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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EA-2014-0207

SURREBUTTAL TESTIMONY OF

DR. ANTHONY WAYNE GALLI, P.E.

ON BEHALF OF

GRAIN BELT EXPRESS CLEAN LINE LLC

October 14, 2014

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I. INTRODUCTION

Q. Please state your name, present position, and business address.

A. My name is Anthony Wayne Galli. I am Executive Vice President – Transmission and Technical Services of Clean Line Energy Partners LLC ("Clean Line"), the ultimate parent company of Grain Belt Express Clean Line LLC ("Grain Belt Express" or "Company"), the Applicant in this proceeding.

Q. Have you previously submitted prepared testimony and exhibits in this proceeding?

A. Yes, I have previously submitted direct testimony on March, 26, 2014, and additional direct testimony dated June 27, 2014.

Q. What is the subject matter of this surrebuttal testimony?

A. I am responding to certain issues raised in the rebuttal testimonies of other parties in this proceeding, including witnesses representing Commission Staff, the Missouri Landowners Alliance ("MLA"), Eastern Missouri Landowners Alliance d/b/a Show Me Concerned Landowners ("Show Me"), Rockies Express Pipeline, and Christina Reichert. Additionally, I will provide an update on the Grain Belt Express Project's interconnection studies with PJM.

Q. Please summarize your testimony's organization.

A. Section II of my testimony addresses Commission Staff's recommendations for conditions on Grain Belt Express' certificate of convenience and necessity ("CCN"). Section III addresses the recommendations for CCN conditions proposed by Rockies Express Pipeline. Section IV addresses Staff's concern that the Project may create transmission congestion and other issues related to the Project's interconnection. Section V responds to issues related to the Project's technical specification, including its power levels and design criteria. Section VI addresses operational issues raised in rebuttal testimony submitted by other parties in this proceeding.

II. RESPONSE TO STAFF CONDITIONS

Q. Commission Staff recommended a number of conditions to the Company's CCN. What your response to these conditions?

A. Schedule DAB-14 to David Berry's surrebuttal testimony summarizes the Company's response to Staff's proposed conditions. Below I explain in more detail the Company's position with respect to conditions relating to the subject matter of my testimony in this proceeding.

Q. What is the Company's response to the specific technical and engineering conditions recommended by Staff witness Robert Leonberger?

A. Below is the response to each of the recommendations raised in the rebuttal testimony of Mr. Leonberger:

i. Page 5, lines 5-7: Mr. Leonberger recommends that *"the Commission limit the authority it gives for building the HVDC transmission line in any CCN to construction of a HVDC transmission line built with DMR [dedicated metallic return] conductors."*

Response – Grain Belt Express finds this condition acceptable. The Project has been designed as such and will be built utilizing DMR conductors.

ii. Page 6, lines 2-7: Mr. Leonberger recommends that *"the Commission limit any CCN it issues in this case by explicitly requiring the installation of protection and control safety systems that will automatically de-energize the system when an abnormal or fault condition occurs. Staff also recommends that the Commission condition any such CCN by requiring proof to the Commission that these safety* *systems are operational prior to commercial operation of the Grain Belt Express HVDC electric transmission line."*

Response – Grain Belt Express find these two conditions acceptable and to be good practice both from the aspect of public safety and the protection of equipment. In the absence of these conditions, the Company would have implemented appropriate control and protection measures, but there is no objection to formalizing this commitment.

iii. Page 6, line 22 to page 7, line 7: Mr. Leonberger recommends that Grain Belt Express conduct studies that include *"the effect of tower footing groundings, if used; analysis of metallic underground facilities, other AC lines, and telecommunications facilities within a half a mile of the HVDC transmission line; analysis of metallic underground facilities, other AC lines, and telecommunications facilities within two miles of the HVDC converter station, a determination whether there are locations where the HVDC line parallels a pipeline and an existing AC line and, if so, whether there are any combined effects on steel pipelines (and underground metallic facilities); a determination of how the interference study will be conducted (for example, continuous 24-hour recordings at a certain time of year); and the effects of the HVDC transmission line exiting the converter station."*

Response – Grain Belt Express finds this recommendation acceptable but has concerns on the Commission specifying distances. Regardless of the condition, the Company will perform all appropriate technical studies to assess the potential impacts to subsurface utility facilities. However, with regard to the distance from the transmission line (1/2 mile) and from the converter station (two miles) to be studied, Grain Belt Express proposes that the appropriate distances be determined by an engineering firm well versed in such analysis. In order to ensure that the studies review all subsurface utility facilities that are potentially impacted, the Company will, with assistance from an appropriate expert and input from Staff, identify <u>all</u> potentially impacted subsurface utility facilities and incorporate them into the studies. Limiting the study ranges to any arbitrary distance may not capture all affected subsurface utilities, or it may include some which have no practical need of study.

iv. Page 8, lines 11-21: Mr. Leonberger recommends that *"if the Commission issues Grain Belt Express a CCN in this case it include as a condition that if any of the studies show that mitigation measures are identified/needed, those measures must be in place prior to commercial operation of the HVDC transmission line. The Commission should also require that these studies be made available to Staff and affected facility owners at least 45 days prior to commercial operation of the HVDC transmission line and that these engineering studies/analyses are conducted by persons knowledgeable in (1) HVDC power lines, (2) DC-to-AC converter stations, (3) pipeline cathodic protection systems, (4) corrosion of underground metallic facilities, (5) interference with AC utility lines, (6) interference with telecommunications facilities, and (7) the effects of DC and AC interference on the facilities identified in Exhibit 3 of Grain Belt Express' Application."*

Response – Grain Belt Express finds this condition acceptable and considers it to be a best practice and in the interest of all parties involved.

v. Page 9, lines 12-15: Finally, Mr. Leonberger recommends that *"the Commission order Grain Belt Express to file annual status updates on discussions with Staff regarding the need for additional studies, a summary of the results of any additional studies, and any mitigation measures that have been implemented to address underground metallic structures, telecommunications facilities, and AC lines."*

Response – Grain Belt Express accepts this condition as reasonable and will prepare an annual status update per Staff's recommendation.

Q. What is your response to the specific technical and engineering conditions recommended in the rebuttal testimony of Staff witness Shawn Lange?

A. Below is the response to each of the conditions recommended by Mr. Lange:

i. Page 2, lines 13-30: Mr. Lange recommends that" *the Commission order Grain Belt Express to provide for Commission acceptance, the following items:*

- *Completed Storm Restoration Plans for the proposed project,*
- *The Interconnection Agreement with SPP,*
- *The Interconnection Agreement with MISO, and*
- *The Interconnection Agreement with PJM,*
- *MISO Feasibility Study,*
- *MISO System Planning Phase Study,*
- *MISO Definitive Planning Phase Study,*

- *SPP Dynamic Stability Assessment of Grain Belt Express Clean Line HVDC Project,*
- *SPP Steady State Review,*
- *SPP System Impact Study,*
- *PJM Feasibility Study,*
- *PJM System Impact Study,*
- *PJM Facilities Study, and*
- *Any further study necessary for interconnection with any of SPP, MISO, or PJM"*

Response – Although Grain Belt Express does not understand the term "acceptance" in this context, it agrees to submit such reports to the Commission as they become available. Therefore, Grain Belt Express suggests replacing the phrase "to provide for Commission acceptance" with "to submit to the Commission when completed."

ii. Page 3, lines 1-4: Mr. Lange recommends that " *the Commission order Grain Belt Express to comply with the appropriate NERC standards for a project of this scope and size, National Electric Safety Code for a project of this scope and size, 4 CSR 240-18.010, and the Overhead Power Line Safety Act section 319.075 et al.*"

Response – Grain Belt Express finds this condition acceptable.

iii. Page 3, lines 5-9: Shawn Lange recommends that " *the Commission order Grain Belt Express to provide to the Commission completed, documentation of the Grain Belt Express plan, equipment, and engineering drawings to achieve compliance* *with NERC standards for a project of this scope and size, National Electric Safety Code for a project of this scope and size, 4 CSR 240-18.010, and the Overhead Power Line Safety Act section 319.075 et al."*

Response – Grain Belt Express finds this condition acceptable and will provide all as-built drawings and final design documentation.

iv. Page 3, lines 10-12: Mr. Lange recommends that "*the Commission order Grain Belt Express to meet a short-circuit ration of at least two, at the Kansas converter station, Missouri converter station, and the converter station near Sullivan, Indiana.*"

Response – Grain Belt Express cannot accept this condition because: (1) it confuses a "rule of thumb" for an electric reliability standard; (2) it could be extremely burdensome and expensive; and (3) because it fails to recognize that the RTO interconnection processes will assure a reliable interconnection.

In the implementation of an HVDC project, a short-circuit ratio of 2.0 is a "rule of thumb" when initially analyzing whether additional measures may be needed to support robust voltage and system recovery following a fault. It is <u>not</u> an electric reliability or safety standard, such as a NERC standard, that must be met in all circumstances. The Commission should not impose a technical rule of thumb as an inflexible condition that could lead to a large and expensive increase in the transmission upgrades needed to accommodate the Project. Modern HVDC control systems and fast-acting dynamic reactive equipment such as static var compensators ("SVC") or static synchronous compensators ("STATCOM") allow many existing HVDC projects to operate reliably in systems with a short-circuit ratio less than two. If these technologies are more appropriate than a large number of transmission upgrades, Grain Belt Express should be allowed to implement them. Examples of successful HVDC projects operating in a short-circuit ratio environment of around 2.0 or less include: Basslink (connecting the Australian mainland to Tasmania built by Siemens), Haenam-Cheju (connecting the South Korean mainland and island of Jeju, built by Alstom), the McNeill project in Canada, the High Gate project in Vermont, and the Garabi project between Brazil and Argentina.

Importantly, the RTOs and incumbent utilities, with which the Project will interconnect, study stability and voltage issues related to the Project and assure that its interconnection is robust and reliable. These studies take into account the totality of system conditions and the Project's control systems. The RTOs, interconnecting utilities, and the Company can be relied upon to ensure a reliable interconnection as mandated by NERC standards and enforce those standards under FERC oversight. The Commission should not prescribe to the RTOs that they must build more upgrades to reach an arbitrary short circuit ratio if there is a more appropriate solution.

v. Page 3, lines 13-16: Mr. Lange recommends that "*the Commission order Grain Belt Express to provide to the Commission as completed, documentation of the Grain Belt Express plan, equipment, and engineering drawings to achieve a short-circuit ratio of at least two, for each converter station.*"

Response – Grain Belt Express disagrees with this recommendation for the reasons stated above. However, the Company agrees to provide, when completed, documentation that shows the Project meets all the requirements of the utilities and RTOs with which the Project will interconnect.

vi. Page 7, lines 12-14: Mr. Lange recommends that "*any Granting of a Certificate of Convenience and Necessity be conditioned on Grain Belt Express providing the Storm Response Plan to the Commission.*"

Response – Grain Belt Express finds this condition acceptable as it fully intends to develop necessary storm/emergency restoration plans for the Project's transmission line and converter stations prior to commercial operation. Grain Belt Express will makes these plans available to Commission Staff once they have been developed and finalized.

III. RESPONSE TO ROCKIES EXPRESS PIPELINE CONDITIONS

Q. In his rebuttal testimony, Robert Allen, on behalf of Rockies Express Pipeline LLC ("REX"), indicates several possible concerns of HVDC lines and interactions with gas pipelines. Do you share those concerns?

A. Mr. Allen raises the general concerns of pipeline coating damage, pipeline corrosion, loss of cathodic protection, and damage to corrosion control and monitoring equipment. These are indeed appropriate issues to study whenever a new piece of infrastructure parallels a gas pipeline. In fact, if another gas pipeline paralleled the REX pipeline, it is my understanding that there would need to be coordination of the cathodic protection equipment, and of the monitoring and control equipment between the two pipelines. It is not uncommon for pipelines and transmission lines to parallel each other and these concerns are commonly dealt with through coordinated mitigation studies. The Company is committed to studying the potential impacts of the Project on the REX pipeline and all potentially affected subsurface utility facilities

Q. What is the Company's response to the technical recommendations suggested by Mr. Allen in his rebuttal testimony?

A. Below are the responses to eight of the recommendations suggested by Mr. Allen in his rebuttal testimony. Recommendation #1 is discussed in Company witness Timothy Gaul's surrebuttal testimony and in my response to Recommendation #7 because, as Mr. Allen noted on page 9 of his rebuttal, both relate to monitoring systems. Regarding Mr. Allen's comment in Recommendation #1 that "[i]deally, where the HVDC line parallels REX's pipeline, it should be located 1,000 feet or more away from the pipeline," Grain Belt Express expressly disagrees. Such a policy is not a common industry practice, not a good routing practice, and unnecessary from a safety perspective.

i. Recommendation #2 at Page 10, lines 7-11: Mr. Allen recommends that Grain Belt Express "*be required, after an exact route for the HVDC line is determined and prior to the commencement of construction, to conduct a DC interference analysis to determine the mitigation measures necessary to prevent the negative effects to the pipeline and related facilities that I outlined.*"

Response – Grain Belt Express finds this recommendation acceptable and will perform such analysis in coordination with all affected pipelines.

ii. Recommendation #3 at Page 10, lines 21-23 to page 11, lines 1-2: Mr. Allen recommends that Grain Belt Express "*be required to confirm all data or other assumptions about REX's pipeline system including routing, soil resistivity, cathodic protection systems and pipeline facilities, coating type and condition, wall thickness, and other technical parameters with appropriate REX personnel before engaging in the DC interference analysis.*"

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Response – Grain Belt Express finds this recommendation acceptable.

iii. Recommendation #4 at Page 11, line 22: Mr. Allen recommends "*that all crossings of the HVDC line over the REX pipeline be required to be at 90 degrees angles, plus or minus 10 degrees.*"

Response – Grain Belt Express does not agree to this recommendation as presented. In response to a data request regarding this recommendation, Mr. Allen conceded that there were no industry standards or best practices supporting this recommendation nor any technical studies substantiating this arbitrary requirement.[1] Some degree of flexibility is therefore appropriate. Grain Belt would agree to the recommendation if it were reworded to state: "When engineering, routing, and cost constraints allow, as reasonably determined by Grain Belt Express, all crossings of the HVDC line over the REX pipeline will be at 90 degree angles, plus or minus 10 degrees."

iv. Recommendation #5 at Page 12, line 6: Mr. Allen recommends that Grain Belt Express in regard to crossing structures "*not be permitted to construct towers closer than 300 feet from the pipeline.*"

Response – Grain Belt Express does not agree to this recommendation as presented. In response to a data request on this recommendation, Mr. Allen conceded that there were no industry standards or best practices supporting this recommendation nor any technical studies substantiating this requirement.[2] Mr.

[1] *See* Response 5 to Rockies Express Responses to Grain Belt Express' First Set of Data Requests, attached as Schedule AWG-11.

[2] *See* Response 6 to Rockies Express Responses to Grain Belt Express' First Set of Data Requests, attached as Schedule AWG-11.

Allen stated that he had assumed a 600' span between structures and that 300' was the mid-span. Grain Belt Express will agree to provide REX with preliminary and final pole locations and to meet with REX regarding crossing permits, the assessment of impacts, and the need for appropriate mitigations.

v. Recommendation #6 at Page 12, lines 18-22: Mr. Allen recommends *"that as to grounding the towers nearest [sic] pipeline crossings, GBX be required to locate (install) any ground rods or other local methods of grounding towers on the side of the tower farthest from the pipeline. If additional grounding methods at towers near crossing are required, only ground rods or ground wells are acceptable."* Mr. Allen further recommends that Grain Belt Express *"not be permitted to use counterpoise methods of grounding in tower spans where the pipeline will be crossing between towers."*

Response – Grain Belt Express finds this recommendation unacceptable as proposed. Studies will be completed in collaboration with the potentially impacted utilities, including Rockies Express Pipeline, that operate nearby underground facilities. The studies will determine what grounding techniques are appropriate. Rather than impose specific engineering restrictions before the issues are actually understood in detail, Grain Belt Express suggests that the best engineering decisions can be made after the conclusion of the applicable studies.

vi. Recommendation #7 at Page 13, lines 14-17: Mr. Allen recommends *Grain Belt Express "install a DC voltage monitoring system at each crossing of the HVDC line and REX's pipeline. GBX [the Company] should be required to provide the* *specifications and capabilities of any proposed system to REX for REX's prior review and approval."*

Response – Grain Belt Express finds this recommendation unacceptable as proposed. Studies will be completed in collaboration with the potentially impacted utilities operating underground facilities, including Rockies Express Pipeline, and will determine what voltage monitoring systems are required. As with Recommendation #6, Grain Belt Express suggests that the best engineering decisions can be made after the conclusion of the applicable studies. Grain Belt Express can commit, however, to implement the voltage monitoring that is prescribed by the technical studies.

vii. Recommendation #8 at Page 14, lines 14-17: Mr. Allen recommends *Grain Belt Express "be required to immediately notify REX pipeline operations personnel if and when a fault occurs <u>anywhere</u> on the HVDC line, and to disclose the approximate location of the fault condition, the magnitude and duration of the fault current situation, and the time when the system returned to normal operation."*

Response – Grain Belt Express disagrees with this recommendation as premature. The applicable DC interference studies, to be conducted by an independent engineering firm, should determine the notice requirements and need for voltage monitoring devices to provide this notice. Grain Belt Express can commit, however, to provide the notice that is recommended by the technical studies to be conducted with Rockies Express Pipeline.

viii. Recommendation #9 at Page 14, lines 16-17: Mr. Allen recommends *Grain Belt Express "be required to conduct DC interference analysis with respect to the converter stations."*

Response – Grain Belt Express finds this recommendation acceptable since it already intends to follow best utility practices, to perform studies assessing the impact of faulted conditions on subsurface utility facilities near the converter station, and to implement any necessary mitigation measures.

IV. INTERCONNECTION ISSUES AND RESPONSE TO STAFF'S CONCERN ABOUT CONGESTION

Q. On page 11, line 18 of his rebuttal testimony Shawn Lange discusses Staff concerns with the "MISO Steady State review study". Do you share Mr. Lange's concern regarding the congestion in the area and the studies that he has referenced?

A. No, I do not. Mr. Lange actually points to the studies that were conducted by Siemens PTI at Clean Line's request and confirmed by Southwest Power Pool ("SPP") as part of the SPP Criteria 3.5 studies, not the MISO feasibility analysis. As I stated in my direct testimony at pages 11-13, the SPP Criteria 3.5 studied the impacts of the Grain Belt Express Project on the SPP system and did not focus on the MISO footprint, though the area was indeed monitored and MISO participated in the studies. The MISO feasibility study (attached as Schedule AWG-6 to my direct testimony) is MISO's view of the interconnection under the MISO and Ameren Missouri interconnection requirements, and it clearly indicates that there are no thermal overloads associated with the cases they have studied.

Q. Why is the MISO feasibility study a more reliable view of congestion at the point of the Project's injection?

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A. The MISO feasibility study, unlike the SPP Criteria 3.5 Studies, focuses on the MISO system and the deliverability of the Project's injection to load in MISO during steady state conditions. Further, the base case of the SPP Criteria 3.5 studies was, in essence, an N-1 scenario where one pole of the HVDC converter had tripped and approximately 1,800 MW was being injected into the SPP grid in western Kansas. If such a contingency occurs, the generation in Kansas connected to the Project would be curtailed or tripped offline in a period of less than one second. Thus, any congestion in MISO that occurs during such a contingency would be extremely short-lived.

Q. Should the overloads that were seen in the SPP study, but that were mitigated by the MISO Multi-Value Portfolio ("MVP") projects be a cause for concern if there is a delay in the implementation of the MVPs?

A. No, I do not believe they raise a concern. As noted above, any such congestion would be extremely short lived and cured by the curtailment or tripping of the wind generation connected to the Project.

Q. In his rebuttal testimony at page 11, lines 17-19, Mr. Lange asserts that the existence of a Special Protection Scheme ("SPS") at the Ameren Missouri's Audrain CT plant indicates that the area is congested. Do you agree with this assertion?

A. No. I understand that if the Audrain combustion turbines are dispatched at 100% and the line(s) leaving Audrain heading south trip, the SPS reduces the generator dispatch unit to prevent an overload at Palmyra due to increased flows to the north. An SPS is designed to deal with certain contingency situations that require a generator to respond over a very short time interval; it is not designed to deal with transmission congestion under normal operating conditions.

In a nodal LMP market such as MISO, the security constrained economic dispatch manages congestion under normal conditions. The dispatch issues generation instructions to minimize cost subject to transmission constraints. In the event transmission congestion occurs, it will show up in the LMPs received by a generator at a specific location.

Q. Does the evidence regarding LMPs near the Project's point of injection indicate that congestion is a common issue?

A. No, as discussed in the surrebuttal testimonies of David Berry and Robert Cleveland, neither historical LMPs nor the Company's PROMOD analysis indicate that congestion is a common or significant issue.

Q. Is there any reason to believe, as suggested by Staff witness Sarah Kliethermes at page 10, lines 10-14 of her rebuttal testimony, that the Project will exacerbate existing congestion issues and could cause an RTO to recommend a new transmission upgrade to relieve that congestion?

A. No. In the MISO planning process, transmission projects to relieve congestion are implemented based on the total economic value of the transmission congestion. If the congestion occurs infrequently, and if historical and forecasted LMPs do not show a substantial cost from congestion, then it is unlikely that MISO would recommend new transmission projects to relieve it.

With respect to the issues raised regarding congestion in Mr. Lange's testimony, I have described above that both the SPP Criteria 3.5 Studies and the Audrain SPS deal with system contingency events, not recurring congestion issues. As is detailed in Mr. Berry's surrebuttal testimony, Ms. Kliethermes' discussion of the economic value of congestion is inaccurate and misstates the impact of the Project. Neither Ms. Kliethermes nor Mr. Lange has presented evidence that the Project will actually cause economic congestion in MISO of any substantial magnitude. Therefore, there is no reason to believe new transmission lines will be needed to resolve economic congestion because of the Project.

Q. In his rebuttal testimony at page 13, lines 18-21, Commission Staff witness Shawn Lange asserts that the Project's "SPP System Impact Study" did not include additional planned wind within the SPP footprint area ...." What is your response?

A. The apparent source of Mr. Lange's comment is a statement on page 39 of the SIS Report (Schedule AWG-4) which refers to "Additional considerations for **future** studies of the GBX project ... [emphasis added]." When the SPP Transmission Working Group approved the Project's interconnection studies, it specified that the studies should be updated once the exact locations of the wind generation connected to the Project are known, and with the appropriate scenario models (i.e., models containing any updated SPP information since the last studies were performed) to confirm there are no adverse impacts on the system.

To be clear, however, the Project's interconnection studies with SPP explicitly consider 3756 MW of new wind generation directly connected to the Project, as indicated on page 2-12 of the Dynamic Stability Assessment report completed as part of the approved SPP Criteria 3.5 studies.[3] Additionally, the report, minus the appendices, is attached to this testimony as AWG-9. This Dynamic Stability Assessment report also

[3]http://www.grainbeltexpresscleanline.com/sites/grain_belt/media/docs/GBX_Stabiltiy_Study_Report_031413_with_Appendices_JA.pdf

considers wind that was already interconnected to the SPP grid and additional wind generation included in the scenario cases that were approved by the SPP Transmission Working Group for the analysis.

Q. What is the Company's response to the rebuttal testimony of Staff witness Daniel I. Beck at page 5, line 17, stating that the Company's view that the Project would not incur any interconnection upgrades is unreasonable?

A. Mr. Beck's comment relates to the Company's Application, which states on page 3 that the estimated Project cost of $2.2 billion "does not include the cost of upgrades required to interconnect the Project to electric transmission grid." The Application does not state the position that Mr. Beck attributes to it. Rather, the Application highlights that there is an additional cost not included in the $2.2 billion estimate.

The levelized cost of energy model presented in David Berry's direct testimony includes an estimate of network upgrade costs. In his surrebuttal testimony, Mr. Berry updates his model to include the estimated upgrade costs from the PJM System Impact study, which I discuss below.

Q. Has Grain Belt Express recently received the PJM System Impact Study ("SIS") report?

A. Yes, Grain Belt Express received the PJM SIS report on October 1, 2014. I have attached the study as Schedule AWG-10.

Q. Does the PJM SIS report identify any required system upgrades to accommodate the reliable interconnection of the Grain Belt Express Project to PJM?

A. Yes. The PJM SIS report identifies the system upgrades required to accommodate the reliable interconnection of the Project. The primary upgrade is the construction of a new

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line, the Sullivan-Reynolds 765 kV line. PJM estimates that the cost to construct this line is $500 million. Grain Belt Express expected that this upgrade would be required and had included its cost in its business plan prior to the receipt of the report.

In addition to this system upgrade, PJM identified two additional required system upgrades that need to be finalized as they involve coordination with other RTOs and/or other interconnection customers. They are:

- Upgrade the wave-trap at Dumont station on X1-020 765 kV line: Estimated cost of $1 million; and
- Rework the breaker and line arrangement at the new Reynolds 345 kV station, which is to be owned by Northern Indiana Public Service Company, which is in MISO: No estimate has yet been provided, although I expect its cost to be in the $5-10 million range.

Q. Will the stability analysis in the PJM SIS be updated as more granular information about the HVDC converter design becomes available?

A. Yes. In preparing the SIS, PJM and AEP used the generic HVDC models that are available in the standard library of software modeling tools used to perform such studies. When PJM conducts the Facilities Study, Grain Belt Express will provide PJM and AEP with a more detailed model of the Project's HVDC system that will include the full control capabilities of the proposed system. I expect this model to fully address the outstanding stability issues that PJM and AEP observed during the SIS because it will include the comprehensive, responsive capabilities of the Project's HVDC system within the short timescales studied. The facilities study is expected to commence in November 2014.

Q. Does the PJM SIS report identify any other upgrades to accommodate the reliable interconnection of the Grain Belt Express project?

A. Yes. In addition to the Sullivan-Reynolds 765 kV line, the following attachment facilities for the Project are required to physically interconnect to the Breed 345 kV substation:

- Three 345 kV breakers, and
- Dual 345 kV revenue metering.

PJM estimated the cost of these attachment facilities to be $3,447,100.

V. <u>PROJECT TECHNICAL SPECIFICATION</u>

Q. Staff witness Michael Stahlman in his rebuttal at page 2 states that "staff cannot confidently describe the parameters for Grain Belt Express' transmission project." Has Grain Belt Express provided a sufficient description of the Project's parameters?

A. Yes. The record in this proceeding is clear as to the basic technical specifications of the Project. While these specifications have evolved during the four years the Project has been under development, there should be no confusion about the Project that Grain Belt Express is proposing to construct in this proceeding. Mr. Stahlman's uncertainty appears to stem from reading different documents provided to Staff during discovery without taking into account when the documents were prepared.

Q. What are the rating specifications of the converter stations?

A. As stated in paragraph 6 of the Application, the Project is being designed to simultaneously deliver 3,500 MW to AEP's system in western Indiana and 500 MW to Ameren's eastern Missouri system. These MW values are being specified on the AC side of the respective converter stations, thus the converter stations have to be rated slightly higher to account for the losses associated with them.

Q. What is the design rating of the eastern converter station?

A. The Project's eastern converter station that will deliver 3,500 MW in western Indiana needs to be rated at approximately 3,525 MW to account for losses at the station. When the Company provides the HVDC vendors with our design specifications, we will specify a delivered amount of megawatts on a continuous basis and the vendor will rate the converter station accordingly.

Q. Regarding the rating of the converter station in Missouri, you have stated that it should be rated to deliver 500 MW to the Ameren system. However, you have also stated that the converter may have nameplate ratings as high as 1000 MW. Why is there a need to essentially double the rating of the Missouri converter relative to the delivered MW range?

A. Similar to the eastern converter station, the Missouri converter station needs to be rated slightly higher than the 500 MW it is delivering to Ameren's system to account for losses. However, when dealing with multi-terminal DC lines, there is a rule of thumb that states that the smallest converter station should be rated between 20-30% of the largest converter station so that during faulted conditions, the equipment in the smallest station is not over stressed. Much of this depends upon the vendor control capabilities and external system conditions as well. Thus, the converter transformers and valves at the Missouri converter station could be rated for 1,000 MW. In doing this, one effectively increases the inductance in the HVDC circuit, which improves the ability to manage fault conditions. However, this technical rating would not result in the converter station actually delivering more power. The Project has an interconnection request to MISO for 500 MW and therefore will not be allowed by the RTO to inject more than 500 MW. The power injected can be strictly limited by the HVDC control system as this is a control set point and not a rating issue. Should Grain Belt Express seek to deliver more than 500 MW in eastern Missouri, it must submit an interconnection request for the incremental values above 500 MW to MISO, as well as obtain the permission of this Commission based on the condition proposed by Commission Staff and accepted by Grain Belt Express.

Q. What is the rating of the Kansas converter station?

A. To accommodate the simultaneous delivery of 3,500 MW to western Indiana and 500 MW to Missouri, the Kansas converter station needs to be rated high enough to account for its own losses, the losses of the other two converter stations, and the losses of the HVDC line. This equates to a rating of approximately 4,300 MW.

Q. What is the total power to be delivered into PJM?

A. The Project has an interconnection request to PJM for total delivered power of 3,500 MW. The Project will not be allowed to inject more than 3,500 MW without a subsequent interconnection queue process in PJM.

Q. Mr. Stahlman at page 9, line 19 of his rebuttal testimony notes that the Sullivan, Indiana injection was not studied at 3,500 MW. How do you respond?

A. To be clear, PJM has studied and will continue to study the Project based on a 3,500 MW injection. The upgrades identified by PJM in the System Impact Study, described above and attached as Schedule AWG-10, are to accommodate a 3,500 MW injection.

While it is true that the SPP studies assumed 3,000 MW injection at Sullivan (with the remaining 500 MW assumed to be injected in eastern Missouri), the SPP study was primarily intended to study the impact of the Project as an interconnection to the SPP system. This study was not intended to fully assess the impact of injecting the Project's power in to the AC systems in eastern Missouri and western Indiana, which PJM is doing. Rather, the SPP studies focus on system impacts in abnormal operating conditions with a focus on the SPP system. Prior to operation, the SPP studies will be refreshed once the proprietary HVDC vendor models become available in order to confirm current study results, at which point the analysis will include the full 3,500 MW injection in PJM.

Q. Do you agree with the statement by Jeffrey M. Gray on behalf of the Missouri Landowners Alliance ("MLA") in his rebuttal at page 7 that the Grain Belt Express Project would not be an integrated component of MISO or SPP?

A. No, his statement is quite misleading. Although PJM will have functional control over the Project, its real-time operations will be coordinated by PJM with SPP and MISO because the Project will be operating in three RTOs. Thus, from an operational perspective, the Project will be an integrated component of the PJM, SPP and MISO systems, like any other transmission or generation facility.

Q. What is your response to the rebuttal testimony at page 13 of Christina Reichert that the Project's transmission lines should be buried rather than constructed overhead?

A. This is not technically feasible for a variety of significant reasons. Underground cable systems for electric power transmission are very complex and very dependent upon a number of factors in order to operate efficiently and reliably. To date, there have been no underground cable systems designed or installed at the proposed voltage (±600 kV) and power ratings (4,000 MW) of the Grain Belt Express Project or its proposed length (approximately 750 miles). The highest achieved cable ratings for underground or underwater HVDC, thus far, are ±500 kV at about 2000 MW. They are utilized in very specific applications and for relatively short distances compared to the Grain Belt Express Project.

A project entitled "Western Link" that has been proposed to connect Scotland to Wales via a ±600 kV, 2000 MW cable project is currently in development. However, to my knowledge, the cable vendor has yet to successfully install the cable. Assuming that the Western Link project is successful in developing a 600 kV cable, it still cannot be directly applicable to the Grain Belt Express Project for three main reasons: (1) the Western Link project has a significantly smaller power rating (2000 MW v. the Project's 4,000 MW); (2) the Western Link project is an undersea project, which provides for an atmosphere with significant cooling capabilities so that additional losses are not incurred, as compared with the heat dissipation issues of underground cable systems; and (3) the Western Link project is less than 250 miles in length (compared to the Project's 750 miles).

Additionally, there are no standard industry testing protocols for HVDC cables at this voltage. As a result, the Company cannot be reasonably assured that building the first experimental underground cable system in the world at such unprecedented voltage and power ratings could be done reliably and economically.

Other challenges of buried high voltage lines include the fact that these cables cannot be directly buried (i.e., be buried under the ground without any kind of extra covering, sheathing, or piping to protect it). Rather, the lines must be mechanically protected by being buried in a duct bank, conduit, or tunnels with frequent access from the surface for splices. Open trench construction is typically utilized when cable is buried, and the trench remains open for a significant amount of time as sections are spliced together. Splicing the type of cable that would be required for the Grain Belt Express Project would take several days to a week to complete due to the complexity of the process, and would require specialized skills and equipment that to my knowledge is not directly available in this country.

The large size of the cable, due to insulation requirements, also means that underground cable is extremely heavy relative to overhead conductors and only relatively short sections can be spooled and shipped due to size and weight. I would expect that less than 1000 meters could be effectively spooled and transported which would mean that a splice would need to occur every 1000 meters. Another detriment to underground cable systems is repair time. In the event of a failure of a cable, the outages are significantly longer than with overhead lines. Moreover, due to the specialized labor required to splice the cables, the availability of personnel to make the repairs could delay restoration of service. Excavation of the site could also be required to locate the failure.

VI. OPERATIONAL ISSUES

Q. What is your response to concerns raised by Show Me witness Kurt C. Kielisch at page 15 of his rebuttal regarding stray voltage from high voltage transmission lines and the impact it has on dairy cows?

A. The term "stray voltage" typically refers to extraneous, unwanted voltage that appears on grounded surfaces in buildings, barns, or other structures. This may also be referred to as a neutral-earth ("neutral to earth") voltage. These voltages are generated as a result of improper wiring techniques (e.g., the neutral conductor is grounded at multiple points, defective equipment, or incorrect wiring of transformers), or incorrect connections at the distribution utility transformer, where the distribution utility has connected the high side neutral and the low side neutral together. Because the Grain Belt Express Project will have no distribution lines and will not have direct interaction with distribution systems in the areas through which the line is passing, it will not create stray voltage issues. The same pertains to areas around the converter station.

Further, to the general question of health and productivity of cattle operations and agriculture, I am aware of several studies that have assessed the impacts on agricultural operations and did not find any adverse impact:

- According to an epidemiologic study of 500 herds of Holstein dairy cattle using multiple indicators, herd health did not differ between periods before and after a nearby +/- 400 kV direct current line was energized. These results did not vary based on the herd's distance from the high voltage direct current power line.[4]
- Another study conducted by Oregon State University titled "Joint HVDC Agricultural Study" determined that no differences were found between cattle and crops raised under +/-500 kV direct current lines and those raised away from the lines.[5]

[4] F.B. Martin, A. Bender, G., Steurnagel, R.A. Robinson, et al., "Epidemiologic Study of Holstein Dairy Cow Performance and Reproduction near a High Voltage Direct Current Powerline," 19 J. Toxicol. Environ. Health 303-324 (1986).
[5] R.J. Raleigh, Joint HVDC Agricultural Study: Final Report to Bonneville Power Administration (Ore. State. Univ., 1988).

- A report by the Western Interstate Commission for Higher Education also determined that a +/- 400 kV direct current transmission line did not affect crops, vegetation, or nearby wildlife, nor were the electric and magnetic fields from the line felt by persons walking in the right-of-way.[6]

Q. What is the Company's response to certain safety concerns identified in the public comments submitted to the Commission, as summarized in the rebuttal testimony at page 7, line 5 of Staff witness Natelle Dietrich?

A. The Project will use dedicated metallic return conductors, as opposed to ground electrodes, which will eliminate the possibility of the Project injecting ground current during normal operating conditions. To assess the impact of ground current from the Project during abnormal conditions, Grain Belt Express will conduct appropriate studies in coordination with utilities operating underground facilities such as pipelines near the Project's transmission line and converter stations.

Q. What is the Company's response to Christina Reichert's rebuttal testimony at page 10 regarding noise levels from HVDC lines?

A. The audible noise generated from the Project will be in the range of 25-45 dB-A. At the edge of the right-of-way, this will result in a noise level in the same volume range as a whisper.

Q. What is the Company's response to Ms. Reichert's comments at page 17 of her rebuttal testimony regarding the size and voltage of the Grain Belt Express Project?

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[6] D.B. Griffith, "Selected Biological Parameters Associated with a ±400 kV DC Transmission Line in Oregon," Report by the Western Interstate Commission for Higher Education for the Bonneville Power Administration (1977).

A. Ms. Reichert's understanding of the Project and her assertion that it will deploy an uncommon technology are incorrect. HVDC technology has been tested and proven for over 60 years with the first commercial power link being energized in 1958. In North America, there are over 30 HVDC installations, dating as far back as 1968.[7] Worldwide, HVDC applications, similar to the Grain Belt Project, are commonplace. Since the early 1990s, there have been over 16 significant applications in China and India, including projects as high as ±800 kV delivering more than 6,000 MW. Australia, New Zealand, Brazil, Japan and Europe have all installed significant HVDC transmission projects since the late 1960s[8]

Q. What is the Company's response to Ms. Reichert's rebuttal testimony at page 17 regarding the Company's statements concerning magnetic fields from overhead HVDC lines and the Earth's static magnetic field?

A. The booklet Ms. Reichert referred to provides reference to the magnetic fields generated by a variety of sources that the general public is familiar with. This includes MRI machines (15,000,000 – 40,000,000 mG), battery-operated appliances (3,000 – 10,000 mG), and electrified railways (less than 10,000 mG). The booklet also describes magnetic fields generated by HVDC transmission lines both at 500 kV (300 – 600 mG) and 600 kV (less than 900 mG). As illustrated by the figures above, HVDC lines are

[7] DC and Flexible AC Transmission Subcommittee of the IEEE Transmission and Distribution Committee by the Working Group on HVDC and FACTS, HVDC Projects Listing (July 2009); available at: http://www.ece.uidaho.edu/hvdcfacts/Projects/HVDCProjectsListingJuly2009-existing.pdf (last visited Oct. 14, 2014).

[8] Chan-Ki Kim, et al., HVDC Transmission: Power Conversion Applications in Power Systems (John Wiley & Sons, 2009).

indeed less than or similar to the Earth's magnetic field when compared to other sources that the general public is exposed to on a regular and frequent basis.

Q. What is the Company's response to the rebuttal testimony at page 9 of Kurt Kielisch that because high voltage transmission lines are not insulated, irrigation systems should not spray water on the electric lines in order to avoid electrical damage to the irrigation system?

A. To the contrary, high voltage lines are insulated from the structures they are suspended on. However, because the electrical conductors do not have an outer plastic jacket like electric cables, care must be taken that any irrigation system operating under the line does not spray a continuous stream of water onto pole conductors. If such a situation were to occurr, the Project will have the necessary protection and control system in place to de-energize the line once such a condition is detected. More importantly, Grain Belt Express will work with any land owner who operates an irrigation system to mitigate this possibility.

Q. What is the Company's response to Mr. Kielisch's rebuttal testimony at page 10 that a power line has a minimum distance of 20-24 feet above ground at the low sag point?

A. The minimum clearance of an electric transmission line is predicated on the operating voltage of the line, as set forth in the National Electric Safety Code ("NESC"). For the Grain Belt Express Project, the minimum clearance outlined by NESC is 31 feet. In addition to this, the Company, per its design criteria (Schedule AWG-3 to my direct testimony, discussed at page 10) is adding a minimum 3-foot buffer. Thus, the lowest the pole conductors will be is 34 feet above ground. It is important to note that the Project will be designed to maintain this minimum clearance during the most stressful conditions (e.g., hot summer days with high currents flowing). As a result, the electrical conductors will have more than a 34-foot clearance from ground for the majority of its operation.

Q. What is the Company's response to the rebuttal testimonies of Mr. Kielisch at page 12 and of Charles E. Kruse at page 12 that high voltage transmission lines may interfere with GPS units?

