations were conducted with the Project in service at full output of 200.1 MW.

Two base cases, 2011 summer peak and 2011 winter peak conditions, each comprising of a power flow and corresponding dynamics database were provided by SPP.

Power Factor Test

The results of the power factor analysis showed that with the MVAR capability of the Siemens WTG , GEN-2011-001 is required to maintain a 97% leading (supplying VARs) to 97% lagging (absorbing VARs) power factor at the point of interconnection.

Stability Simulations

Twenty-six (26) faults were considered for the transient stability simulations which included three-phase faults and single-line-to-ground faults at the locations defined by SPP. The results of the simulation showed neither angular nor voltage instability problems in the SPP system for the twenty-six faults. The study finds that the interconnection of the proposed project does not impact the stability performance of the SPP system for the faults tested on the supplied base cases.

Introduction

Project Overview

This report presents the results of the Prerliminary Impact Study Interconnection Request PISIS-2011-001 (group 11) which includes GEN-2011-001 (the "Project"). The rsults of the impact study comprising of power factor and stability analyses. The Project has a nominal 200.1 MW maximum rating studied using Siemens 2.3 MW wind turbine generators ("WTGs"). The Point of Interconnection ("POI") is a new 345 kV tap on the existing Post Rock-Axtell 345 kV line.

Figures 1-1 shows the interconnection diagram of the Project to SPP's system as modeled in the power flow cases.

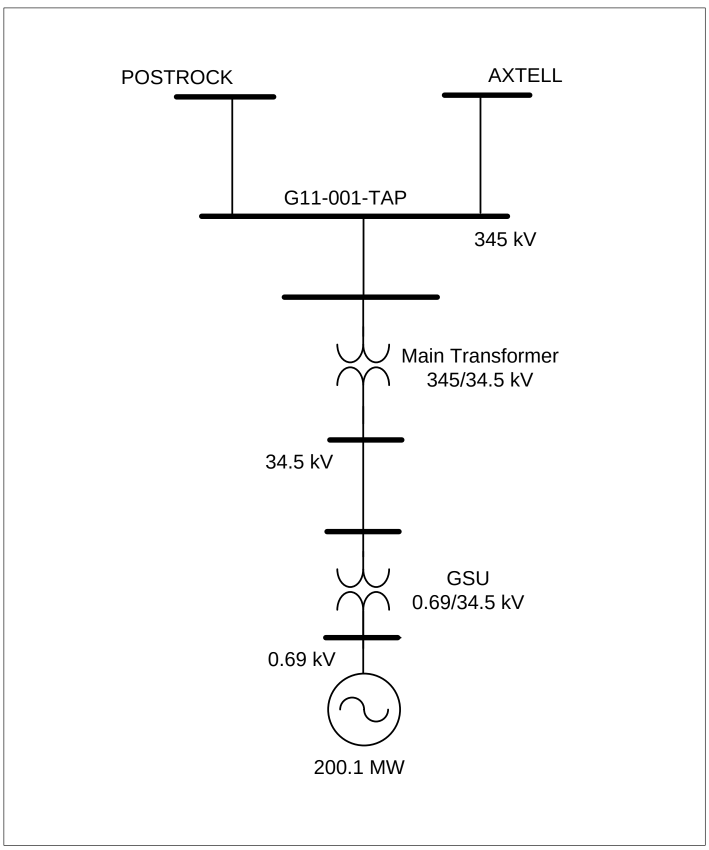

Figure 0-1 Power Flow Model for GEN-2011-001

Table 0-2 shows the list of prior queued projects modeled in the base case.

Table 0-2 List of Prior Queued Projects

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2003-006A	201	Vestas V90 3.0MW	Elm Creek 230kV
GEN-2003-019	247.5	GE 1.5MW & Vestas 3.0MW	Smoky Hills 230kV
GEN-2006-031	75	Gas	Knoll 115kV
GEN-2006-032	200	Gamesa 2.0MW	South Hays 230kV
GEN-2008-092	201	GE 1.5MW	Knoll 230kV
GEN-2009-011	49.7	Siemens 2.3MW	Tap on the Plainville to Phillipsburg 115kV line
GEN-2009-008	200	GE 1.6MW	South Hays 230kV
GEN-2009-020	48.6	Vestas V90 1.8MW (GE)	Tap on the Balzine to Nekoma 69kV line
GEN-2010-048	70	Nordex 2.5MW	Tap on the Ross Beach to Redline 115kV line
GEN-2010-057	201	GE 1.5MW	Rice County 230kV

Objectives

The objectives of the study are to conduct power factor analysis and to determine the impact of interconnecting the proposed Project on SPP’s system stability.

Power Factor Analysis

Methodology

Power factor analysis was conducted for the Project using a methodology which is summarized as follows:

1. Turn off the Project wind farm as modeled (as well as prior queued projects at the same point of interconnection). Replace the wind farms by a generator at the high side bus with the MW of the wind farms and no VAR capability.

2. Model a VAR generator at the wind farm's substation high voltage bus. The VAR generator is set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter or 1.0 p.u. voltage, whichever is higher.

3. Conduct steady state contingency analysis to determine the power factor necessary at the POI for each contingency.

4. If the required power factor at the POI is beyond the capability of the studied wind turbines, capacitor banks may be considered for the stability analysis. The preference is to locate the capacitance banks on the 34.5 kV customer side. Factors to sizing capacitor banks include:

    4.1. The ability of the wind farm to meet FERC Order 661A (low voltage ride through) with and without capacitor banks.
    4.2. The ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage).
    4.3. If wind farms trips on high voltage, power factor lower than unity may be required.

