INTERCONNECTION SYSTEM IMPACT STUDY REPORT FOR PROJECT GI-1401

TOTAL REQUESTED OUTPUT OF 325 MW IN BUTTE COUNTY, SD

WESTERN AREA POWER ADMINISTRATION

GI-1401: Queue Date: January 6, 2014;   In-Service Date: Q4 2017 or Q1 2018

Primary Point of Interconnection: Maurine – Newell 115 kV line
Secondary Point of Interconnection: Maurine 230 kV Bus

CEII Removed

Report Issued: July 6, 2015
ABB Report #: 2014-E-13938-A

SUBMITTED TO:
Western Area Power Administration

PREPARED BY:
ABB Power Systems Consulting
940 Main Campus Drive, Suite 300
Raleigh, NC 27606

ABB Inc. **Technical Report**

Basin Electric Power Cooperative (BEPC) **Western Area Power Administration (WAPA)**	ABB Report #: 2014-E-13938-A	
Interconnection System Impact Study Report – Project # GI-1401	Issued: July 6, 2015	# Pages 67 + Appendices

EXECUTIVE SUMMARY

Western Area Power Administration (WAPA) commissioned ABB Inc., to perform an Interconnection System Impact Study (ISIS) for the interconnection of a 325 MW wind farm in Butte County, SD. The proposed generating project is queued in the WAPA/BEPC/Heartland Integrated System "IS" generator interconnection queue with a queue number of GI-1401. The primary point of interconnection of the proposed project is the Maurine – Newell 115 kV line, approximately 27 miles from Maurine in Butte County, SD. An alternate or secondary point of interconnection at the Maurine 230 kV bus was also studied.

This included an assessment of the impact of the proposed project based on steady-state, constrained interface, short-circuit and stability analysis. The study evaluated the impact of the proposed project and various mitigation strategies were evaluated at both points of interconnection.

A summary of the study results is presented below:

Steady-State Analysis

Steady-state analysis was performed for near-term (2014/2015) and out-year (2024) conditions. For the purposes of this analysis, the wind farm was dispatched to the MISO footprint east of the Twin Cities.

Impacts were observed on several local area transmission facilities. The extent of the impact depends on the status of some prior-queued generator interconnections in the study area (See Section 3.1 for details; based on the available information, some of these prior-queued interconnections have not been approved for transmission service as of the time of this study). In general, system performance is worse with these prior-queued interconnections that do not have approval for transmission service. Transmission constraints for the Primary and Secondary points of interconnection with these prior-queued interconnections included are presented for informational purposes only because it is unknown whether the prior-queued projects will proceed with transmission service. See Appendix D.

Analysis was also performed to determine possible injection constraints without the aforementioned prior-queued projects that have not been approved for transmission service. Tables 1 and 2 list the observed injection constraints for the Primary and Secondary points of interconnection for near-term cases, respectively. Tables 3 and 4 list the observed injection constraints for the Primary and Secondary points of interconnection for out-year cases, respectively. In addition, voltage collapse was observed following critical contingencies in the local area. See Section 3.4 for details.

Mitigation is necessary in order to accommodate the entire requested amount of 325 MW. The following mitigation strategies were studied. These mitigation approaches were studied for both points of interconnection.

Partial interconnection can be achieved with modest line upratings summarized as follows:

- Upgrade Maurine – Newell 115 kV line to 134 MVA (normal and emergency)
- Upgrade Newell – Elk Creek – Rapid City 115 kV lines to 134 MVA (normal and emergency)

  The above system improvements that bring the rating to 134 MVA will require terminal equipment upgrades and assume that there are no clearance/sag issues.

- Upgrade Rapid City – Dry Creek 115 kV line to 250 MVA (normal and emergency)

  As per WAPA, this 115 kV line is new and comprises 556 ACSS conductor – which is capable of a 250 MVA rating.

It should be noted that the above upgrades allow only a portion of the 325 MW to be accommodated for interconnection. With the upgrades, results show that the maximum allowable injection is: 103 MW (Primary POI) and 51 MW (Secondary POI). It should be noted that interconnection of 51 MW at the Secondary POI would require the addition of 38 MVAr of shunt compensation at the Newell 115 kV bus to mitigate observed low voltage violations. Interconnection above 51 MW would require additional system improvements. Analysis shows that upgrading the Maurine 230/115 kV transformer to 250-300 MVA can increase the maximum allowable injection to approximately 200 MW at the Secondary POI. Interconnection at this level would also require a total of 65 MVAr of shunt compensation at the Newell 115 kV bus in the out-year timeframe. See section 3.5.1.2 for details.