A. As discussed in my direct testimony, it is extremely unlikely that the Project will interfere with GPS signals because the frequencies that are used to communicate between orbiting satellites and GPS units, including those associated with farm equipment, are much higher than the frequency of radio noise from the Project's transmission line. On pages 25 and 26 of my direct testimony, I cite two studies that were conducted after the 2009 Wisconsin Department of Agriculture report that Mr. Kruse relies upon to make his assertion that further studies are required. These studies were published in 2011[9] and 2012,[10] and explicitly focused on the operation of GPS underneath HVDC lines. While it is theoretically possible that a signal from a single GPS satellite could be blocked or degraded due to the physical presence of a transmission structure in the line-of-sight between the GPS receiver and the satellite, this is extremely unlikely to result in the loss of functionality for a GPS receiver in an agriculture setting. GPS receivers require only three satellite signals to calculate horizontal positions on earth, but typically can access 12 or more satellites simultaneously. Thus, it is very unlikely that a transmission line,

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[9] Pollock & Wright, "Effects of Transmission Lines on Global Positioning Systems," PLAN Group, Manitoba Hydro DC-Line GNSS Survey Report (2011).

[10] J.B. Bancroft, A. Morrison, G. Lachapelle, "Validation of GNSS under 500,000 V Direct Current (DC) Transmission Lines," 83 Computers and Electronics in Agriculture 58, 66 (2012).

which would only physically block satellite signals from one direction, could cause the loss of a GPS signal. In the very unlikely event that any interference occurred, Grain Belt Express would discuss mitigation and other potential remedies with the individual landowner.

Q. What is the Company's response to Mr. Kruse's rebuttal at page 15 that in the event of a storm, the Project will damage land?

A. Grain Belt Express recognizes this possibility and fully intends to compensate any landowners for damage that occurs as a result of the Project during a storm, as well as for damages incurred during restoration efforts associated with the Project. Further, Grain Belt Express has agreed to the Staff condition to file a Storm Restoration Plan with the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing it to Construct, Own, Operate, Control, Manage and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood 345 kV transmission line.	))))))))	Case No. EA-2014-0207

AFFIDAVIT OF ANTHONY WAYNE GALLI

STATE OF TEXAS)
) ss
COUNTY OF HARRIS)

Anthony Wayne Galli, being first duly sworn on his oath, states:

1. My name is Anthony Wayne Galli. I am Executive Vice President – Transmission and Technical Services of Clean Line Energy Partners LLC.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of Grain Belt Express Clean Line, LLC consisting of 31 pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Anthony Wayne Galli

Subscribed and sworn to before me this 14 day of October, 2014.

Notary Public

My Commission Expires: 19 April 2015

SHAWN M. SCOTT
NOTARY PUBLIC
LONOKE COUNTY, AR
Exp. Apr. 19, 2015

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Siemens PTI Report Number: R022-13

Dynamic Stability Assessment of Grain Belt Express Clean Line HVDC Project

Prepared for

Clean Line Energy Partners LLC

Submitted by:

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March 2013

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SIEMENS

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Date	Rev.	Description
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March 14, 2013	2	Clean Line team's comments incorporated

Contents

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Executive Summary

Clean Line Energy Partners LLC is currently developing the Grain Belt Express Clean Line (GBX) Project. The project is planned to be a multi-terminal ±600 kV HVDC bi-pole line which will transport large amounts of new, renewable energy, primarily sourced from wind turbine generators (WTG). The wind turbine generation will be independently developed within the Southwest Power Pool's (SPP) geographic footprint in and around the northwestern portion of Oklahoma and in the southwestern portion of Kansas. The power will then be transmitted via the GBX Project approximately 500-550 miles to a location at or near the Palmyra Tap 345kV bus in the Ameren Missouri (AMMO in the MISO) and then a further 200 miles to the Sullivan 765kV substation in the American Electric Power (AEP in the PJM) power systems. The Project will have a planned delivery capability of 3,500 MW as measured at the receiving ends of the HVDC line (500 MW at Palmyra Tap and 3,000 MW at Sullivan). The Sullivan terminal will be designed to receive up to 3,500 MW.

Siemens Industry, Power Technologies International (Siemens PTI) was engaged to evaluate the impacts of the GBX Project from a steady state and dynamic performance point of view. This report presents the stability analysis results to determine the dynamic performance of the study area due to the addition of the GBX Project.

The wind turbine generation is modeled as Type 3 (doubly fed induction generators) and Type 4 (full converter) located within a possible collector system. The collector system design considered in this study is a best engineering estimate based on available wind potential resources in the vicinity of the northwestern portion of Oklahoma and in the southwestern portion of Kansas. It is expected that the wind generation is collected using a 138 kV transmission network connecting the wind parks to main 345 kV stations and then ultimately transferred to the HVDC rectifier station via a 345 kV transmission network. For this analysis, the wind generation was directly connected to the HVDC rectifier station via a 345 kV network without modeling of the 138 kV collection system. Future design studies will include design of the 138 kV system to collect the wind generation and deliver it to the 345 kV transmission network. The collector system losses and reactive power needs of the GBX Project will be covered by the project wind generation and interconnected reactive power sources such that minimal exchange of real and reactive power with SPP at the Point of Interconnection (POI) is maintained under normal operating conditions. However, following the loss of a pole in the GBX project, some of the power flowing through the project will temporarily flow into the SPP system.

As part of the study, several disturbances within the vicinity of the GBX Project were selected to evaluate the dynamic performance of the system. Study methodology and assumptions were discussed with SPP and other affected parties. Affected parties were determined in the January 7, 2013 issued report entitled *Steady State Assessment of the Grain Belt Express Clean Line HVDC Project.*

During the analysis of the Clean Line Plains and Eastern (P&E) project, dynamic reactive support from synchronous condensers was proposed as a solution to handle the low Short Circuit Ratio (SCR[1] of less than 2) at the point of interconnection. Taking advantage of the

[1] Ratio of 3-phase short circuit MVA without the WTG in place to the total wind turbine generation capacity

P&E project stability study evaluation, and given that the interconnection points for both the P&E and the GBX projects have similar short circuit levels (in the order of 5,000 MVA), dynamic reactive support of 900 MVAr from synchronous condensers was modeled at the rectifier station. The addition of 900 MVAr from synchronous condensers increased the SCR to slightly higher than 2 under system intact conditions. Note that this was modeled as a single synchronous condenser as part of the reactive compensation at the rectifier station and its size and division into smaller units was not optimized in this study as this will be undertaken during the detailed design of the GBX project and its controls.

Three scenarios, 2017 Summer Peak, 2017 Light Load and 2022 Summer Peak, with different dispatch and loading conditions are considered in the study. These scenarios were identified by SPP staff and the affected parties as relevant scenarios considering the project's expected in-service dates.

The following are the main conclusions of the overall system stability analysis:

- As proprietary HVDC models from the yet to be selected HVDC vendor are not available, HVDC models from the PSS/E library are used. These HVDC models do not fully capture the control capability of the HVDC converter stations thus, up to 900 MVAr from a synchronous condenser are required, from a modeling perspective, for the PSS/E stability models to solve by improving the short circuit levels (i.e. system strength) at the Clark County 345 kV substation. This condenser was considered in all cases. Once proprietary HVDC models are provided by the HVDC vendor, the control capability of the HVDC converter can be properly modeled and thus reduce the required amount of synchronous condensers. Furthermore, for reliability and practical reasons, smaller parallel synchronous condensers would be used to make up the required total. This synchronous condenser is to be optimized at the time of the GBX project design

- Faults at Rockport that involve tripping the 765 kV line to Jefferson require the GBX Project generation injection at Sullivan to be reduced, while keeping the full reactive capability of the inverter station available. The associated WTG is assumed to flow in the underlying AC system during the stability runs

- For an N-1-1 outage at Clark County substation, it is necessary to trip approximately 877 MW of the project WTG

The main results of the study that drove these conclusions are summarized below:

- Taking advantage of the P&E Stability Study, and given that the Hitchland and Clark County substations have similar short circuit levels (around 5,000 MVA); up to 900 MVAr from synchronous condensers were proposed for all simulations

- The 2017 Summer Peak case showed stable study area dynamic performance for all selected faults except for 3ph fault at Rockport substation (Fault # 34)

  - For this particular fault, all on-line generating units at the Rockport plant have stepped out of synchronism with the rest of the system. Tripping of these units does not have an adverse impact on the rotor angle stability of rest of the study area

- By reducing the GBX project injection at Sullivan by 1,500 MW (achieved by blocking one pole), the Rockport generating units remain on-line and in synchronism with the system. Note that full reactive compensation (switched shunts) is required at the converter stations to meet the voltage performance criteria

- The 2017 Light Load case showed stable study area dynamic performance for all selected faults except for Fault # 34. For this fault, the voltages around the Sullivan substation area did not meet the voltage performance criteria

  - By reducing the GBX project injection at Sullivan by 1,500 MW (achieved by blocking one pole), the voltages around the Sullivan substation met the voltage performance criteria

- The 2022 Summer Peak case showed stable study area dynamic performance for all selected faults except for a 3ph fault at Rockport substation (Fault # 34)

  - For this particular fault, all on-line generating units at Rockport plant have stepped out of synchronism with the rest of the system. Tripping of these units does not have adverse impact on the rotor angle stability of the rest of the study area

  - By reducing the GBX project injection at Sullivan 1,500 MW (achieved by blocking one pole), the Rockport generating units remain on-line and in synchronism with the system. Note that full reactive compensation (switched shunts) is required at the converter stations to meet the voltage performance criteria.

Again, it should be noted that it may be possible to reduce the size of the recommended 900 MVAr from synchronous condensers by HVDC control schemes at the converter stations. However, this combination was not tested in this study and it will be part of the reactive optimization of the Project design as well as the selection of the required number of parallel synchronous condensers once proprietary HVDC models become available.

Section

1

Introduction

Clean Line Energy Partners LLC (Clean Line) is currently developing the Grain Belt Express Clean Line Project (GBX Project) which will use a multi-terminal HVDC technology to deliver primarily wind generated electricity from southwestern Kansas and northwestern Oklahoma to serve load centers in the AMMO and AEP control areas. The GBX Project is being developed as a ±600-kV HVDC overhead line and is expected to interconnect the Clark County 345 kV substation (SPP) to the Palmyra 345 kV Tap (AMMO) and the Sullivan 765 kV substation (AEP) through a new 345 kV substation and three 765/345 kV transformers. The connection of wind turbine generation resources to Sullivan via Palmyra Tap is proposed as an approximately 700-750 mile[2] multi-terminal HVDC transmission line at or near the Palmyra Tap (AMMO in the MISO) substation and Sullivan (AEP in the PJM).

Siemens Industry, Power Technologies International (Siemens PTI) has provided consulting services to Clean Line to estimate the steady state impacts of the GBX Project. In continuation to this effort, Siemens PTI has also conducted the system stability study to determine the impact of the GBX Project on dynamic performance of the power system within the study area.

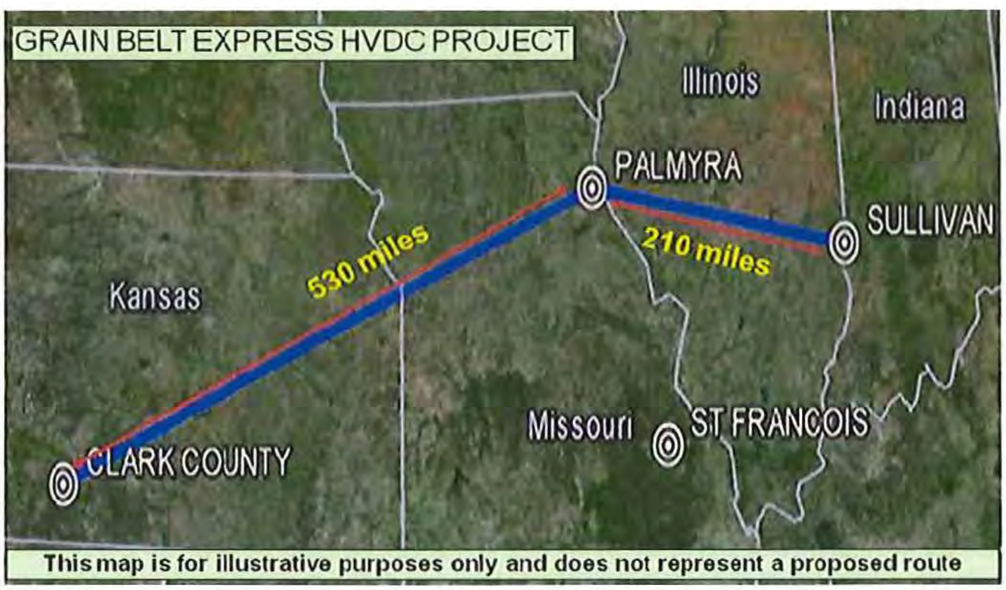

Figure 1-1: Approximate Geographic Location of the GBX Project

[2] Actual mileage will be dependent upon final routing.

This report presents the study methodology, summary of the stability analysis results, and proposed solutions to the identified issues. The report is organized as follows:

Section 2 of this report presents the stability case development process which includes generation and transmission topology changes within the study area, modeling of the proposed HVDC line, and modeling of the GBX Project's expected Wind Turbine Generation (WTG).

Section 3 presents methodology and assumptions used in the study. The selected list of disturbances for evaluating the dynamic performance of the system along with performance evaluation criteria are presented in this section.

Section 4 presents analysis of study results and major findings of the study.

Section 5 presents the analysis of three phase (3ph) faults at Spearville and Clark County substations with prior line outages. This analysis was done to evaluate the impact of pre-existing outages on the lines that, as will be observed, had the most significant impact on stability.

Section 6 presents the summary of swing current analysis on key underlying SPP 345 kV lines for 3ph faults at both converter stations that involves double pole outage.

Section 7 presents the sensitivity case of reduced GBX Project generation of 1,750 MW (250 MW injection at Palmyra and 1,500 MW inject at Sullivan) in 2017 Light Load scenario. This case was assessed without the proposed synchronous condenser.

Section 8 presents the sensitivity case of connecting the GBX Project to 345 kV network at Sullivan. Selected 3ph faults are studied for dynamic performance of the study area.

Section 9 presents the study conclusions and recommendations.

Finally, the Appendices section presents dynamic model parameters and stability plots for all three scenarios.

Section

2

Stability Case Development

The stability analysis is performed using the "2011 Build 1 Stability Package"[3] (called here after "Stability Package") provided by SPP. Since the steady state analysis was performed using the "2011 Build 2 scenario"[4] (called here after "Build 2") cases, we compared the load flow cases from the Stability Package and the Build 2 scenario for any generation and transmission topology changes that needed to be incorporated in the Stability Package.

This section presents generation and transmission changes and provides details of the GBX Project addition along with collector system description.

2.1 Generation Changes

Table 2-1 shows the generation comparison of the 2017 Summer Peak case[5]. The table also shows the wind generation dispatched in both cases. Both cases have substantially similar dispatch (a maximum of 4% difference was noted in relevant areas). No additional generation was added with the exception of the wind turbine generation associated with the GBX project.

Similarly, Table 2-2 shows the generation comparison between the Build 2 case and Stability Package case for the 2017 Light Load case and Table 2-3 shows the generation comparison between the Build 2 case and Stability Package case for the 2022 Summer Peak case. No additional generation was added except for the GBX project wind generation as the dispatches were practically identical.

The branch loadings of the Stability Package load flow cases (2017 Summer Peak, 2017 Light Load and 2022 Summer Peak) were compared against the normal line rating (Rate A) within the SPP footprint[6], and no thermal overloads were observed.

Further, the Stability Package load flow cases were compared against the Build 2 scenario load flow cases for any significant changes in branch loadings. The comparison criteria include changes greater than 3% in branch loadings (MW) for branches operating at 230 kV and above voltage levels within the SPP footprint. The branch loading tables are listed in Appendix A, by each balancing area. It can be observed from these tables that most of the branch loadings in the Stability Package load flow cases differ from those of the Build 2 scenario load flow cases by less than +/- 50 MW except for very few lines with a difference between 50 MW and 100 MW.

Based on generation and branch loading comparisons, it is assumed that both the Stability Package load flow cases and Build 2 scenario load flow cases are stressed identically for the

[3] 2011 Build 1 package was the latest available stability package at the time of the study
[4] These are the original cases received from SPP
[5] The delta change in Pgen (%) = (Pgen in Stability Case/Pgen in Build 2 – 1)X100
[6] SPP footprint is defined as areas 500 – 599, 640, 645 and 650

purpose of this study and no additional generation was added other than the expected project's WTG generation. The next section presents the transmission topology changes.

Table 2-1: Generation Comparison – 2017 Summer Peak

		2017 Summer Peak Build 2				2017 Summer Peak Stability				Change in Total
		Total		Wind		Total		Wind		
Area		Pgen	Pmax	Pgen	Pmax	Pgen	Pmax	Pgen	Pmax	Pgen
534	SUNC	1,118	2,029	89	759	1,111	2,161	47	313	-1%
531	MIDW	135	408	33	261	130	249	36	102	-4%
536	WERE	6,489	7,740	46	150	6,587	7,740	46	150	2%
526	SPS	6,615	8,589	63	994	6,601	8,358	57	879	0%
525	WFEC	1,305	2,673	22	539	1,305	2,597	22	255	0%
524	OKGE	6,961	9,306	99	1,141	6,975	9,199	105	882	0%
520	AEPW	10,117	16,799	23	388	10,107	16,670	15	214	0%
541	KCPL	4,495	5,336	240	308	4,493	5,336	240	308	0%
540	GMO	1,184	2,028	0	170	1,178	2,028	0	170	0%
545	INDN	202	288	0	0	202	288	0	0	0%
515	SWPA	1,996	2,564	0	122	1,996	2,564	0	122	0%
502	CLEC	3,663	4,617	0	0	3,663	4,617	0	0	0%
351	EES	29,083	42,202	0	0	29,084	42,202	0	0	0%
503	LAFA	168	465	0	0	168	465	0	0	0%
504	LEPA	123	211	0	0	123	211	0	0	0%
523	GRDA	1,217	1,532	0	0	1,265	1,532	0	0	4%
527	OMPA	196	197	0	0	193	197	0	0	-2%
542	KACY	580	961	0	0	580	961	0	0	0%
544	EMDE	1,106	1,460	0	0	1,107	1,460	0	0	0%
546	SPRM	879	1,060	0	0	879	1,060	0	0	0%
330	AECI	4,538	5,622	0	0	4,522	5,622	0	0	0%
640	NPPD	2,907	4,687	22	345	2,907	4,687	22	345	0%
645	OPPD	3,249	3,781	12	60	3,249	3,766	12	45	0%
	Total	**88,326**	**124,555**	**650**	**5,237**	**88,425**	**123,969**	**603**	**3,785**	**0%**

Table 2-2: Generation Comparison – 2017 Light Load

		2017 Light Load Build 2				2017 Light Load Stability				Change in Total Pgen
		Total		Wind		Total		Wind		
Area		Pgen	Pmax	Pgen	Pmax	Pgen	Pmax	Pgen	Pmax	
534	SUNC	652	2,029	102	439	643	2,481	139	566	-1%
531	MIDW	85	408	75	261	86	304	75	158	0%
536	WERE	5,070	7,740	0	0	5,121	7,740	80	150	1%
526	SPS	3,330	8,578	123	834	3,328	8,501	165	993	0%
525	WFEC	1,264	2,673	37	200	1,267	2,682	97	340	0%
524	OKGE	2,419	9,306	123	1,141	2,412	9,194	129	882	0%
520	AEPW	2,858	16,799	23	388	2,855	16,670	15	214	0%
541	KCPL	2,375	5,336	0	308	2,376	5,336	0	308	0%
540	GMO	285	2,028	0	170	284	2,028	0	170	0%
545	INDN	0	288	0	0	0	288	0	0	0%
515	SWPA	999	2,564	0	122	999	2,564	0	122	0%
502	CLEC	1,800	4,617	0	0	1,800	4,617	0	0	0%
351	EES	19,334	42,202	0	0	19,335	42,202	0	0	0%
503	LAFA	54	465	0	0	54	465	0	0	0%
504	LEPA	85	211	0	0	85	211	0	0	0%
523	GRDA	727	1,532	0	0	750	1,532	0	0	3%
527	OMPA	107	197	0	0	107	197	0	0	-1%
542	KACY	236	961	0	0	236	961	0	0	0%
544	EMDE	98	1,460	0	0	98	1,460	0	0	0%
546	SPRM	257	1,060	0	0	257	1,060	0	0	0%
330	AECI	1,181	5,622	0	0	1,174	5,622	0	0	-1%
640	NPPD	1,484	4,687	77	345	1,484	4,687	77	345	0%
645	OPPD	1,154	3,813	21	60	1,154	3,813	21	60	0%
	Total	**45,856**	**124,576**	**582**	**4,268**	**45,903**	**124,614**	**798**	**4,308**	**0%**

Table 2-3: Generation Comparison – 2022 Summer Peak

		2022 Summer Peak Build 2				2022 Summer Peak Stability				Change in Total Pgen
		Total		Wind		Total		Wind		
Area		Pgen	Pmax	Pgen	Pmax	Pgen	Pmax	Pgen	Pmax	
534	SUNC	1,304	2,029	78	439	1,306	2,283	91	434	0%
531	MIDW	136	408	33	261	136	249	36	102	0%
536	WERE	6,744	7,740	0	0	6,894	7,740	46	150	2%
526	SPS	7,424	8,605	47	834	7,411	8,374	57	879	0%
525	WFEC	1,536	2,673	8	200	1,538	2,616	50	274	0%
524	OKGE	7,389	9,306	99	1,141	7,405	9,194	105	882	0%
520	AEPW	10,706	16,799	73	388	10,695	16,670	65	214	0%
541	KCPL	4,788	5,342	240	308	4,786	5,342	240	308	0%
540	GMO	1,343	2,028	60	170	1,337	2,028	60	170	0%
545	INDN	216	288	0	0	216	288	0	0	0%
515	SWPA	2,031	2,564	52	122	2,031	2,564	52	122	0%
502	CLEC	3,609	4,617	0	0	3,610	4,617	0	0	0%
351	EES	30,260	42,202	0	0	30,262	42,202	0	0	0%
503	LAFA	310	465	0	0	310	465	0	0	0%
504	LEPA	128	211	0	0	128	211	0	0	0%
523	GRDA	1,315	1,532	0	0	1,349	1,532	0	0	3%
527	OMPA	248	197	0	0	214	197	0	0	-14%
542	KACY	594	961	0	0	594	961	0	0	0%
544	EMDE	1,203	1,460	0	0	1,204	1,460	0	0	0%
546	SPRM	998	1,160	0	0	998	1,160	0	0	0%
330	AECI	4,930	5,622	0	0	4,917	5,622	0	0	0%
640	NPPD	3,123	4,687	22	345	3,123	4,687	22	345	0%
645	OPPD	3,506	3,990	12	60	3,506	3,975	12	45	0%
	Total	**93,843**	**124,886**	**724**	**4,268**	**93,971**	**124,436**	**836**	**3,925**	**0%**

2.2 Transmission Topology Changes

The Stability Package load flow cases were compared with those of Build 2 scenario cases for transmission topology changes in the 230 kV and above voltage level networks within the SPP area.

In all comparisons, no major changes were observed except that in a Build 2 case the Longwood (508809) – El Dorado (337562) 345 kV line is tapped at Sarpet (337376) substation and is connected to the 230 kV network through a step down transformer. In the Stability Package load flow cases, this line is not tapped at Sarpet. It is assumed that this change in configuration will not affect the case since this line is located far from the GBX Project, and hence it was not modeled in the Stability Package cases.

Furthermore, in the 2022 Summer Peak stability load flow case, a Spearville – Jaybird 345 kV line connected to the Moore county 138 kV substation as shown in Figure 2-1 was found. This line was not found in any of the Build 2 or ITP cases. Therefore, to make the stability case consistent with the load flow cases used for the steady state analysis a conservative approach was taken. The line and the three winding transformer from the 2022 Summer Peak Stability were removed from the model.

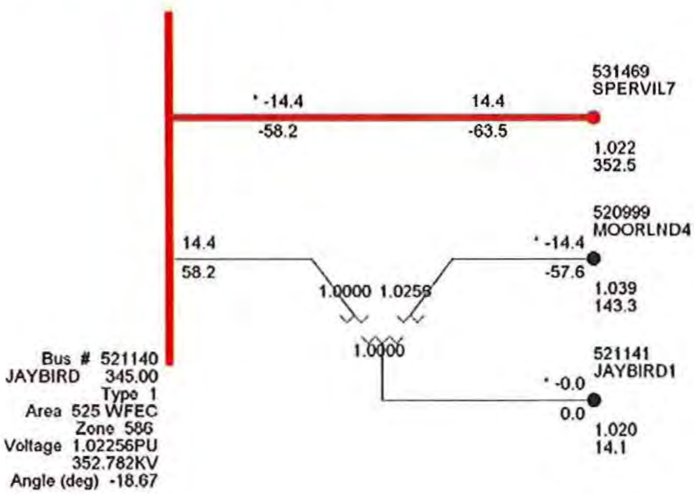

Figure 2-1: Spearville – Jaybird 345 kV Line (2022 Summer Peak)

Figure 2-2 shows the transmission topology around the Hitchland and Spearville area in the 2017 Summer Peak Stability Package case. Note that the northern part of the Group 2 Priority Projects (called the V-plan) is not modeled according to the latest configuration. For example, the Thistle substation is still named as Flat Ridge. This load flow case was modified to represent the latest expected configuration by adding the following projects:

- The Group 2 Priority Projects were updated to represent the latest information provided by ITC to SPP[7]

[7] This configuration was found to be updated in SPP's ITP cases

- The Hitchland 345 kV substation is expanded to represent the latest information provided by SPS (i.e. a Hitchland 2 substation was added to the system.)
- Additional corrections included:
  - Transformer at Thistle connected to Medicine Lodge is kept out of service
  - Line reactors along the lines from Hitchland – Woodward were initially wrongly placed on the line section of Hitchland 1 to Hitchland 2 substations. These reactors were moved on to the Hitchland – Woodward line section

Figure 2-3 shows the transmission topology around the Hitchland and Spearville area in the modified 2017 Summer Peak Stability Package. Similarly, these changes are also applied to 2017 Light Load and 2022 Summer Peak cases.

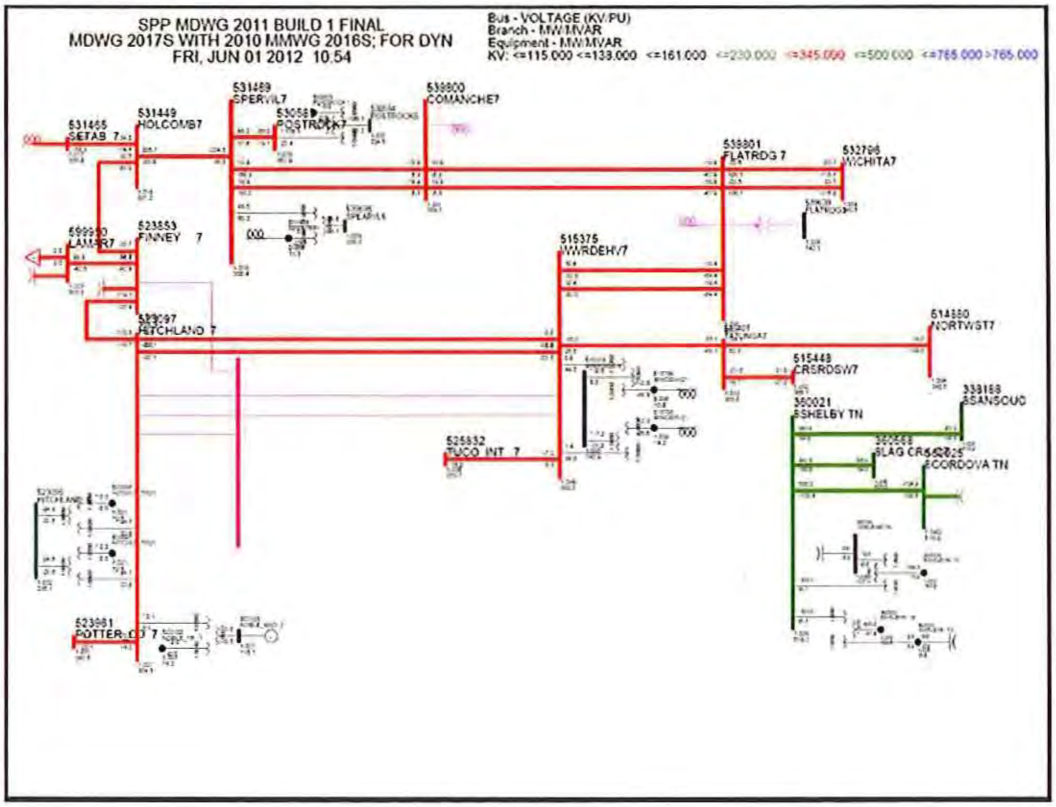

Figure 2-2: Transmission Topology around Hitchland and Spearville – 2017 Summer Peak Stability Case

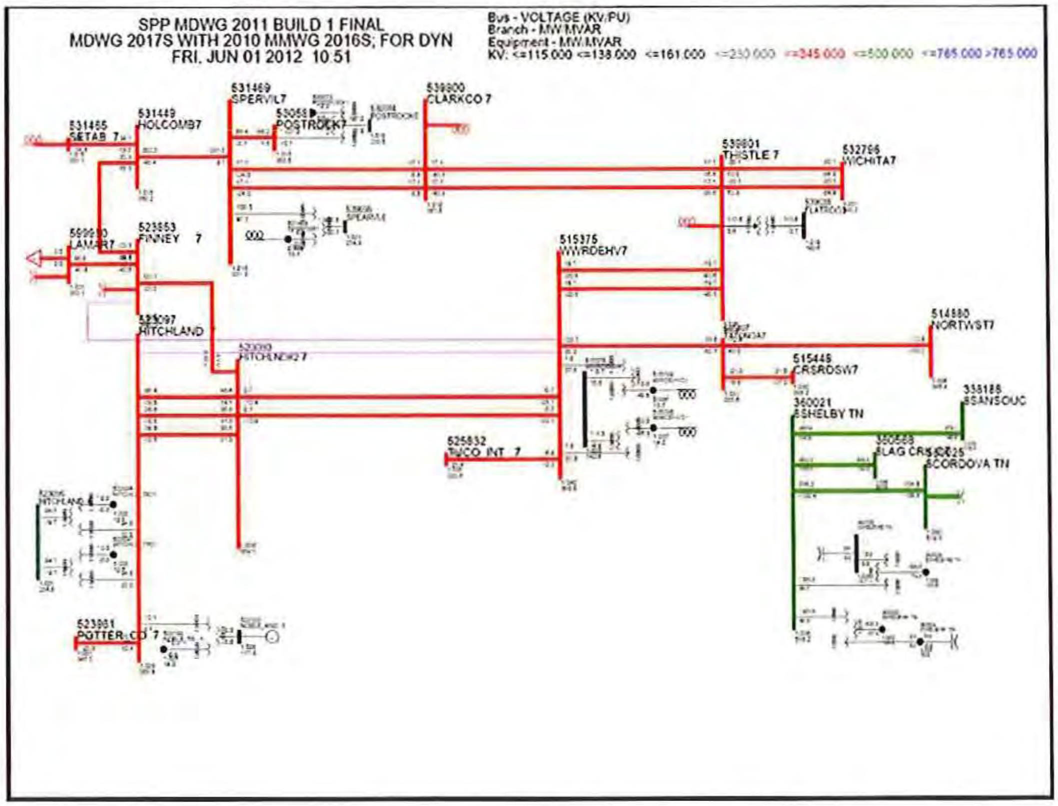

Figure 2-3: Transmission Topology around Hitchland and Spearville – 2017 Summer Peak Modified Stability Case

2.2.1 MISO Multi Value Projects

The following projects have been added to the system to reflect MISO's Multi Value Projects (MVP) near the project injection locations as shown in Figure 2-4 and Figure 2-5.

- Ottumwa – MO wind zone – Adair 345 kV lines
- Adair 345 kV/161 kV transformer
- Palmyra Tap – Palmyra 345 kV line
- Quincy – Meredosia – WZ IL – Pawnee – Pana – Mt Zion – Kansas – Sugar Creek 345 kV lines
- 345 kV/138 kV transformers at Quincy (1), Pawnee (2), Pana (1) and Mt Zion (1)
- Greentown – Brook Stone 765 kV line
- Brook Stone 765 kV/345 kV transformer
- Brook Stone – Reynolds – Burr Oak – Hiple 345 kV lines
- Robinson Park – Weeds Lake 345 kV line is tied to Hiple

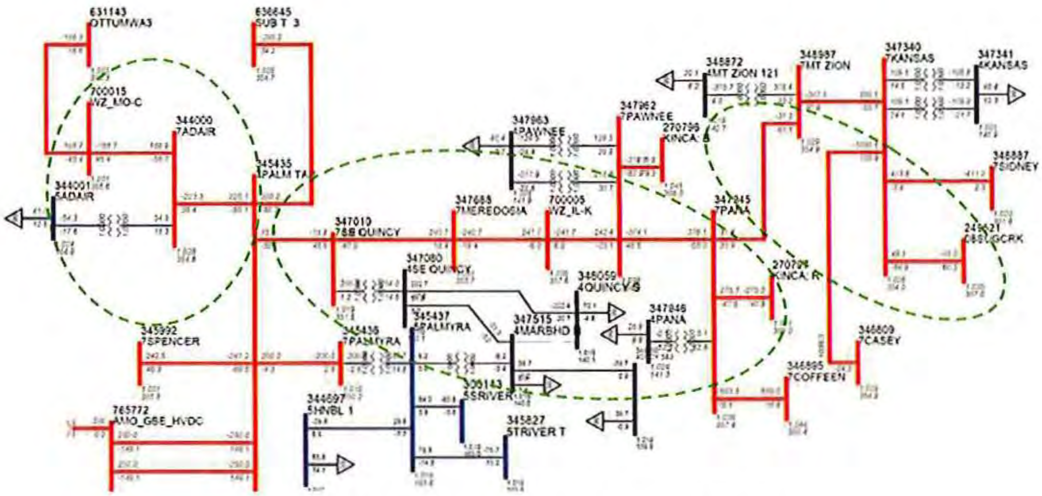

Figure 2-4: MISO Multi Value Projects (MVP) – 1

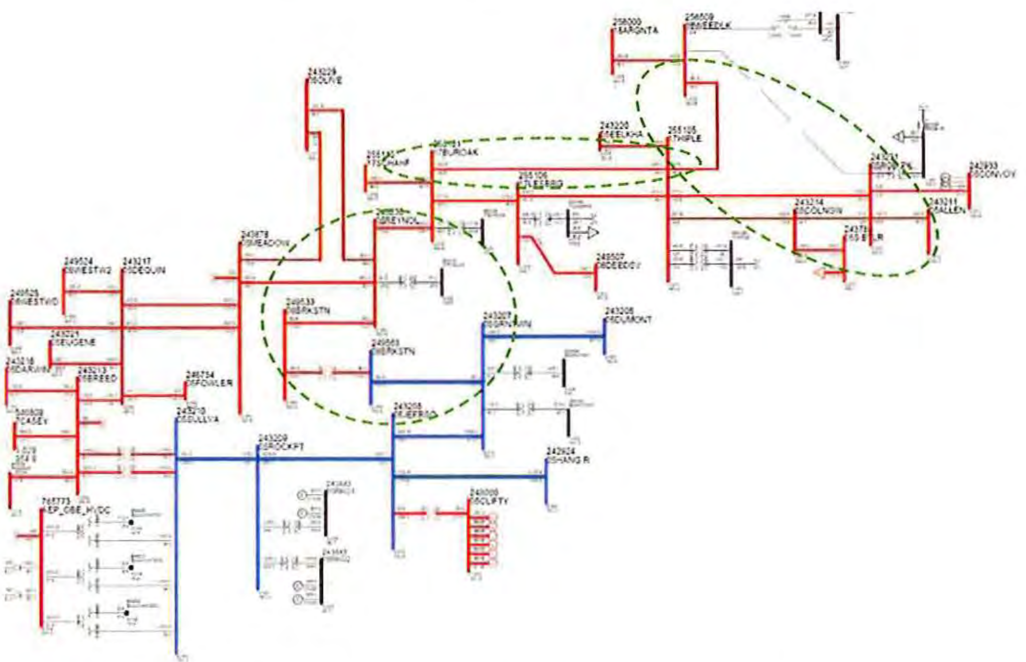

Figure 2-5: MISO Multi Value Projects (MVP) – 2

These projects are not the entirety of the MISO MVP, but a selection of the projects that are located in the area of influence of the GBX.

The next section presents the details of the GBX Project addition on top of these modified Stability Package load flow cases.

2.3 Grain Belt Express Project Addition

The Grain Belt Express project addition was done in two steps: (1) HVDC line addition and, (2) Wind Turbine Generation (WTG) addition. The modeling of the GBX project is similar to that done in the Steady State models except that the project's required reactive compensation at the converter stations and the collector system representation were modified as described in this section.

2.3.1 HVDC Line Addition

The GBX HVDC project was modeled as a three-terminal HVDC bi-pole originating at Clark County 345 kV substation (SPP) and delivering 500 MW at Palmyra Tap 345 kV substation (AMMO) and remaining 3,000 MW at Sullivan 345 kV substation (AEP). The inverter at Sullivan substation is connected to a new 345 kV substation and then to 765 kV network through three 765/345 kV transformers. The static reactive compensation at the converter stations is modeled in several steps of 275 MVAr units as described below. Note that the reactive compensation[8] at the rectifier station is slightly higher due to a higher rated windward converter station requirement in order to account for converter station and DC line losses.

Table 2-4 shows the available fault levels and the short circuit ratio (SCR)[9] calculated with 4,000 MW of additional wind generation. An SCR of 1.29 indicates an extremely weak interconnection point[10] at Clark County.

Table 2-4: Short Circuit Ratio at Clark County

	Without SC		With SC	
ClarkCo - 539800	Fault MVA	SCR[1]	Fault MVA	SCR[1]
2017 LL	4844.48	1.21	8406.06	2.10
2017 SP	5471.96	1.37	9034.25	2.26
2022 SP	5950.93	1.49	9514.52	2.38

1. SCR calculated for a wind capacity of 4,000 MW

During Clean Line Plains and Eastern (P&E) project studies, dynamic reactive support from synchronous condensers was proposed as one possible solution to handle the low short circuit levels (SCR of less than 2) at the point of interconnection. Taking advantage of the P&E project stability study evaluation, and given that the interconnection points for both P&E and GBX projects have similar short circuit levels (around 5,000 MVA); a dynamic reactive support of 900 MVAr synchronous condenser is proposed at the rectifier station. As shown in the table, the addition of a 900 MVAr synchronous condenser increased the SCR slightly higher than 2 under system intact conditions.

The following combination of reactive compensation at the converter stations is modeled as part of the addition of HVDC multi-terminal line:

- Reactive compensation at the Clark County rectifier station is modeled as 275x5 resulting in 1,375 MVAr of static switched shunt reactive compensation, and a

[8] The total reactive compensation is sized as approximately 60% of the MW flow along the HVDC line and this flow is higher at the rectifier station compared to the inverter station due to line losses.
[9] Short circuit ratio is a measure of strength of the interconnection point and is defined as the ratio of available fault MVA level to the capacity of the wind generation addition.
[10] In several studies, for example the CREZ reactive study, it was observed that SCR less than 2 is an indication of a weak interconnection point.

synchronous condenser of 900 MVAr resulting in a combined total of 2,275 MVAr. The dynamic parameters of this SC are provided in Appendix B

- Reactive compensation at the Sullivan inverter station is modeled as 275x7 MVAr resulting in a total of 1,925 MVAr of static switched shunts
- Reactive compensation at the Palmyra inverter station is modeled as 300x1 MVAr of static switched shunts

As will be discussed in later sections, withproper control schemes at the HVDC converter stations, it should be possible to reduce the size of the proposed 900 MVAr synchronous condenser. At this time it is anticipated that required dynamic support would be somewhere between 450 MVAr and 900 MVAr. Its final size will be dependent, among other things, on the converter station voltage control design.

Figure 2-6 shows the configuration of the three-terminal HVDC line and Table 2-5 through Table 2-9 show the multi-terminal bi-pole HVDC line parameters used in the load flow case. The tables show the modeling information for Pole 1, and are similar for Pole 2.