Analysis

The 200.1 MW Project wind farm was turned off in the power flow model. A 200.1 MW plant with no VAR capability was modeled at the Project's 345 kV bus. A VAR generator was also modeled at the same bus and was set to hold a voltage of 1.00 p.u. at the POI. The pre-contingency voltages at POI in the provided power flow models are 0.998 and 0.993 in the summer and winter cases, respectively.

The VAR generator either supplies or absorbs reactive power for different contingencies as summarized in Table 2-1. The highest values obtained are as follows:

1. For the summer case, the VAR generator supplies 37.7 MVAR for the outage of Axtell-Sweet Water 345 kV line and absorbs 53.7 MVAR for the loss of

Axtell 345/115 kV transformer. The corresponding power factors are 98% (lead) and 97% (lag), respectively.

2. For the winter case, the VAR generator supplies 53.6 MVAR for the outage of Axtell-Sweet Water 345 kV line and absorbs 50.2 MVAR for the loss of Gen-2011-001 Tap-Axtell 345 kV line. The corresponding power factors are 97% (lead) and 97% (lag), respectively.
3. The corresponding power factor requirements for GEN-2011-001 are 97% leading (supplying VARs) and 97% lagging (absorbing VARs)

Table 0-1 VAR Generator Output in Summer and Winter Peak Cases for GEN-2011-001

CASE	CONTINGENCY	POWER FACTOR		MW @ POI	VARGEN MVAR
SP	BASE CASE	0.99	Lag	200.1	-23.3
	MULLERGREN - SPEARVILLE 230 KV LINE	1.00	Lag	200.1	-19.0
	SMOKY HILLS - KNOLL 230 KV LINE	1.00	Lag	200.1	-5.8
	POST ROCK - KNOLL 230 KV LINE	0.98	Lag	200.1	-41.4
	POST ROCK - SOUTH HAYS 230 KV LINE	0.99	Lag	200.1	-25.6
	POST ROCK 230 KV - 345 KV TRANSFORMER	0.99	Lag	200.1	-27.4
	MINGO - RED WILLOW 345 KV LINE	1.00	Lag	200.1	-6.2
	GEN-2011-001 TAP - POST ROCK 345 KV LINE	0.98	Lag	200.1	-37.2
	GEN-2011-001 TAP - AXTELL 345 KV LINE	0.97	Lag	200.1	-52.3
	GEN-2007-040 TAP - SPEARVILLE 345 KV LINE	0.99	Lag	200.1	-29.3
	GEN-2010-016 TAP - SPEARVILLE 345 KV LINE	1.00	Lead	200.1	8.8
	COMANCHE - MEDICINE LODGE 345 KV LINE	1.00	Lag	200.1	-10.7
	AXTELL - PAULINE 345 KV LINE	1.00	Lag	200.1	-9.4
	AXTELL - SWEET WATER 345 KV LINE	0.98	Lead	200.1	37.7
	AXTELL 115 KV - 345 KV TRANSFORMER	0.97	Lag	200.1	-53.7
WP	BASE CASE	1.00	Lag	200.1	-0.1
	MULLERGREN - SPEARVILLE 230 KV LINE	1.00	Lead	200.1	4.4
	SMOKY HILLS - KNOLL 230 KV LINE	1.00	Lead	200.1	16.8
	POST ROCK - KNOLL 230 KV LINE	0.99	Lag	200.1	-28.5
	POST ROCK - SOUTH HAYS 230 KV LINE	1.00	Lag	200.1	-7.2
	POST ROCK 230 KV - 345 KV TRANSFORMER	1.00	Lag	200.1	-5.2
	MINGO - RED WILLOW 345 KV LINE	1.00	Lead	200.1	15.1
	GEN-2011-001 TAP - POST ROCK 345 KV LINE	0.98	Lag	200.1	-36.9
	GEN-2011-001 TAP - AXTELL 345 KV LINE	0.97	Lag	200.1	-50.2
	GEN-2007-040 TAP - SPEARVILLE 345 KV LINE	1.00	Lag	200.1	-8.7
	GEN-2010-016 TAP - SPEARVILLE 345 KV LINE	0.99	Lead	200.1	32.0
	COMANCHE - MEDICINE LODGE 345 KV LINE	1.00	Lead	200.1	8.9
	AXTELL - PAULINE 345 KV LINE	1.00	Lag	200.1	-2.9
	AXTELL - SWEET WATER 345 KV LINE	0.97	Lead	200.1	53.6
	AXTELL 115 KV - 345 KV TRANSFORMER	0.99	Lag	200.1	-20.8

Conclusion

Based on the reactive capability of the Siemens WTGs and the results of the power factor test, GEN-2011-001 is required to maintain a 97% leading (supplying VARs) to 97% lagging (absorbing VARs) power factor at the point of interconnection.

Stability Analysis

Assumptions

The following assumptions were adopted for the dynamic simulations:

1. Constant maximum and uniform wind speed for the entire period of study.
2. Wind turbine control models with their default values.
3. Under/over voltage/frequency protection use manufacturer settings.

Faults Simulated

Twenty-six (26) faults were considered for the transient stability simulations which included three phase and single-phase line faults at the locations defined by SPP. Single-phase line faults were simulated by applying a fault impedance to the positive sequence network at the fault location to represent the effect of the negative and zero sequence networks on the positive sequence network. The fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. This method is in agreement with SPP current practice. Prior queued projects shown in Table 0-2 and units in areas 520, 524, 525, 526, 531, 534, 536, 640, 645, and 650 were monitored in the simulations.

Table 0-1 shows the list of simulated contingencies. It also shows the fault clearing time and the time delay before re-closing for all the studied faults.

Table 0-1 List of Simulated Faults

Cont. No.	Cont. Name	Description
37	FLT01-3PH	3 phase fault on the Mullergren (539679) – Spearville (539695) 230kV line, near Mullergren. a. Apply fault at Mullergren 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.
38	FLT02-1PH	Single phase fault and sequence like previous
39	FLT03-3PH	3 phase fault on the Smoky Hills (530592) to Knoll (530558) 230kV line, near Smoky Hills. a. Apply fault at Smoky Hills 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.
40	FLT04-1PH	Single phase fault and sequence like previous
41	FLT05-3PH	3 phase fault on the Post Rock (530584) to Knoll (530558) 230kV line, near Post Rock. a. Apply fault at Post Rock 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.
42	FLT06-1PH	Single phase fault and sequence like previous
43	FLT07-3PH	3 phase fault on the Post Rock (530584) to South Hays (530582) 230kV line, near Post Rock. a. Apply fault at Post Rock 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.
44	FLT08-1PH	Single phase fault and sequence like previous
45	FLT09-3PH	3 phase fault on one of the Post Rock 230kV (530584) to 345kV (530583) transformers, near the 230kV bus. a. Apply fault at Post Rock 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
46	FLT10-3PH	3 phase fault on the Mingo (531451) to Red Willow (640325) 345kV line, near Mingo. a. Apply fault at Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
47	FLT11-1PH	Single phase fault on the line in previous fault. a. Apply fault at Mingo 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.
48	FLT12-3PH	3 phase fault on the GEN-2011-001 Tap (580129) to Post Rock (530583) 345kV line, near GEN-2011-001 Tap. a. Apply fault at GEN-2011-001 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
49	FLT13-1PH	Single phase fault on the line in previous fault. a. Apply fault at GEN-2011-001 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
50	FLT14-3PH	3 phase fault on the GEN-2011-001 Tap (580129) to Axtell (640065) 345kV line, near GEN-2011-001 Tap. a. Apply fault at GEN-2011-001 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

Cont. No.	Cont. Name	Description
51	FLT15-1PH	Single phase fault on the line in previous fault. a. Apply fault at GEN-2011-001 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
52	FLT16-3PH	3 phase fault on the GEN-2007-040 Tap (531000) to Spearville (531469) 345kV line, near GEN-2007-040 Tap. a. Apply fault at GEN-2007-040 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
53	FLT17-1PH	Single phase fault on the line in previous fault. a. Apply fault at GEN-2007-040 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
54	FLT18-3PH	3 phase fault on the GEN-2010-016 Tap (576704) to Spearville (531469) 345kV line, near GEN-2010-016 Tap. a. Apply fault at GEN-2010-016 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
55	FLT19-1PH	Single phase fault on the line in previous fault. a. Apply fault at GEN-2010-016 Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
56	FLT20-3PH	3 phase fault on one of the Comanche (531451) to Medicine Lodge (765342) 345kV lines, near Comanche. a. Apply fault at Comanche 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
57	FLT21-1PH	Single phase fault on the line in previous fault. a. Apply fault at Comanche 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.
58	FLT22-3PH	3 phase fault on the Axtell (640065) to Pauline (640312) 345kV line, near Axtell. a. Apply fault at Axtell 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
59	FLT23-1PH	Single phase fault on the line in previous fault. a. Apply fault at Axtell 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.
60	FLT24-3PH	3 phase fault on the Axtell (640065) to Sweet Water (640374) 345kV line, near Axtell. a. Apply fault at Axtell 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
61	FLT25-1PH	Single phase fault on the line in previous fault. a. Apply fault at Axtell 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.
62	FLT26-3PH	3 phase fault on the Axtell 115kV (640066) to 345kV (640065) transformer, near the 115kV bus. a. Apply fault at Axtell 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

The simulations were performed with a 0.5-second steady-state run followed by the appropriate disturbance as described in Table 0-1. Simulations were run for a minimum 10-second duration to confirm proper machine damping.

Simulation Results

The stability simulations with the twenty-six specified faults did not find any angular or voltage instability problems in the SPP system. The study finds that the interconnection of the proposed project does not impact the stability performance of the SPP system for the faults tested on the supplied base cases.

Conclusions

The findings of GEN-2011-001 impact study are as follows:

The results of the power factor analysis showed that with the MVAR capability of the Siemens WTG, GEN-2011-001 is required to maintain a 97% leading (supplying VARs) to 97% lagging (absorbing VARs) power factor at the point of interconnection.

The stability simulations with the twenty-six specified faults did not find any angular or voltage instability problems in the SPP system. The study finds that the interconnection of the proposed project does not impact the stability performance of the SPP system for the faults tested on the supplied base cases.

T: Stability Study for Group 12

- No requests were located in the cluster group

U: Stability Study for Group 13

- See report below

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Southwest Power Pool, Inc. (SPP)

Preliminary Impact Study PISIS-2011-001: Group 13

Final Report

PXE-0500
Revision #01

August 2011

Submitted By:
Mitsubishi Electric Power Products, Inc. (MEPPI)
Power Systems Engineering Services Department
Warrendale, PA

Title: **Preliminary Impact Study PISIS-2011-001: Group 13: Final Report PXE-0500**
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EXECUTIVE SUMMARY

SPP requested an Interconnection System Impact Study for PISIS-2011-001: Group 13. The Interconnection System Impact Study required a Power Factor Analysis and a Stability Analysis detailing the impacts of the study interconnecting project as shown in Table ES-1.

Table ES-1
Interconnection Project Evaluated

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2010-044	99	Siemens 2.3 MW	Tap on the Harbine to Beatrice 115 kV line (580056)

SUMMARY OF POWER FACTOR ANALYSIS

Power Factor Analysis shows that GEN-2010-044 has a power factor range of 0.9098 to 0.9993 leading (absorbing).

SUMMARY OF STABILITY ANALYSIS

The Stability Analysis determined that no wind turbine tripping or system instability occurs from interconnecting GEN-2010-044 at 100% output.