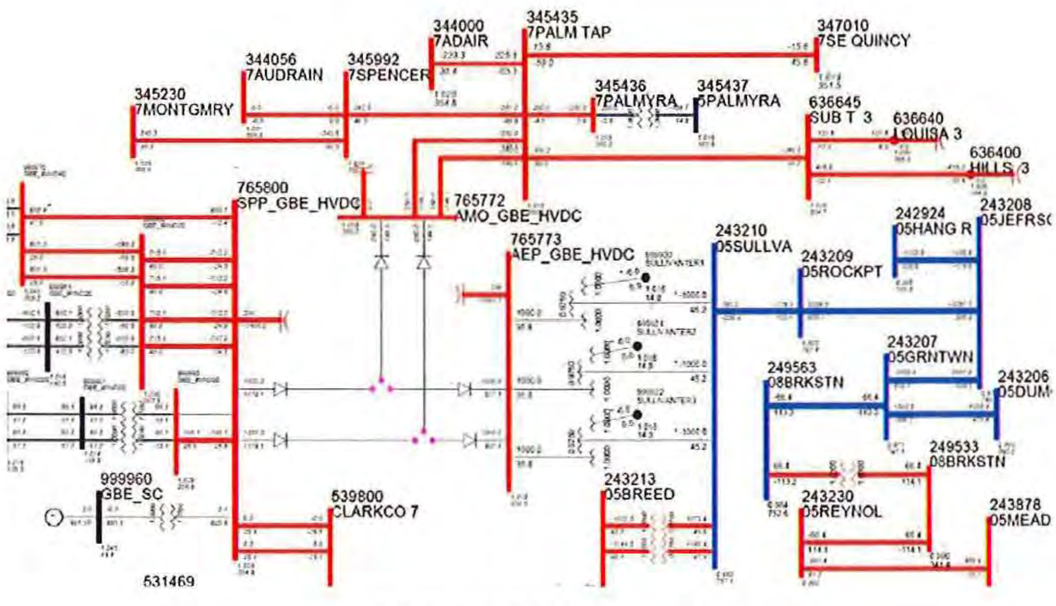

Figure 2-6: GBX HVDC Multi-Terminal Line

Table 2-5: HVDC Line Modeling in Load Flow Case – Showing Two Poles/Lines

Line Name	Control mode	Number of Converters	Number of DC buses	Number of DC links	Vcmode kV	(+ pole) inverter ac bus	(- pole) inverter ac bus
1	Power	3	6	5	300	765773	0
2	Power	3	6	5	300	765773	0

Table 2-6 Converter Parameters – Showing for Pole 1

Converter Number	Bus Number	Bus Name	Pole (Pos./Neg.)	Min (deg)	Max (deg)	Setval (kV/amps/MW)	Nb	Ebase (kV)
1	765800	SPP_GBE_HVDC345.00	1	5	24	1850	1	345
2	765772	AMO_GBE_HVDC345.00	1	15	25	-250	1	345
3	765773	AEP_GBE_HVDC345.00	1	15	25	600	1	345

Table 2-7 Converter Parameters (Contd.) – Showing for Pole 1

Converter Number	Bus Number	Rc (ohms)	Xc (ohms)	Transformer Ratio (p.v.)	Tap (pu)	Tap Min (pu)	Tap Max (pu)	Tap Step (pu)	Margin (pu)	Particip. factor
1	765800	0	26.42	1.5819	1	0.85	1.15	0.00625	0	1
2	765772	0	185.3	1.5572	1.03125	0.85	1.15	0.00625	0	1
3	765773	0	29.93	1.5342	1.01875	0.85	1.15	0.00625	0	1

Table 2-8 DC Bus Numbers – Showing for Pole 1

DC Bus	DC bus Name	Converter Bus	Area Number	Zone Number	Owner Number	RG (ohms)	2nd DC Bus
1	DC_RECT	765800	534	1529	1	9999	0
2	DC_RECT_P	None	534	1529	1	9999	0
3	DC_INV2_P	None	534	1529	1	9999	0
4	DC_INV1	765772	356	1330	1	9999	0
5	DC_INV2	765773	205	1252	1	9999	0
6	DC_INV1_P	None	534	1529	1	9999	0

Table 2-9 DC Link Parameters – Showing for Pole 1

DC Link	From DC Bus	From DC Name	To DC Bus	To DC Name	Id	Metered (From/To)	RDC (ohms)	LDC-Mh
1	1	DC_RECT	2	DC_RECT_P	1	1	0.02	500
2	2	DC_RECT_P	6	DC_INV1_P	1	1	9.134	0
3	6	DC_INV1_P	3	DC_INV2_P	1	1	3.619	0
4	3	DC_INV2_P	5	DC_INV2	1	1	0.02	500
5	6	DC_INV1_P	4	DC_INV1	1	1	0.02	500

2.3.2 Wind Turbine Generation Addition

2.3.2.1 Collector System Representation

At the time of the stability study, updated information was available regarding the possible wind generating plant locations. This section describes the updated collector system representation used for stability studies.

The collector system layout is preliminary and is based on analytical work performed by Clean Line to determine high-potential wind sites dictated by resource potential and environmental factors. Figure 2-7 shows the geographic locations where WTG could be developed that could access the GBX Project along with their corresponding sizes. It should be highlighted that this figure is neither final nor an exhaustive analysis of viable wind sites and was provided by Clean Line in order to simulate a potential collector system model.

Around 1,278 MW of potential generation are available within approximately 10 miles of the rectifier station. The other circles show other viable wind resource areas at farther distances from the rectifier station along with the associated potential megawatts within each area.

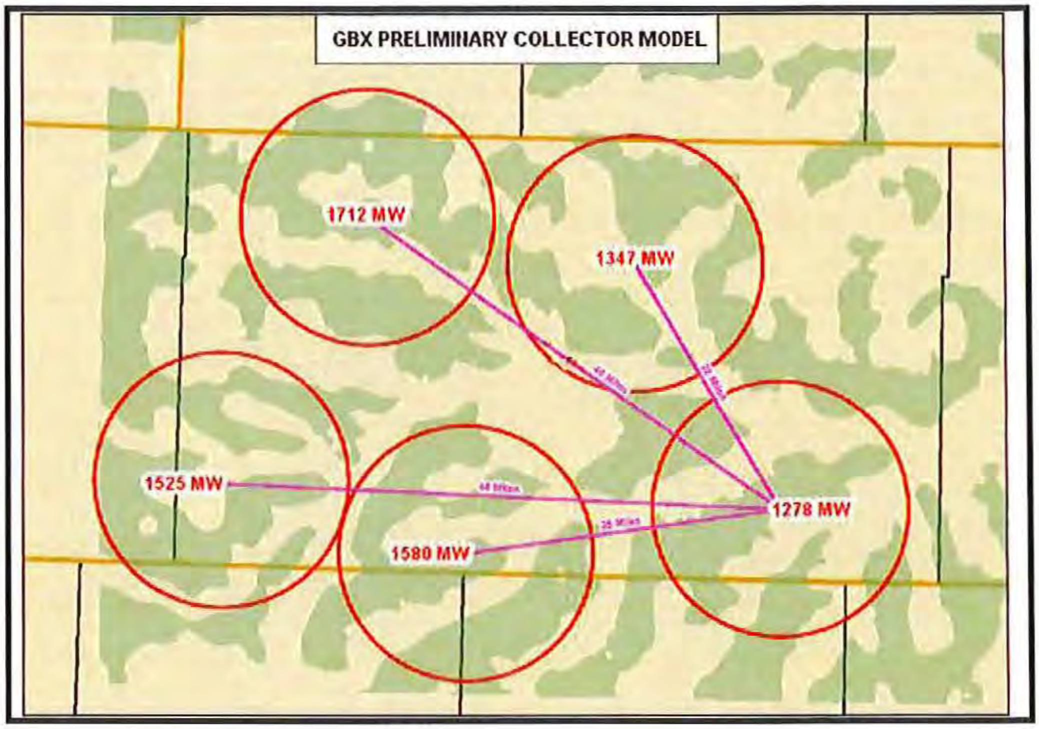

Figure 2-7: GBX Preliminary Draft Collector System – Potential Wind Locations

For the purposes of stability studies, Siemens PTI recommended modeling only Type 3 (doubly fed induction generators) and Type 4 (full converter) WTG's in each of the renewable resource areas. The developed model involves a 345 kV transmission network as a backbone to move power from the wind areas to the rectifier station. The transmission is gradually stepped down near the WTG to match its voltage level. Conceptually, Figure 2-8 shows the wind circles with a transmission system overlay comprised of 345 kV, 138 kV, 34.5 kV lines. The voltage levels of the Type 3 and Type 4 WTG's are also shown. The 345 kV transmission facilities from the rectifier station are assumed to have lengths of 1-mile, 20-miles and 40-miles depending on the location of the resources. The number and sizing of the transmission elements are chosen to provide a viable path for the WTG's under N-1 conditions to transfer maximum possible generation to the rectifier station.

Enough WTG was modeled in order to ensure that collector system and HVDC line and converter losses are accounted for with a resultant delivery of 3,000 MW to AEP and remaining 500 MW to AMMO, while maintaining close to zero flows across the interconnection between SPP and the GBX rectifier station.

Figure 2-9 shows the proposed collector system representation modeled in the 2017 Summer Peak case with the dispatched generation levels at three sites (1-mile, 20-mile, and 40-mile) for a total dispatched level of 3,756 MW.

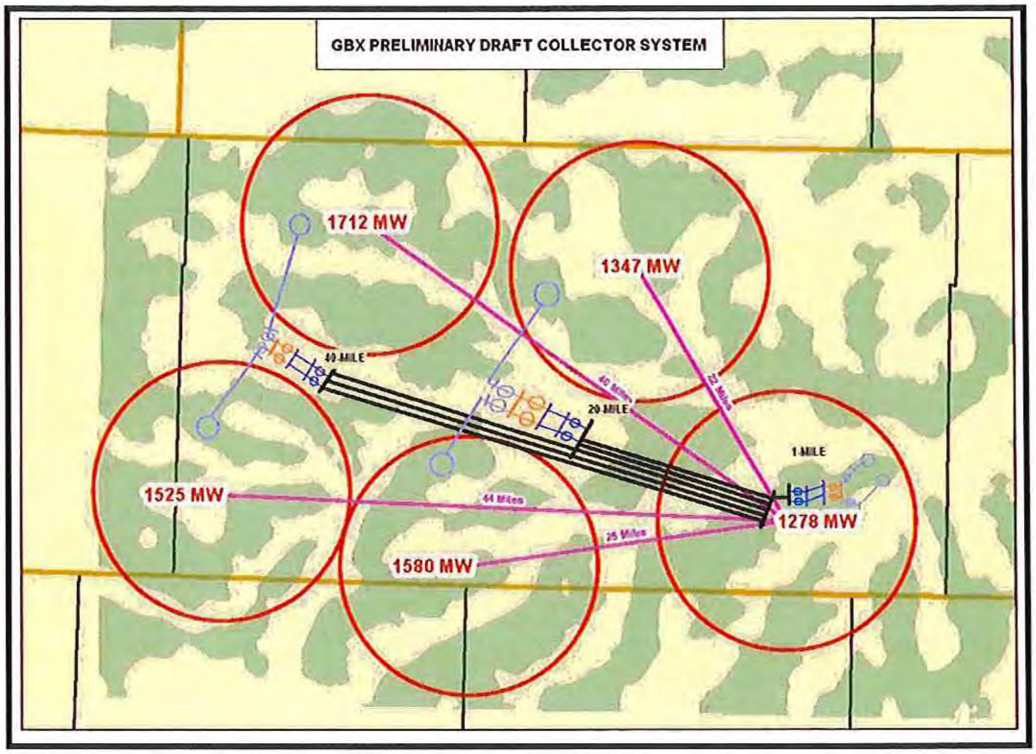

Figure 2-8: Proposed Collector System Representation for the Study

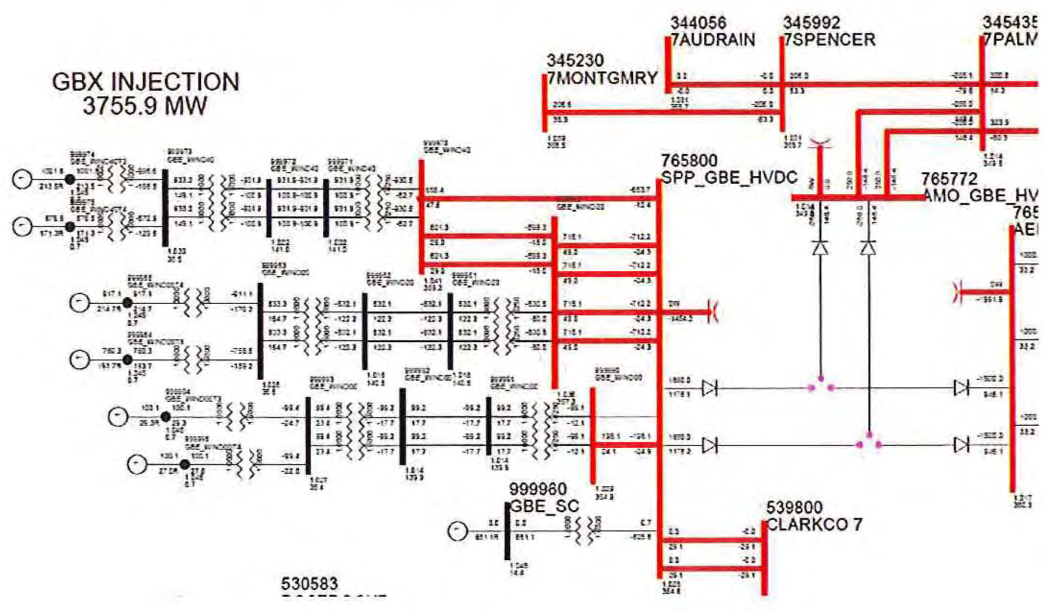

Figure 2-9: Proposed Collector System Modeled in 2017 Summer Peak Case

Table 2-10 shows the 345 kV line parameters used for the study. The 138 kV network is currently modeled using zero impedance lines, as it is typically the case in these studies where the actual location of the wind generation plants is unknown. Future interconnection studies for the individual wind plants, once they are identified, will incorporate detailed modeling of the 138 kV lines and equivalent 34.5 kV collector system, and will identify any additional requirements to ensure stable operation of the plants.

Table 2-11 shows the assumed ratings of collector system transformers used in the study.

Table 2-10: 345 kV Line Parameters

	R (pu)	X (pu)	B (pu)	MVA	Amp
1 mile	0.00003	0.00046	0.00940	1631	2729
20 mile	0.00059	0.00927	0.18584	1631	2729
40 mile	0.00118	0.01853	0.37168	1631	2729

Table 2-11: Assumed Ratings of Collector System Transformers

Site	T/F	MVA	Z (pu)	X/R
Site 1	345/138 kV	140	8%	35
1-mile	138/34.5 kV	140	8%	35
Site 2	345/138 kV	1288	8%	35
20-mile	138/34.5 kV	1288	8%	35
Site 3	345/138 kV	1396	8%	35
40-mile	138/34.5 kV	1396	8%	35

Table 2-12 shows the dispatched generation and the mix of WTG type at each site for the 2017 Summer Peak case. Similarly, Table 2-13 and Table 2-14 show totals for the 2017 Light Load and the 2022 Summer Peak cases, respectively. Two key points to be noted:

- Around 5% of the total generation is dispatched at Site 1, 45% of total generation is dispatched at Site 2 and 50% of total generation is dispatched at Site 3, thus there is a bias towards remote generation
- Though the mix of generation varies between individual sites, the total generation is split approximately 50% between Type 3 and Type 4 WTG's

Table 2-12: WTG at Each Site of the Proposed Collector System – 2017 Summer Peak

Pgen	Site 1	Site 2	Site 3	Total
MW	200	1677	1878	3756
% of Total	5%	45%	50%	100%
Distance	1 mile	20 miles	40 miles	

	Pgen	Site 1	Site 2	Site 3	Total
Type3	MW	100	760	1002	1862
Type4	MW	100	917	877	1894
Type3	%	50%	45%	53%	50%
Type4	%	50%	55%	47%	50%

Table 2-13: WTG at Each Site of the Proposed Collector System – 2017 Light Load

Pgen	Site 1	Site 2	Site 3	Total
MW	200	1677	1878	3756
% of Total	5%	45%	50%	100%
Distance	1 mile	20 miles	40 miles	

	Pgen	Site 1	Site 2	Site 3	Total
Type3	MW	100	760	1002	1862
Type4	MW	100	917	877	1894
Type3	%	50%	45%	53%	50%
Type4	%	50%	55%	47%	50%

Table 2-14: WTG at Each Site of the Proposed Collector System – 2022 Summer Peak

Pgen	Site 1	Site 2	Site 3	Total
MW	200	1677	1878	3756
% of Total	5%	45%	50%	100%
Distance	1 mile	20 miles	40 miles	

	Pgen	Site 1	Site 2	Site 3	Total
Type3	MW	100	760	1002	1862
Type4	MW	100	917	877	1894
Type3	%	50%	45%	53%	50%
Type4	%	50%	55%	47%	50%

2.3.2.2 Generation Type

The Type 3 doubly-fed induction generators (DFIG) and the Type 4 full-scale converter connected asynchronous generators are considered to represent the GBX Project wind turbine generation. The Type 3 generators are represented by an equivalent 1.5 MW GE wind turbine driven generator and the Type 4 generators are represented by an equivalent 2.5 MW GE wind turbine driven generator. The dynamic model parameters of these generators are shown in Appendix B.

The equivalent Type 3 and Type 4 WTG's were modeled at each site resulting in a total of 6 generators in load flow models as shown in Table 2-15, Table 2-16, and Table 2-17. The dispatched generation varies slightly among the three cases. It is assumed that around 95% of installed capacity (Pmax) is being dispatched. Table 2-18 shows the generator transformer data for Type 3 and Type 4 WTG.

Table 2-15: WTG Dispatch – 2017 Summer Peak Case

Bus	Type	# Units	Pgen	Pmax	Qmin	Qmax	Mbase	Pgen/Pmax
999974	3	701	1001.8	1052	-509	509	1171	95%
999975	4	368	876.6	920	-442	442	1104	95%
999984	3	532	760.3	798	-386	386	888	95%
999985	4	385	917.1	963	-462	462	1155	95%
999994	3	70	100.1	105	-51	51	117	95%
999995	4	42	100.1	105	-50	50	126	95%
			3755.9	**3942**			**4561**	

Table 2-16: WTG Dispatch – 2017 Light Load Case

Bus	Type	# Units	Pgen	Pmax	Qmin	Qmax	Mbase	Pgen/Pmax
999974	3	701	1001.8	1052	-509	509	1171	95%
999975	4	368	876.5	920	-442	442	1104	95%
999984	3	532	760.3	798	-386	386	888	95%
999985	4	385	917.1	963	-462	462	1155	95%
999994	3	70	100.1	105	-51	51	117	95%
999995	4	42	100.1	105	-50	50	126	95%
			3755.8	**3942**			**4561**	

Table 2-17: WTG Dispatch – 2022 Summer Peak Case

Bus	Type	# Units	Pgen	Pmax	Qmin	Qmax	Mbase	Pgen/Pmax
999974	3	701	1001.8	1052	-509	509	1171	95%
999975	4	368	876.6	920	-442	442	1104	95%
999984	3	532	760.3	798	-386	386	888	95%
999985	4	385	917.1	963	-462	462	1155	95%
999994	3	70	100.1	105	-51	51	117	95%
999995	4	42	100.1	105	-50	50	126	95%
			3755.9	**3942**			**4561**	

Table 2-18: Generator Transformer Data for each WTG type

	Unit MVA	Z (pu)	X/R
Type 3	1.75	5.75%	7.5
Type 4	2.8	6%	7.5

The project wind generation is injected into the GBX Project AC substation with a scheduled transfer of 3,500 MW through the three-terminal HVDC bi-pole link. The injected wind generation (approximately 3,756 MW) accounts for losses in the collector system, DC line losses, and losses in the converter stations such that exactly 3,000 MW (measured at inverter station) is being injected into the AEP balancing area and 500 MW (measured at inverter station) into AMMO balancing area. In order to balance the injected project generation, six balancing areas within PJM are considered for scaling down of generation such that 3,000 MW of project generation is being injected. Similarly, two balancing areas within MISO are considered for scaling down of generation in order to inject 500 MW of project generation.

Table 2-19 shows the generation scaling for 2017 Light Load condition. The PJM areas are scaled down by around 8.7% while the MISO areas are scaled down by around 5.9%, against their combined generation dispatch (Pgen). Table 2-20 and Table 2-21 show the generation scaling for 2017 Summer Peak and 2022 Summer Peak conditions, respectively.

Table 2-19 Selected Balancing Areas for Generation Scale Down – 2017 Light Load

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
201	AP	5378.9	4854.8
202	FE	5461.7	5093.1
205	AEP	9787.6	8960
209	DAY	1996.4	1956.9
215	DLCO	2228	2001.2
222	CE	9550.2	8583.9
		34402.8	31449.9
	3000	**8.7%**	

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
356	AMMO	3152.7	2968.7
357	AMIL	5384.9	5092.3
		8537.6	8061
	500	**5.9%**	

Table 2-20 Selected Balancing Areas for Generation Scale Down – 2017 Summer Peak

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
201	AP	9973	9601.5
202	FE	13675.2	13156.5
205	AEP	24159.7	23358
209	DAY	3761.3	3628.8
215	DLCO	3296.7	3173.5
222	CE	26083.8	25141.3
		80949.7	78059.6
	3000	**3.7%**	

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
356	AMMO	9136.2	8926
357	AMIL	11703.3	11455.8
		20839.5	20381.8
	500	**2.4%**	

Table 2-21 Selected Balancing Areas for Generation Scale Down – 2022 Summer Peak

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
201	AP	10345.1	9977.3
202	FE	13557.7	13065.7
205	AEP	25117.7	24326.7
209	DAY	4067.8	3930.6
215	DLCO	3322.8	3204.3
222	CE	28123.4	27149.7
		84534.5	81654.3
	3000	**3.5%**	

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
356	AMMO	9574.3	9363.2
357	AMIL	12044.2	11798.5
		21618.5	21161.7
	500	**2.3%**	

Figure 2-10 shows the final topology with the GBX project modeled in the 2017 Sumer Peak Case.

Figure 2-11 and Figure 2-12 show the similar representation for 2017 Light Load and 2022 Summer Peak cases, respectively. This final configuration includes a 900 MVAr synchronous condenser that displaces an equal amount of static reactive compensation at the Clark County 345 kV substation, as discussed in this report.

The dynamic model parameters of the HVDC line and WTG are presented in Appendix B.

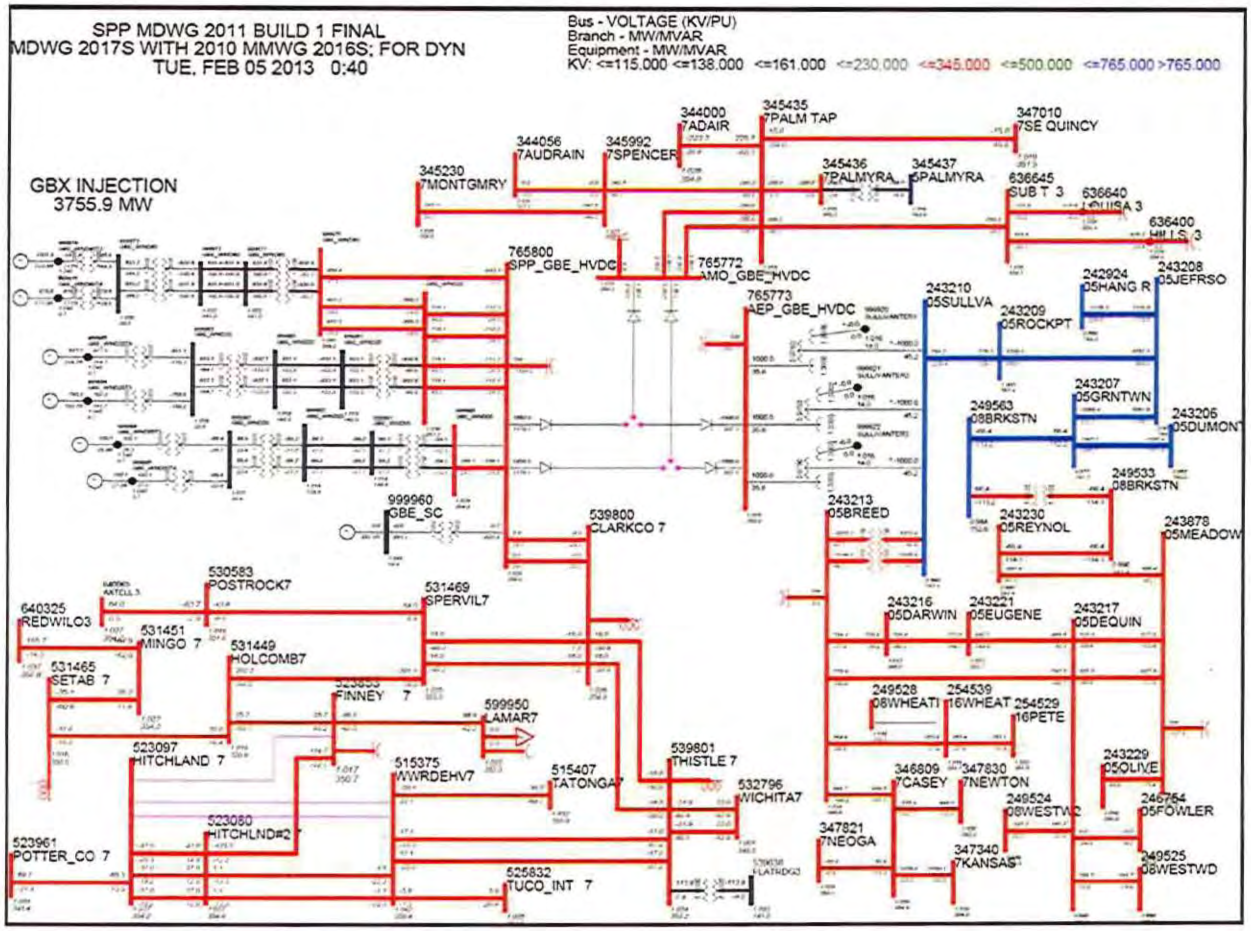

Figure 2-10: 2017 Summer Peak – Topology with GBX Project

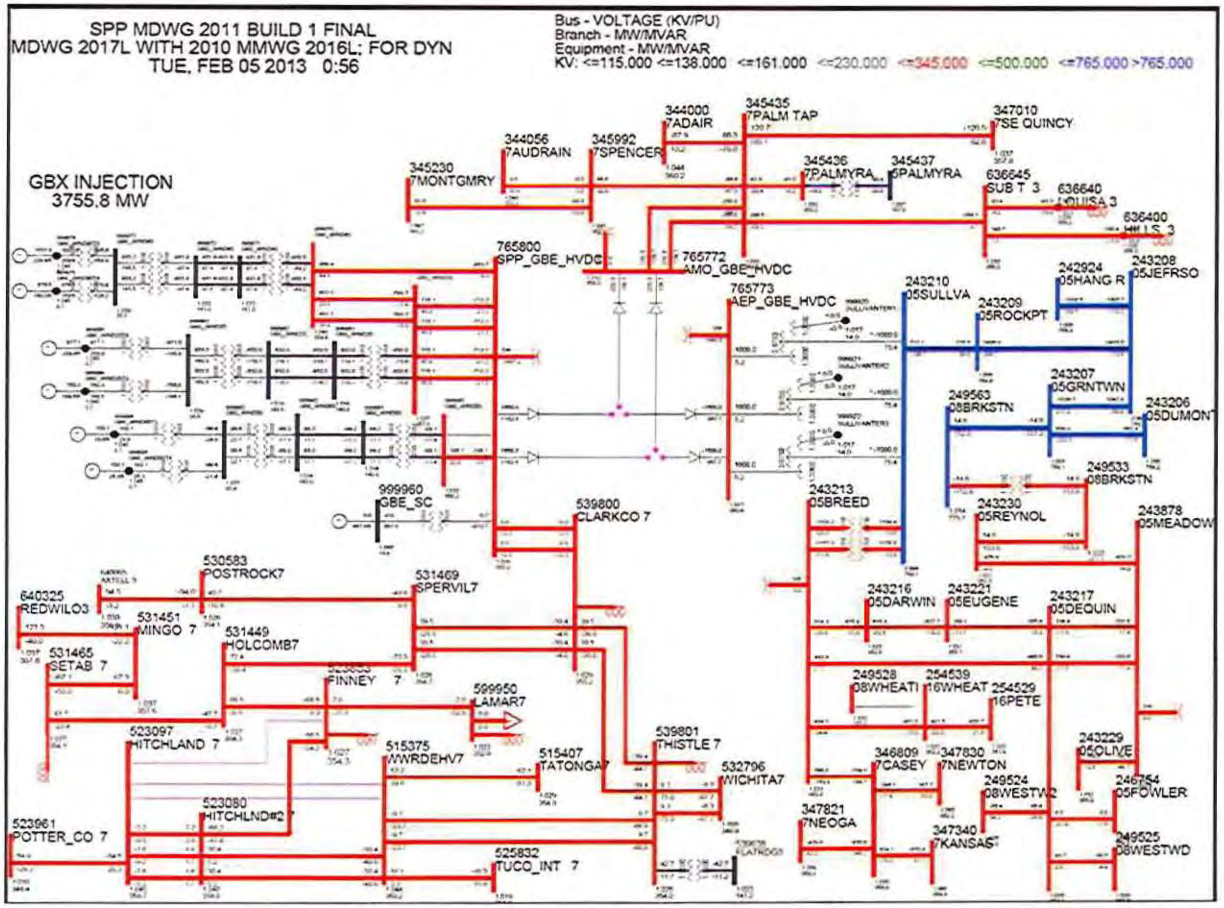

Figure 2-11: 2017 Light Load – Topology with GBX Project

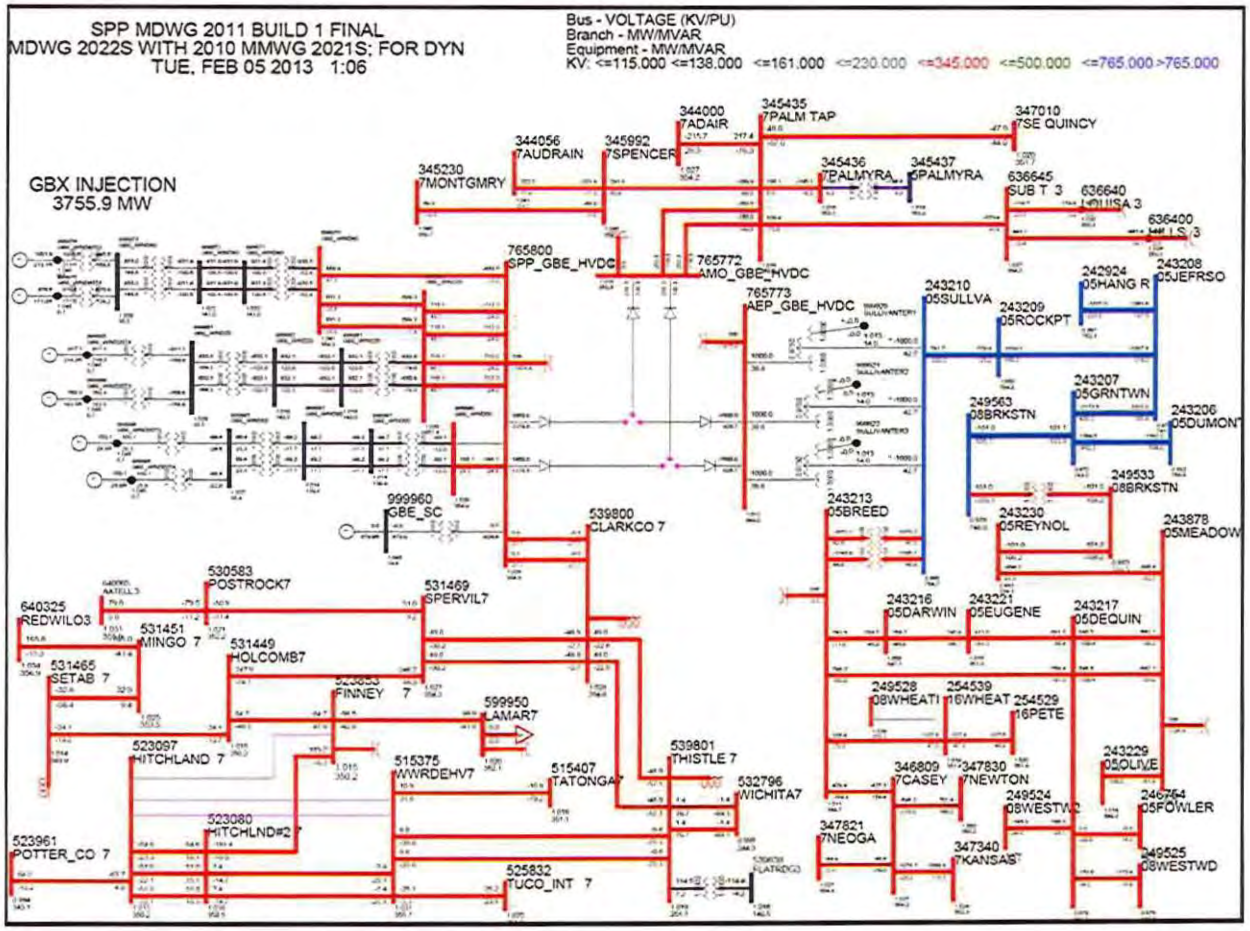

Figure 2-12: 2022 Summer Peak – Topology with GBX Project

Section

3

Study Methodology

This section presents the methodology and assumptions used for the stability study followed by the performance criteria used in the assessment of the dynamic behavior of the GBX Project for selected disturbances in its vicinity.

3.1 Assumptions

The following assumptions were used for this study:

- The dynamic simulations were performed using PSS®E Revision 30
- The 2011 Build 1 Stability Package provided by SPP was used for all simulations
- One quarter of a system cycle (0.004167 sec) was used as the time step in all simulations
- All simulations were run for 10 seconds
- Major generating units electrically close to the location where disturbances were applied (approximately up to 10 buses) were monitored for dynamic performance of the study area[11]. In particular,
  - Terminal voltages and rotor angles were monitored for all synchronous generating units in areas listed in Table 3-1
  - For other areas not shown in the table (e.g. AEP, AMMO), selected generating units listed in Table 3-2 and Table 3-3 were added for monitoring their terminal voltages and rotor angles

Table 3-1: Areas Including all Synchronous Units for Monitoring

AREA	NAME	AREA	NAME
523	GRDA	540	GMO
524	OKGE	541	KCPL
526	SPS	542	KACY
531	MIDW	640	NPPD
534	SUNC	330	AECI
536	WERE	351	EES

[11] Assumption is that if none of the units at this electrical distance from the selected disturbance location loses synchronism with SPP system then no other generating units located beyond this point will lose synchronism

Table 3-2: Other Units included for Monitoring – Around Palmyra

Location	Units included for monitroing	Area
Audrain	Units at 344061, 344062, 344063	356 AMMO
Callaway	Unit at 344225	356 AMMO
Kinmundy	Unit at 344876	356 AMMO
Labody	Units at 344894, 344895	356 AMMO
Meramad	Units at 345132, 345156	356 AMMO
Osage	Unit at 345400	356 AMMO
Peno Creek	Units at 345441	356 AMMO
Rush Island	Unit at 345670	356 AMMO
Sioux	Units at 345756, 345765	356 AMMO
Venice	Unit at 345882	356 AMMO
Raccoon Ck	Unit at 345994	356 AMMO
Goose Creek	Unit at 345998	356 AMMO
Keokuk	Unit at 344863	356 AMMO
Alsey	Unit at 346516	357 AMIL
Avena	Unit at 346573	357 AMIL
Coffeen	Unit at 346897	357 AMIL
Gibson City	Unit at 347112	357 AMIL
Grand Tower	Unit at 347170	357 AMIL
Holland Energy	Unit at 347231	357 AMIL
Hutsonville	Unit at 347271	357 AMIL
RELU	Unit at 347819	357 AMIL
Newton	Units at 347832	357 AMIL
Clinton	Unit at 349101	357 AMIL
Vermilion	Unit at 349109	357 AMIL
WoodRiver	Unit at 349115	357 AMIL
Havana	Unit at 349121	357 AMIL
Tilton	Unit at 349122	357 AMIL
Baldwin	Unit at 349126	357 AMIL
Prairie State	Unit at 349129	357 AMIL
Edwards	Unit at 349632	357 AMIL
Duck Ck	Unit at 349633	357 AMIL
Railsplitter	Unit at 349724	357 AMIL

Table 3-3 Other Units Included for Monitoring – Around Sullivan

Location	Units included for monitroing	Area
Rockport	Units at 243442, 243443	205 AEP
Petersburg	Units at 254811-254814	216 IPL
Gibson	Units at 251861-251865	208 DEM
Wheatland	Units at 251897-251900	208 DEM
Merom	Units at 248773	207 HE
Clifty Ck	Units at 248000	206 OVEC
Trimble Co	Units at 324034 - 324041	363 LGEE
Cayuga	Units at 251849, 251850	208 DEM
Amos	Units at 242891 - 242893	205 AEP
Mountaineer	Units at 242894	205 AEP
Mitchel	Units at 243188, 243189	205 AEP
Muskingum	Unit at 242940	205 AEP
Lawrenceburg	Units at 243226	205 AEP
Tanner	Unit at 243233	205 AEP
Cook	Units at 243440, 243441	205 AEP
Conesville	Unit at 243622	205 AEP
Bigsandy	Units at 243763, 243764	205 AEP
Killen	Unit at 253038	209 DAY
Stuart	Unit at 253077	209 DAY

3.2 Fault Definitions

In general, the following faults were tested to assess the dynamic performance of generating units in the study area:

- Three-phase (3ph) bolted faults with normal clearing time and outage of faulted line
- Primary protection failure – Single Line to Ground (SLG) faults with delayed clearing time and outage of the faulted line
- Stuck breaker – Single Line to Ground (SLG) faults with delayed clearing time and outage of faulted line along with other lines as required

In particular, faults tested at the HVDC converter stations include:

- Three-phase bolted fault at 345 kV rectifier and inverter stations
  - Cleared in normal time (manual unblocking of both poles during simulation)
  - Cleared in normal time followed by single pole unblocking (manual unblocking during simulation)
  - Cleared in normal time followed by both poles blocked
- SLG fault with delayed clearing time (stuck breaker)

The fault clearing times for different types of faults and voltage levels are shown in Table 3-4. Note that the line reclosing sequence was not considered in fault definitions. The MTDC1T HVDC model was used to represent the GBX three-terminal HVDC line in all dynamic simulations. This model is a well-tested PSS®E table driven model. The model provides the flexibility of manual unblocking of the pole by changing the model ICONs. Please refer to PSS®E manual for additional details of the model.

Table 3-4: Fault Clearing Times

Type	Description	500 kV and above (Cycles)	345 kV and below (Cycles)
3PH	3ph, Normal clearing	4	5
SLG	SLG, delayed due to protection failure	13	16
SLG	SLG, delayed due to breaker failure	13	16

The fault sequence for 3ph faults cleared in normal time is carried out as:

- Three-phase bolted fault applied at bus terminal
- Fault is cleared in 4 or 5 cycles depending on voltage (refer to Table 3-4) and followed by tripping of the faulted line

The fault sequence for SLG faults cleared in delayed time due to primary system protection failure is carried out as:

- SLG fault applied at bus terminal
- Fault is cleared after 13 or 16 cycles depending on voltage (refer to Table 3-4) followed by tripping of the faulted line

The fault sequence for SLG faults cleared in delayed time due to a stuck breaker is carried out as:

- SLG fault applied at bus terminal
- Fault is cleared after 13 or 16 cycles depending on voltage (Table 3-4) followed by tripping the faulted line and any other lines as required

Table 3-5 shows a list of all studied three-phase faults with normal clearing. Table 3-6 shows all SLG faults (protection failure) considered in the study.