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SECTION 1: OBJECTIVES

The objective of this report is to provide Southwest Power Pool, Inc. (SPP) with the deliverables for the "Preliminary Impact Study PISIS-2011-001: Group 13." SPP requested an Interconnection System Impact Study for GEN-2010-044, which requires a Power Factor Analysis, a Stability Analysis, and an Impact Study Report.

SECTION 2: BACKGROUND

The Siemens Power Technologies, Inc. PSS/E power system simulation program Version 30.3.3 was used for this study. SPP provided the stability database cases for both summer peak[1] and winter peak[2] seasons and a list of contingencies to be examined. The model includes the study project and the previously queued projects as listed in Table 2-1 and Table 2-2, respectively. Refer to Appendix A for the steady-state and dynamic model data for the study project. A power flow one-line diagram of GEN-2010-044 interconnection project is shown in Figure 2-1.

The Power Factor analysis will determine the power factor at the point of interconnection for the wind interconnection project for pre-contingency and post-contingency conditions. Table 2-3 lists the contingencies developed from the three-phase fault definitions provided in the Group's interconnection impact study request.

The Stability Analysis will determine the impacts of the new interconnecting project on the stability and voltage recovery of the nearby system 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 will be investigated. Three-phase and single-phase faults will be examined as listed in Table 2-3.

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[1] *MDWG_2010_2011SP_PISIS-2010-044.sav – summer peak filename.*

[2] *MDWG_2010_2011WP_PISIS-2010-044.sav – winter peak filename.*

Table 2-1
Interconnection Project Evaluated

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2010-044	99	Siemens 2.3 MW	Tap on the Harbine to Beatrice 115 kV line (580056)

Table 2-2
Previously Queued Nearby Interconnection Projects Included

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2006-014	300	G.E. 1.5 MW	WFarms 161 kV (89572)
GEN-2006-017	300	Clipper 2.5 MW	WFarms 161 kV (89572)
GEN-2007-015	135	G.E. 1.5 MW	Tap on the Humboldt to Kelley 161 kV line (579244)
GEN-2007-017	99	G.E. 1.5 MW	WFarms 161 kV (89572)
GEN-2007-053	110	Gamesa 2.0 MW	WFarms 161 kV (89572)
GEN-2008-119O	60	G.E. 1.5 MW	S1399 161 kV (646399)
GEN-2008-129	641/675 MW	Combined Cycle	Pleasant Hill 161 kV (541225)
GEN-2009-040	73.8	Vestas V90 1.8 MW	Tap on Smittyville Coop to Knob Hill 115 kV line (560287)
GEN-2010-036	4.6	GENROU	6th Street 115 kV (533264)
GEN-2010-041	10.5	G.E. 1.5 MW	S1399 161 kV (646399)
GEN-2010-047	72	G.E. 1.6 MW	Tap on the Beatrice to Harbine 115 kV line (580056)
GEN-2010-056	151	Vestas V90 1.8 MW	Tap on Saint Joseph to Cooper 345 kV line (582056)
GEN-2011-011	50	GENROU	Iatan 345 kV (542982)
GEN-2011-018	73.6	Siemens 2.3 MW	Steele City 115 kV (640246)

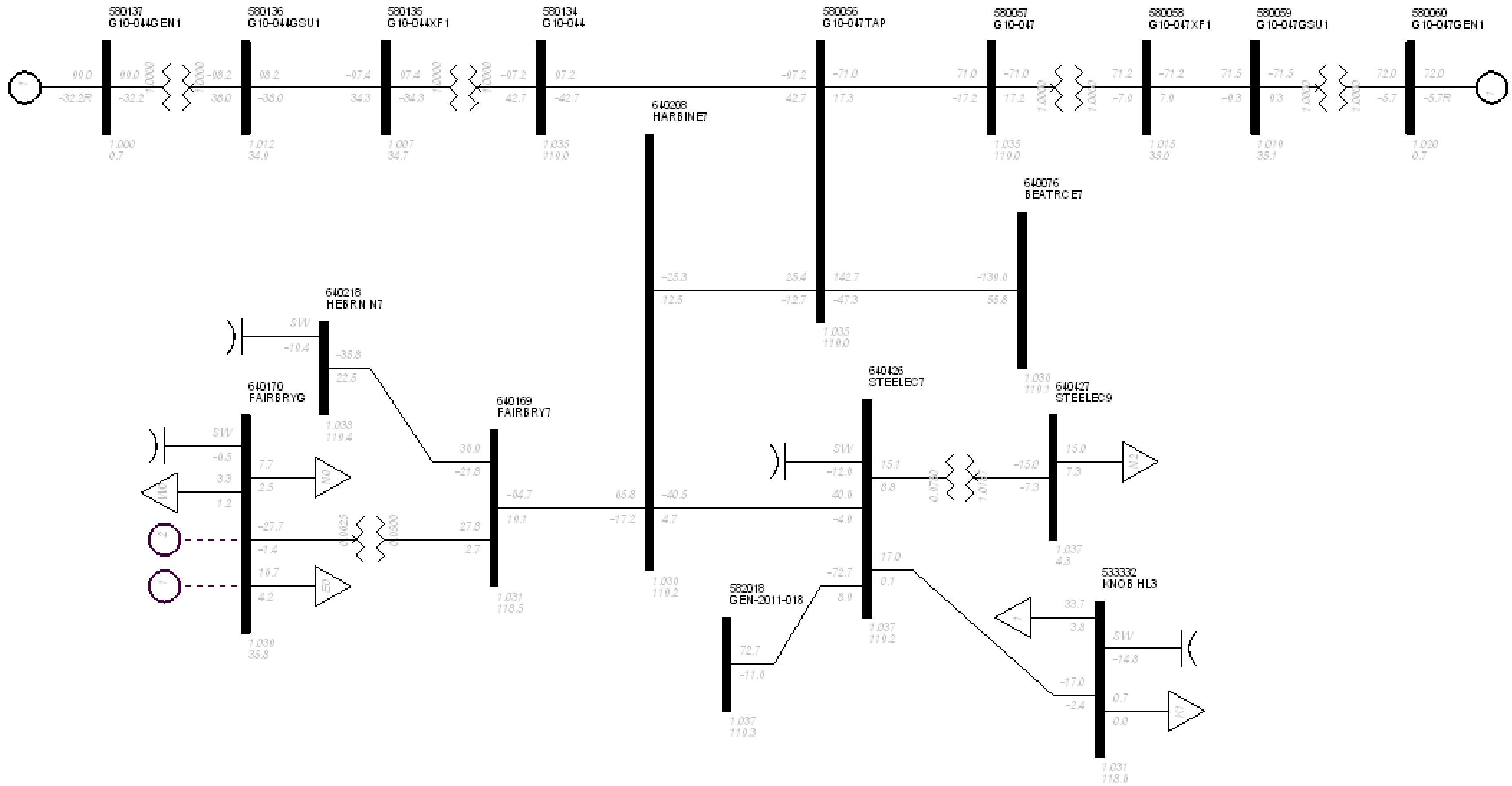

Figure 2-1. Power flow one-line diagram for interconnection project GEN-2010-044.

Table 2-3
Case List with Contingency Description

Ref. No.	Case Name	Description
1	FLT01-3PH	3 phase fault on the Fairport (300039) to Cooper (640139) 345 kV line, near Fairport. a. Apply fault at Fairport 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
2	FLT02-1PH	*Single phase fault and sequence like previous*
3	FLT03-3PH	3 phase fault on the Cooper (640139) to Atchison (635017) 345 kV line, near Cooper. a. Apply fault at Cooper 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
4	FLT04-1PH	*Single phase fault and sequence like previous*
5	FLT05-3PH	3 phase fault on the Moore (640277) to Cooper (640139) 345 kV line, near Moore. a. Apply fault at Moore 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
6	FLT06-1PH	*Single phase fault and sequence like previous*
7	FLT07-3PH	3 phase fault on the Nebraska City (645458) to Cooper (640139) 345 kV line, near Cooper. a. Apply fault at Cooper 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on the Cooper (640139) to 161 kV transformer on the 345 kV bus. a. Apply fault at Cooper 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
10	FLT10-3PH	3 phase fault on the Steele City (640426) to Harbine (640208) 115kV line, near Harbine. a. Apply fault at Harbine 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
11	FLT11-1PH	*Single phase fault and sequence like previous*
12	FLT12-3PH	3 phase fault on the Steele City (640426) to Knob Hill (533332) 115kV line, near Steele City. a. Apply fault at Steele City 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
13	FLT13-1PH	*Single phase fault and sequence like previous*
14	FLT14-3PH	3 phase fault on the Knob Hill (533332) to Greenleaf (539665) 115kV line, near Knob Hill. a. Apply fault at Knob Hill 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
15	FLT15-1PH	*Single phase fault and sequence like previous*
16	FLT16-3PH	3 phase fault on the Knob Hill (533332) to GEN-2009-040 Tap (560287) 115kV line, near Knob Hill. a. Apply fault at Knob Hill 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
17	FLT17-1PH	*Single phase fault and sequence like previous*

Table 2-3 (continued)
Case List with Contingency Description

Ref. No.	Case Name	Description
18	FLT18-3PH	3 phase fault on the Harbine (640208) to Fairbury (640169) 115kV line, near Harbine. a. Apply fault at Harbine 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
19	FLT19-1PH	*Single phase fault and sequence like previous*
20	FLT20-3PH	3 phase fault on the GEN-2010-047 Tap (580056) to Harbine (640208) 115kV line, near GEN-2010-047 Tap. a. Apply fault at GEN-2010-047 Tap 115 kV 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	FLT21-1PH	*Single phase fault and sequence like previous*
22	FLT22-3PH	3 phase fault on the GEN-2010-047 Tap (580056) to Beatrice (640076) 115kV line, near GEN-2010-047 Tap. a. Apply fault at GEN-2010-047 Tap 115 kV 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.
23	FLT23-1PH	*Single phase fault and sequence like previous*
24	FLT24-3PH	3 phase fault on the Beatrice (640076) to Beatrice Power Station (640088) 115kV line, near Beatrice. a. Apply fault at Beatrice 115 kV 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.
25	FLT25-1PH	*Single phase fault and sequence like previous*
26	FLT26-3PH	3 phase fault on the Beatrice (640076) to Steiner (640361) 115kV line, near Beatrice. a. Apply fault at Beatrice 115 kV 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	FLT27-1PH	*Single phase fault and sequence like previous*
28	FLT28-3PH	3 phase fault on the Beatrice Power Station (640088) to Clatonia (640111) 115kV line, near Beatrice Power Station. a. Apply fault at Beatrice Power Station 115 kV 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	FLT29-1PH	*Single phase fault and sequence like previous*
30	FLT30-3PH	3 phase fault on the Sheldon 115 kV (640278) to Moore 345 kV (640277) transformer on the 345 kV bus. a. Apply fault at Moore 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

SECTION 3: POWER FACTOR ANALYSIS

Task Objective

The objective of this task is to quantify the power factor at the point of interconnection for the wind farm during base case and system contingencies. SPP transmission planning practice requires interconnecting generation projects to maintain the power factor (pf) at the Point of Interconnection (POI) near unity for system intact conditions and within +/- 0.95 pf for post-contingency conditions.