Table 3-5: List of Three-phase Faults – Normal Clearing

3 Phase Faults, Normal Clearing			
No	Type	Description	kV
1	3ph, both poles blocked	At Clark Co 765800, both poles are blocked	345
2	3ph, single pole recovery	At Clark Co 765800, one pole is recovered	345
3	3ph, both poles recovery	At Clark Co 765800, both poles are recovered	345
4	3ph, both poles blocked	At Sullivan 765773, both poles are blocked	345
5	3ph, single pole recovery	At Sullivan 765773, one pole is recovered	345
6	3ph, both poles recovery	At Sullivan 765773, both poles are recovered	345
7	3ph, both poles blocked	At Palmyra 765772, both poles are blocked	345
8	3ph, single pole recovery	At Palmyra 765772, one pole is recovered	345
9	3ph, both poles recovery	At Palmyra 765772, both poles are recovered	345
10	3ph, single pole recovery	the Palmyra inverter of the recovered pole is still	345
11	3ph, normal clearing	Clarck Co 539800 - Thistle 539801	345
12	3ph, normal clearing	Clark Co 539800 - Spearville 531469	345
13	3ph, normal clearing	Thistle 539801 - Witchita 532796	345
14	3ph, normal clearing	Thistle 539801 - Woodward 515375	345
15	3ph, normal clearing	Woodward 515375 - Tatonga 515407	345
16	3ph, normal clearing	Spearville 531469 - Holcomb 531449	345
17	3ph, normal clearing	Spearville 531469 - Postrock 530583	345
18	3ph, normal clearing	Spearville 345/230 kV TF (531469 - 539695)	345/230
19	3ph, normal clearing	Spearville 539695 - Mulgreen 539679	230
20	3ph, normal clearing	Postrock 530583 - Axtell 640065	345
21	3ph, normal clearing	Holcomb 531449 - Finney 523853	345
22	3ph, normal clearing	Holcomb 531449 - Setab 531465	345
23	3ph, normal clearing	Finney 523853 - Hitchland 523080	345
24	3ph, normal clearing	Finney 523853 - Lamar 599950	345
25	3ph, normal clearing	Setab 531465 - Mingo 531451	345
26	3ph, normal clearing	Mingo 531451 - Redwillow 640325	345
27	3ph, normal clearing	Sullivan 3wnd TF (243210-765773-999920)	765/345
28	3ph, normal clearing	Sullivan 765/345 kV TF (243210 - 243213)	765/345
29	3ph, normal clearing	Sullivan 243210 - Rockport 243209	765
30	3ph, normal clearing	Breed 243213 - Casey 346809	345
31	3ph, normal clearing	Breed 243213 - Darwin 243216	345
32	3ph, normal clearing	Breed 243213 - Dequine 243217	345
33	3ph, normal clearing	Breed 243213 - Wheat 254539	345
34	3ph, normal clearing	Rockport 243209 - Jefferson 243208	765
35	3ph, normal clearing	Palmyra 765772 - Palmyra tap 345435	345
36	3ph, normal clearing	Palmyra Tap 345435 - Sub T 636645	345
37	3ph, normal clearing	Palmyra Tap 345435 - Plamyra 345436	345
38	3ph, normal clearing	Palmyra Tap 345435 - Adair 344000	345
39	3ph, normal clearing	Palmyra Tap 345435 - Spencer 345992	345
40	3ph, normal clearing	Palmyra Tap 345435 - Se Quincy 347010	345

Table 3-6: List of SLG Faults – Protection Failure

SLG Faults Delayed Clearing (Protection Failure)			
No	Type	Description	kV
41	SLG, delayed clearing	Clarck Co 539800 - Thistle 539801	345
42	SLG, delayed clearing	Clark Co 539800 - Spearville 531469	345
43	SLG, delayed clearing	Thistle 539801 - Witchita 532796	345
44	SLG, delayed clearing	Thistle 539801 - Woodward 515375	345
45	SLG, delayed clearing	Woodward 515375 - Tatonga 515407	345
46	SLG, delayed clearing	Spearville 531469 - Holcomb 531449	345
47	SLG, delayed clearing	Spearville 531469 - Postrock 530583	345
48	SLG, delayed clearing	Spearville 345/230 kV TF (531469 - 539695)	345/230
49	SLG, delayed clearing	Spearville 539695 - Mulgreen 539679	230
50	SLG, delayed clearing	Postrock 530583 - Axtell 640065	345
51	SLG, delayed clearing	Holcomb 531449 - Finney 523853	345
52	SLG, delayed clearing	Holcomb 531449 - Setab 531465	345
53	SLG, delayed clearing	Finney 523853 - Hitchland 523080	345
54	SLG, delayed clearing	Finney 523853 - Lamar 599950	345
55	SLG, delayed clearing	Setab 531465 - Mingo 531451	345
56	SLG, delayed clearing	Mingo 531451 - Redwillow 640325	345
57	SLG, delayed clearing	Sullivan 3wnd TF (243210-765773-999920)	765/345
58	SLG, delayed clearing	Sullivan 765/345 kV TF (243210 - 243213)	765/345
59	SLG, delayed clearing	Sullivan 243210 - Rockport 243209	765
60	SLG, delayed clearing	Breed 243213 - Casey 346809	345
61	SLG, delayed clearing	Breed 243213 - Darwin 243216	345
62	SLG, delayed clearing	Breed 243213 - Dequine 243217	345
63	SLG, delayed clearing	Breed 243213 - Wheat 254539	345
64	SLG, delayed clearing	Rockport 243209 - Jefferson 243208	765
65	SLG, delayed clearing	Palmyra 765772 - Palmyra tap 345435	345
66	SLG, delayed clearing	Palmyra Tap 345435 - Sub T 636645	345
67	SLG, delayed clearing	Palmyra Tap 345435 - Plamyra 345436	345
68	SLG, delayed clearing	Palmyra Tap 345435 - Adair 344000	345
69	SLG, delayed clearing	Palmyra Tap 345435 - Spencer 345992	345
70	SLG, delayed clearing	Palmyra Tap 345435 - Se Quincy 347010	345

The stuck breaker faults are considered only at three substations as listed in Table 3-7. The breaker arrangements at the converter stations were not yet defined at the time of the study therefore, Siemens PTI defined these stuck breaker faults based on technical judgment as described below.

Table 3-7: List of SLG Faults – Stuck Breaker

SLG Fault, Delayed Clearing (Stuck Breaker)			
No	Type	Description	kV
71	SLG, delayed clearing	Fault at Rectifier, block the pole and trip line to collector system	345
72	SLG, delayed clearing	Fault at Sullivan, trip 3wnd and 2wnd transformers	765/345
73	SLG, delayed clearing	Fault at Palmyra Tap, trip lines to inverter station and to Palmyra	345

At Rectifier 345 kV substation

Figure 3-1 shows the assumed breaker and half representation shared by the HVDC line and the WTG projects. For a SLG fault on the line very close to the substation, the bus breaker (B3) operates in 5 cycles to try to clear the fault and the HVDC protection blocks the pole. The middle breaker (B2) is stuck thus the backup protection operates in 11 cycles to isolate the fault by tripping the line to the collector system of WTG. The total fault duration is 16 cycles. Note that this arrangement prevents a single stuck breaker from tripping both poles.

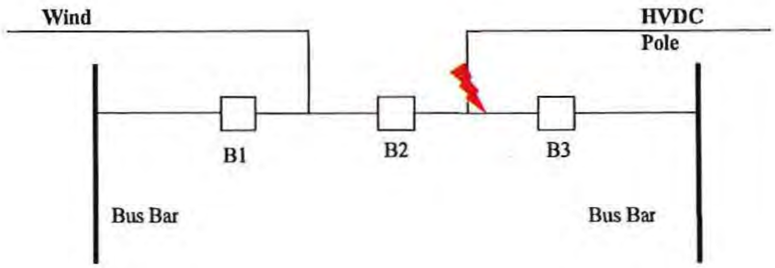

Figure 3-1: Assumed Breaker Arrangement at Rectifier Station

At Sullivan 765 kV substation:

Figure 3-2 shows the assumed breaker and half representation shared by the 3-winding transformer connected to the inverter station and 2-winding transformer connected to Breed 345 kV station. For a SLG fault near the 3-winding transformer, the bus breaker (B1) operates in 4 cycles to try to clear the fault. The middle breaker (B2) is stuck thus the backup protection operates in 9 cycles to isolate the fault by tripping the 2-winding transformer connected to Breed. The total fault duration is 13 cycles.

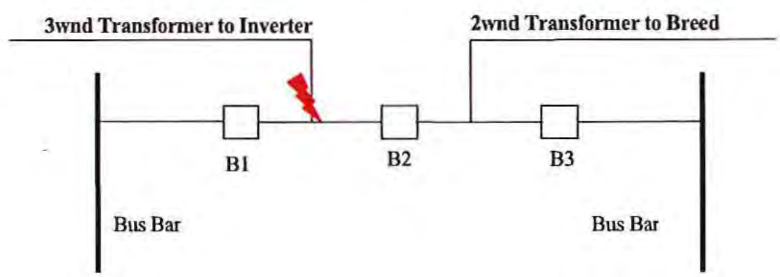

Figure 3-2: Assumed Breaker Arrangement at Sullivan 765 kV Station

At Palmyra Tap 345 kV substation:

Figure 3-3 shows the assumed breaker and half representation shared by the line connected to the HVDC inverter station and the line to Palmyra substation. For a SLG fault on the line very close to the substation as shown in the figure, the bus breaker (B1) operates in 5 cycles to try to clear the fault. The middle breaker (B2) is stuck thus the backup protection operates in 11 cycles to isolate the fault by tripping the line connected to Palmyra. The total fault duration is 16 cycles.

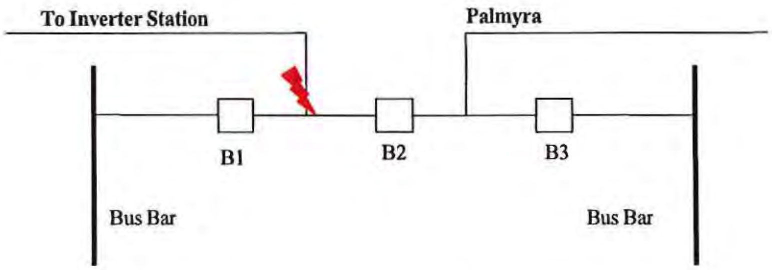

Figure 3-3: Assumed Breaker Arrangement at Palmyra Tap 345 KV Station

3.2.1 Quick Reactor Switching (QRS) at Rockport

The existing Quick Reactor Switching (QRS) scheme was modeled for faults at Rockport that involves tripping of Rockport – Jefferson 765 kV line (FLT#34 and FLT#64). As per the actual language from PJM's Transmission Operations Manual 3, the QRS is described as below:

"Quick Reactor Switching (QRS) – The 765 kV Rockport–Sullivan 150 MVAR shunt reactor bank at Rockport automatically opens within 5 cycles and recloses in 1 minute for contingencies on the Rockport – Jefferson 765 kV line. This works in conjunction with the Fast Valving scheme to improve voltage and stability after select contingencies."

In this study, the Rockport reactors and the Rockport – Jefferson 765 kV line were disconnected at the same time, i.e. in 4 cycles for 3ph faults and 13 cycles for SLG faults measured from the fault inception time.

3.2.2 Fast Valve Control Action at Rockport Plant

Siemens PTI was aware of the fast valve control action at Rockport plant, but it was not utilized in this study. The intention is to evaluate the GBX Project performance in the absence of the fast valve control at Rockport plant. The dynamic model of the Rockport units does not simulate the fast valve control action of the speed governor associated with these units. It is our anticipation that simulating the fast valve control action at Rockport units would help rotor angle stability and voltage recovery further.

3.3 Equivalent Fault Admittance Values for SLG Faults

In order to simulate SLG faults, equivalent fault admittances representing the negative and zero sequence networks as seen from the fault location ($1/[Z_0+Z_2]$) are required. These fault admittance values were provided by SPP, MISO and PJM, and are shown in Table 3-8, Table 3-9 and Table 3-10, respectively.

Table 3-8: Fault Admittance Values on SPP Side[12]

Bus	Substation	Fault Admt (MVA)
765800	Rectifier 345 kV	129.64-j3057
539800	Clark Co 345 kV	129.64-j3057
523853	Finney 345 kV	229.27-j3013.33
531449	Holcomb 345 kV	212.32-j3113.02
531451	Mingo 345 kV	130.09-j1151.86
530583	Postrock 345 kV	213.89-j2100.5
531465	Setab 345 kV	156.14-j1530.21
531469	Spearville 345 kV	266.24-j3244.89
539695	Spearville 230 kV	168.83-j2594.27
539801	Thistle 345 kV	447.72-j2322.42
515375	Woodward 345 kV	425.64-j2792.85

Table 3-9: Fault Admittance Values on MISO Side

Bus	Substation	Fault Admt (MVA)
344056	Montegomery 345 kV	1013.78 -j 5071.61
345992	Spencer Ck 345 kV	396.96 j 3724.16
345230	Audrain 345 kV	396.96 j 3724.16
345435	Palmyra Tap 345 kV	554.76 -j 3067.22
765772	Palmyra 345 kV	499.53 -j 2771.19

Table 3-10 Fault Admittance Values on PJM Side

Bus	Substation	Fault Admt (MVA)
243210	Sullivan 765 kV	560.85 -j 7054.15
243209	Rockport 765 kV	400.917 -j11751.02
243213	Breed 345 kV	744.02 -j 7838.9

3.4 Dynamic Stability Performance Criteria

The following criteria were used in evaluating the study area dynamic performance for the selected disturbances:

- Voltage dip should not exceed more than 25% of nominal voltage or not below 0.75 pu. SPP currently does not have a criteria in this respect but we understand that one is under study and the assumptions above are normally accepted (e.g. WECC.)
- Post disturbance voltages should stay within acceptable operating limits (within +5% and -10% of nominal voltage)
- Generating units within the study area should remain in synchronous operation following clearing of the fault
  - This is ensured by well damped rotor angle and electric power dynamic responses

[12] Admittances are expressed in MVA calculated as the per unit value x 100 MVA.

- System frequency deviation immediately following the inception of a fault is within under frequency load-shedding protection and prime mover limits

Whenever a particular disturbance results in loss of synchronism of a generating unit and/or post-disturbance transmission system voltages are below acceptable limits in the study area, one of the following techniques (or a combination) is studied as a potential solution to resolve the issue:

- Reduction of the fault clearing time
- Provide additional dynamic reactive support, as required
- Additional measures such as special protection schemes (SPS), with the assistance of affected parties, as necessary

Section

4

Stability Analysis Results

The GBX project was modeled in all three scenarios provided by SPP. The stability packages were updated for each case that was used in the dynamic simulations. Response files were created for the selected disturbances to automate the simulation process.

Initialization of all three cases provided the following dynamic model initialization issues:

- Vestas machines at buses 639579, 639698 and 693722 showed warnings related to a mismatch between Pmax and Mbase. For these units, the Mbase was replaced with Pmax to remove these warnings

- A CBEST model at bus 401080 showed a warning related to a mismatch between Xsource in the load flow case and the dynamic data. The value in the load flow case was changed to match its counterpart in the dynamic data file

After modifying the load flow cases with the above changes, a no-fault (flat run) was performed to ensure numerical stability in the integration process used in the dynamic simulation. A successful run was obtained for all three scenarios. Following these flat runs, dynamic simulations for all selected faults were tested to assess the dynamic performance of the GBX Project and all generating units in the study area. The next section presents the stability analysis results for each scenario.

4.1 2017 Summer Peak Case Results

4.1.1 Three Phase Faults

The 3ph stability analysis results identified the following key faults that pose significant stress on the system:

- Fault # 29 – 3ph fault at Sullivan and cleared by tripping the 765 kV line to Rockport

- Fault # 34 – 3ph fault at Rockport and cleared by tripping the 765 kV line to Jefferson

Fault # 29

During the steady state analysis of the GBX Project, we identified that Fault # 29 was a severe fault and requires additional reactive support. However, this fault showed stable performance during the dynamic analysis as the HVDC controls adjust their angles to minimum values to provide the required reactive support. It is important to note that this additional support obtained through the HVDC controls is just enough to maintain the system voltages to meet the performance criteria as shown in Figure 4-1. We consider this fault as severe, but the corresponding dynamic performance of the study area is acceptable. Later in this report, it is shown that the GBX Project 345 kV connection at Sullivan provides better voltage performance for the same fault.

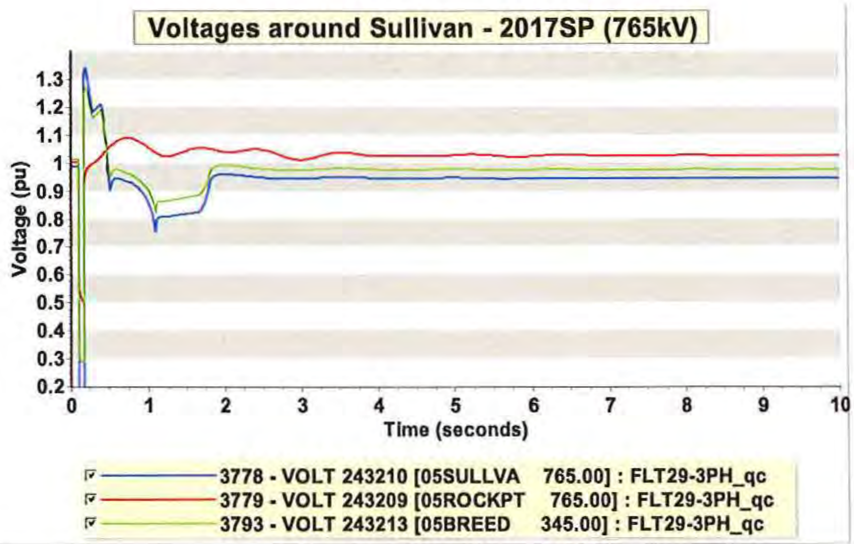

Figure 4-1: Voltages around Sullivan – Fault # 29

Fault # 34

For this particular fault, all on-line generating units at the Rockport plant were tripped by the out-of-step protection associated with these units as they have stepped out of synchronism with the system. In addition to the GBX Project generation of 3,000 MW, around 2,600 MW of generation at the Rockport plant is now pushed back in to the Sullivan 765 kV substation and onto the underlying 345 kV network at Breed substation. Due to this severe stress on the system, bus voltages within the vicinity of Sullivan substation are not able to recover immediately after clearing the fault. The Rockport units are tripped at around 1.25 seconds time and following this the system voltages recover as shown in Figure 4-2. Note that the tripping of Rockport units does not have an adverse impact on rotor angle stability of the system and the balance of the monitored units within the study area remained in synchronism.

As a mitigation scheme, one pole of the multi-terminal HVDC line is blocked immediately after clearing the fault thus limiting the GBX Project injection into Sullivan substation to 1,500 MW. Note that the remaining 1,500 MW of GBX Project generation will flow into the SPP system at the rectifier station. While blocking the pole, two options are explored as described below:

1. The capacitor banks at Sullivan inverter station are reduced by half in size. In this case, it is observed that the Rockport units tripped at 2 seconds which is not a desired performance. Figure 4-3 shows the corresponding voltage performance around Sullivan area

2. The capacitor banks at Sullivan Inverter station are allowed to operate at their full capacity[13]. It is noted that Rockport units did not trip in this case and the corresponding voltage performance is shown in Figure 4-4. The voltage dip is about 17.8% (measured voltage of 0.822 pu) and meets the voltage performance criteria

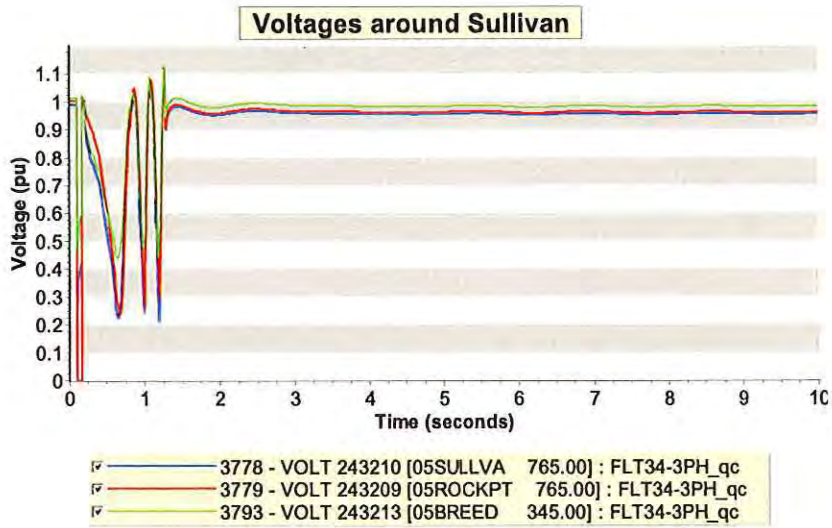

Figure 4-2: Voltages around Sullivan – Fault # 34

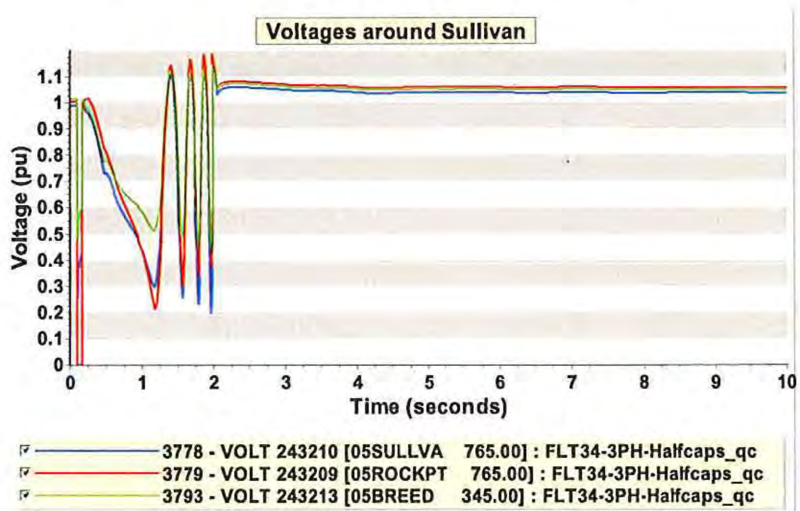

Figure 4-3: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 34

[13] The idea of not following the pole outage with tripping of shunt capacitors is a practical approach unless over voltages are observed, which is not the case for the fault under consideration. Hence leaving the full compensation is justifiable.

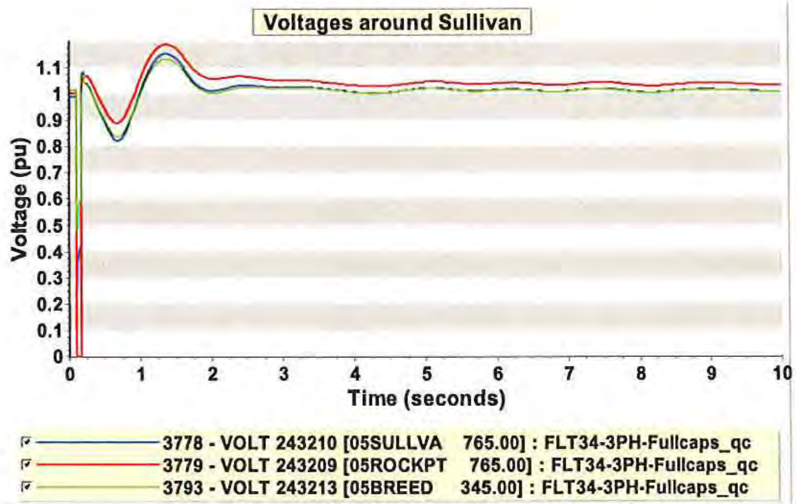

Figure 4-4: Voltages around Sullivan with One pole Blocked (Full Cap Banks) – Fault # 34

4.1.2 SLG Faults – Protection Failure

All SLG faults (protection failure) showed stable dynamic performance of the study area, except for Fault # 64 which is a SLG fault at Rockport 765 kV substation and is cleared by tripping the 765 kV line to Jefferson substation. Similar to the 3ph fault (Fault # 34), all on-line generating units at Rockport plant were tripped by the out-of-step protection associated with these units as they have stepped out of synchronism with the system. The bus voltages within the vicinity of Sullivan substation are not able to recover immediately after clearing the fault, but as shown in Figure 4-5, the voltages started recovering after the Rockport units are tripped at around 1.45 seconds.

As a mitigation scheme, one pole of the multi-terminal HVDC line is blocked immediately after clearing the fault; thus, the GBX injection into Sullivan is limited to 1,500 MW. The remaining 1,500 MW of GBX Project generation will flow into the SPP system.

Figure 4-6 shows the voltage performance while the pole is blocked and capacitor banks at Sullivan inverter are reduced by half in size. The Rockport units did not trip and the system voltages recovered. However, the observed voltage dip is about 27.9% (measured voltage of 0.721 pu) which is not acceptable as per the proposed performance criteria of 25%.

Figure 4-7 shows the voltage performance while one pole is blocked with the capacitor banks at Sullivan inverter operating at their full capacity. The Rockport units did not trip and the voltages around Sullivan are smoothly recovered after clearing the fault. The observed voltage dip is about 8% (observed voltage of 0.92 pu).

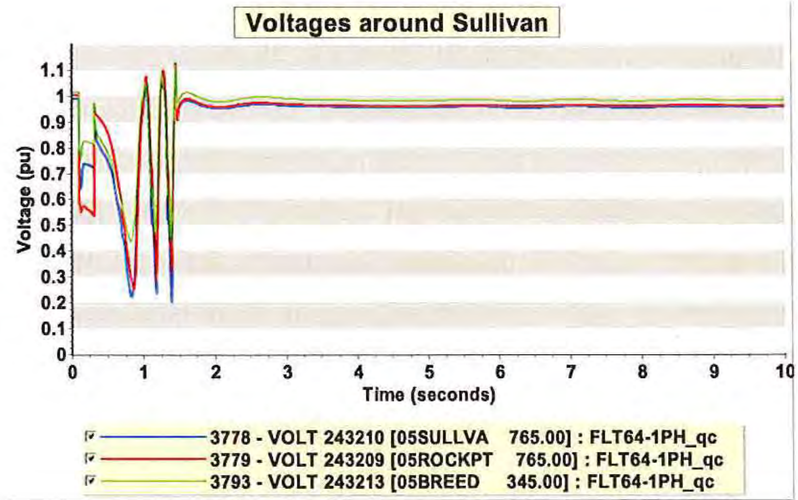

Figure 4-5: Voltages around Sullivan – Fault # 64

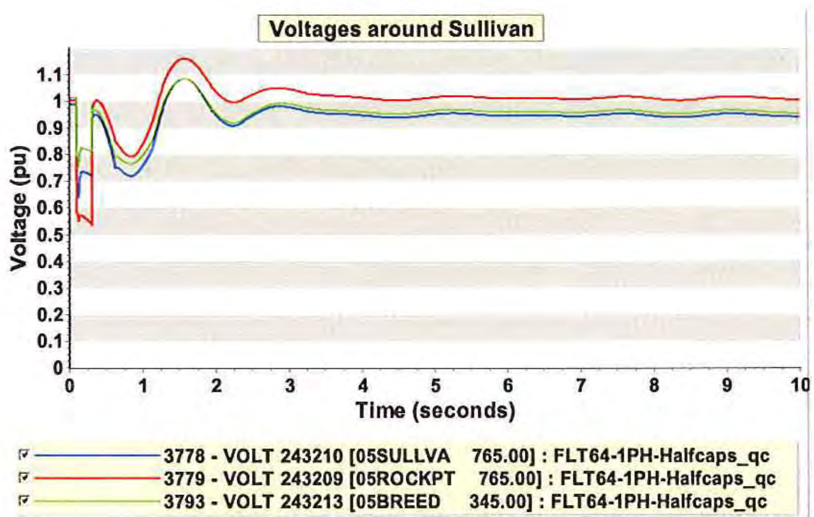

Figure 4-6: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 64

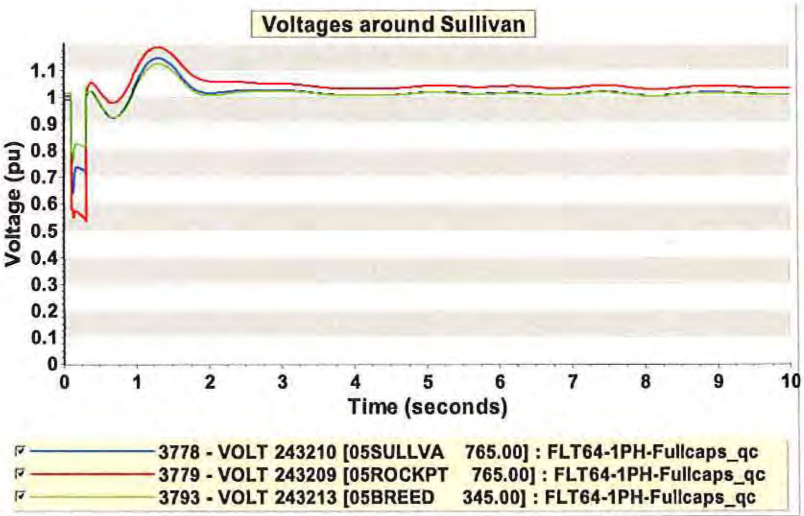

Figure 4-7: Voltages around Sullivan with One Pole Blocked (Full Cap Banks) – Fault # 64

4.1.3 SLG Faults – Stuck Breaker

The study area showed stable performance for the selected SLG faults (stuck breaker).

4.1.4 Observations

Appendix C shows the 2017 Summer Peak stability analysis plots for both 3ph and SLG faults. The following are the key observations of the stability analysis:

- The 3ph fault at Sullivan that involves tripping of Sullivan–Rockport 765 kV lines appears to be severe but the study area is stable
- Faults at Rockport that involve tripping of the Rockport–Jefferson 765 kV line are considered as critical faults. These faults require the GBX Project injection into Sullivan to be reduced while maintaining full shunt reactive compensation capability at converter stations
  - In this study, we reduced the GBX injection into Sullivan to 1,500 MW by blocking one pole of the HVDC line. The remaining GBX Project generation is allowed to sink into the SPP system
  - Though it was not tested in this study, we believe that the actual GBX injection into Sullivan could be higher than 1,500 MW

Further, Table 4-1 shows the list of units tripped due to under-frequency relay action for almost all tested faults. Testing these faults on the pre-project case revealed that these same units were also tripping due to the same under-frequency relay action and thus the GBX project is not the cause of tripping. Similar behavior was observed during the stability study of the Plains and Eastern project and at that time we raised this issue with SPP and, per their suggestion, we ignored these messages while analyzing the results.

Table 4-1 Units Tripped for all Faults

Contingency	Dynamic Performance of Units
All Faults	Machine 3 at bus 253627 Tripped for under frequency at 2.5833s
	Machine 1 at bus 253625 Tripped for under frequency at 2.7208s
	Machine 2 at bus 253626 Tripped for under frequency at 2.7208s

4.2 2017 Light Load Case Results

4.2.1 Three Phase Faults

All 3ph faults showed stable dynamic performance of the study area. Unlike the Peak Load conditions, it was observed that Rockport units did not trip for the critical fault at Rockport substation (Fault # 34) due to less dispatched generation of 1,760 MW at the Rockport plant (as opposed to 2,600 MW dispatched in Peak Load conditions), but the Sullivan area voltages did not meet the voltage performance criteria. Figure 4-8 shows the corresponding voltage performance at Sullivan substation. The first dip immediately after clearing the fault is about 37.3% (observed voltage of 0.627 pu) and the voltage recovery is poor.

As a mitigation scheme, one pole of the multi-terminal HVDC line is blocked immediately after clearing the fault thus limiting the GBX Project injection into Sullivan substation to 1,500 MW. Figure 4-9 shows the corresponding voltage performance with the capacitor banks at the inverter station reduced to half in size. The bus voltages around Sullivan substation area have recovered smoothly, meeting the voltage performance criteria.

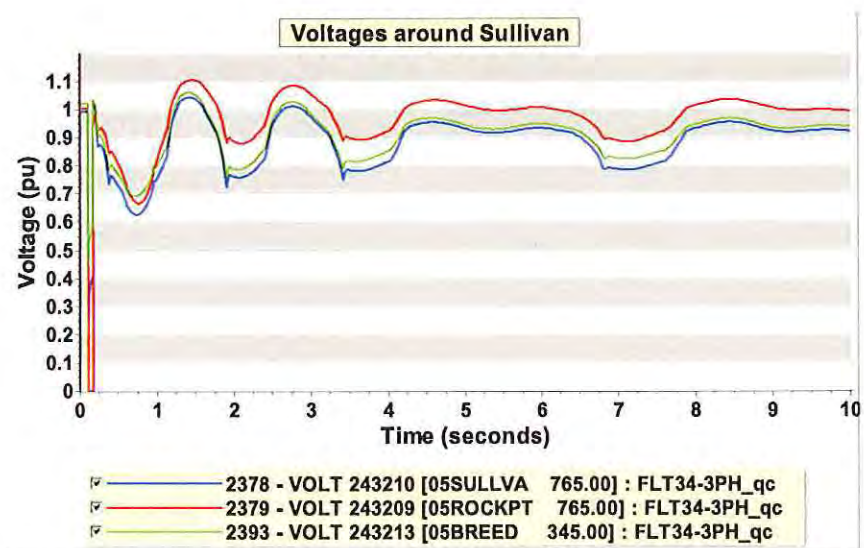

Figure 4-8: Voltage around Sullivan – Fault # 34

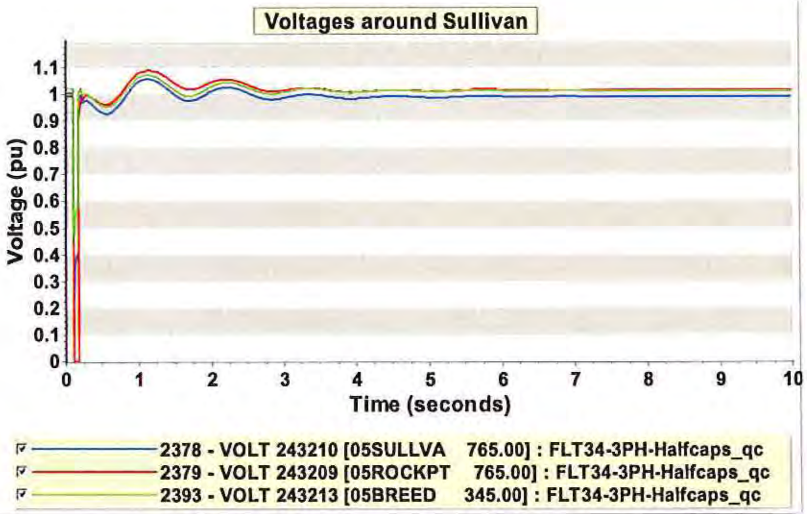

Figure 4-9: Voltage around Sullivan with One Pole is Blocked (Half Cap Banks) – Fault # 34

4.2.2 SLG Faults (Protection Failure)

The SLG faults analysis results showed similar performance as that of 3ph faults analysis. All SLG faults (protection failure) showed stable dynamic performance of the study area, except for Fault # 64. The Rockport units remained on-line for this fault, but the voltages around Sullivan are not completely recovered as shown in Figure 4-10. The observed voltage dip is about 31.2% (measured voltage of 0.688 pu).

As a mitigation scheme, one pole of the multi-terminal HVDC line is blocked immediately after clearing the fault thus limiting the GBX Project injection into Sullivan substation to 1,500 MW. Figure 4-11 shows the corresponding voltage performance with the capacitor banks at the inverter station reduced to half in size. The bus voltages around Sullivan substation area have recovered smoothly, meeting the voltage performance criteria.

4.2.3 SLG Faults (Stuck Breaker)

The study area showed stable performance for the selected SLG faults (stuck breaker).

4.2.4 Observations

Appendix D shows the 2017 Light Load stability analysis plots for both 3ph and SLG faults. The following are the key observations of the stability analysis:

- Faults at Rockport that involves tripping of Rockport–Jefferson 765 kV line are considered as critical faults.
- Though the Rockport units did not trip for these critical faults, the voltage performance around Sullivan substation is not acceptable. These faults require the GBX Project injection into Sullivan to be reduced to maintain desired voltage performance. It is not required to maintain the full shunt reactive compensation capability at converter stations

- In this study, we reduced the GBX injection into Sullivan to 1,500 MW by blocking one pole of the HVDC line. The remaining GBX Project generation is allowed to sink into the SPP system
- Though it was not tested in this study, we believe that the actual GBX injection into Sullivan could be higher than 1,500 MW

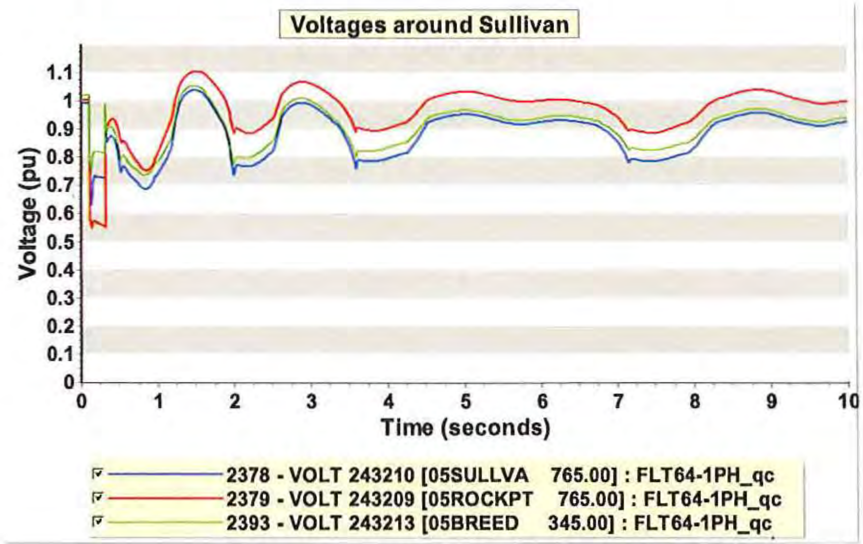

Figure 4-10: Voltages around Sullivan – Fault # 64

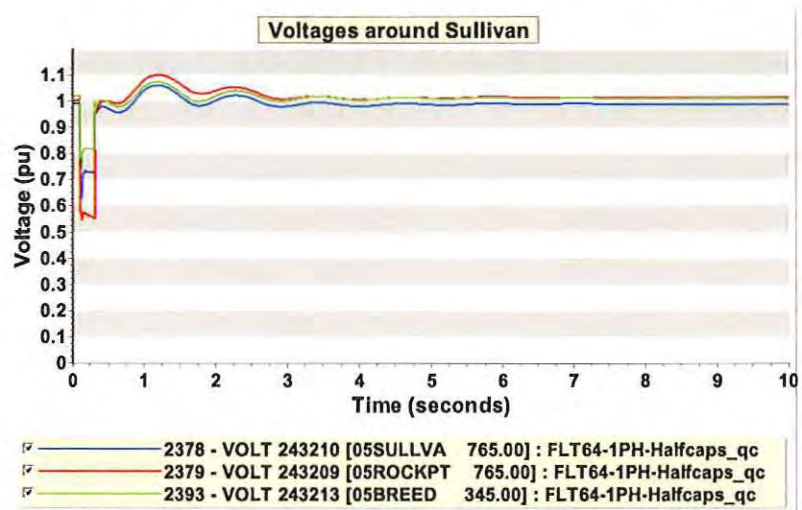

Figure 4-11: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 64

4.3 2022 Summer Peak Case Results

The 2022 Summer Peak stability analysis results are in general similar to that of 2017 Summer Peak stability analysis results. They both have similar observations as described in following subsections.

4.3.1 Three Phase Faults

The 3ph stability analysis results identified the following key faults that pose significant stress on the system:

- Fault # 29 – 3ph fault at Sullivan and cleared by tripping the 765 kV line to Rockport
- Fault # 34 – 3ph fault at Rockport and cleared by tripping the 765 kV line to Jefferson

Fault # 29

During the steady state analysis of the GBX Project, we identified that Fault # 29 was a severe fault and requires additional reactive support. However, this fault showed stable study area performance during the stability analysis as the HVDC controls adjust their angles to minimum values to provide the required reactive support. It is important to note that this additional support obtained through the HVDC controls is just enough to maintain the system voltages to meet the performance criteria as shown in Figure 4-12. The observed voltage dip is about 25% (measured voltage of 0.75 pu).

We consider this fault as severe; but the corresponding dynamic performance of the study area is acceptable. Later in this report, it is shown that the GBX Project 345 kV connection at Sullivan provides better voltage performance for the same fault.

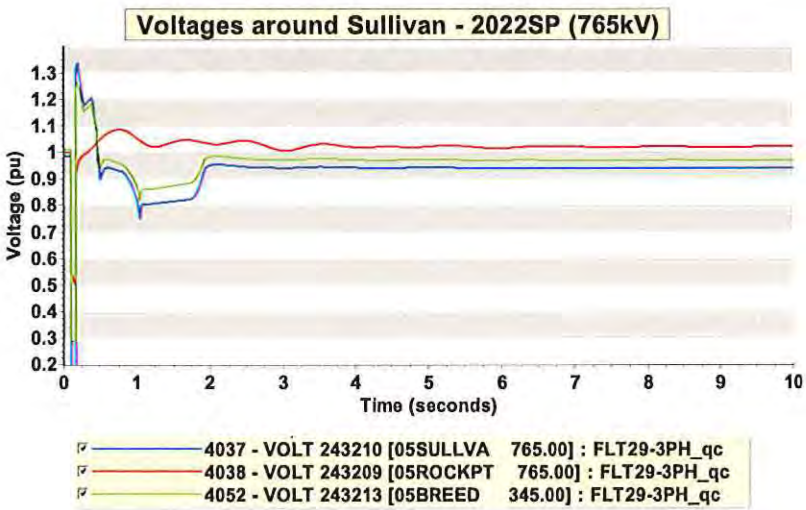

Figure 4-12: Voltages around Sullivan – Fault # 29

Fault # 34

Similar to the 2017 Summer Peak scenario, voltages around Sullivan substation did not recover immediately after the fault is cleared as shown in Figure 4-13. The Rockport generating units are tripped at about 1.27 seconds time and then the system voltages started to recover. However, the rest of the monitored units in the study area remained in synchronism with the system, thus tripping of Rockport units does not have an adverse effect on rotor angle stability of the study area.

Figure 4-14 shows the voltage performance at Sullivan with one of the HVDC lines blocked and with corresponding reduction of reactive compensation at the converter stations to half in size. This mitigation scheme did not help as the Rockport units still tripped at around 1.9 seconds time.

With full reactive compensation (switched shunts) available at the Sullivan inverter followed by pole blocking (as opposed to reducing to half in size), it was observed that the Rockport units remain on-line and the Sullivan side voltages recovered as shown in Figure 4-15. The voltage dip is about 20.2% (measured voltage of 0.798 pu) meeting the voltage performance criteria.

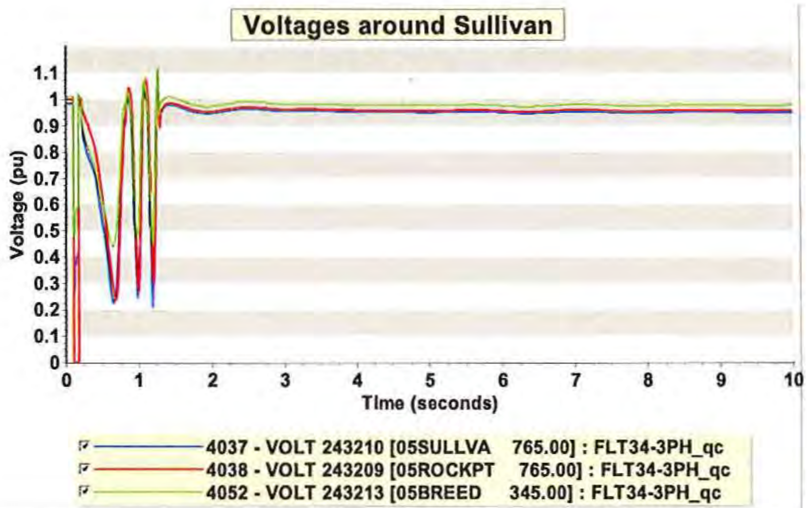

Figure 4-13 Voltages around Sullivan – Fault # 34

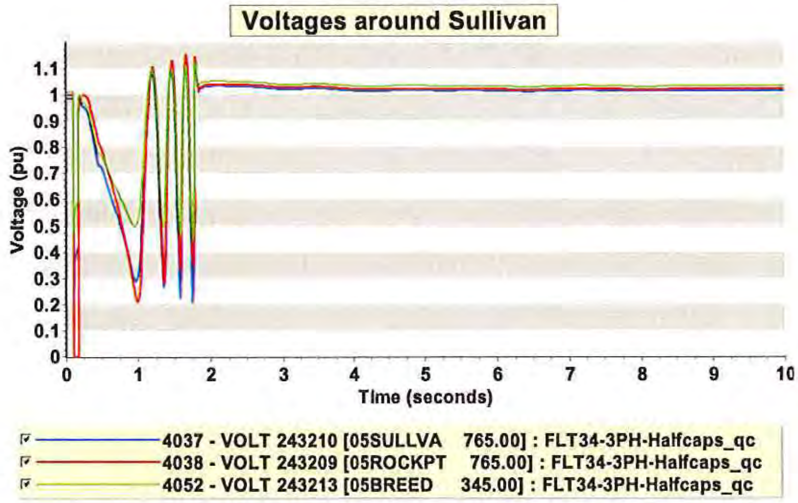

Figure 4-14 Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 34

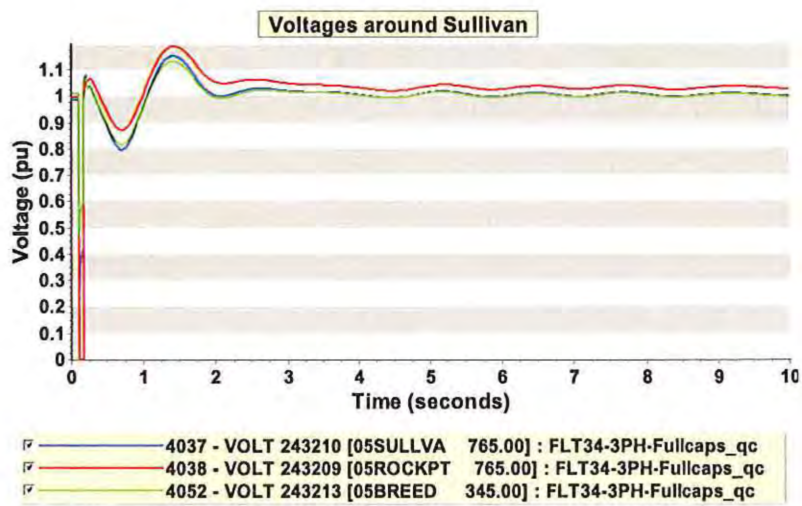

Figure 4-15 Voltages around Sullivan with One Pole Blocked (Full Cap Banks) – Fault # 34

4.3.2 SLG Faults (Protection Failure)

All SLG faults (protection failure) showed stable dynamic performance of the study area, except for Fault # 64. Again, similar to the 3ph fault (Fault # 34) all on-line generating units at Rockport plant were tripped by the out-of-step protection associated with these units as they have stepped out of synchronism with the system. The bus voltages within the vicinity of Sullivan substation are not able to recover immediately after clearing the fault, but as shown in Figure 4-16, the voltages started recovering after the Rockport units are tripped at around 1.45 seconds.

Figure 4-17 shows the voltage performance when one pole is blocked and the capacitor banks at the Sullivan inverter are reduced by half in size. The Rockport units did not trip and the system voltages are recovered. However, the observed voltage dip is about 28.9% (measured voltage of 0.711 pu) which is not acceptable as per the proposed performance criteria of 25%.

Figure 4-18 shows the voltage performance when one pole is blocked and with the capacitor banks at the Sullivan inverter operating at their full capacity. The Rockport units did not trip and the voltages around Sullivan recovered smoothly after clearing the fault. The observed voltage dip is about 8.3% (measured voltage of 0.917 pu).

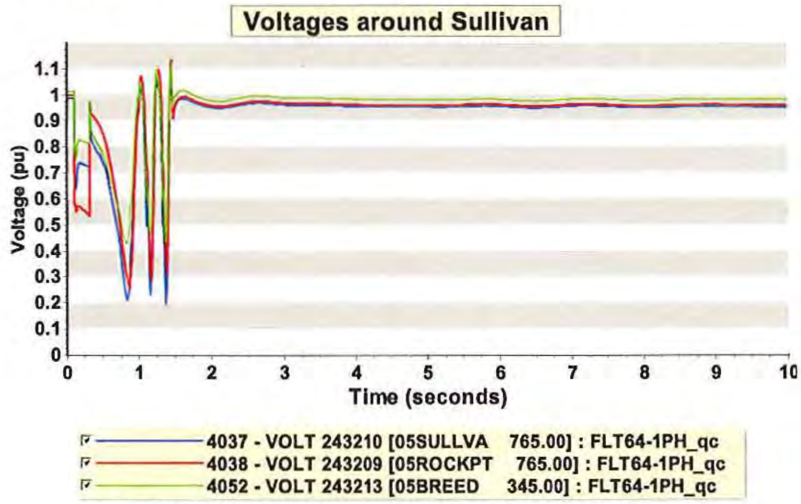

Figure 4-16: Voltages around Sullivan – Fault # 64

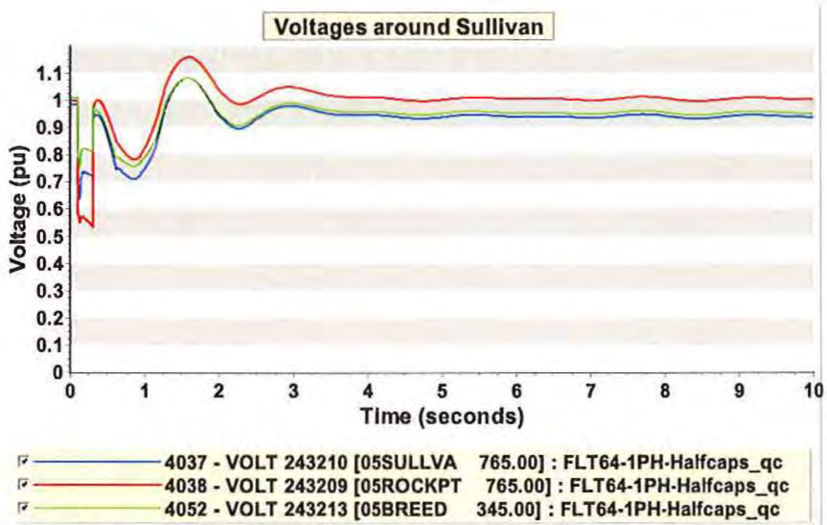

Figure 4-17: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 64

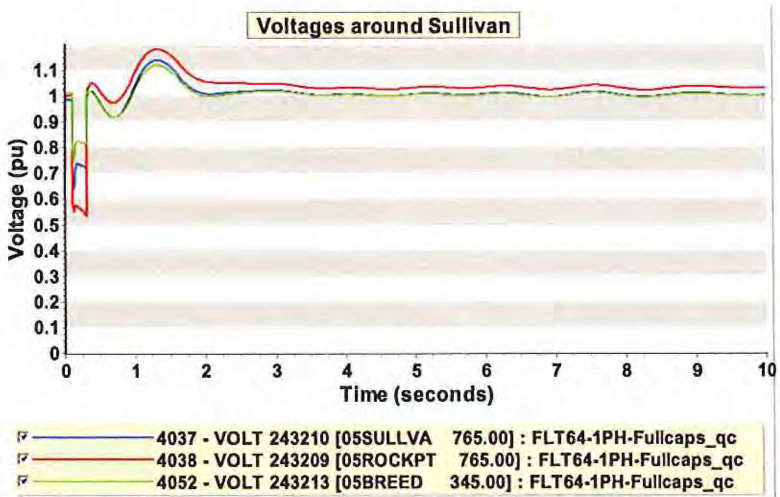

Figure 4-18: Voltages around Sullivan with One Pole Blocked (Full Cap Banks) – Fault # 64

4.3.3 SLG Faults (Stuck Breaker)

The study area showed stable performance for the selected SLG faults (stuck breaker).

4.3.4 Observations

Appendix E shows the 2017 Summer Peak stability analysis plots for both 3ph and SLG faults. The following are the key observations of the stability analysis:

- The 3ph fault at Sullivan that involves tripping of Sullivan – Rockport 765 kV lines appears to be severe but the study area is stable

- Faults at Rockport that involves tripping of Rockport to Jefferson 765 kV line are considered as critical faults. These faults require the GBX Project injection into Sullivan to be reduced while maintaining full shunt reactive compensation capability at the converter stations

  - In this study, we reduced the GBX injection into Sullivan to 1,500 MW by blocking one pole of the HVDC line. The remaining GBX Project generation is allowed to sink into the SPP system

  - Though it was not tested in this study, we believe that the actual GBX injection into Sullivan could be higher than 1,500 MW

Furthermore, it is noted that Unit # 1 at bus 200020 (225 PJM) was tripped by over speed relay action between 5 and 10 seconds into dynamic simulation, for almost all faults. This unit was tripped in the Plains & Eastern project as well and tests on the pre-project case revealed that the unit tripped due to bad modeling data and not due to the GBX project.

Section

5

N-1-1 Outages at Clark County and Spearville Substations

This section presents the stability assessment of the GBX Project for 3ph faults at Spearville and Clark County substations with a prior outage of a line, for example for maintenance purposes. This situation is treated as N-1-1 outage since the first line was taken out of service and allowed for manual adjustments in the system, and then a fault occurs at or near the substation that trips the second line. We consider such N-1-1 outages nearby the GBX Project that may impact the dynamic performance of the study area and need to be addressed.

This analysis was conducted for faults at Spearville and Clark County substations as they are close to the GBX Project rectifier station and the associated impacts will be more severe compared to faults at substations far from the project location. The selected faults are tested on 2017 Light Load, 2017 Summer Peak and 2022 Summer Peak scenarios. The following subsections will provide the analysis results.

5.1 Spearville Substation

Table 5-1 shows the list of faults considered at Spearville substation. The description of the events is presented below.

Table 5-1 3Ph Faults at Spearville Substation

No	Description	kV
12A	1. Prior Outage of Clark Co - Spearville Ckt 1 2. 3ph fault at Spearville substation 3. Clear the fault, trip Clark Co - Spearville Ckt 2	345
17A	1. Prior Outage of Spearville - Holcomb 345kV line 2. 3ph fault at Spearville substation 3. Clear the fault, trip Spearville - Postrock 345kV line	345

Fault 12A: A separate load flow case was created with Clark County–Spearville 345 kV circuit 1 taken out of service. The load flow case was solved with taps and switched shunts allowed to move. This accounts for the first line outage and manual adjustments. Then a 3ph fault was applied at Spearville substation that was cleared in 5 cycles of normal clearing time by tripping the Clark County–Spearville 345 kV circuit 2.

Fault 17A: A separate load flow case was created with the Spearville–Holcomb 345 kV line taken out of service. The load flow case was solved with taps and switched shunts allowed to move. This accounts for the first line outage and manual adjustments. Then a 3ph fault was applied at Spearville substation that was cleared in 5 cycles of normal clearing time by tripping the Spearville–Post Rock 345 kV line.

Analysis Results: The stability results indicate that the study area is stable for the selected faults in all three scenarios. The corresponding stability plots are shown in Appendix F.

5.2 Clark County Substation

Table 5-2 shows the list of faults at Clark County substation. The description of the events is presented below.

Table 5-2: 3Ph Faults at Clark County Substation

No	Description	kV
11A	1. Prior Outage of Clark Co - Thistle Ckt 1 2. 3ph fault at Clark Co substation 3. Clear the fault, trip Clark Co - Thistle Ckt 2	345
12B	1. Prior Outage of Clark Co - Spearville Ckt 1 2. 3ph fault at Clark Co substation 3. Clear the fault, trip Clark Co - Spearville Ckt 2	345

Fault 11A: A separate load flow case was created with Clark County–Thistle 345 kV circuit 1 taken out of service. The load flow case was solved with taps and switched shunts allowed to move. This accounts for the first line out and manual adjustments. Then a 3ph fault was applied at Clark County substation that was cleared in 5 cycles of normal clearing time by tripping the Clark County–Thistle 345 kV circuit 2.

Fault 12B: This fault is similar to Fault 12A described above, except that the fault was applied at Clark County substation.

Analysis Results: Faults 11A and 12B are tested on 2017 Light Load, 2017 Summer Peak and 2022 Summer Peak scenarios. We observed that the GBX Project wind units have tripped for both faults in all three scenarios which is not a desired performance.

When the fault is applied at Clark County substation, the HVDC poles are blocked right away which results in ramping up of GBX Project wind units as there is no path for the wind generation to flow in to the SPP system because of the fault at Clark County. After the fault is cleared, the HVDC poles attempt to unblock but before they are completely unblocked, the wind generation attempts to sink into the SPP system momentarily. However, because of the outage of the double circuit line, there is not sufficient system strength to support this sudden flow. In the meantime, the wind units continue to accelerate to unacceptable speeds and eventually get tripped before the HVDC poles are completely recovered.

Another way to understand this situation is through the available short circuit levels at Clark County substation under different transmission topology conditions. Table 5-3 shows the fault MVA levels without the new WTG at Clark County when all transmission circuits are in-service (SC Test 1), and how the fault MVA levels decrease in the event of double circuit outage to Spearville (SC Test 2) and Thistle (SC Test 3). These values are computed with the 900 MVAr from synchronous condensers connected. The table also shows the short circuit ratio (SCR) calculated with 4,000 MW of additional wind generation.

Note that there is a significant reduction in short circuit level even with the synchronous condenser taking the values from 8,406 MVA (SCR of 2.10) to 6,141 MVA (SCR of 1.54) for the outage of double circuit line to Spearville in 2017 Light Load scenario. This value further goes down to 6,126 MVA (SCR of 1.53) for the outage of double circuit line to Thistle. Similar values can be observed for 2017 and 2022 Sumer Peak scenarios.

Table 5-3 Fault MVA and Short Circuit Ratio at Clark County

		SC Test 1		SC Test 2		SC Test 3	
Scenario	Bus #	Fault MVA	SCR	Fault MVA	SCR	Fault MVA	SCR
2017 LL	539800	8406	2.10	6141	1.54	6126	1.53
2017 SP	539800	9034	2.26	6275	1.57	6494	1.62
2022 SP	539800	9076	2.27	6278	1.57	6528	1.63

SC Test 1 = All Transmission in-service

SC Test 2 = Clark Co - Spearville Double Ckt Out

SC Test 3 = Clark Co - Thistle Double Ckt Out

SCR calculated for a wind capacity of 4,000 MW

As a mitigation scheme, we tripped some of the GBX Project generation and observed that the HVDC poles and system voltages recovered smoothly thus the study area is stable. Table 5-4 shows the amount of generation that needs to be tripped for Fault 11A and 12B in all three scenarios. The wind unit modeled at bus 999984 was tripped to achieve 760 MW of generation reduction, and the wind unit at bus 999975 was tripped to achieve 877 MW of generation reduction. Note that the scheduled flow along the HVDC poles was also reduced simultaneously. The corresponding stability plots are shown in Appendix F.

Table 5-4 Curtailed GBX Project WTG

	2017LL (MW)	2017SP (MW)	2022SP (MW)
Fault 11A	877	760	760
Fault 12B	877	877	877

5.3 Summary

The key points that summarize the N-1-1 outage analysis:

- The study area is stable for faults at Spearville substation with a prior line outage
- The GBX Project generation needs to be reduced up to 877 MW for faults at Clark County substation with a prior line outage
- For faults at Clark County, the loss of double circuit line to Spearville is more severe compared to losing the double circuit line to Thistle as per the system conditions

5.4 Additional Considerations

As mentioned at several instances in this report, the short circuit strength at Clark County is important for close-in faults under different operating conditions. Recall that for the same reason, a synchronous condenser (up to 900 MVAr) was modeled at the rectifier station to improve the system strength. Currently, it was modeled as a single unit in load flow models but in reality it will be installed as several units of smaller capacity for reliability reasons. Furthermore, the actual size of the synchronous condenser depends on the capability of

HVDC controls, and will be determined later during the detailed design study phase of the Project.

The results above can also be used to infer what could happen for the loss of partial capability of the synchronous condenser assuming it was modeled in several smaller units. In such a case, unless spare capacity is installed, the short circuit capability at Clark County (close to the rectifier station) would be decreased, in a way similar to losing the double circuit lines as discussed in previous subsections. We did not perform the test, but by taking advantage of the N-1-1 outage analysis results, we anticipate that the GBX Project generation may need to be partially curtailed in the event of losing some capability of the synchronous condenser. The value of the generation reduction will be a function of the lost MVA support and the system configuration.

Section

6

Transient Current Flow Analysis

This section presents the evaluation of the transient current increase on key underlying SPP 345 kV lines following the sudden loss of both poles with the objective of evaluating the possibility of the protection tripping of these lines.

In extreme conditions such as double pole outage, all the project wind generation of 3,576 MW (as modeled) flows in to the SPP system resulting in increased currents along the lines near by the project. This sudden increase in currents might be of interest from a protection point of view and this section presents the analysis of such transient current flows along the nearby lines for selected faults.

Table 6-1 shows the selected faults that create significant increase in currents along the lines close to the project. These faults involve blocking of both poles thus all GBX Project generation will flow in to the SPP system.

We observed that measured peak currents are high for 2017 Light Load scenario, and these are shown in Table 6-2. It can be observed that the maximum transient currents are below the lines' nominal currents for all monitored lines, except for the 345 kV line from Clark County to the rectifier station. For faults which block both poles, the transient current can be up to 144% of the nominal current in the lines connecting the Project to Clark County, but this peak happens for a few tenths of a second and should not result in operation of the protection.

Figure 6-1 to Figure 6-3 show the transient current flows along the 345 kV lines at the Clark County substation close to the GBX Project for the faults listed in above table.

Table 6-1 Faults Simulated for the Current Flow Analysis

3 Phase Faults, Normal Clearing			
No	Type	Description	kV
1	3ph, both poles blocked	At Clark Co 765800, both poles are blocked	345
4	3ph, both poles blocked	At Sullivan 765773, both poles are blocked	345
7	3ph, both poles blocked	At Palmyra 765772, both poles are blocked	345

Table 6-2 Measured Current Peaks

					Maximum Transient Current (post fault opening)					
Monitored 345 kV Lines			Normal Rating		Fault # 1		Fault # 4		Fault # 7	
From	To	Id	MVA	I nominal (A)	Amps	% I nominal (A)	Amps	% I nominal (A)	Amps	% I nominal (A)
765800 SPP_GBE_HVDC	539800 CLARKCO 7	1	1793	3001	4314	144%	4296	143%	4291	143%
539800 CLARKCO 7	539801 THISTLE 7	1	1793	3001	2365	79%	2379	79%	2375	79%
539800 CLARKCO 7	531469 SPERVIL7	1	1793	3001	1929	64%	1901	63%	1899	63%

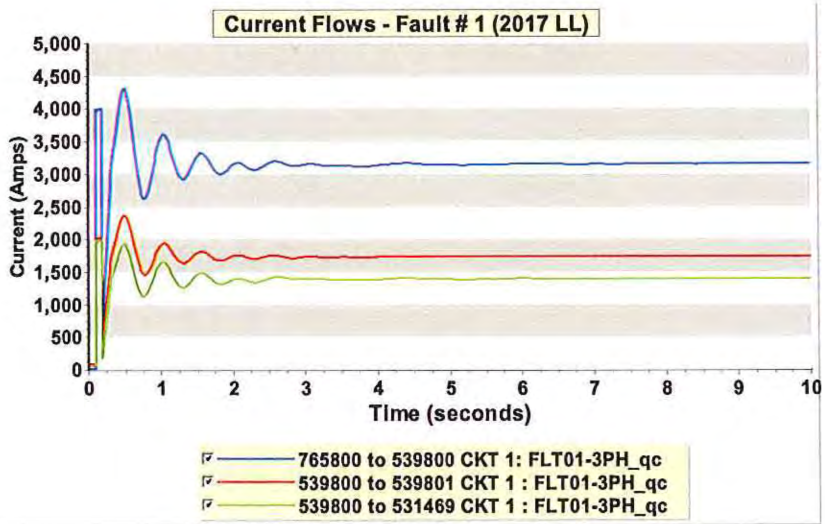

Figure 6-1 Fault # 1 – 2017 Light Load

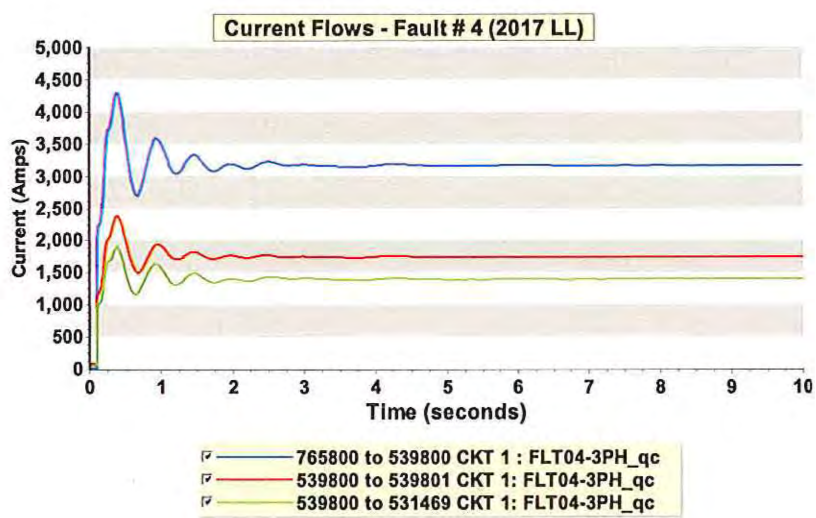

Figure 6-2 Fault # 4 – 2017 Light Load

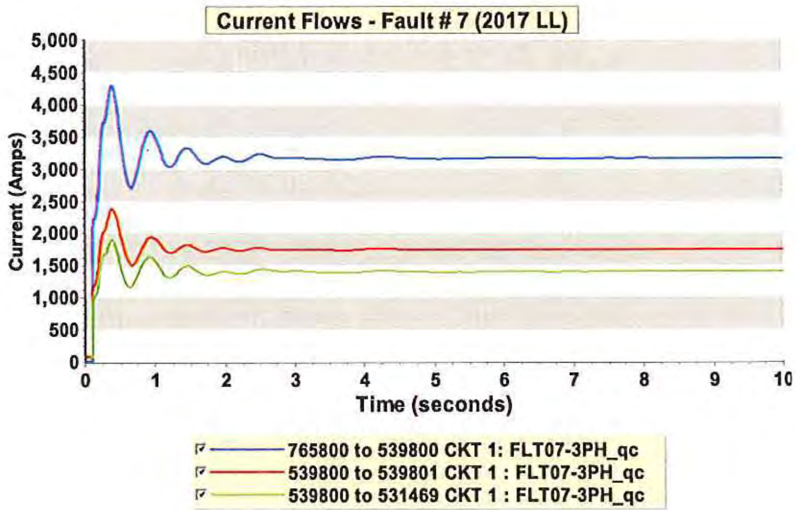

Figure 6-3 Fault # 7 – 2017 Light Load

Section

7

Sensitivity Case of 1750 MW Project Generation

A sensitivity case of reduced project wind generation of 1,750 MW (half of the originally studied 3,500 MW of wind generation) and injections in to Sullivan substation (1,500 MW) and Palmyra substation (250 MW) was developed to study the project impacts with reduced wind generation.

The load flow case with 3,756 MW of GBX Project generation was modified by turning-off approximately half of the generation as opposed to reducing the dispatched generation while keeping the same installed capacity. Table 7-1 shows the dispatched generation after modifying the load flow case with reduced installed capacity.

Figure 7-1 shows the updated project generation where the units connected by dotted lines indicate turned-off units. Also note that the synchronous condenser is turned off since the installed capacity of wind is reduced almost by half, resulting in a short circuit ratio of higher than 2. The reactive compensation at both converter stations is 1,100 MVAr (4x275).

This sensitivity was implemented on a 2017 Light Load case and tested for a 3ph fault in the lines connecting the GBX Project's HVDC converter to the Clark County 345 kV substation as shown in the Table 7-2. The list also includes critical faults at the Sullivan end of the project.

Appendix G shows the corresponding stability plots, where it can be observed that the system is stable; all units remain online, rotor oscillations are well damped and system voltages remain within acceptable ranges.

Table 7-1 Project WTG with Reduced Installed Capacity and Reactive Limits

Bus	Type	# Units	Pgen	Pmax	Qmin	Qmax	Mbase	Pgen/Pmax
999984	3	532	737.1	798	-386	386	888	92.4%
999985	4	385	889.1	963	-462	462	1155	92.4%
999994	3	70	97.0	105	-51	51	117	92.4%
999995	4	42	97.0	105	-50	50	126	92.4%
			1820.3	**1971**			**2286**	

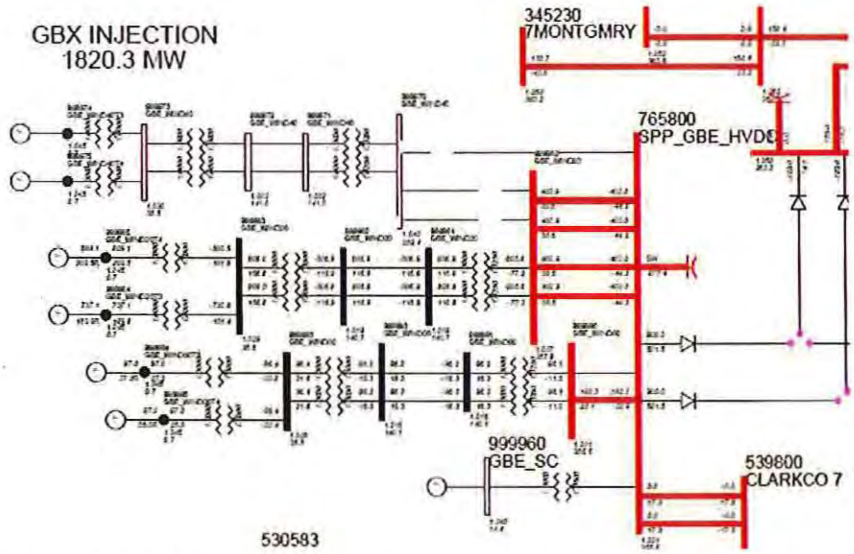

Figure 7-1 Reduced Project Wind Generation – Dotted lines shows turned-off elements

Table 7-2: List of Fault for 1750 MW Sensitivity Case

No	Description	kV
1	At Clark Co 765800, both poles are blocked	345
2	At Clark Co 765800, one pole is recovered	345
3	At Clark Co 765800, both poles are recovered	345
11	Clarck Co 539800 - Thistle 539801 ckt 1	345
12	Clark Co 539800 - Spearville 531469 ckt 1	345
29	Sullivan 243210 - Rockport 243209	765
34	Rockport 243209 - Jefferson 243208	765

Section

8

345 kV Connection Option at Sullivan

The HVDC inverter at Sullivan is rated at 345 kV and is connected to the 765 kV bus at Sullivan through three transformers. It was observed that most of the GBX Project generation flows back into the underlying 345 kV network through existing 765/345 kV transformers at Breed making them overload during certain contingencies. Since the HVDC converters are rated at 345 kV, a sensitivity case of connecting the GBX Project directly to the 345 kV network at Sullivan substation (as opposed to the 765 kV Sullivan bus via three transformers) was studied.

Figure 8-1 shows the 345 kV connection of the GBX Project at Sullivan substation. The inverters are connected to Breed via a 345 kV double circuit line of approximately 10 miles long. Though these lines are modeled as double circuit, the final configuration may have more than two circuits for N-1 capability depending on the conductor ratings.

We anticipate that this connection change would impact the GBX Project performance more for faults at Sullivan than at Clark County. For this reason, the stability analysis was performed for selected contingencies (only 3ph faults) at converter stations and at receiving end points as shown in the Table 8-1. This list includes all faults at the receiving end that were tested during the stability analysis with GBX Project connected to 765 kV bus at Sullivan. The Quick Reactor Switching (QRS) was simulated for the Fault # 34, but not the fast valve control action at Rockport plant.

The stability analysis was conducted on 2017 Light Load, 2017 Summer Peak and 2022 Summer Peak scenarios. The following subsections will present the study results.

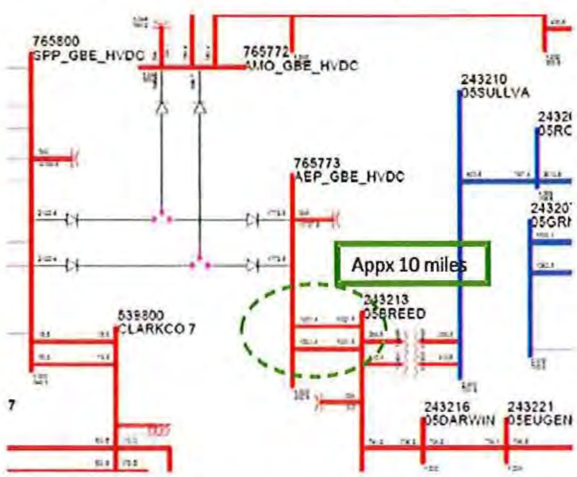

Figure 8-1: 345 kV Connection of the GBX Project at Sullivan

Table 8-1 Selected Contingencies

3 Phase Faults, Normal Clearing			
No	Type	Description	kV
1	3ph, both poles blocked	At Clark Co 765800, both poles are blocked	345
2	3ph, single pole recovery	At Clark Co 765800, one pole is recovered	345
3	3ph, both poles recovery	At Clark Co 765800, both poles are recovered	345
4	3ph, both poles blocked	At Sullivan 765773, both poles are blocked	345
5	3ph, single pole recovery	At Sullivan 765773, one pole is recovered	345
6	3ph, both poles recovery	At Sullivan 765773, both poles are recovered	345
7	3ph, both poles blocked	At Palmyra 765772, both poles are blocked	345
8	3ph, single pole recovery	At Palmyra 765772, one pole is recovered	345
9	3ph, both poles recovery	At Palmyra 765772, both poles are recovered	345
27	3ph, normal clearing	Sullivan 765773 - Breed 243213	345
28	3ph, normal clearing	Sullivan 765/345 kV TF (243210 - 243213)	765/345
29	3ph, normal clearing	Sullivan 243210 - Rockport 243209	765
30	3ph, normal clearing	Breed 243213 - Casey 346809	345
31	3ph, normal clearing	Breed 243213 - Darwin 243216	345
32	3ph, normal clearing	Breed 243213 - Dequine 243217	345
33	3ph, normal clearing	Breed 243213 - Wheat 254539	345
34	3ph, normal clearing	Rockport 243209 - Jefferson 243208	765
35	3ph, normal clearing	Palmyra 765772 - Palmyra tap 345435	345
36	3ph, normal clearing	Palmyra Tap 345435 - Sub T 636645	345
37	3ph, normal clearing	Palmyra Tap 345435 - Plamyra 345436	345
38	3ph, normal clearing	Palmyra Tap 345435 - Adair 344000	345
39	3ph, normal clearing	Palmyra Tap 345435 - Spencer 345992	345
40	3ph, normal clearing	Palmyra Tap 345435 - Se Quincy 347010	345

8.1 2017 Summer Peak Case Results

All 3ph faults showed stable dynamic performance of the study area except for the critical fault at Rockport (Fault # 34). As shown in Figure 8-2, the Rockport generating units are tripped at about 1.51 seconds time and then the system voltages started to recover. However, the rest of the monitored units in the study area remained in synchronism with the system thus tripping of the Rockport units does not have further adverse effects on rotor angle stability of the study area.

Figure 8-3 shows the voltage performance at Sullivan with one of the HVDC lines blocked with corresponding reduction of reactive compensation at the converter stations by half in size. The Rockport units did not trip and the voltages are well recovered. However, the observed voltage dip is about 39.1% (measured voltage of 0.609 pu) not meeting the desired voltage performance criteria. Note that for a similar situation when GBX Project is connected to the 765 kV bus at Sullivan, the Rockport units have tripped as the reactive requirement is higher in this case to supply the losses across the Project transformers at Sullivan.

With full reactive compensation (switched shunts) available at the Sullivan inverter followed by one pole blocking (as opposed to reducing by half in size), it was observed that the Rockport units remain on-line and the Sullivan side voltages recovered as shown in Figure 8-4.

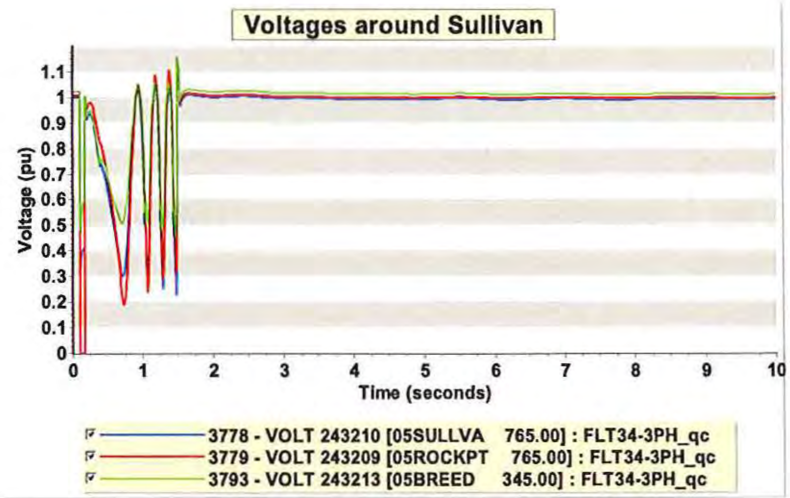

Figure 8-2: Voltages around Sullivan – Fault # 34

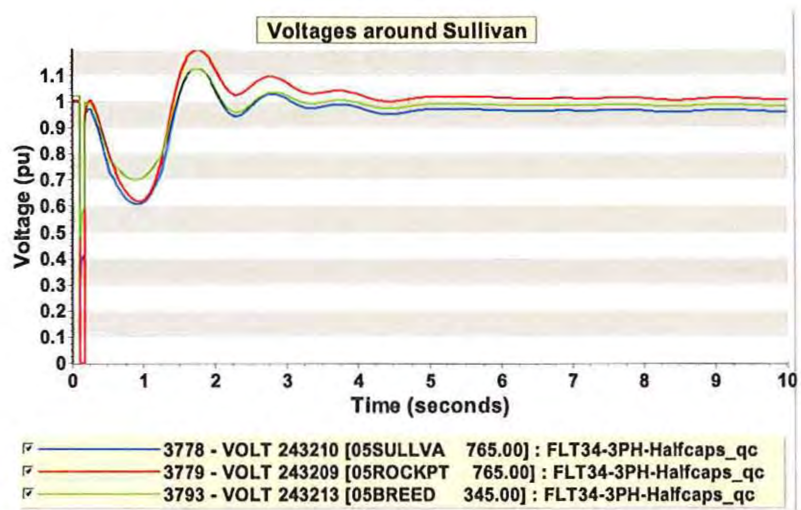

Figure 8-3: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 34

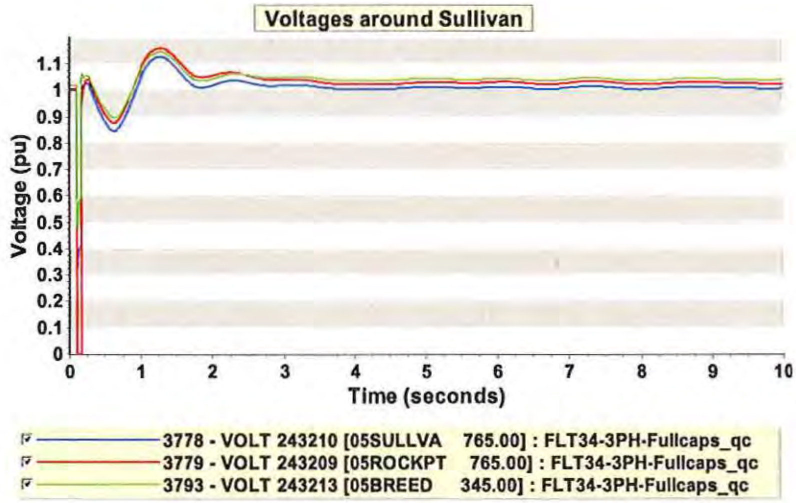

Figure 8-4: Voltages around Sullivan with One Pole Blocked (Full Cap Banks) – Fault # 34

8.2 2017 Light Load Case Results

All 3ph faults showed stable dynamic performance of the study area. Unlike the Peak Load conditions, it was observed that Rockport units did not trip for the critical fault at the Rockport substation (Fault # 34) due to less dispatched generation of 1,760 MW at the Rockport plant (as opposed to 2,600 MW dispatched in Peak Load conditions). As shown in Figure 8-5, a voltage dip of 25.5% (measured voltage of 0.745 pu) was observed around the Sullivan area.