Approach

Both winter peak and summer peak power flows provided by SPP were examined prior to the Power Factor Analysis to ensure they contained the proposed study project modeled at 100% of the nameplate rating and any previously queued projects listed in Table 2-2. There was no suspect power flow data in the study area. The proposed study project at the point of interconnection was turned off during the power factor analysis. The wind farm was then replaced by a generator modeled at the point of interconnection bus with the same real power (MW) capability as the wind farm and open limits for the reactive power set points (Mvar). The generator was set to hold the POI scheduled bus voltage. Contingencies from the three-phase fault definitions provided in Table 2-3 were then applied and the reactive power required to maintain the bus voltage was recorded.

For request GEN-2010-044, the interconnecting wind farm was disabled at bus 580137 and a generator was placed at the high side bus (Bus 580134). The generator was modeled with P_{GEN} = 99 MW, Q_{Min} = -9999 Mvar, and Q_{Max} = 9999 Mvar. All buses and transformers connected between bus 580134 and 580137 were disabled. The scheduled voltage for the POI (GEN-2010-047 Tap) was 1.0347 p.u. for summer peak and 1.0246 for winter peak conditions.

Results

The power factor was calculated for summer and winter peak conditions. Table 3-1 shows the power factor results for GEN-2010-044 (99 MW). Note that a positive Q (Mvar) output illustrates that the generator is absorbing reactive power from the system, implying a leading power factor; a negative Q (Mvar) illustrates that the generator is supplying reactive power to the system, implying a lagging power factor.

Table 3-1
Power Factor Analysis - GEN-2010-044 (99 MW)*

Ref. No.	Summer Peak			Winter Peak		
	Power Factor		Q** (MVAR)	Power Factor		Q** (MVAR)
Base	0.9163	Leading	43.28	0.9417	Leading	35.38
1	0.9161	Leading	43.34	0.9425	Leading	35.10
3	0.9168	Leading	43.11	0.9456	Leading	34.05
5	0.9181	Leading	42.75	0.9515	Leading	32.02
7	0.9162	Leading	43.29	0.9438	Leading	34.66
9	0.9187	Leading	42.55	0.9500	Leading	32.53
10	0.9333	Leading	38.10	0.9520	Leading	31.82
12	0.9098	Leading	45.15	0.9367	Leading	37.00
14	0.9126	Leading	44.36	0.9471	Leading	33.56
16	0.9297	Leading	39.21	0.9380	Leading	36.57
18	0.9406	Leading	35.73	0.9642	Leading	27.24
20	0.9383	Leading	36.50	0.9655	Leading	26.70
22	0.9993	Leading	3.66	0.9968	Leading	7.95
24	0.9469	Leading	33.60	0.9467	Leading	33.67
26	0.9272	Leading	39.99	0.9482	Leading	33.17
28	0.9285	Leading	39.58	0.9577	Leading	29.74
30	0.9281	Leading	39.71	0.9766	Leading	21.82

*The scheduled voltage for the POI (GEN-2010-047 Tap) was 1.0347 p.u. for summer peak and 1.0246 p.u. for winter peak conditions

**A positive Q (Mvar) output illustrates the generator is absorbing Mvars from the system, which implies a leading power factor; negative Q (Mvar) output shows the generator is supplying Mvars to the system implying a lagging power factor.

Summary

Power Factor Analysis shows that GEN-2010-044 has a power factor range of 0.9098 to 0.9993 leading (absorbing).

SECTION 4: STABILITY ANALYSIS

Objective

The objective of the stability analysis was to determine the impacts of the new wind farm at the GEN-2010-047 Tap point along the Harbine to Beatrice 115 kV line on the stability and voltage recovery of the nearby system. If problems with stability or voltage recovery were identified the need for reactive compensation or system upgrades were investigated.

Approach

Both winter peak and summer peak power flows provided by SPP were examined prior to the Stability Analysis to ensure they contained the proposed study project modeled at 100% of the nameplate rating and previously queued projects listed in Table 2-2. There was no suspect power flow data in the study area. The dynamic datasets were also verified and stable initial system conditions (i.e., "flat lines") were achieved. Three-phase and single line-to-ground faults listed in Table 2-3 were examined. Single-phase fault impedances were calculated to result in a voltage of approximately 60% of the pre-fault voltage. Refer to Table 4-1 for a list of the calculated single-phase fault impedances used for the analysis.

Table 4-1
Calculated Single-Phase Fault Impedances

Ref. No.	Casename	Single-Phase Fault Impedance (MVA)	
		Summer Peak	Winter Peak
2	FLT02-1PH	-5000	-5000
4	FLT04-1PH	-9750	-9500
6	FLT06-1PH	-8000	-7500
8	FLT08-1PH	-9750	-9500
11	FLT11-1PH	-1000	-937.5
13	FLT13-1PH	-687.5	-687.5
15	FLT15-1PH	-687.5	-656.3
17	FLT17-1PH	-687.5	-656.3
19	FLT19-1PH	-1000	-937.5
21	FLT21-1PH	-1000	-937.5
23	FLT23-1PH	-1125	-1000
25	FLT25-1PH	-1625	-1250
27	FLT27-1PH	-1625	-1250
29	FLT29-1PH	-1875	-1312.5

Bus voltages and previously queued generation in the study area were monitored in addition to the bus voltages in the following areas:

- 531 MIDW
- 534 SUNC
- 536 WERE
- 540 MIPU
- 541 KACP
- 640 NPPD
- 645 OPPD

The results of the analysis determined if reactive compensation or system upgrades were required to obtain acceptable system performance. If additional reactive compensation was required, the size, type, and location were determined. The proposed reactive reinforcements would ensure the wind farm meets FERC Order 661A low voltage requirements and return the wind farm to its pre-disturbance operating voltage. If the results indicated the need for fast responding reactive support, dynamic support such as an SVC or STATCOM was investigated. If tripping of the prior queued projects was observed during the stability analysis (for under/over voltage or under/over frequency) the simulations were re-ran with the prior queued project's voltage and frequency tripping disabled. If stability problems were identified, the maximum acceptable generation level for the GEN-2010-044 to operate without causing any stability problems was quantified. Stability analysis results indicated that GEN-2010-044 can interconnect at 100% output for all contingencies.

Results

Refer to Table 4-2 for a summary of the Stability Analysis results. The initial simulations were run for summer and winter peak conditions and all contingencies remained stable. Figure 4-1 shows the response of the GEN-2010-044 generator during a three-phase fault on the GEN-2010-047 Tap to Beatrice 115 kV line (FLT22-3PH) during summer peak conditions. Figure 4-2 shows selected bus voltages in the study area during FLT22-3PH which is a representative case for the "worst" delayed voltage recovery and "most severe" voltage dip.

Table 4-2
Stability Analysis Summary of Results

Ref. No.	Casename	Summer		Winter	
		Stable?	Acceptable Voltages?	Stable?	Acceptable Voltages?
1	FLT01-3PH	Stable	Yes	Stable	Yes
2	FLT02-1PH	Stable	Yes	Stable	Yes
3	FLT03-3PH	Stable	Yes	Stable	Yes
4	FLT04-1PH	Stable	Yes	Stable	Yes
5	FLT05-3PH	Stable	Yes	Stable	Yes
6	FLT06-1PH	Stable	Yes	Stable	Yes
7	FLT07-3PH	Stable	Yes	Stable	Yes
8	FLT08-1PH	Stable	Yes	Stable	Yes
9	FLT09-3PH	Stable	Yes	Stable	Yes
10	FLT10-3PH	Stable	Yes	Stable	Yes
11	FLT11-1PH	Stable	Yes	Stable	Yes
12	FLT12-3PH	Stable	Yes	Stable	Yes
13	FLT13-1PH	Stable	Yes	Stable	Yes
14	FLT14-3PH	Stable	Yes	Stable	Yes
15	FLT15-1PH	Stable	Yes	Stable	Yes
16	FLT16-3PH	Stable	Yes	Stable	Yes
17	FLT17-1PH	Stable	Yes	Stable	Yes
18	FLT18-3PH	Stable	Yes	Stable	Yes
19	FLT19-1PH	Stable	Yes	Stable	Yes
20	FLT20-3PH	Stable	Yes	Stable	Yes
21	FLT21-1PH	Stable	Yes	Stable	Yes
22	FLT22-3PH	Stable	Yes	Stable	Yes
23	FLT23-1PH	Stable	Yes	Stable	Yes
24	FLT24-3PH	Stable	Yes	Stable	Yes
25	FLT25-1PH	Stable	Yes	Stable	Yes
26	FLT26-3PH	Stable	Yes	Stable	Yes
27	FLT27-1PH	Stable	Yes	Stable	Yes
28	FLT28-3PH	Stable	Yes	Stable	Yes
29	FLT29-1PH	Stable	Yes	Stable	Yes
30	FLT30-3PH	Stable	Yes	Stable	Yes