While this voltage dip is marginal against the performance criteria of 25% dip, Figure 8-6 shows the improved voltage performance when one pole is blocked.

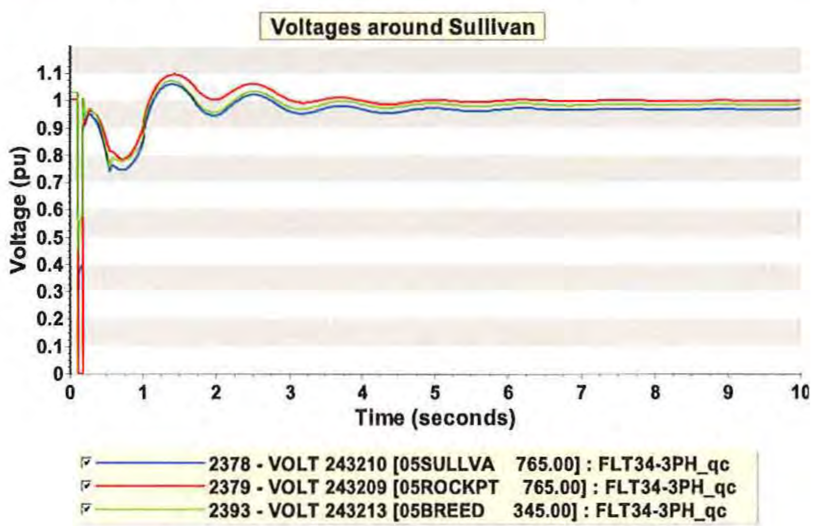

Figure 8-5: Voltages around Sullivan – Fault # 34

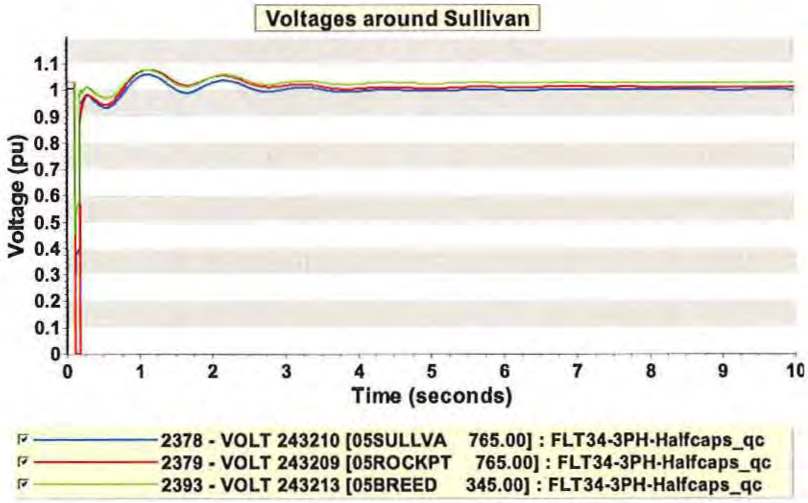

Figure 8-6: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 34

8.3 2022 Summer Peak Case Results

All 3ph faults showed stable dynamic performance of the study area except for the critical fault at Rockport (Fault # 34). As shown in Figure 8-7, the Rockport generating units are tripped at about 1.51 seconds time and then the system voltages started to recover. However, the rest of the monitored units in the study area remained in synchronism with the system thus tripping of Rockport units does not have further adverse effects on rotor angle stability of the study area.

Figure 8-8 shows the voltage performance at Sullivan with one of the HVDC lines blocked and with corresponding reduction of reactive compensation at the converter stations by half in size. The Rockport units did not trip and the voltages are well recovered. However, the observed voltage dip is about 38.2% (measured voltage of 0.618 pu) not meeting the desired voltage performance criteria. Note that the Rockport units have tripped for the similar situation when the GBX Project is connected to the 765 kV bus at Sullivan.

With full reactive compensation (switched shunts) available at the Sullivan inverter followed by one pole blocking (as opposed to reducing by half in size), it was observed that the Rockport units remained on-line and the Sullivan side voltages recovered as shown in Figure 8-9.

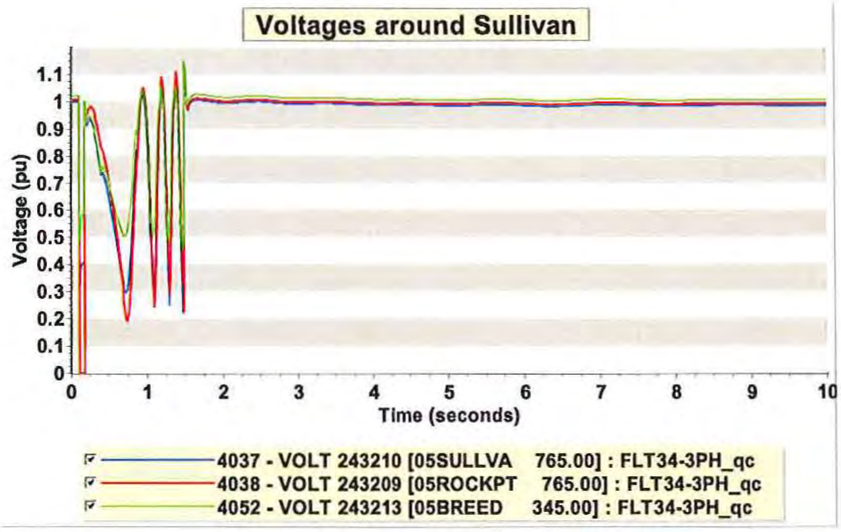

Figure 8-7: Voltages around Sullivan – Fault # 34

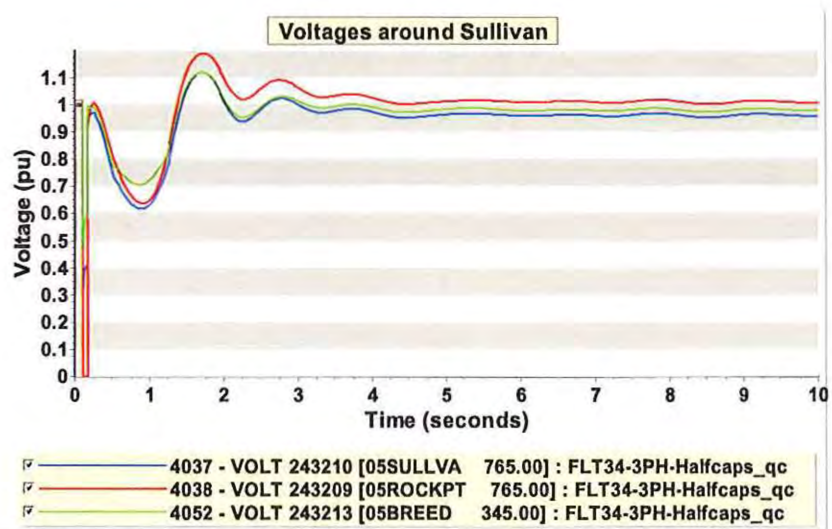

Figure 8-8: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 34

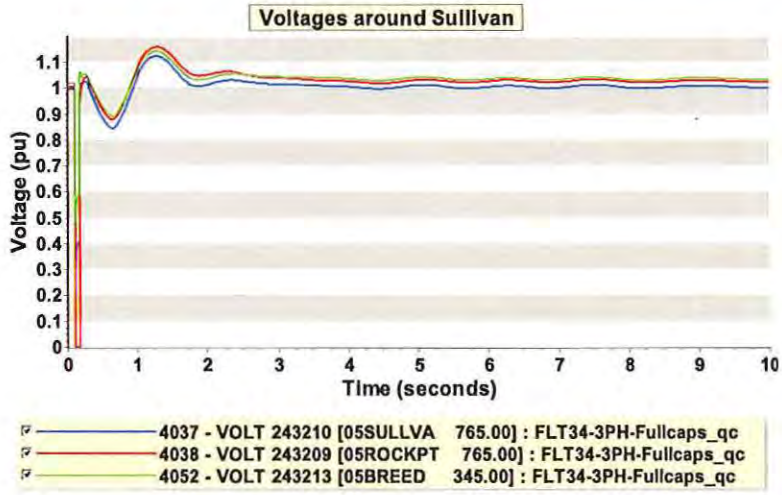

Figure 8-9: Voltages around Sullivan with One Pole Blocked (Full Cap Banks) – Fault # 34

8.4 Comparison of 765 kV and 345 kV Connections

We observed that the reactive requirement at Sullivan substation is higher for the 765 kV connection option mainly because of the losses across the GBX Project transformers and the increased flow on the 765/345 kV transformer to Breed. This reduction in reactive power consumption for the direct 345 kV connection option (as no transformation is required in this case) is contributing to the better voltage performance for faults at Sullivan and Rockport.

Figure 8-10 shows the voltage performance for a 3ph fault at Sullivan (Fault # 29) with the 765 kV connection option. The voltage performance for the same fault with 345 kV connection option can be seen in Figure 8-11. It is evident from these figures that the 345 kV connection offers better voltage performance for faults at Sullivan.

Also for faults at Rockport (Fault # 34), the 2017 Light Load scenario with 345 kV connection option showed much better voltage recovery (refer to Figure 8-5) compared to that of 765 kV connection option (refer to Figure 4-8).

In peak loading conditions with 765kV connection option, the Rockport units tripped for the same fault (Fault # 34) when one pole was blocked with the reduced capacitor banks at the Sullivan inverter station as shown in Figure 4-3 and Figure 4-14. For the similar condition with 345 kV connection option, it was observed that the Rockport units did not trip as shown in Figure 8-3 and Figure 8-8.

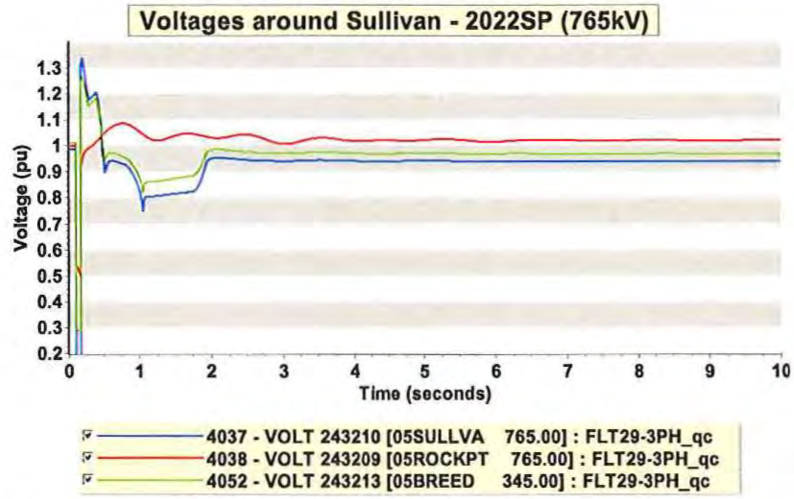

Figure 8-10: Voltage Performance for Fault # 29 – 2022SP 765 kV Connection Option

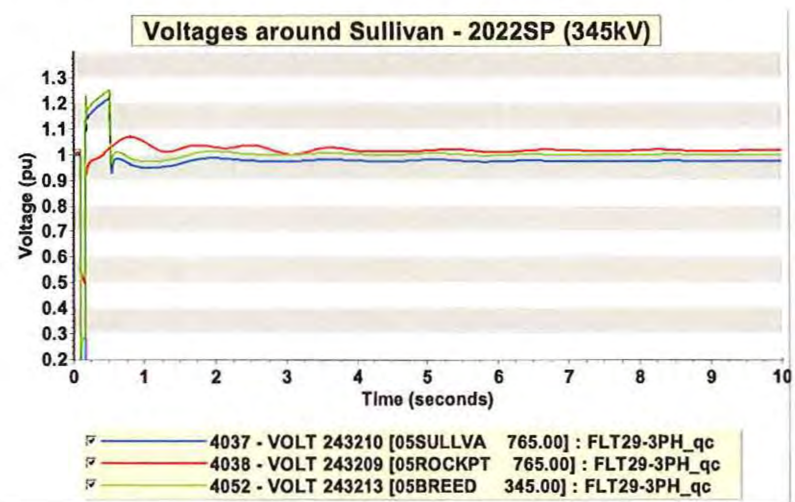

Figure 8-11: Voltage Performance for Fault # 29 – 2022SP 345 kV Connection Option

8.5 Observations

In general, similar results were observed for both 765 kV and 345 kV connection options at Sullivan. However, better voltage performance can be observed with 345 kV connection option.

Section

9

Conclusions

The following are the main conclusions of the system stability analysis.

- As proprietary HVDC models from the yet to be selected HVDC vendor are not available, HVDC models from the PSS/E library are used. These HVDC models do not fully capture the control capability of the HVDC converter stations and therefore up to a 900 MVAr synchronous condenser is required, from a modeling perspective, for the PSS/E stability models to solve by to improving the short circuit levels (i.e. system strength) at the Clark County 345 kV substation. This condenser was considered in all cases. Note, once proprietary HVDC models are provided by the HVDC vendor, the control capability of the HVDC converter can be properly modeled and the required amount of synchronous condensers could be reduced. Furthermore, for reliability and practical reasons, smaller parallel synchronous condensers would be used to make up the required improvement in short circuit levels. This synchronous condenser is to be optimized at the time of the GBX project design

- The 2017 Summer Peak case showed stable study area dynamic performance for all selected faults except for the 3ph fault at Rockport substation (Fault # 34)

  - For this particular fault, all on-line generating units at the Rockport plant have stepped out of synchronism with the rest of the system. Tripping of these units does not have adverse impact on the rotor angle stability of rest of the study area

  - By reducing the GBX project generation by 1,500 MW (achieved by blocking one pole), the Rockport generating units remain on-line and in synchronism with the system. Note that it is required to have full reactive compensation (switched shunts) at all converter stations to meet the voltage performance criteria

- The 2017 Light Load case showed stable study area dynamic performance for all selected faults except for Fault # 34. For this fault, the voltages around Sullivan substation area did not meet the voltage performance criteria

  - By reducing the GBX project generation by 1,500 MW (achieved by blocking one pole) the voltages around Sullivan substation did meet the voltage performance criteria

- The 2022 Summer Peak case showed stable study area dynamic performance for all selected faults except for the 3ph fault at Rockport substation (Fault # 34)

  - For this particular fault, all on-line generating units at Rockport plant have stepped out of synchronism with the rest of the system. Tripping of these units does not have adverse impacts on rotor angle stability of rest of the study area

  - By reducing the GBX project generation by 1,500 MW (achieved by blocking one pole), the Rockport generating units remain on-line and in synchronism with the system. Note that it is required to have full reactive compensation (switched shunts) at all converter stations to meet the voltage performance criteria

- The 3ph fault at Sullivan followed by the trip of the line to Rockport (Fault # 34) appears to be severe for peak load conditions from a voltage perspective but showed stable study area performance and met the voltage performance criteria

- With a prior outage of a line at Clark County, a 3ph fault that trips the second line (N-1-1 outage) requires up to approximately 877 MW disconnection of GBX Project wind generation

- During the double pole outage condition, transient currents with a peak of 148% (2017 Light Load) were observed along the 345 kV lines connected from Project rectifier station to Clark County. However, this peak exists for only few tenths of a second

- The stability analysis of the GBX Project with the 345 kV connection option showed similar results as that of the 765 kV connection. However, better voltage performance can be observed with the 345 kV connection option

Overall, the interconnection of the GBX project showed a stable study area dynamic performance for the selected disturbances, with few exceptions especially in the Peak Loading conditions. The recommended solution to the unstable cases is reduction of GBX project generation by 1,500 MW (tested by blocking one pole) while maintaining full reactive compensation (switched shunts) at all converter stations for the critical faults at the PJM side and approximately 900 MW (877 MW) reduction of GBX project generation (tested by disconnecting project wind generation) for critical N-1-1 conditions at the SPP side.

A 900 MVAr synchronous condenser is proposed to improve the short circuit capability in the Clark County area to increase the SCR at the POI of the expected wind generation. It may be possible to reduce the size of the synchronous condenser by HVDC controls at converter stations, as well as the required number of smaller parallel units; however, this was not considered in this study and should be considered during the project reactive power requirement optimization stage.

Merchant Transmission Interconnection PJM Impact Study Report

For

PJM Merchant Transmission Request Queue Position X3-028

Breed 345 kV

October/2014

System Impact Study
Breed 345 kV Merchant Transmission Project

Introduction

This System Impact Study report provides the documentation of an assessment that has been performed by PJM Interconnection, LLC and American Electric Power (AEP) in response to a request made by Clean Line Energy Partners LLC to evaluate the effects of proposed Grain Belt Express Clean Line. This is a proposed High Voltage Direct Current (HVDC) Transmission Line between Kansas and the AEP system in western Indiana. The System Impact Study evaluation was limited to the PJM footprint. MISO effects will be evaluated as part of the Facilities Process according to the Joint Operating Agreement (JOA) between PJM and MISO.

As per the PJM study process, the X3-028 Project assessment was accomplished by: 1. Evaluating the reliability impact of the proposed facilities and connection on the interconnected transmission system by the performance of a power flow study; 2. Ensuring compliance with the NERC, ReliabilityFirst, PJM and AEP Reliability Standards by identifying the system reinforcements that will need to be installed for an interconnection of the proposed project; 3. Coordinating and cooperating with the PJM staff and AEP by participating in project meetings and issuing this report as a part of the PJM study process; 4. Performing a Steady State, Short-Circuit and Dynamics Study as necessary; 5. Conducting all studies in accordance with the PJM Manuals, the "AEP Requirements for Connecting to the Transmission System".

Attachment Facilities

A new breaker string consisting of three (3) new 345 kV breakers and dual 345 kV revenue metering will be required to attach Queue Project #X3-028 to the Breed 345 kV Substation see Figure 1 for details, and Table 1 for estimated costs. Figure 2 shows the physical location of Breed 345 kV Substation.

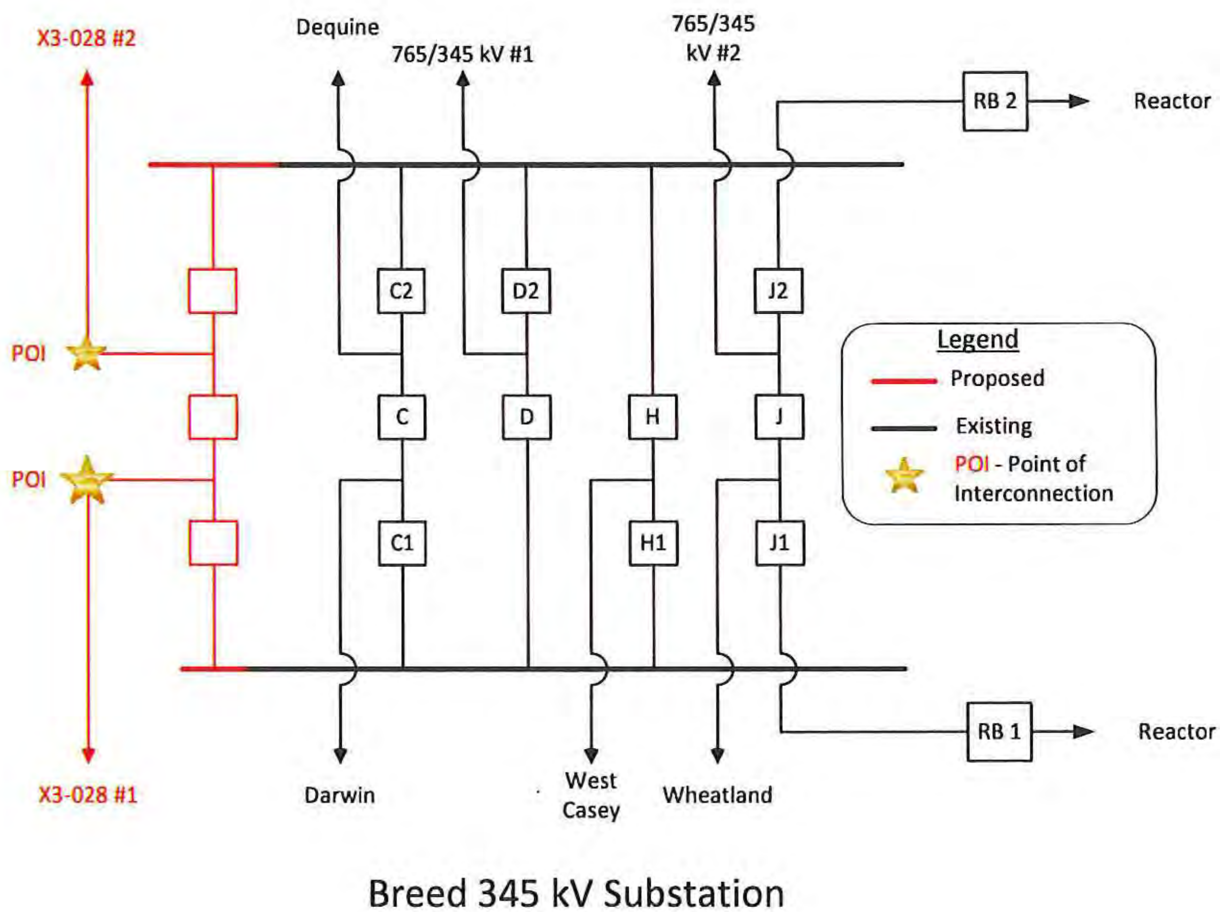

Figure 1

Network Upgrade Number	Table 1 Attachment Facilities	Estimated Cost
n4279	Three – 345 kV breaker string	$2,763,700
n4280	Dual – 345 kV revenue metering	$683,400
	Total Cost	$3,447,100

Figure 2 –**Location of Breed 345 kV Substation near Fairbanks Indiana**

Network Impacts

The Queue Project #X3-028 was studied as a 3500.0 MW (Capacity 1500.0 MW) injection into the Breed 345 kV substation in the AEP area. Project #X3-028 was evaluated for compliance with reliability criteria for summer peak conditions in 2015. Potential network impacts were as follows:

Generator Deliverability

(Single or N-1 contingencies for the Capacity portion only of the interconnection)

Table 2 - X3-028 Generator Deliverability

#	Type	Contingency Name	Affected Area	Facility Description	Bus From	Bus To	Cir.	PF	Loading Initial	Loading Final	Rating Type	Rating MVA	MW Con.	FG App.
1	N-1	4689_B2_TOR15257	AEP - AEP	05MEADOW-05REYNOL 345 kV line	243878	243230	1	AC	89.4	101.28	NR	971	116.11	1
2	N-1	05JEFRSO _05ROCKPT _122	AEP - AEP	05BREED-05DEQUIN 345 kV line	243213	243217	1	DC	80.47	101.68	NR	972	206.24	3
3	N-1	05JEFRSO _05ROCKPT _122	AEP - AEP	05BREED-05DARWIN 345 kV line	243213	243216	1	DC	76.12	109.63	NR	972	325.7	14
4	N-1	05JEFRSO _05ROCKPT _122	AEP - AEP	05DARWIN-05EUGENE 345 kV line	243216	243221	1	DC	76.2	109.74	NR	971	325.7	15
5	N-1	05JEFRSO _05ROCKPT _122	AEP - MISO AMIL	05BREED-7CASEY 345 kV line	243213	346809	1	DC	74.65	114.13	NR	1332	525.85	17
6	N-1	6490_B2_TOR3002545	AEP - AEP	05DEQUIN-05MEADOW 345 kV line	243217	243878	1	AC	99.75	114.77	NR	972	144.92	18
7	N-1	6472_B2_TOR15258	AEP - AEP	05DEQUIN-05MEADOW 345 kV line	243217	243878	2	AC	99.85	114.88	NR	971	144.92	19
8	N-1	667_B2_TOR1697	AEP - AEP	05EUGENE-05DEQUIN 345 kV line	243221	243217	1	AC	99.9	111.83	NR	972	104.22	16

Multiple Facility Contingency

(Double Circuit Tower Line, Failed Breaker and Bus Fault contingencies for the full energy output)

Table 3 - X3-028 Multiple Facility Contingency														
#	Type	Contingency Name	Affected Area	Facility Description	Bus From	Bus To	Cir.	PF	Loading Initial	Loading Final	Rating Type	Rating MVA	MW Con.	FG App.
1	LFFB	6523_C2_05MEADOW 345-A1	AEP - AEP	05REYNOL-05OLIVE 345 kV line	243230	243229	1	DC	81.17	101.56	ER	1195	243.7	2
2	LFFB	1760_C2_05JEFRSO 765-A	AEP - OVEC	05JEFRSO 765/345 kV transformer	243208	248000	1	DC	54.55	101.78	ER	1935	913.89	4
3	LFFB	3002_C2	AEP - AEP	05DARWIN-05EUGENE 345 kV line	243216	243221	1	DC	52.14	105.69	ER	1419	759.96	5
4	LFFB	3183_C2	AEP - AEP	05DARWIN-05EUGENE 345 kV line	243216	243221	1	DC	52.14	105.69	ER	1419	759.96	6
5	LFFB	3002_C2	AEP - AEP	05BREED-05DARWIN 345 kV line	243213	243216	1	DC	52.14	105.69	ER	1419	759.96	7
6	LFFB	3183_C2	AEP - AEP	05BREED-05DARWIN 345 kV line	243213	243216	1	DC	52.14	105.69	ER	1419	759.96	8
7	LFFB	2930_C2	AEP - AEP	05DARWIN-05EUGENE 345 kV line	243216	243221	1	DC	52.79	106.44	ER	1419	761.25	9
8	LFFB	2930_C2	AEP - AEP	05BREED-05DARWIN 345 kV line	243213	243216	1	DC	52.79	106.44	ER	1419	761.25	10
9	LFFB	6523_C2_05MEADOW 345-A1	AEP - AEP	05MEADOW-05REYNOL 345 kV line	243878	243230	1	DC	88.07	107.17	ER	1419	270.93	11
10	LFFB	6485_C2_05DEQUIN 345-C1	AEP - AEP	05DEQUIN-05MEADOW 345 kV line	243217	243878	1	AC	94.78	121.18	ER	1304	344.26	20
11	LFFB	4704_C2_05DEQUIN 345-B1	AEP - AEP	05DEQUIN-05MEADOW 345 kV line	243217	243878	2	AC	98.32	125.71	ER	1257	344.26	22
12	LFFB	2930_C2	AEP - AEP	05BREED-05DEQUIN 345 kV line	243213	243217	1	DC	83.1	132.96	ER	972	484.61	23

Short Circuit

(Summary form of Cost allocation for breakers will be inserted here if any)

Table 4 - Short Circuit Results							
#	Bus	Breaker	Rating Type	With X3-028	Without X3-028	% Difference	Note
1	05BREED 345.kV	C1	T	105.10%	93.10%	12.00%	New Over-duty
2	05OLIVE 345.kV	E1	T	102.50%	97.90%	4.60%	New Over-duty

1. AEP submitted a Supplemental Project to completely rebuild the Breed 345 kV station. The Breed station rebuild will utilize new 63 kA breakers.

2. Olive CB E1 was replaced with a 63 kA breaker in 2012

Contribution to Previously Identified Overloads

(This project contributes to the following contingency overloads, i.e. "Network Impacts", identified for earlier generation or transmission interconnection projects in the PJM Queue)

None.

Steady-State Voltage Requirements

(Results of the steady-state voltage studies should be inserted here)

Per the Generator Deliverability results (and also the N-1 common mode voltage analysis), the following contingencies cause a voltage collapse for various dispatch scenarios, all involving the dispatch of X3-028:

Cont. Type	Contingency Name	Contingency Description
single	'05JEFRSO_05ROCKPT_122'	Loss of Jefferson - Rockport
Line_FB	2930_C2	Loss of Jefferson-Rockport & Jefferson 765/345 kV XFMR
Line_FB	3002_C2	Loss of Jefferson-Rockport & Rockport 765/138 kV XFMR
Line_FB	3106_C2_V3-032	Loss of Breed-Casey & Breed-Darwin-Eugene
Line_FB	3183_C2	Loss of Jefferson-Rockport & Rockport 765/138 kV XFMR

Note: for the contingencies above involving the loss of the Rockport – Jefferson 765 kV line, there is an Operating Procedure in PJM Manual M03 which states to reduce the Rockport generation to 50% (assumed to be ~ 1310 MW total output) to prevent stability issues on the system. This was modeled and tested. There is still a voltage collapse for the above contingencies while the Rockport generation is reduced to 50% of the total output. This is due to the dispatch and contribution of X3-028.

Per PJM manual M03, to alleviate system instabilities, under single contingency conditions, total mechanical power of the Rockport plant shall be reduced to 50% within 1 second of the contingency. Plant will be ramped up backed to near 100% based on the event within 10 seconds. At this point system will be operating under N-1 conditions with Rockport plant at near 100% based on the event. If another contingency occurs on the nearby system with an impact on Rockport plant, mechanical power of the Rockport plant shall be reduced permanently to 50% to alleviate system instabilities. At this point system will be operating under N-2 or N-1-1 conditions with Rockport plant at 50%.

N-1-1 Analysis

No violations identified.

MISO Impacts

To be determined in the Facilities Study.

Light Load Analysis

The following facilities were identified as potential constraints in the light load analysis:

- Breed-Wheatland 345 kV, maximum loading 124.5% for a single contingency, 122.1 % for a breaker contingency
- Eugene-Cayuga Sub 345 kV, maximum loading 107.3% for a single contingency, 105.2 % for a breaker contingency
- Cayuga Sub – Cayuga 345 kV, maximum loading 105.1% for a single contingency, 103.1 % for a breaker contingency

As the first two constraints are PJM-MISO tie lines, and the third is a MISO internal facility, these results are preliminary, and will be reviewed and finalized as part of the PJM-MISO coordination during the Facilities Study.

Stability and Reactive Power Requirement
(Results of the dynamic studies should be inserted here)

The stability analysis performed to date also identifies that the Pioneer project upgrades are necessary. However, even with inclusion of the reinforcements identified to mitigate steady-state needs, X3-028 failed to meet criteria for a number of studied contingencies summarized below:

- For several contingencies the X3-028 HVDC circuits are disconnected from the system (permanently blocked) prior to fault clearing or mid-simulation.
- The addition of the X3-028 HVDC line causes the Fowler Ridge and Meadow Lake wind farms to trip for several contingencies.
- X3-028 HVDC circuits were manually deblocked (post fault clearing) for the contingencies which caused the DC line to disconnect prior to fault clearing. Tripping of the Fowler Ridge and Meadow Lake wind farms still occurs.

Blocking of X3-028 was able to be resolved for some contingencies through the addition of dynamic compensation of approximately +800 MVAr and -1000

MVAr. However, dynamic compensation was not sufficient to consistently eliminate the blocking for contingencies involving the Rockport – Jefferson 765 kV circuit.

As X3-028 is required to stay connected to the system for all faults, an updated model that exhibits this behavior is needed. The results suggest that further transmission reinforcement may also be required; the extent of this reinforcement cannot be identified prior to an updated X3-028 dynamic model being available. The full Stability report is attached at the end of the System Impact report.

New System Reinforcements
(Upgrades required to mitigate reliability criteria violations, i.e. Network Impacts, initially caused by the addition of this project generation)

1. Per the dynamic model provided for X3-028, there will be 9 banks of 275 MVAR per bank totaling 2475 MVAR connected to the Breed end of the DC line. Per the dynamic simulation, 8 of the 9 banks are on to support the HVDC converters, leaving 1 bank of 275 MVAR available for net injection into the PJM system at Breed. This 275 MVAR injection into Breed was assumed available for all voltage studies.
2. PJM 2018 base line upgrade B2287 to loop the Meadowlake – Olive 345 kV line into Reynolds 345 kV. The expected cost responsibility for X3-028 is $0.
3. MISO approved 345 kV MVP project to build a new Reynolds – Bur Oak – Hiple 345 kV line. This project is expected to be in-service in 2018. The expected cost responsibility for X3-028 is $0.
4. A segment of the MISO approved Pioneer project to build a new Reynolds – Greentown 765 kV line as well as a 765/345 kV transformer at Reynolds. This project is expected to be in-service in 2018. The cost for this project is estimated to be $270 M. The expected cost responsibility for X3-028 is $0.
5. A segment of the MISO (unapproved) Pioneer project to build a new Sullivan - Reynolds 765 kV line. The cost for this project is estimated to be $500 M. The expected cost responsibility for X3-028 is $500 M.

   It would take Pioneer LLC (3) three to (4) four years to build this section of the 765 kV line from the time CSA is signed.

   Sullivan – Reynolds 765 kV line: $480 million
   Work at Sullivan Station: $10 million
   Work at Reynolds Station: $10 million
   Total Cost: $500 million

With the 5 New System Reinforcements modeled above, all reliability violations are resolved except for the following, which still need to be addressed:

A. (AEP - AEP) The X1-020 TAP-05DUMONT 765 kV line (from bus 907110 to bus 243206 ckt 1) loads from 76.15% to 101.18% (AC power flow) of its emergency rating (4465 MVA) for the line fault with failed breaker contingency outage of '2932_C2_05JEFRSO 765-A2'. This project contributes approximately 944.44 MW to the thermal violation.

CONTINGENCY '2932_C2_05JEFRSO 765-A2'
 OPEN BRANCH FROM BUS 242924 TO BUS 243208 CKT 1 / 242924 05HANG R 765 243208 05JEFRSO 765 1
 OPEN BRANCH FROM BUS 243208 TO BUS 248000 CKT 1 / 243208 05JEFRSO 765 248000 06CLIFTY 345 1
 END

Mitigation: Upgrade Wavetrap at Dumont station on Dumont – X1-020 765 kV line at an estimated cost of $1 Million.

~~B. (AEP - AEP) The 05DEQUIN-05MEADOW 345 kV line (from bus 243217 to bus 243878 ckt 2) loads from 83.87% to 101.64% (AC power flow) of its emergency rating (1257 MVA) for the line fault with failed breaker contingency outage of '4704_C2_05DEQUIN 345-B1'. This project contributes approximately 223.33 MW to the thermal violation.~~

~~CONTINGENCY '4704_C2_05DEQUIN 345-B1'~~
 ~~OPEN BRANCH FROM BUS 243217 TO BUS 243878 CKT 1 / 243217 05DEQUIN 345 243878 05MEADOW 345 1~~
 ~~OPEN BRANCH FROM BUS 243217 TO BUS 249525 CKT 1 / 243217 05DEQUIN 345 249525 08WESTWD 345 1~~
 ~~OPEN BRANCH FROM BUS 249525 TO BUS 249874 CKT 1 / 249525 08WESTWD 345 249874 08WESTWD 138 1~~
 ~~END~~

Rating on Dequine – Meadow Lake 345 kV ckt #2 is SN/SE 971/1304 MVA.

C. (AEP - AEP) The 05MEADOW-05REYNOL 345 kV line (from bus 243878 to bus 243230 ckt 1) loads from 114.53% to 136.61% (AC power flow) of its emergency rating (1419 MVA) for the line fault with failed breaker contingency outage of 'ADD7'. This project contributes approximately 313.35 MW to the thermal violation.

CONTINGENCY 'ADD7'
 OPEN BRANCH FROM BUS 243230 TO BUS 998560 CKT 1 /* Reynolds 765/345 kV XF
 OPEN BRANCH FROM BUS 243230 TO BUS 255173 CKT 1 /* Reynolds 345/138 kV XF
 OPEN BRANCH FROM BUS 243230 TO BUS 243878 CKT 2 /* Reynolds-Meadow line #2
 END

Mitigation Plan: Reynolds 765/345 kV is going to be NIPSCO's station. Loading on Meadow Lake – Reynolds 345 kV #1 can be brought down by reworking breaker and line arrangement at the new Reynolds 345 kV station. AEP/PJM would need to work with NIPSCO/MISO on this during facilities study.

D. (AEP - AEP) The 05MEADOW-05REYNOL 345 kV line (from bus 243878 to bus 243230 ckt 2) loads from 114.56% to 136.65% (AC power flow) of its emergency rating (1419 MVA) for the line fault with failed breaker contingency outage of 'ADD6'. This project contributes approximately 313.46 MW to the thermal violation.

```
CONTINGENCY 'ADD6'
  OPEN BRANCH FROM BUS 243230 TO BUS 998560 CKT 1 /* Reynolds 765/345
kV XF
  OPEN BRANCH FROM BUS 243230 TO BUS 255173 CKT 1 /* Reynolds 345/138
kV XF
  OPEN BRANCH FROM BUS 243230 TO BUS 243878 CKT 1 /* Reynolds-Meadow
line #1
  END
```

Mitigation Plan: Reynolds 765/345 kV is going to be NIPSCO's station. Loading on Meadow Lake – Reynolds 345 kV #1 can be brought down by reworking breaker and line arrangement at the new Reynolds 345 kV station. AEP/PJM would need to work with NIPSCO/MISO on this during facilities study.

<u>Contribution to Previously Identified System Reinforcements</u>

(Overloads initially caused by prior Queue positions with additional contribution to overloading by this project. This project may have a % allocation cost responsibility which will be calculated and reported for the Impact Study)
(Summary form of Cost allocation for transmission lines and transformers will be inserted here if any)

None

Delivery of Energy Portion of Interconnection Request

PJM also studied the delivery of the energy portion of this interconnection request. Any problems identified below are likely to result in operational restrictions to the project under study. The developer can proceed with network upgrades to eliminate the operational restriction at their discretion by submitting a Merchant Transmission Interconnection request.

Only the most severely overloaded conditions are listed. There is no guarantee of full delivery of energy for this project by fixing only the conditions listed in this section. With a Transmission Interconnection Request, a subsequent analysis will be performed, which will study all overload conditions associated with the overloaded element(s) identified.

X3-028 Delivery of Energy Portion of Interconnection Request													
					Bus				Loading		Rating		
#	Type	Contingency Name	Affected Area	Facility Description	From	To	Cir.	PF	Initial	Final	Type	MVA	MW Con.
1	N-1	05DUMONT _05GRNTWN _120-X1-020A	AEP - AEP	05REYNOL-05OLIVE 345 kV line	243230	243229	1	AC	85.62	106.06	NR	972	198.66
2	N-1	05DUMONT _05GRNTWN _120-X1-020A	AEP - AEP	05REYNOL-05OLIVE 345 kV line	243230	243229	2	AC	85.62	106.06	NR	972	198.66
3	N-1	16_B2	AEP - AEP	05SULLVA 765/345 kV transformer	243213	243210	3	AC	53.84	112.22	NR	1852	1154.23
4	N-1	05JEFRSO _05ROCKPT _122	AEP - MISO IPL	05BREED-16WHEAT 345 kV line	243213	254539	1	DC	35.54	138.66	NR	956	985.85

Stability Study Report

Executive Summary

PJM Queue Project X3-028 is an HVDC Merchant Transmission Interconnection Request for 3500 MW (Maximum Facility Output) connecting to Breed 345 kV substation in the American Electric Power (AEP) system. This report describes the dynamic simulation analysis of X3-028 as part of the overall system impact study.

The load flow scenario for this analysis was based on the RTEP 2017 light load case, modified to include applicable queue projects. The case also takes into account the entire proposed Pioneer Project, identified as required by the loadflow analysis.