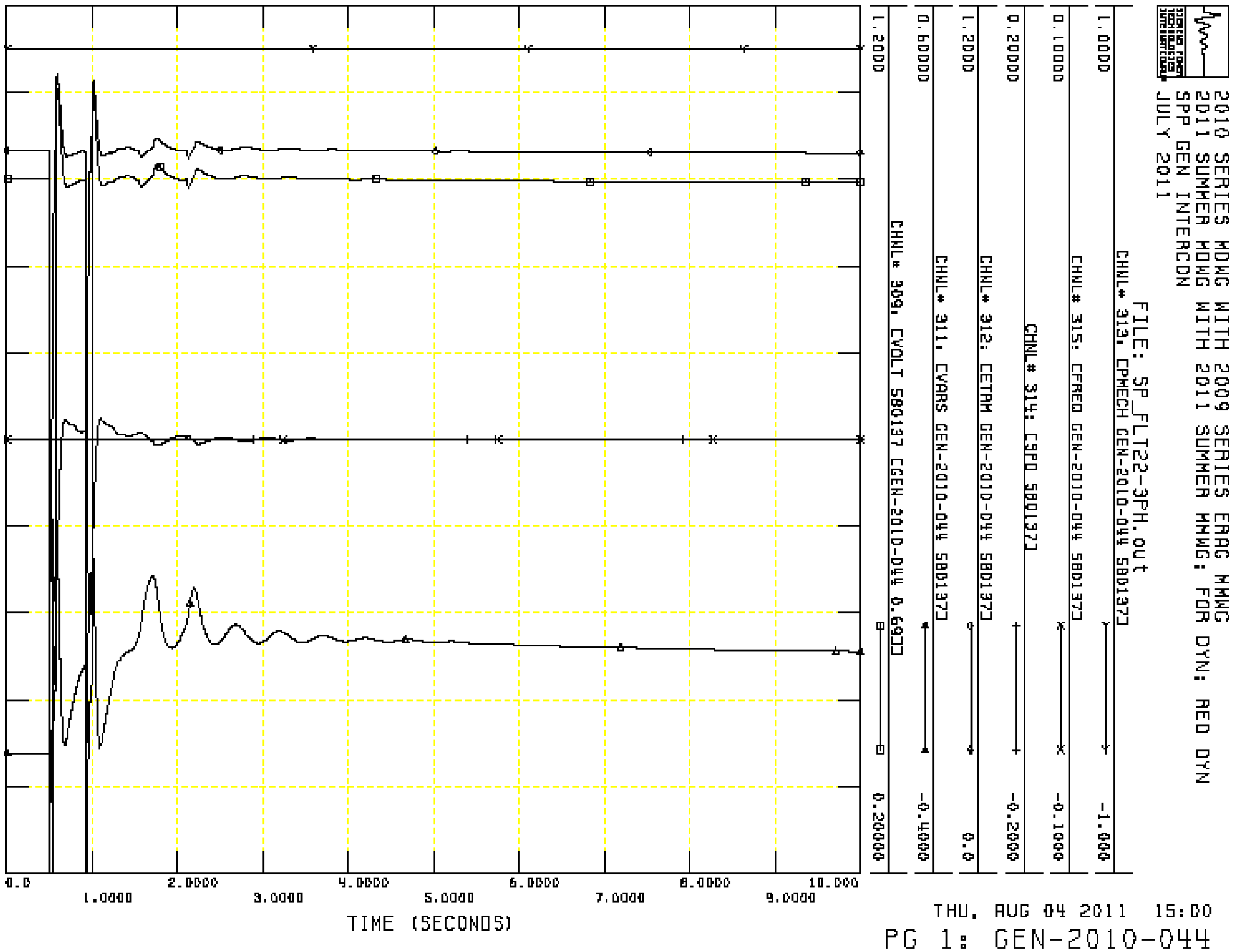

Figure 4-1. Response of GEN-2010-044 project during case FLT22-3PH for summer peak conditions.

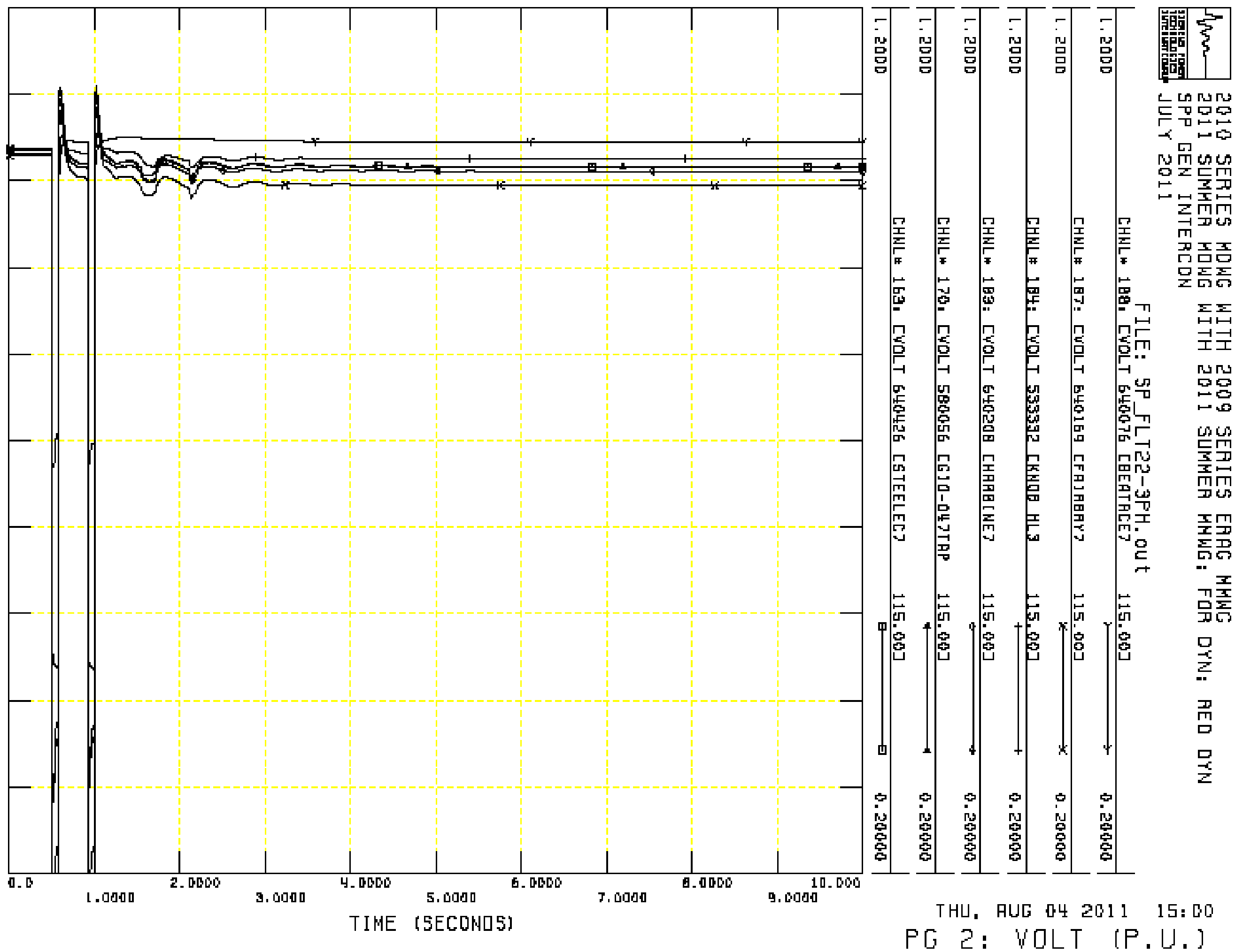

Figure 4-2. Response of selected area bus voltages for case FLT22-3PH for summer peak conditions.

Summary

The stability analysis determined that no wind generator tripping or system instability occurs by interconnecting the Group 13 project at 100% output. Refer to Appendix B and Appendix C for the stability plots of the study area and nearby system's bus voltage and generator's response during the disturbance for the summer peak and winter peak conditions, respectively.

SECTION 5: CONCLUSIONS

Power Factor Analysis

Power Factor Analysis shows that GEN-2010-044 has a power factor range of 0.9098 to 0.9993 leading (absorbing).

Stability Analysis

The Stability Analysis determined that no wind turbine tripping or system instability occurs from interconnecting GEN-2010-044 at 100% output.

V: Stability Study for Group 14

- No requests were located in the cluster group

W: Stability Study for Group 15

- No requests were located in the cluster group