X3-028 was tested for compliance with NERC, PJM and other applicable criteria. 112 fault contingencies were studied. The studied faults include:

a) Steady state operation
b) Three phase faults with normal clearing time
c) Three phase faults with loss of multiple-circuit tower line
d) Single phase bus faults with normal clearing time
e) Single phase faults with single phase stuck breaker
f) Single phase faults with delayed clearing at remote end due to primary relaying failure
g) Three phase faults under outages.

For all the simulated faults, the queue project under study along with the rest of the PJM system were required to maintain synchronism and have all states returning to an acceptable new condition following the disturbance.

For a number of the studied contingencies, X3-028 failed to meet criteria:

- For several contingencies the X3-028 HVDC circuits are disconnected from the system (permanently blocked) prior to fault clearing or mid-simulation.
- The addition of the X3-028 HVDC line causes the Fowler Ridge and Meadow Lake wind farms to trip for several contingencies.
- X3-028 HVDC circuits were manually deblocked (post fault clearing) for the contingencies which caused the DC line to disconnect prior to fault clearing. Tripping of the Fowler Ridge and Meadow Lake wind farms still occurs.

Blocking of X3-028 was able to be resolved for some contingencies through the addition of dynamic compensation of approximately +800 MVAr and -1000 MVAr. However, dynamic compensation was not sufficient to consistently eliminate the blocking for contingencies involving the Rockport – Jefferson 765 kV circuit.

As X3-028 is required to stay connected to the system for all faults, an updated model that exhibits this behavior is needed. The results suggest that further transmission reinforcement may also be required; the extent of this reinforcement cannot be confirmed prior to an updated X3-028 dynamic model being available.

1. Introduction

Generation Interconnection Request X3-028 is for the interconnection of two 1750 MW 600 kV HVDC circuits (configured as a 3500 MW, +/- 600 kV bipole) from southwestern Kansas into the American Electric Power (AEP) network in Western Indiana.

PJM contracted Power Systems Consultants (PSC) to carry out this dynamic simulation analysis of X3-028 as part of the overall system impact study. This analysis is effectively a screening study to determine whether the addition of X3-028 will meet the dynamics requirements of the NERC and PJM reliability standards.

In this report, the X3-028 queue project and how it is proposed to be connected to the grid are first described, followed by a description of how the project is modeled in this study. The fault cases are then described and analyzed, and lastly a discussion of the results is provided.

2. Description of Project

The proposed X3-028 queue project consists of two 1750 MW, 600 kV DC transmission lines that connect the SPP system to the PJM system at Breed 345 kV (POI) in the AEP network.

Figure 1 shows how X3-028 has been modeled in this study at the PJM end. Table 1 lists the parameters given in the Impact Study Data Form and the corresponding parameters of the X3-028 loadflow model.

Additional X3-028 project details are provided in Attachments 1 through 5:

- Attachment 1 contains the Impact Study data;
- Attachment 2 shows the one-line diagram of the AEP network in the vicinity of X3-028;
- Attachment 3 provides a diagram of the PSS/E model in the vicinity of X3-028;
- Attachment 4 gives the X3-028 PSS/E loadflow model – this includes the complete project including the wind generation located in the SPP system; and
- Attachment 5 contains the dynamic models for the X3-028. These are based on user models supplied to PJM by the developer.

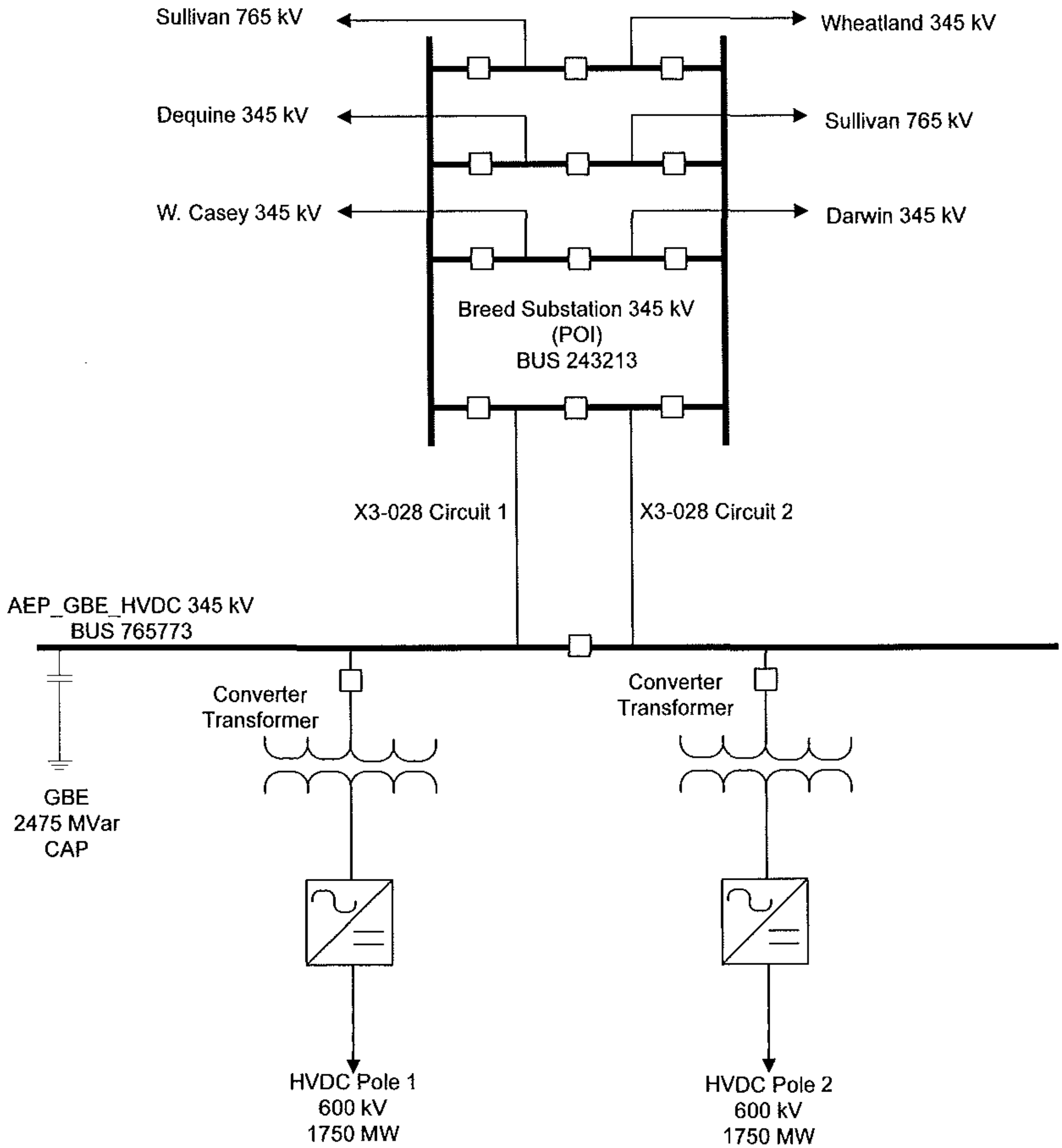

Figure 1: X3-028 Plant Model[1]

[1] The breaker configuration at bus 765773 has been assumed.

Table 1: X3-028 Plant Model

	Impact Study Data	Model
HVDC Circuits	N/A	2 X 1750 MW +/- 600 kV Dynamic data as included in Attachment 5

The loadflow data describing X3-028 HVDC circuits and related wind generation located in the SPP Network was extracted from a PSS/E sav case supplied by the developer to PJM.

3. Loadflow and Dynamics Case Setup

The dynamics simulation analysis was carried out using PSS/E Version 32.2.1.

The load flow scenario and fault cases for this study are based on PJM's Regional Transmission Planning Process[2] and discussions with PJM.

The selected load flow scenario is the RTEP 2017 light load case, provided by PJM, with the following modifications:

a) Addition of all applicable queue projects prior to X3-028.
b) Addition of the X3-028 queue project.
c) Removal of withdrawn and subsequent queue projects in the vicinity of X3-028.
d) Dispatch of units in the PJM system in order to maintain slack generators within limits.
e) Removal of several distant generation units from the dynamic simulation to avoid initialization problems.

For the intact network (network without outages), in the loadflow case the two X3-028 DC circuits were dispatched to inject a total power of 3500 MW (maximum rating) into the AEP network. The loadflow case for the intact system included the entire Pioneer Project, in order to meet requirements arising from prior loadflow analysis. Attachment 1B contains the one-line diagram describing the entire Pioneer Project.

For three phase faults under outages, the three loadflow scenarios identified in Table 2 were studied.

[2] Manual 14B: PJM Region Transmission Planning Process, Rev 19, September 15 2011, Attachment G: PJM Stability, Short Circuit, and Special RTEP Practices and Procedures.

Table 2: X3-028 and Rockport dispatch scenarios under outages

Circuit under outage	Pre-Mitigation		Post-Mitigation	
	Total X3-028 dispatch into AEP network (MW)	**Total Rockport units dispatch (MW)**	**Total X3-028 dispatch into AEP network (MW)**	**Total Rockport units dispatch (MW)**
Breed – West Casey 345 kV circuit	3500	2640 (maximum rating)	1500[3]	2640 (maximum rating)
Rockport – Jefferson 765 kV circuit	3500	2250[4]	3500	2250[4]

Generation within the PJM500 system (area 225 in the PSS/E case) and within a 5-bus radius of Breed 345 kV (POI) has been dispatched online at maximum output (PMAX); exceptions and the reasons for them are listed in Table 3.

Table 3: Generation at reduced output within 5-bus radius of X3-028

Bus	Name	Unit	PGEN (MW)	PMAX (MW)	Reason
248000	06CLIFTY 345.00	6	73.26	366.3	Conflict with governor model, PMAX not achievable
248000	06CLIFTY 345.00	A	110	124.74	
248000	06CLIFTY 345.00	B	110	124.74	
248000	06CLIFTY 345.00	C	110	623.7	
243226	05LAWBG1 345.00	1A	151	172.9	Conflict with governor model, PMAX not achievable
243226	05LAWBG1 345.00	1B	151	172.9	
243227	05LAWBG2 345.00	2A	151	195.67	
243227	05LAWBG2 345.00	2B	151	195.67	
270001	20ZELDA 345.00	1	170	191	Conflict with governor model, PMAX not achievable
270001	20ZELDA 345.00	2	170	191	
270001	20ZELDA 345.00	3	170	191	
270000	20FOOTHL 345.00	1	170	191	Conflict with governor model, PMAX not achievable
270000	20FOOTHL 345.00	2	170	191	
243233	05TANNER 345.00	D	280	294	Conflict with governor model, PMAX not achievable

[3] To maintain stability in the outage cases, X3-028 needed to be curtailed to 1500 MW, which is the Firm Transmission Injection Right (FTIR) value.
[4] Maximum recommended power output stated in Section 5 of PJM Manual 3: Transmission Operations for this outage.

4. Fault Cases

Table 6 to Table 12 list the contingencies that were studied, with representative worst case total clearing times provided by PJM. Each contingency was studied over a 10 second simulation time interval. Faults were applied to transmission circuits and transformers connected to the Point of Interconnection or one bus removed[5] (up to two buses removed for delayed (Zone 2) clearing faults).

The studied faults included :

a) Steady state operation
b) Three phase faults with normal clearing time
c) Three phase faults with loss of multiple-circuit tower line
d) Single phase bus faults with normal clearing time
e) Single phase faults with single phase stuck breaker
f) Single phase faults with delayed clearing at remote end due to primary relaying failure
g) Three phase faults under outages

The one line diagram of the AEP network in Attachment 2 shows where faults were applied.

The positive sequence fault impedances for single line to ground faults were derived from a separate short circuit case provided by PJM, updated by PSC to reflect latest system configuration, active queue projects and updates to X3-028 models. . Attachment 7 gives the positive sequence fault impedances for single-line to ground faults.

5. Evaluation Criteria

This study is focused on the queue project, along with the rest of the PJM system, maintaining synchronism and having all states return to an acceptable new condition following the disturbance. The recovery criteria applicable to this study are as per the PJM Region Transmission Planning Process:

a) System transient stability should be maintained.
b) The X3-028 DC circuits should maintain their pre-contingent power injection into the POI following the fault.
c) Post-contingency oscillations should be positively damped with a damping margin of at least 3%.
d) Post-contingency voltages should remain within +/- 0.05 pu of the pre-contingency voltages at transmission level buses.

[5] One bus removed from the POI refers to buses with transmission circuit breakers, not tee-offs or buses with only supply circuit breakers.

6. Summary of Results

Plots from the dynamic simulations are provided in

- Attachment 6a, for the intact system, without and with +800/-1000 MVAr dynamic reactive support;
- Attachment 6b, for outages, without and with +800/-1000 MVAr dynamic reactive support;

with results summarized in Table 6 to Table 12.

Of the 78 contingencies tested on the intact network under a single possible loadflow scenario, 26 failed to meet the recovery criteria due to unexpected blocking of the X3-028 circuits and tripping of multiple units. In an attempt to address violations observed during the study, dynamic reactive support of +800 / -1000 MVAr was modeled at the inverter (PJM) terminal of X3-028, and the unstable contingencies were retested.

While the recovery performance of the network was improved with the addition of dynamic reactive support, one stuck breaker contingency remained unstable; additionally, multiple contingencies failed to meet the PJM voltage recovery criteria. The contingencies for which criteria were not met are listed in Table 4.

Table 4: Intact network contingencies where recovery criteria were not met

X3-028 case	Unstable: Post fault block of X3-028 and units tripped	Post-contingency voltage deviation greater than ±0.05 p.u.
Post-Pioneer Project	3N01, 3N02, 3N03, 3N04, 3N05, 3N06, 3N20, 3N21, 3N22, 3N24, 3N25, 3T01, 3T02, 1B04, 1B07, 1B16, 1B23, 1B24, 1B25, 1B26, 1B27, 1B28, 1B29, 1D16, 1D18, 1D19	
With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project	1B23	3N24, 3N25, 1B24, 1B25, 1B26, 1B27, 1D18, 1D19

Although only one contingency is unstable in the particular results presented in Table 4, multiple contingencies involving the loss of the Rockport – Jefferson 765 kV circuit were found to be unstable following very slight changes to the loadflow. The results suggest that transmission reinforcement may be required in addition to the Pioneer Project, as the instability issues consistently involve the loss of the Rockport – Jefferson 765 kV circuit.

In addition to the post fault block of the X3-028 circuits detailed in Table 4, regardless of the presence or otherwise of the dynamic compensation, the X3-028 circuits blocked prior to fault clearing for three phase faults at Breed 345 kV (POI), Sullivan 765 kV and Rockport 765 kV buses. In these cases the X3-028 circuits needed to be manually deblocked post fault clearing. These results imply that the X3-028 dynamic model requires an update, as the response of the model to nearby faults is unpredictable at present.

6.1 Outages

Of the 34 outage contingencies studied, 17 failed to meet criteria due to unexpected blocking of the X3-028 circuits and tripping of multiple units. Dynamic reactive support of +800 / -1000 MVAr was modeled at the inverter (PJM) terminal of X3-028 and the unstable contingencies were retested. The contingencies for which criteria were not met are listed in Table 5.

Table 5: Outage condition contingencies where recovery criteria were not met

X3-028 case	Unstable: Post fault block of X3-028 and units tripped
Post-Pioneer Project	MA.3N01, MA.3N02, MA.3N03, MA.3N04, MA.3N05, MA.3N20, MA.3N21, MA.3N24, MB.3N01, MB.3N02, MB.3N03, MB.3N04, MB.3N05, MB.3N06, MB.3N10, MB.3N20, MB.3N21
With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project	Nil

For the contingencies tested, the dynamic reactive support prevents the post fault blocking of the X3-028 circuits.

In addition to the +800 / -1000 MVAr dynamic compensation, it was found that for a outage on the Breed – West Casey 345 kV circuit, the X3-028 injection needs to be curtailed to 1500 MW (the Firm Transmission Injection Right value) to maintain stability during a three phase fault at Rockport 765 kV on the Jefferson circuit.

Further maintenance outage simulations may be required following network reinforcement to resolve stability issues on the intact network case.

6.2 Dynamic Reactive Support

Additional dynamic reactive support of +800 / -1000 MVAr was modeled at the inverter (PJM) terminal of X3-028 (AEP_GBE_HVDC 345 kV bus).

The +800 / -1000 MVAr level of dynamic reactive support was determined from two onerous fault contingencies:

- *Three phase fault at Rockport 765 kV on the Jefferson circuit, to determine required lagging dynamic reactive support.* After the fault is cleared, a power swing of units at Rockport 765 kV results in a ~0.8 pu transient undervoltage at Breed 345 kV. The output of the X3-028 switched 2475 MVAr capacitor bank is reduced to 1584 MVAr at 0.8 pu voltage. 800 MVAr of dynamic reactive support was selected to compensate for the reduced output of the switched capacitor bank.
- *Three phase fault at Breed 345 kV on X3-028 circuit 1 (3N01), to determine leading dynamic reactive support.* As part of the post-fault tripping action, 3N01 permanently blocks one of the two X3-028 HVDC circuits. When the X3-028 HVDC circuit is blocked, the switched 2475 MVAr capacitor bank on the inverter (PJM) side causes the post-contingency voltages at Breed 345 kV and other nearby buses to significantly increase and exceed the +/- 0.05 pu pre- to post-contingency steady-state voltage change criterion. 1000 MVAr of leading dynamic reactive capability is needed to prevent violation of pre- to post-contingency voltage change of +/- 0.05 pu criterion.

Table 6: Steady State Operation

Fault ID	Duration	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
SS01	Steady state 20 sec	Stable	Stable

Table 7: Three-phase Faults with Normal Clearing

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
3N01	Fault at Breed 345 kV on X3-028 circuit 1.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Trips Q01, East 1 and 2. Post-fault voltage criterion not met.)	Stable (X3-028 DC Circuit 1 blocked)
3N02	Fault at Breed 345 kV on Dequine circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Post-fault voltage criterion not met.)	Stable
3N03	Fault at Breed 345 kV on Sullivan 765/345 kV transformer 1.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Trips Q01, East 1 and 2. Post-fault voltage criterion not met.)	Stable
3N04	Fault at Breed 345 kV on Darwin circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Trips Q01, East 1 and 2. Post-fault voltage criterion not met.)	Stable
3N05	Fault at Breed 345 kV on Wheatland circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Trips Q01, East 1 and 2. Post-fault voltage criterion not met.)	Stable
3N06	Fault at Breed 345 kV on West Casey circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Trips Q01, East 1 and 2. Post-fault voltage criterion not met.)	Stable
3N07	Fault at Dequine 345 kV on Meadow Lake SW circuit 1.	3.5	Stable	Stable
3N08	Fault at Dequine 345 kV on Eugene circuit.	3.5	Stable	Stable

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
3N09	Fault at Dequine 345 kV on Breed circuit.	3.5	Stable	Stable
3N10	Fault at Dequine 345 kV on Fowler Ridge Junction circuit.	3.5	Stable (Trips Fowler Ridge units)	Stable (Trips Fowler Ridge units)
3N11	Fault at Dequine 345 kV on Westwood circuit 1.	3.5	Stable	Stable
3N12	Fault at Meadow Lake SW 345 kV on Dequine circuit 1.	3.5	Stable	Stable
3N13	Fault at Meadow Lake SW 345 kV on Reynolds - Olive circuit.	3.5	Stable	Stable
3N14	Fault at Meadow Lake SW 345 kV on S06 Transformer 1 (trips S06 unit).	3.5	Stable	Stable
3N15	Fault at Meadow Lake SW 345 kV on T126/T127 circuit.	3.5	Stable (Trips T126 and T127 units)	Stable (Trips T126 and T127 units)
3N16	Fault at Meadow Lake SW 345 kV on Unit 1.	3.5	Not Used	Not Used
3N17	Fault at Meadow Lake SW 345 kV on Unit 2.	3.5	Not Used	Not Used
3N18	Fault at Darwin 345 kV on Eugene circuit.	3.5	Stable	Stable
3N19	Fault at Darwin 345 kV on Breed circuit.	3.5	Stable	Stable

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
3N20	Fault at Sullivan 765 kV on Sullivan 765/345 kV transformer 1.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Trips Q01, East 1 and 2. Post-fault voltage criterion not met.)	Stable
3N21	Fault at Sullivan 765 kV on Rockport circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Trips Q01, T126, East 1 and 2. Post-fault voltage criterion not met.)	Stable
3N22	Fault at Sullivan 765 kV on Reynolds circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Post-fault voltage criterion not met.)	Stable
3N24	Three phase fault at Rockport 765 kV POI on Jefferson circuit.	3.0	Unstable (X3-028 DC Circuit 1 and 2 blocked. Results in network non convergence and subsequent PSS/E crash.)	Stable* Post-fault voltage criterion not met
3N25	Three phase fault at Jefferson 765 kV on Rockport circuit.	3.0	Unstable (X3-028 DC Circuit 1 and 2 blocked. Results in network non convergence and subsequent PSS/E crash.)	Stable* Post-fault voltage criterion not met

**** Although this contingency was stable under the single possible loadflow scenario simulated, instability (unanticipated blocking of X3-028 circuits) can occur for this contingency under slightly altered loadflow conditions.***

Table 8: Three-phase Faults with Loss of Multiple-circuit Tower Line

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
3T01	Fault at Breed 345 kVon Darwin circuit resulting in tower failure. Fault cleared with loss of Dequine – Breed circuit, Darwin – Breed circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Post-fault voltage criterion not met.)	Stable
3T02	Fault at Breed 345 kV on Dequine circuit resulting in tower failure. Fault cleared with loss of Dequine – Breed circuit and Dequine – Eugene circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Post-fault voltage criterion not met.)	Stable
3T03	Fault at Dequine 345 kV on Meadow Lake SW circuit resulting in tower failure. Fault cleared with loss of Dequine – Meadow Lake SW circuits 1 and 2.	3.5	Stable	Stable
3T04	Fault at Meadow Lake 345 kV on Olive circuit resulting in tower failure. Fault cleared with loss of Meadow Lake SW – Olive circuit, Meadow Lake SW – Reynolds circuit, Olive – Reynolds circuit and Reynolds 345/138 kV Transformer 1.	3.5	Stable	Stable

Table 9: Single-phase Bus Faults with Normal Clearing

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
1S01	Fault at Reynolds 345 kV on Bus 1. Fault cleared with loss of Dequine – Reynolds – Olive circuit and Reynolds 345/138 kV Transformer 1.	3.5	Stable	Stable
1S02	Fault at Dequine 345 kV on Bus 1. Fault cleared with loss of Westwood circuit 1.	3.5	Stable	Stable
1S03	Fault at Dequine 345 kV on Bus 2. Fault cleared with loss of Westwood circuit 2.	3.5	Stable	Stable

Table 10: Single-phase Faults with Stuck Breaker

Fault ID	Fault description	Clearing Time Normal/ Stuck Breaker (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
1B01	Fault at Breed 345 kV on X3-028 circuit 1. Breaker stuck to X3-028 circuit 2. Fault cleared with loss of X3-028 circuit 2.	3.5/16	Stable (X3-028 DC Circuit 1 and 2 blocked.)	Stable (X3-028 DC Circuit 1 and 2 blocked.)
1B02	Fault at Breed 345 kV on Dequine circuit. Breaker C stuck. Fault cleared with loss of Sullivan 765/345 kV transformer 1.	3.5/16	Stable	Stable
1B03	Fault at Breed 345 kV on Sullivan 765/345 kV Transformer 1. Breaker C stuck. Fault cleared with loss of Dequine circuit.	3.5/16	Stable	Stable
1B04	Fault at Breed 345 kV on Darwin circuit. Breaker D stuck. Fault cleared with loss of West Casey circuit.	3.5/16	Unstable (X3-028 DC Circuit 1 and 2 blocked. Trips Q01, East 1 and 2. A number of GBE units are also tripped. Post-fault voltage criterion not met.)	Stable
1B05	Fault at Breed 345 kV on Wheatland circuit. Breaker A stuck. Fault cleared with loss of Sullivan circuit 2 and Sullivan 765/345 kV transformer 2.	3.5/16	Stable	Stable
1B06	Fault at Breed 345 kV on Sullivan circuit 2. Breaker A stuck. Fault cleared with loss of Wheatland circuit.	3.5/16	Stable	Stable
1B07	Fault at Breed 345 kV on West Casey circuit. Breaker D stuck. Fault cleared with loss of Darwin circuit.	3.5/16	Unstable (X3-028 DC Circuit 1 and 2 blocked. Trips Q01, East 1 and 2. Post-fault voltage criterion not met.)	Stable

Fault ID	Fault description	Clearing Time Normal/ Stuck Breaker (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
1B08	Fault at Dequine 345 kV on Meadow Lake SW circuit 1. Breaker B stuck. Fault cleared with loss of Eugene circuit.	3.5/16	Stable	Stable
1B09	Fault at Dequine 345 kV on Eugene circuit. Breaker B stuck. Fault cleared with loss of Meadow Lake SW circuit 1.	3.5/16	Stable	Stable
1B10	Fault at Dequine 345 kV on Breed circuit. Breaker C stuck. Fault cleared with loss of Meadow Lake SW circuit 2.	3.5/16	Stable	Stable
1B11	Fault at Dequine 345 kV on Westwood circuit 1. Breaker B1 stuck. Fault cleared with loss of Meadow Lake SW circuit 1.	3.5/16	Stable	Stable
1B12	Fault at Dequine 345 kV on Westwood circuit 2. Breaker C2 stuck. Fault cleared with loss of Breed circuit.	3.5/16	Stable	Stable
1B13	Fault at Meadow Lake SW 345 kV on Reynolds - Olive circuit. Breaker B stuck. Fault cleared with loss of S06.	3.5/16	Stable (Trips S06 unit).	Stable (Trips S06 unit).
1B14	Fault at Meadow Lake SW 345 kV on Olive circuit. Breaker A stuck. Fault cleared with loss of T126/T127 circuit.	3.5/16	Stable (Trips T126 and T127 units)	Stable (Trips T126 and T127 units)
1B15	Fault at Meadow Lake SW 345 kV on T126/T127 circuit. Breaker A stuck. Fault cleared with loss of Olive circuit.	3.5/16	Stable (Trips T126 and T127 units)	Stable (Trips T126 and T127 units)
1B16	Fault at Meadow Lake SW 345 kV on S06 circuit. Breaker B stuck. Fault cleared with loss of Reynolds - Olive circuit.	3.5/16	Cannot complete fault simulation. PSS/E crashing.	Stable

Fault ID	Fault description	Clearing Time Normal/ Stuck Breaker (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
1B17	Fault at Meadow Lake SW 345 kV on Dequine circuit 1. Breaker C stuck. Fault cleared with loss of no additional circuits.	3.5/16	Stable	Stable
1B18	Fault at Darwin 345 kV on Eugene circuit. Breaker A stuck. Fault cleared with loss of Darwin – Breed circuit.	3.5/16	Stable	Stable
1B19	Fault at Darwin 345 kV on Breed circuit. Breaker A stuck. Fault cleared with loss of Darwin – Eugene circuit.	3.5/16	Stable	Stable
1B20	Fault at Sullivan 765 kV on Sullivan 765/345 kV transformer 1. Breaker A stuck. Fault cleared with loss of Sullivan – Rockport circuit.	3.5/16	Stable	Stable
1B21	Fault at Sullivan 765 kV on Rockport circuit. Breaker A stuck. Fault cleared with loss of Sullivan 765/345 kV transformer 1.	3.5/16	Stable	Stable
1B22	Fault at Sullivan 765 kV on Reynolds circuit. Stuck Breaker. Fault cleared with loss of Sullivan 765/345 kV transformer 1.	3.5/16	Stable	Stable
1B23	Single phase fault at Rockport 765 kV POI on Jefferson circuit. Breaker C2 stuck. Fault cleared with loss of AK Steel 138kV circuit 2.	3.0 / 12.0	Unstable (X3-028 DC Circuit 1 and 2 blocked. Tripping of multiple units)	Unstable (X3-028 DC Circuit 1 and 2 blocked. Trips East 1, East 2 and West 1 at Fowler Ridge. Multiple instances of "network not converged")
1B24	Single phase fault at Jefferson 765 kV on Rockport circuit. Breaker B stuck. Fault cleared with loss of 765/345 kV transformer T-1 and Clifty Creek.	3.0 / 12.0	Unstable (X3-028 DC Circuit 1 and 2 blocked. Tripping of multiple units)	Stable* Post-fault voltage criterion not met

Fault ID	Fault description	Clearing Time Normal/ Stuck Breaker (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
1B25	Single phase fault at Jefferson 765 kV on Rockport circuit. Breaker B1 stuck. Fault cleared with loss of Greentown 765 kV circuit.	3.0 / 12.0	Unstable (X3-028 DC Circuit 1 and 2 blocked. Results in network non convergence and subsequent PSS/E crash.)	Stable* Post-fault voltage criterion not met
1B26	Single phase fault at Jefferson 765 kV on Greentown circuit. Breaker B1 stuck. Fault cleared with loss of Rockport 765 kV circuit.	3.0 / 12.0	Unstable (X3-028 DC Circuit 1 and 2 blocked. Tripping of multiple units)	Stable* Post-fault voltage criterion not met
1B27	Single phase fault at Jefferson 765 kV on 765/345 kV transformer T1. Breaker B stuck. Fault cleared with loss of Rockport 765 kV circuit.	3.0 / 12.0	Unstable (X3-028 DC Circuit 1 and 2 blocked. Tripping of multiple units)	Stable* Post-fault voltage criterion not met
1B28	Single phase fault at Jefferson 765 kV on Hanging Rock circuit. Breaker A stuck. Fault cleared with loss of Greentown 765 kV circuit.	3.5 / 13.0	Unstable (Multiple instances of "network not converged")	Stable*
1B29	Single phase fault at Jefferson 765 kV on Hanging Rock circuit. Breaker A2 stuck. Fault cleared with loss of 765/345 kV transformer T-1 and Clifty Creek.	3.5 / 13.0	Unstable (Multiple instances of "network not converged")	Stable*

Although this contingency was stable under the single possible loadflow scenario simulated, instability (unanticipated blocking of X3-028 circuits) can occur for this contingency under slightly altered loadflow conditions.

Table 11: Single-phase Faults with Delayed Clearing at Remote End

Fault ID	Fault description	Clearing Time Normal / Delayed Clearing (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
1D01	Fault at Breed 345 kV on Dequine circuit. Delayed clearing at Dequine 345 kV.	3.5/60	Stable	Stable
1D02	Fault at Breed 345 kV on Sullivan 765/345 kV transformer 1. Delayed clearing at Sullivan 765 kV.	3.5/60	Stable	Stable
1D03	Fault at Breed 345 kV on Darwin circuit. Delayed clearing at Darwin 345 kV.	3.5/60	Stable	Stable
1D04	Fault at Breed 345 kV on Wheatland circuit. Delayed clearing at Wheatland 345 kV.	3.5/60	Stable	Stable
1D05	Fault at Breed 345 kV on West Casey circuit. Delayed clearing at West Casey 345 kV.	3.5/60	Stable	Stable
1D06	Fault at Eugene 345 kV on Dequine circuit. Delayed clearing at Dequine 345 kV.	3.5/60	Stable	Stable
1D07	Fault at Eugene 345 kV on Darwin circuit. Delayed clearing at Darwin 345 kV.	3.5/60	Stable	Stable
1D08	Fault at Westwood 1 on Dequine circuit. Delayed clearing at Dequine 345 kV.	3.5/60	Stable	Stable
1D09	Fault at Meadow Lake SW 345 kV on Dequine circuit 1. Delayed clearing at Dequine 345 kV.	3.5/60	Stable	Stable
1D10	Fault at Olive 345 kV on Reynolds – Meadow Lake SW circuit. Delayed clearing at Meadow Lake SW 345 kV.	3.5/60	Stable	Stable
1D11	Fault at Olive 345 kV on Meadow Lake SW circuit. Delayed clearing at Meadow Lake SW 345 kV.	3.5/60	Stable	Stable

Fault ID	Fault description	Clearing Time Normal / Delayed Clearing (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support, Post-Pioneer Project
1D12	Fault at Dequine 345 kV on Meadow Lake SW circuit 1. Delayed clearing at Meadow Lake SW 345 kV.	3.5/60	Stable	Stable
1D13	Fault at Darwin 345 kV on Breed circuit. Delayed clearing at Breed 345 kV.	3.5/60	Stable	Stable
1D14	Fault at Sullivan 765 kV on Sullivan 765/345 kV transformer 1. Delayed clearing at Breed 345 kV.	3.5/60	Stable	Stable
1D15	Fault at Dequine 345 kV on Breed circuit. Delayed clearing at Breed 345 kV.	3.5/60	Stable	Stable
1D16	Fault at Rockport 765 kV on Sullivan circuit. Delayed clearing at Sullivan 765 kV.	3.5/0	Cannot complete fault simulation. PSS/E crashing.	Stable
1D17	Fault at Reynolds 765 kV on Sullivan circuit. Delayed clearing at Sullivan 765 kV.	3.5/0	Stable	Stable
1D18	Single phase fault at Rockport 765 kV POI on Jefferson circuit. Delayed clearing at Jefferson.	3.0 / 3.0	Unstable (X3-028 DC Circuit 1 and 2 blocked. Results in network non convergence and subsequent PSS/E crash.)	Stable* Post-fault voltage criterion not met
1D19	Single phase fault at Jefferson 765 kV on Rockport circuit. Delayed clearing at Rockport.	3.0 / 3.0	Unstable (X3-028 DC Circuit 1 and 2 blocked. Results in network non convergence and subsequent PSS/E crash.)	Stable* Post-fault voltage criterion not met

****Although this contingency was stable under the single possible loadflow scenario simulated, instability (unanticipated blocking of X3-028 circuits) can occur for this contingency under slightly altered loadflow conditions.***

Table 12: Three-phase Faults under Outages Without Dynamic Reactive Support

Equipment Under Outage	Fault ID	Fault description	Clearing Time (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support[6], Post-Pioneer Project
Breed – West Casey 345 kV circuit	MA.3N01	Fault at Breed 345 kV on X3-028 circuit 1.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Nearby wind machines tripped)	Stable (X3-028 DC Circuit 1 and 2 blocked)
	MA.3N02	Fault at Breed 345 kV (on Dequine circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Multiple instances of "network failed to converge" results in PSS/E crash)	Stable
	MA.3N03	Fault at Breed 345 kV on Sullivan 765/345 kV transformer 1.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Multiple instances of "network failed to converge" results in PSS/E crash)	Stable
	MA.3N04	Fault at Breed 345 kV (X3-028 POI) on Darwin circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Nearby wind machines tripped)	Stable
	MA.3N05	Fault at Breed 345 kV (X3-028 POI) on Wheatland circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Multiple instances of "network failed to converge" results in PSS/E crash)	Stable
	MA.3N07	Fault at Dequine 345 kV on Meadow Lake SW circuit 1.	3.5	Stable	Stable

[6] In addition to the +800 / -1000 MVAr dynamic reactive support, for an outage on the Breed – West Casey 345 kV circuit X3-028 HVDC circuit injection was curtailed to 1500 MW (the Firm Transmission Injection Right value) in the load flow to maintain dynamic stability.

Equipment Under Outage	Fault ID	Fault description	Clearing Time (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support[6], Post-Pioneer Project
	MA.3N09	Fault at Dequine 345 kV on Breed circuit.	3.5	Stable	Stable
	MA.3N10	Fault at Dequine 345 kV on Fowler Ridge Junction circuit.	3.5	Stable (Trips Fowler Ridge units)	Stable (Trips Fowler Ridge units)
	MA.3N15	Fault at Meadow Lake SW 345 kV on T126/T127 circuit.	3.5	Stable (Trips T126 and T127 units)	Stable (Trips T126 and T127 units)
	MA.3N18	Fault at Darwin 345 kV on Eugene circuit.	3.5	Stable	Stable
	MA.3N19	Fault at Darwin 345 kV on Breed circuit.	3.5	Stable	Stable
	MA.3N20	Fault at Sullivan 765 kV on Sullivan 765/345 kV transformer 1.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Multiple instances of "network failed to converge" results in PSS/E crash)	Stable
	MA.3N21	Fault at Sullivan 765 kV on Rockport circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Nearby wind machines tripped)	Stable
	MA.3N23	Fault at Rockport 765 kV on Sullivan circuit.	3.5	Stable	Stable
	MA.3N24	Fault at Rockport 765 kV on Jefferson circuit. (Fast Valving on Rockport units active)	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Multiple instances of "network failed to converge" results in PSS/E crash)	Stable

Equipment Under Outage	Fault ID	Fault description	Clearing Time (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support[6], Post-Pioneer Project
	MA.3N25	Fault at Jefferson 765 kV on Greentown circuit.	3.5	Stable	Stable
	MA.3N26	Fault at Jefferson 765 kV on Hanging Rock circuit.	3.5	Stable	Stable
Rockport – Jefferson 765 kV circuit	MB.3N01	Fault at Breed 345 kV (X3-028 POI) on X3-028 circuit 1.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Multiple instances of "network failed to converge" results in PSS/E crash)	Stable
	MB.3N02	Fault at Breed 345 kV (X3-028 POI) on Dequine circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Nearby wind machines tripped)	Stable
	MB.3N03	Fault at Breed 345 kV (X3-028 POI) on Sullivan 765/345 kV transformer 1.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Nearby wind machines tripped)	Stable
	MB.3N04	Fault at Breed 345 kV (X3-028 POI) on Darwin circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Multiple instances of "network failed to converge" results in PSS/E crash)	Stable
	MB.3N05	Fault at Breed 345 kV (X3-028 POI) on Wheatland circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Nearby wind machines tripped)	Stable
	MB.3N06	Fault at Breed 345 kV (X3-028 POI) on West Casey circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Nearby wind machines tripped)	Stable

Equipment Under Outage	Fault ID	Fault description	Clearing Time (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support[6], Post-Pioneer Project
	MB.3N07	Fault at Dequine 345 kV on Meadow Lake SW circuit 1.	3.5	Stable	Stable
	MB.3N09	Fault at Dequine 345 kV on Breed circuit.	3.5	Stable	Stable
	MB.3N10	Fault at Dequine 345 kV on Fowler Ridge Junction circuit.	3.5	Network failed to converge, results in PSS/E crash.	Stable (Trips Fowler Ridge units)
	MB.3N15	Fault at Meadow Lake SW 345 kV on T126/T127 circuit.	3.5	Stable (Trips T126 and T127 units)	Stable (Trips T126 and T127 units)
	MB.3N18	Fault at Darwin 345 kV on Eugene circuit.	3.5	Stable	Stable
	MB.3N19	Fault at Darwin 345 kV on Breed circuit.	3.5	Stable	Stable
	MB.3N20	Fault at Sullivan 765 kV on Sullivan 765/345 kV transformer 1.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Multiple instances of "network failed to converge" results in PSS/E crash)	Stable
	MB.3N21	Fault at Sullivan 765 kV on Rockport circuit.	3.5	Unstable (X3-028 DC Circuit 1 and 2 blocked. Multiple instances of "network failed to converge" results in PSS/E crash)	Stable
	MB.3N23	Fault at Rockport 765 kV on Sullivan circuit.	3.5	Stable	Stable

Equipment Under Outage	Fault ID	Fault description	Clearing Time (Cycles)	Post-Pioneer Project	With +800 / -1000 MVAr Dynamic Reactive Support[6], Post-Pioneer Project
	MB.3N25	Fault at Jefferson 765 kV on Greentown circuit.	3.5	Stable	Stable
	MB.3N26	Fault at Jefferson 765 kV on Hanging Rock circuit.	3.5	Stable	Stable

Attachment 1. X3-028 Impact Study Data

Attachment 1a. X3-028 Impact Study Data Form

Attachment 1b. The Pioneer Project one-line diagram

Attachment 2. AEP One Line Diagram

Attachment 3. PSS/E Model One Line Diagram

Attachment 4. X3-028 PSS/E Case Data

Attachment 5. X3-028 PSS/E Dynamics Data

Attachment 6. Plots from Dynamic Simulations

Attachment 6a. Plots from Dynamic Simulations – Intact Network

Results from fault contingencies applied on intact network, both without and with +800/-1000 MVAr dynamic reactive support at X3-028.

Attachment 6b. Plots from Dynamic Simulations – Outages

Results from fault contingencies applied on network with outages, both without and with +800/-1000 MVAr dynamic reactive support at X3-028. In addition to the +800/-1000 MVAr dynamic reactive support, for an outage on the Breed – West Casey 345 kV circuit, the X3-028 injection was curtailed to 1500 MW in the load flow.

Attachment 7. Fault Admittances

Appendices

The following appendices contain additional information about each flowgate presented in the body of the report. For each appendix, a description of the flowgate and its contingency was included for convenience. However, the intent of the appendix section is to provide more information on which projects/generators have contributions to the flowgate in question. Although this information is not used "as is" for cost allocation purposes, it can be used to gage other generators impact.

It should be noted the generator contributions presented in the appendices sections are full contributions, whereas in the body of the report, those contributions take into consideration the commercial probability of each project.

Appendix 1

(AEP - AEP) The 05MEADOW-05REYNOL 345 kV line (from bus 243878 to bus 243230 ckt 1) loads from 89.4% to 101.28% (AC power flow) of its emergency rating (971 MVA) for the single line contingency outage of '4689_B2_TOR15257'. This project contributes approximately 116.11 MW to the thermal violation.

CONTINGENCY '4689_B2_TOR15257'
  OPEN BRANCH FROM BUS 243878 TO BUS 243229 CKT 1 / 243878 05MEADOW 345 243229 05OLIVE 345 1
  END

Bus Number	Bus Name	Full Contribution
243879	05MLCS-1	1.2
294944	Q-001 C1	1.22
294945	Q-001 C2	1.22
294962	Q-003 C	1.22
292412	T-126 C	1.2
292416	T-127 C	1.2
LTF	V2-031	1.58
LTF	V2-032	1.56
LTF	V2-033	0.02
LTF	V2-034	1.08
LTF	W1-079	1.21
LTF	W2-033	12.01
LTF	W3-083	2.01
LTF	W4-049	0.56
LTF	X1-056	1.85
LTF	X1-057	1.85
LTF	X1-058	1.85
LTF	X1-065	1.21
LTF	X2-042	43.47
LTF	X3-020	4.44
900404	X3-028 C	116.12

Appendix 2

(AEP - AEP) The 05REYNOL-05OLIVE 345 kV line (from bus 243230 to bus 243229 ckt 1) loads from 81.17% to 101.56% (**DC power flow**) of its emergency rating (1195 MVA) for the line fault with failed breaker contingency outage of '6523_C2_05MEADOW 345-A1'. This project contributes approximately 243.7 MW to the thermal violation.

CONTINGENCY '6523_C2_05MEADOW 345-A1'
 OPEN BRANCH FROM BUS 243878 TO BUS 243229 CKT 1 / 243878 05MEADOW 345 243229 05OLIVE 345 1
 END

Bus Number	Bus Name	Full Contribution
243879	05MLCS-1	0.93
246431	BUCHANAN	-0.21
294944	Q-001 C1	0.99
294945	Q-001 C2	0.99
294946	Q-001 E1	50.87
294947	Q-001 E2	50.87
294962	Q-003 C	0.99
294963	Q-003 E	50.87
290213	S-006 E	48.36
292412	T-126 C	0.93
292413	T-126 E	47.76
292416	T-127 C	0.93
292417	T-127 E	47.76
LTF	V2-031	1.82
LTF	V2-032	1.79
LTF	V2-033	0.03
LTF	V2-034	1.24
LTF	W1-079	1.17
LTF	W2-033	11.99
LTF	W3-083	2.32
LTF	W4-049	0.55
LTF	X1-056	1.79
LTF	X1-057	1.79
LTF	X1-058	1.79
LTF	X1-065	1.17
LTF	X2-042	42.31
LTF	X3-020	5.09
900404	X3-028 C	104.45

900405	X3-028 E	139.26

Appendix 3

(AEP - AEP) The 05BREED-05DEQUIN 345 kV line (from bus 243213 to bus 243217 ckt 1) loads from 80.47% to 101.68% (**DC power flow**) of its emergency rating (972 MVA) for the single line contingency outage of '05JEFRSO _05ROCKPT _122'. This project contributes approximately 206.24 MW to the thermal violation.

CONTINGENCY '05JEFRSO _05ROCKPT _122'
 DISCONNECT BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 /* 765/765KV, AREA 205/205.
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	14.14
243443	05RKG2	13.92
LTF	V2-031	2.3
LTF	V2-032	2.27
LTF	V2-033	0.03
LTF	V2-034	1.57
LTF	V4-060	0.54
LTF	V4-061	0.54
LTF	W1-016	0.54
LTF	W1-017	0.54
LTF	W1-018	0.54
LTF	W1-019	0.54
LTF	W1-020	0.49
LTF	W1-079	0.39
LTF	W2-033	4.4
LTF	W3-083	2.93
LTF	W4-049	0.28
LTF	X1-056	1.09
LTF	X1-057	1.09
LTF	X1-058	1.09
LTF	X1-065	0.39
LTF	X2-042	12.49
LTF	X3-020	6.32
900404	X3-028 C	206.24

Appendix 4

(AEP - OVEC) The 05JEFRSO 765/345 kV transformer (from bus 243208 to bus 248000 ckt 1) loads from 54.55% to 101.78% (**DC power flow**) of its emergency rating (1935 MVA) for the line fault with failed breaker contingency outage of '1760_C2_05JEFRSO 765-A'. This project contributes approximately 913.89 MW to the thermal violation.

CONTINGENCY '1760_C2_05JEFRSO 765-A'
OPEN BRANCH FROM BUS 243207 TO BUS 243208 CKT 1 / 243207 05GRNTWN 765 243208 05JEFRSO 765 1
OPEN BRANCH FROM BUS 242924 TO BUS 243208 CKT 1 / 242924 05HANG R 765 243208 05JEFRSO 765 1
END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	49.14
243443	05RKG2	48.39
294944	Q-001 C1	0.42
294945	Q-001 C2	0.42
294946	Q-001 E1	21.74
294947	Q-001 E2	21.74
294962	Q-003 C	0.42
294963	Q-003 E	21.74
LTF	V2-031	6.91
LTF	V2-032	6.8
LTF	V2-033	0.1
LTF	V2-034	4.71
LTF	V4-060	3.27
LTF	V4-061	3.27
LTF	W1-016	3.27
LTF	W1-017	3.27
LTF	W1-018	3.27
LTF	W1-019	3.27
LTF	W1-020	3.01
LTF	W3-083	8.79
LTF	X2-042	40.96
LTF	X3-020	18.34
LTF	X3-021	9.07
900404	X3-028 C	391.67
900405	X3-028 E	522.22

Appendix 5

(AEP - AEP) The 05DARWIN-05EUGENE 345 kV line (from bus 243216 to bus 243221 ckt 1) loads from 52.14% to 105.69% (**DC power flow**) of its emergency rating (1419 MVA) for the line fault with failed breaker contingency outage of '3002_C2'. This project contributes approximately 759.96 MW to the thermal violation.

CONTINGENCY '3002_C2'
 OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
 OPEN BRANCH FROM BUS 243209 TO BUS 243240 CKT 8 / 243209 05ROCKPT 765 243240 05AKSTL2 138 8
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	22.33
243443	05RKG2	21.99
LTF	V2-031	2.54
LTF	V2-032	2.51
LTF	V2-033	0.04
LTF	V2-034	1.74
LTF	V4-060	0.81
LTF	V4-061	0.81
LTF	W1-016	0.81
LTF	W1-017	0.81
LTF	W1-018	0.81
LTF	W1-019	0.81
LTF	W1-020	0.75
LTF	W2-033	0.97
LTF	W3-083	3.24
LTF	W4-049	0.11
LTF	X1-056	0.42
LTF	X1-057	0.42
LTF	X1-058	0.42
LTF	X3-020	6.9
900404	X3-028 C	325.7
900405	X3-028 E	434.26

Appendix 6

(AEP - AEP) The 05DARWIN-05EUGENE 345 kV line (from bus 243216 to bus 243221 ckt 1) loads from 52.14% to 105.69% (**DC power flow**) of its emergency rating (1419 MVA) for the line fault with failed breaker contingency outage of '3183_C2'. This project contributes approximately 759.96 MW to the thermal violation.

CONTINGENCY '3183_C2'
 OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
 OPEN BRANCH FROM BUS 243209 TO BUS 243239 CKT 7 / 243209 05ROCKPT 765 243239 05AKSTL1 138 7
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	22.33
243443	05RKG2	21.99
LTF	V2-031	2.54
LTF	V2-032	2.51
LTF	V2-033	0.04
LTF	V2-034	1.74
LTF	V4-060	0.81
LTF	V4-061	0.81
LTF	W1-016	0.81
LTF	W1-017	0.81
LTF	W1-018	0.81
LTF	W1-019	0.81
LTF	W1-020	0.75
LTF	W2-033	0.97
LTF	W3-083	3.24
LTF	W4-049	0.11
LTF	X1-056	0.42
LTF	X1-057	0.42
LTF	X1-058	0.42
LTF	X3-020	6.9
900404	X3-028 C	325.7
900405	X3-028 E	434.26

Appendix 7

(AEP - AEP) The 05BREED-05DARWIN 345 kV line (from bus 243213 to bus 243216 ckt 1) loads from 52.14% to 105.69% (**DC power flow**) of its emergency rating (1419 MVA) for the line fault with failed breaker contingency outage of '3002_C2'. This project contributes approximately 759.96 MW to the thermal violation.

CONTINGENCY '3002_C2'
 OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
 OPEN BRANCH FROM BUS 243209 TO BUS 243240 CKT 8 / 243209 05ROCKPT 765 243240 05AKSTL2 138 8
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	22.33
243443	05RKG2	21.99
LTF	V2-031	2.54
LTF	V2-032	2.51
LTF	V2-033	0.04
LTF	V2-034	1.74
LTF	V4-060	0.81
LTF	V4-061	0.81
LTF	W1-016	0.81
LTF	W1-017	0.81
LTF	W1-018	0.81
LTF	W1-019	0.81
LTF	W1-020	0.75
LTF	W2-033	0.97
LTF	W3-083	3.24
LTF	W4-049	0.11
LTF	X1-056	0.42
LTF	X1-057	0.42
LTF	X1-058	0.42
LTF	X3-020	6.9
900404	X3-028 C	325.7
900405	X3-028 E	434.26

Appendix 8

(AEP - AEP) The 05BREED-05DARWIN 345 kV line (from bus 243213 to bus 243216 ckt 1) loads from 52.14% to 105.69% (**DC power flow**) of its emergency rating (1419 MVA) for the line fault with failed breaker contingency outage of '3183_C2'. This project contributes approximately 759.96 MW to the thermal violation.

CONTINGENCY '3183_C2'
OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
OPEN BRANCH FROM BUS 243209 TO BUS 243239 CKT 7 / 243209 05ROCKPT 765 243239 05AKSTL1 138 7
END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	22.33
243443	05RKG2	21.99
LTF	V2-031	2.54
LTF	V2-032	2.51
LTF	V2-033	0.04
LTF	V2-034	1.74
LTF	V4-060	0.81
LTF	V4-061	0.81
LTF	W1-016	0.81
LTF	W1-017	0.81
LTF	W1-018	0.81
LTF	W1-019	0.81
LTF	W1-020	0.75
LTF	W2-033	0.97
LTF	W3-083	3.24
LTF	W4-049	0.11
LTF	X1-056	0.42
LTF	X1-057	0.42
LTF	X1-058	0.42
LTF	X3-020	6.9
900404	X3-028 C	325.7
900405	X3-028 E	434.26

Appendix 9

(AEP - AEP) The 05DARWIN-05EUGENE 345 kV line (from bus 243216 to bus 243221 ckt 1) loads from 52.79% to 106.44% (**DC power flow**) of its emergency rating (1419 MVA) for the line fault with failed breaker contingency outage of '2930_C2'. This project contributes approximately 761.25 MW to the thermal violation.

CONTINGENCY '2930_C2'
 OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
 OPEN BRANCH FROM BUS 243208 TO BUS 248000 CKT 1 / 243208 05JEFRSO 765 248000 06CLIFTY 345 1
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	22.37
243443	05RKG2	22.03
LTF	V2-031	2.56
LTF	V2-032	2.52
LTF	V2-033	0.04
LTF	V2-034	1.74
LTF	V4-060	0.81
LTF	V4-061	0.81
LTF	W1-016	0.81
LTF	W1-017	0.81
LTF	W1-018	0.81
LTF	W1-019	0.81
LTF	W1-020	0.75
LTF	W2-033	1.46
LTF	W3-083	3.26
LTF	W4-049	0.12
LTF	X1-056	0.48
LTF	X1-057	0.48
LTF	X1-058	0.48
LTF	X3-020	6.95
900404	X3-028 C	326.25
900405	X3-028 E	435.

Appendix 10

(AEP - AEP) The 05BREED-05DARWIN 345 kV line (from bus 243213 to bus 243216 ckt 1) loads from 52.79% to 106.44% (**DC power flow**) of its emergency rating (1419 MVA) for the line fault with failed breaker contingency outage of '2930_C2'. This project contributes approximately 761.25 MW to the thermal violation.

CONTINGENCY '2930_C2'
 OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
 OPEN BRANCH FROM BUS 243208 TO BUS 248000 CKT 1 / 243208 05JEFRSO 765 248000 06CLIFTY 345 1
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	22.37
243443	05RKG2	22.03
LTF	V2-031	2.56
LTF	V2-032	2.52
LTF	V2-033	0.04
LTF	V2-034	1.74
LTF	V4-060	0.81
LTF	V4-061	0.81
LTF	W1-016	0.81
LTF	W1-017	0.81
LTF	W1-018	0.81
LTF	W1-019	0.81
LTF	W1-020	0.75
LTF	W2-033	1.46
LTF	W3-083	3.26
LTF	W4-049	0.12
LTF	X1-056	0.48
LTF	X1-057	0.48
LTF	X1-058	0.48
LTF	X3-020	6.95
900404	X3-028 C	326.25
900405	X3-028 E	435.

Appendix 11

(AEP - AEP) The 05MEADOW-05REYNOL 345 kV line (from bus 243878 to bus 243230 ckt 1) loads from 88.07% to 107.17% (**DC power flow**) of its emergency rating (1419 MVA) for the line fault with failed breaker contingency outage of '6523_C2_05MEADOW 345-A1'. This project contributes approximately 270.93 MW to the thermal violation.

CONTINGENCY '6523_C2_05MEADOW 345-A1'
 OPEN BRANCH FROM BUS 243878 TO BUS 243229 CKT 1 / 243878 05MEADOW 345 243229 05OLIVE 345 1
 END

Bus Number	Bus Name	Full Contribution
243879	05MLCS-1	1.2
294944	Q-001 C1	1.22
294945	Q-001 C2	1.22
294946	Q-001 E1	62.87
294947	Q-001 E2	62.87
294962	Q-003 C	1.22
294963	Q-003 E	62.87
290213	S-006 E	62.41
292412	T-126 C	1.2
292413	T-126 E	61.64
292416	T-127 C	1.2
292417	T-127 E	61.64
LTF	V2-031	1.58
LTF	V2-032	1.56
LTF	V2-033	0.02
LTF	V2-034	1.08
LTF	W1-079	1.21
LTF	W2-033	12.01
LTF	W3-083	2.01
LTF	W4-049	0.56
LTF	X1-056	1.85
LTF	X1-057	1.85
LTF	X1-058	1.85
LTF	X1-065	1.21
LTF	X2-042	43.47
LTF	X3-020	4.44
900404	X3-028 C	116.12
900405	X3-028 E	154.82

Appendix 12

(AEP - AEP) The 05DARWIN-05EUGENE 345 kV line (from bus 243216 to bus 243221 ckt 1) loads from 53.78% to 107.11% (**DC power flow**) of its emergency rating (1419 MVA) for the line fault with failed breaker contingency outage of '2929_C2'. This project contributes approximately 756.73 MW to the thermal violation.

CONTINGENCY '2929_C2'
 OPEN BRANCH FROM BUS 243207 TO BUS 243208 CKT 1 / 243207 05GRNTWN 765 243208 05JEFRSO 765 1
 OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	22.23
243443	05RKG2	21.9
LTF	V2-031	2.46
LTF	V2-032	2.43
LTF	V2-033	0.04
LTF	V2-034	1.68
LTF	V4-060	0.74
LTF	V4-061	0.74
LTF	W1-016	0.74
LTF	W1-017	0.74
LTF	W1-018	0.74
LTF	W1-019	0.74
LTF	W1-020	0.68
LTF	W2-033	1.82
LTF	W3-083	3.13
LTF	W4-049	0.14
LTF	X1-056	0.44
LTF	X1-057	0.44
LTF	X1-058	0.44
LTF	X3-020	6.68
900404	X3-028 C	324.32
900405	X3-028 E	432.42

Appendix 13

(AEP - AEP) The 05BREED-05DARWIN 345 kV line (from bus 243213 to bus 243216 ckt 1) loads from 53.78% to 107.11% (**DC power flow**) of its emergency rating (1419 MVA) for the line fault with failed breaker contingency outage of '2929_C2'. This project contributes approximately 756.73 MW to the thermal violation.

CONTINGENCY '2929_C2'
 OPEN BRANCH FROM BUS 243207 TO BUS 243208 CKT 1 / 243207 05GRNTWN 765 243208 05JEFRSO 765 1
 OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	22.23
243443	05RKG2	21.9
LTF	V2-031	2.46
LTF	V2-032	2.43
LTF	V2-033	0.04
LTF	V2-034	1.68
LTF	V4-060	0.74
LTF	V4-061	0.74
LTF	W1-016	0.74
LTF	W1-017	0.74
LTF	W1-018	0.74
LTF	W1-019	0.74
LTF	W1-020	0.68
LTF	W2-033	1.82
LTF	W3-083	3.13
LTF	W4-049	0.14
LTF	X1-056	0.44
LTF	X1-057	0.44
LTF	X1-058	0.44
LTF	X3-020	6.68
900404	X3-028 C	324.32
900405	X3-028 E	432.42

Appendix 14

(AEP - AEP) The 05BREED-05DARWIN 345 kV line (from bus 243213 to bus 243216 ckt 1) loads from 76.12% to 109.63% (**DC power flow**) of its emergency rating (972 MVA) for the single line contingency outage of '05JEFRSO _05ROCKPT _122'. This project contributes approximately 325.7 MW to the thermal violation.

CONTINGENCY '05JEFRSO _05ROCKPT _122'
DISCONNECT BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 /* 765/765KV, AREA 205/205.
END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	22.33
243443	05RKG2	21.99
LTF	V2-031	2.54
LTF	V2-032	2.51
LTF	V2-033	0.04
LTF	V2-034	1.74
LTF	V4-060	0.81
LTF	V4-061	0.81
LTF	W1-016	0.81
LTF	W1-017	0.81
LTF	W1-018	0.81
LTF	W1-019	0.81
LTF	W1-020	0.75
LTF	W2-033	0.97
LTF	W3-083	3.24
LTF	W4-049	0.11
LTF	X1-056	0.42
LTF	X1-057	0.42
LTF	X1-058	0.42
LTF	X3-020	6.9
900404	X3-028 C	325.7

Appendix 15

(AEP - AEP) The 05DARWIN-05EUGENE 345 kV line (from bus 243216 to bus 243221 ckt 1) loads from 76.2% to 109.74% (**DC power flow**) of its emergency rating (971 MVA) for the single line contingency outage of '05JEFRSO _05ROCKPT _122'. This project contributes approximately 325.7 MW to the thermal violation.

CONTINGENCY '05JEFRSO _05ROCKPT _122'
 DISCONNECT BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 /* 765/765KV, AREA 205/205.
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	22.33
243443	05RKG2	21.99
LTF	V2-031	2.54
LTF	V2-032	2.51
LTF	V2-033	0.04
LTF	V2-034	1.74
LTF	V4-060	0.81
LTF	V4-061	0.81
LTF	W1-016	0.81
LTF	W1-017	0.81
LTF	W1-018	0.81
LTF	W1-019	0.81
LTF	W1-020	0.75
LTF	W2-033	0.97
LTF	W3-083	3.24
LTF	W4-049	0.11
LTF	X1-056	0.42
LTF	X1-057	0.42
LTF	X1-058	0.42
LTF	X3-020	6.9
900404	X3-028 C	325.7

Appendix 16

(AEP - AEP) The 05EUGENE-05DEQUIN 345 kV line (from bus 243221 to bus 243217 ckt 1) loads from 99.9% to 111.83% (AC power flow) of its emergency rating (972 MVA) for the single line contingency outage of '667_B2_TOR1697'. This project contributes approximately 104.22 MW to the thermal violation.

CONTINGENCY '667_B2_TOR1697'
 OPEN BRANCH FROM BUS 243213 TO BUS 243217 CKT 1 / 243213 05BREED 345 243217 05DEQUIN 345 1
 END

Bus Number	Bus Name	Full Contribution
LTF	V2-031	2.1
LTF	V2-032	2.07
LTF	V2-033	0.03
LTF	V2-034	1.43
LTF	V4-060	0.06
LTF	V4-061	0.06
LTF	W1-016	0.06
LTF	W1-017	0.06
LTF	W1-018	0.06
LTF	W1-019	0.06
LTF	W1-020	0.06
LTF	W1-079	1.31
LTF	W2-033	11.77
LTF	W3-083	2.67
LTF	W4-049	0.64
LTF	X1-056	2.06
LTF	X1-057	2.06
LTF	X1-058	2.06
LTF	X1-065	1.31
LTF	X2-042	52.53
LTF	X3-020	5.86
900404	X3-028 C	104.22

Appendix 17

(AEP - MISO AMIL) The 05BREED-7CASEY 345 kV line (from bus 243213 to bus 346809 ckt 1) loads from 74.65% to 114.13% (**DC power flow**) of its emergency rating (1332 MVA) for the single line contingency outage of '05JEFRSO _05ROCKPT _122'. This project contributes approximately 525.85 MW to the thermal violation.

CONTINGENCY '05JEFRSO _05ROCKPT _122'
 DISCONNECT BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 /* 765/765KV, AREA 205/205.
 END

Bus Number	Bus Name	Full Contribution
243879	05MLCS-1	0.22
243442	05RKG1	36.06
243443	05RKG2	35.51
294944	Q-001 C1	0.32
294945	Q-001 C2	0.32
294962	Q-003 C	0.32
292412	T-126 C	0.22
292416	T-127 C	0.22
LTF	U4-022	5.58
LTF	U4-023	5.58
LTF	V4-050	37.86
LTF	W1-079	0.62
LTF	W2-033	2.08
LTF	X1-056	0.61
LTF	X1-057	0.61
LTF	X1-058	0.61
LTF	X1-065	0.62
LTF	X2-042	40.49
LTF	X3-021	4.03
900404	X3-028 C	525.86

Appendix 18

(AEP - AEP) The 05DEQUIN-05MEADOW 345 kV line (from bus 243217 to bus 243878 ckt 1) loads from 99.75% to 114.77% (AC power flow) of its emergency rating (972 MVA) for the single line contingency outage of '6490_B2_TOR3002545'. This project contributes approximately 144.92 MW to the thermal violation.

CONTINGENCY '6490_B2_TOR3002545'
OPEN BRANCH FROM BUS 243217 TO BUS 243878 CKT 2 / 243217 05DEQUIN 345 243878 05MEADOW 345 2
END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	6.04
243443	05RKG2	5.95
294944	Q-001 C1	1.49
294945	Q-001 C2	1.49
294962	Q-003 C	1.49
LTF	V2-031	2.13
LTF	V2-032	2.1
LTF	V2-033	0.03
LTF	V2-034	1.45
LTF	W1-079	1.57
LTF	W2-033	15.28
LTF	W3-083	2.71
LTF	W4-049	0.75
LTF	X1-056	2.37
LTF	X1-057	2.37
LTF	X1-058	2.37
LTF	X1-065	1.57
LTF	X2-042	55.36
LTF	X3-020	5.98
900404	X3-028 C	144.92

Appendix 19

(AEP - AEP) The 05DEQUIN-05MEADOW 345 kV line (from bus 243217 to bus 243878 ckt 2) loads from 99.85% to 114.88% (AC power flow) of its emergency rating (971 MVA) for the single line contingency outage of '6472_B2_TOR15258'. This project contributes approximately 144.92 MW to the thermal violation.

CONTINGENCY '6472_B2_TOR15258'
 OPEN BRANCH FROM BUS 243217 TO BUS 243878 CKT 1 / 243217 05DEQUIN 345 243878 05MEADOW 345 1
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	6.04
243443	05RKG2	5.95
294944	Q-001 C1	1.49
294945	Q-001 C2	1.49
294962	Q-003 C	1.49
LTF	V2-031	2.13
LTF	V2-032	2.1
LTF	V2-033	0.03
LTF	V2-034	1.45
LTF	W1-079	1.57
LTF	W2-033	15.28
LTF	W3-083	2.71
LTF	W4-049	0.75
LTF	X1-056	2.37
LTF	X1-057	2.37
LTF	X1-058	2.37
LTF	X1-065	1.57
LTF	X2-042	55.36
LTF	X3-020	5.98
900404	X3-028 C	144.92

Appendix 20

(AEP - AEP) The 05DEQUIN-05MEADOW 345 kV line (from bus 243217 to bus 243878 ckt 1) loads from 94.78% to 121.18% (AC power flow) of its emergency rating (1304 MVA) for the line fault with failed breaker contingency outage of '6485_C2_05DEQUIN 345-C1'. This project contributes approximately 344.26 MW to the thermal violation.

CONTINGENCY '6485_C2_05DEQUIN 345-C1'
 OPEN BRANCH FROM BUS 243217 TO BUS 243878 CKT 2 / 243217 05DEQUIN 345 243878 05MEADOW 345 2
 OPEN BRANCH FROM BUS 243217 TO BUS 249525 CKT 1 / 243217 05DEQUIN 345 249525 08WESTWD 345 1
 OPEN BRANCH FROM BUS 249525 TO BUS 249874 CKT 1 / 249525 08WESTWD 345 249874 08WESTWD 138 1
 END

Bus Number	Bus Name	Full Contribution
294944	Q-001 C1	1.54
294945	Q-001 C2	1.54
294946	Q-001 E1	79.18
294947	Q-001 E2	79.18
294962	Q-003 C	1.54
294963	Q-003 E	79.18
LTF	V2-031	2.17
LTF	V2-032	2.14
LTF	V2-033	0.03
LTF	V2-034	1.48
LTF	W1-079	1.56
LTF	W2-033	15.2
LTF	W3-083	2.76
LTF	W4-049	0.75
LTF	X1-056	2.36
LTF	X1-057	2.36
LTF	X1-058	2.36
LTF	X1-065	1.56
LTF	X2-042	54.79
LTF	X3-020	6.08
900404	X3-028 C	147.54
900405	X3-028 E	196.72

Appendix 21

(AEP - AEP) The 05DEQUIN-05MEADOW 345 kV line (from bus 243217 to bus 243878 ckt 2) loads from 98.39% to 125.29% (AC power flow) of its emergency rating (1257 MVA) for the line fault with failed breaker contingency outage of '6525_C2_05MEADOW 345-D'. This project contributes approximately 338.14 MW to the thermal violation.

CONTINGENCY '6525_C2_05MEADOW 345-D'
 OPEN BRANCH FROM BUS 243217 TO BUS 243878 CKT 1 / 243217 05DEQUIN 345 243878 05MEADOW 345 1
 OPEN BRANCH FROM BUS 243878 TO BUS 243879 CKT 1 / 243878 05MEADOW 345 292412 T-126C 34.5 2
 OPEN BRANCH FROM BUS 292412 TO BUS 292413 CKT 1 / 292412 T-126C 34.5 292413 T-126E 34.5 1
 REMOVE UNIT 1 FROM BUS 292412 / 292412 T-126C 34.5
 REMOVE UNIT 1 FROM BUS 292413 / 292413 T-126E 34.5
 END

Bus Number	Bus Name	Full Contribution
246431	BUCHANAN	-0.26
294944	Q-001 C1	1.49
294945	Q-001 C2	1.49
294946	Q-001 E1	76.34
294947	Q-001 E2	76.34
294962	Q-003 C	1.49
294963	Q-003 E	76.34
LTF	V2-031	2.13
LTF	V2-032	2.1
LTF	V2-033	0.03
LTF	V2-034	1.45
LTF	W1-079	1.57
LTF	W2-033	15.28
LTF	W3-083	2.71
LTF	W4-049	0.75
LTF	X1-056	2.37
LTF	X1-057	2.37
LTF	X1-058	2.37
LTF	X1-065	1.57
LTF	X2-042	55.36
LTF	X3-020	5.98
900404	X3-028 C	144.92
900405	X3-028 E	193.22

Appendix 22

(AEP - AEP) The 05DEQUIN-05MEADOW 345 kV line (from bus 243217 to bus 243878 ckt 2) loads from 98.32% to 125.71% (AC power flow) of its emergency rating (1257 MVA) for the line fault with failed breaker contingency outage of '4704_C2_05DEQUIN 345-B1'. This project contributes approximately 344.26 MW to the thermal violation.

CONTINGENCY '4704_C2_05DEQUIN 345-B1'
 OPEN BRANCH FROM BUS 243217 TO BUS 243878 CKT 1 / 243217 05DEQUIN 345 243878 05MEADOW 345 1
 OPEN BRANCH FROM BUS 243217 TO BUS 249525 CKT 1 / 243217 05DEQUIN 345 249525 08WESTWD 345 1
 OPEN BRANCH FROM BUS 249525 TO BUS 249874 CKT 1 / 249525 08WESTWD 345 249874 08WESTWD 138 1
 END

Bus Number	Bus Name	Full Contribution
294944	Q-001 C1	1.54
294945	Q-001 C2	1.54
294946	Q-001 E1	79.18
294947	Q-001 E2	79.18
294962	Q-003 C	1.54
294963	Q-003 E	79.18
LTF	V2-031	2.17
LTF	V2-032	2.14
LTF	V2-033	0.03
LTF	V2-034	1.48
LTF	W1-079	1.56
LTF	W2-033	15.2
LTF	W3-083	2.76
LTF	W4-049	0.75
LTF	X1-056	2.36
LTF	X1-057	2.36
LTF	X1-058	2.36
LTF	X1-065	1.56
LTF	X2-042	54.79
LTF	X3-020	6.08
900404	X3-028 C	147.54
900405	X3-028 E	196.72

Appendix 23

(AEP - AEP) The 05BREED-05DEQUIN 345 kV line (from bus 243213 to bus 243217 ckt 1) loads from 83.1% to 132.96% (**DC power flow**) of its emergency rating (972 MVA) for the line fault with failed breaker contingency outage of '2930_C2'. This project contributes approximately 484.61 MW to the thermal violation.

CONTINGENCY '2930_C2'
OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
OPEN BRANCH FROM BUS 243208 TO BUS 248000 CKT 1 / 243208 05JEFRSO 765 248000 06CLIFTY 345 1
END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	14.24
243443	05RKG2	14.02
LTF	V2-031	2.34
LTF	V2-032	2.3
LTF	V2-033	0.04
LTF	V2-034	1.59
LTF	V4-060	0.54
LTF	V4-061	0.54
LTF	W1-016	0.54
LTF	W1-017	0.54
LTF	W1-018	0.54
LTF	W1-019	0.54
LTF	W1-020	0.5
LTF	W1-079	0.55
LTF	W2-033	5.68
LTF	W3-083	2.98
LTF	W4-049	0.29
LTF	X1-056	1.24
LTF	X1-057	1.24
LTF	X1-058	1.24
LTF	X1-065	0.55
LTF	X2-042	13.65
LTF	X3-020	6.43
900404	X3-028 C	207.69
900405	X3-028 E	276.92

Appendix 24

(AEP - AEP) The 05BREED-05DEQUIN 345 kV line (from bus 243213 to bus 243217 ckt 1) loads from 84.42% to 133.37% (**DC power flow**) of its emergency rating (972 MVA) for the line fault with failed breaker contingency outage of '2929_C2'. This project contributes approximately 475.79 MW to the thermal violation.

CONTINGENCY '2929_C2'
 OPEN BRANCH FROM BUS 243207 TO BUS 243208 CKT 1 / 243207 05GRNTWN 765 243208 05JEFRSO 765 1
 OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	13.98
243443	05RKG2	13.77
LTF	V2-031	2.17
LTF	V2-032	2.13
LTF	V2-033	0.03
LTF	V2-034	1.48
LTF	V4-060	0.41
LTF	V4-061	0.41
LTF	W1-016	0.41
LTF	W1-017	0.41
LTF	W1-018	0.41
LTF	W1-019	0.41
LTF	W1-020	0.38
LTF	W1-079	0.49
LTF	W2-033	5.82
LTF	W3-083	2.76
LTF	W4-049	0.33
LTF	X1-056	1.13
LTF	X1-057	1.13
LTF	X1-058	1.13
LTF	X1-065	0.49
LTF	X2-042	11.84
LTF	X3-020	5.95
900404	X3-028 C	203.91
900405	X3-028 E	271.88

Appendix 25

(AEP - MISO AMIL) The 05BREED-7CASEY 345 kV line (from bus 243213 to bus 346809 ckt 1) loads from 72.97% to 156.6% (**DC power flow**) of its emergency rating (1466 MVA) for the line fault with failed breaker contingency outage of '2929_C2'. This project contributes approximately 1225.98 MW to the thermal violation.

CONTINGENCY '2929_C2'
OPEN BRANCH FROM BUS 243207 TO BUS 243208 CKT 1 / 243207 05GRNTWN 765 243208 05JEFRSO 765 1
OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	36.03
243443	05RKG2	35.48
294946	Q-001 E1	16.26
294947	Q-001 E2	16.26
294963	Q-003 E	16.26
290213	S-006 E	11.19
292413	T-126 E	11.06
292417	T-127 E	11.06
LTF	U4-022	5.58
LTF	U4-023	5.58
LTF	V4-050	37.95
LTF	W1-079	0.64
LTF	W2-033	2.35
LTF	X1-056	0.62
LTF	X1-057	0.62
LTF	X1-058	0.62
LTF	X1-065	0.64
LTF	X2-042	40.37
LTF	X3-021	3.74
900404	X3-028 C	525.42
900405	X3-028 E	700.56

Appendix 26

(AEP - MISO AMIL) The 05BREED-7CASEY 345 kV line (from bus 243213 to bus 346809 ckt 1) loads from 74.26% to 158.2% (**DC power flow**) of its emergency rating (1466 MVA) for the line fault with failed breaker contingency outage of '2930_C2'. This project contributes approximately 1230.46 MW to the thermal violation.

CONTINGENCY '2930_C2'
 OPEN BRANCH FROM BUS 243208 TO BUS 243209 CKT 1 / 243208 05JEFRSO 765 243209 05ROCKPT 765 1
 OPEN BRANCH FROM BUS 243208 TO BUS 248000 CKT 1 / 243208 05JEFRSO 765 248000 06CLIFTY 345 1
 END

Bus Number	Bus Name	Full Contribution
243442	05RKG1	36.16
243443	05RKG2	35.61
294946	Q-001 E1	16.41
294947	Q-001 E2	16.41
294963	Q-003 E	16.41
290213	S-006 E	11.3
292413	T-126 E	11.16
292417	T-127 E	11.16
LTF	U4-022	5.49
LTF	U4-023	5.49
LTF	V4-050	37.74
LTF	W1-079	0.79
LTF	W2-033	3.39
LTF	X1-056	0.77
LTF	X1-057	0.77
LTF	X1-058	0.77
LTF	X1-065	0.79
LTF	X2-042	41.67
LTF	X3-021	3.89
900404	X3-028 C	527.34
900405	X3-028 E	703.12

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing it to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an interconnection on the Maywood-Montgomery 345 kV Transmission Line	) Case No. EA-2014-0207

INTERVENOR ROCKIES EXPRESS PIPELINE LLC'S
RESPONSES TO GRAIN BELT EXPRESS CLEAN LINE LLC'S
FIRST SET OF DATA REQUESTS

For its responses to Grain Belt Express Clean Line, LLC's First Set of Data Requests to Intervenor Rockies Express Pipeline LLC, Rockies Express and Robert F. Allen state as follows:

1. Please provide all workpapers supporting the rebuttal testimony of Rockies Express witness Robert F. Allen.

RESPONSE: Robert F. Allen has no workpapers supporting his rebuttal testimony.

2. Regarding the statement in the rebuttal testimony of Mr. Allen at page 3, lines 6-8, please identify the studies that should be performed prior to the final structure locations.

RESPONSE: Studies that model DC interference effects to pipeline systems, during both normal operations of the HVDC circuit and during fault conditions or monopolar operations of the HVDC circuit, need to be conducted.

REX is advised that modeling software to conduct such studies is available from companies such as Safe Engineering Services, Beasy Software, and Elecsys.

3. Regarding the reference in the rebuttal testimony of Mr. Allen at page 6, lines 18-21, please provides copies of any studies or industry reports that support the statement that "a fault condition on an HVDC transmission circuit could result in fault current voltages transferring to the pipeline in the <u>tens</u> or <u>hundreds</u> of volts."

RESPONSE: Mr. Allen has not located any published studies or industry reports that support this statement. Studies of which Mr. Allen is aware have not included fault conditions at crossings of pipeline and HVDC circuits where these values may be present. A number of factors make it unlikely that published documents would include such specifics:

- **Industry awareness and reporting is limited due to relatively small number of co-located pipelines and HVDC systems**
- **Studies are often proprietary or confidential to either the HVDC Operator or the Pipeline Operator**

Mr. Allen's statement is supported by the fact that during a fault condition on the HVDC circuit, the DC current may leave the circuit conductors and travel down the tower and into the soil and onto the pipeline. The effect on the pipeline will be dependent on the exact fault current, and the proximity of the towers or other grounding structures to the pipeline. To avoid the possibility of damage to the integrity of the pipeline, REX is recommending a minimum separation distance between the circuit towers and the pipeline.

4. Regarding Recommendation #1 in the rebuttal testimony of Rockies Express witness Robert F. Allen at page 9, please identify any industry best practice that requires the placing of a high-voltage transmission line no closer than 1000 feet from a natural gas pipeline.

RESPONSE: **REX is not aware of any industry best practices that identify specific separation distances between pipelines and HVDC circuits. The current "industry practice" is to recommend that the separation distance between pipelines and HVDC circuits at crossings be as great as possible. For this reason REX recommended a minimum separation distance of 1,000 feet. But this also must be correlated with the results from the interference studies. As indicated in No. 3 above, the lack of published industry best practices is partially due to the small number of HVDC systems presently operating that interact with pipelines along their route. This small number results in limited information about the routing and parameters for separation distance and fault current mitigation. Due to this lack of information in the industry, REX recommends a cautious approach with respect to siting and safe operation of both systems.**

5. Regarding Recommendation #4 in Mr. Allen's rebuttal testimony at pages 11-12, please identify and provide: (a) any studies and any industry best practices or standards that support this recommendation; and (b) any studies that show that direct current (DC) interference is minimized by 90 degree angles during both normal and abnormal situations.

RESPONSE: **5. a) REX is not aware of any industry best practices or standards that support the recommendation. Studies published in the public domain discuss specific systems that are dissimilar to the proposed routing and system design outlined for the GBX project.**
b) As outlined in No. 4 above, because of the small number of HVDC systems presently operating that interact with pipelines

along their route, REX recommends a cautious approach to all pipeline / HVDC circuit crossings. Having HVDC circuits cross the pipeline at a 90 degree angle will ensure that the towers are located at the furthest distance from the pipeline to reduce any effects to the pipeline if there were to be a fault condition at either of the towers at a crossing.

6. Regarding Recommendation #5 in Mr. Allen's rebuttal testimony at page 12, please identify and provide copies of any industry best practices that require the construction of high-voltage electric transmission line towers no closer than 300 feet from a natural gas pipeline when crossing the pipeline.

RESPONSE: See # 4 above. REX is not aware of any industry best practices that outline a minimum separation distance at a crossing between an HVDC circuit and a pipeline. REX's recommendation of 300 feet is based upon an assumed minimum 600 foot span/tower separation for the proposed GBX HVDC circuit. REX recommends that at all crossings of the HVDC circuit and the pipeline, that the pipeline be mid-span with respect to the tower separation.

Prepared By: Robert F. Allen

October 6, 2014