In order to achieve full output under either POI configuration, two options were investigated. The first option studied consisted of 230 kV line upgrades and includes the following system improvements:

- Upgrade GI-1401 POI – Maurine 115 kV line to 230 kV, and connect this line to the Maurine 230 kV bus.
- Upgrade GI-1401 POI – Newell 115 kV line to 230 kV.
- Upgrade Newell – Elk Creek 115 kV line to 230 kV.
- Replace the Elk Creek – Rapid City 115 kV and the Rapid City – Dry Creek 115 kV lines with an Elk Creek – Rapid City East 230 kV line, and assume this 230 kV line will use the same right-of-way as the existing 115 kV lines.
- Add 230/115 kV transformer at Rapid City.

The second option studied consisted of utilizing the modest system improvements mentioned above coupled with an addition of a new Maurine – Philip Tap 230 kV line. This option includes the following upgrades and improvements:

- Upgrade Maurine – Newell 115 kV line to 134 MVA (normal and emergency)
- Upgrade Newell – Elk Creek – Rapid City 115 kV lines to 134 MVA (normal and emergency)

- Upgrade Rapid City – Dry Creek 115 kV line to 250 MVA (normal and emergency)
- Add Maurine – Philip Tap 230 kV line (rating > 322 MVA)
- Upgrade Maurine 230/115 kV transformer (rating > 151 MVA)
- Terminal equipment replacements at Philip 230 kV to get the rating up to 177 MVA at a minimum
- Add 53 MVAr shunt capacitor at Newell 115 kV
- Upgrade Rapid City – Rushmore 115 kV line (rating > 98 MVA)

It should be noted that the above-mentioned mitigation strategies were studied on a limited basis (i.e., summer peak load level and a limited number of contingencies). Additional studies are necessary to test system performance with the proposed upgrades in place e.g., a more exhaustive power flow analysis, performance under light-load conditions to check for potential over-voltages, stability and short-circuit performance etc. These studies will also determine if these upgrades are adequate or if additional system improvements might be required. These studies will only be completed if the developer proceeds at the 325 MW interconnection level. In addition, a separate transmission service study would be required to identify delivery related impacts and associated system upgrades, if long-term transmission service is requested.

In addition to facilities improvements, additional options were investigating that involved the utilization of only Special Protection Scheme (SPS) of running back or tripping GI-1401 to mitigate adverse system impacts following contingencies in the local area. The following conclusions are drawn:

- Application of a SPS is not possible for interconnection at the Primary POI due to the presence of system intact overloads. If these system intact overloads are not mitigated through system reinforcements and/or a reduction in the size of the proposed interconnection, the application of a SPS is not possible. As noted above, modest system improvements allow for up to 103 MW of interconnection at the Primary POI. Results were further reviewed to determine if interconnection *above* 103 MW is possible with a SPS. It was concluded that the application of a SPS is not practical for interconnection above 103 MW at the Primary POI because GI-1401 would be required to be run-back or tripped for a large number of contingencies. Similar comments are applicable if the POI – Maurine 115 kV line were to be upgraded to 230 kV (see section below on upgrading this line to 230 kV).

- Application of a SPS for the Secondary POI is possible – this would allow GI-1401 to be interconnected at the 325 MW level but would require the wind farm to be run-back or tripped for the following contingencies:

  - Loss of Maurine - New Underwood 230 kV line
  - Loss of the Maurine 230/115 kV transformer
  - WSD4NU-EB-C1: New Underwood 230 kV East Bus
  - C2.HTG4-182: Hettinger 230 kV Breaker Failure 182
  - WSD4MA282C2: Maurine 230 kV Breaker Failure 282

  The maximum allowable injections at the Secondary POI for these contingencies without a SPS are tabulated below.

Contingency	Maximum Injection (MW)	Case
Loss of Maurine - New Underwood 230 kV line	65.0	so14
	76.0	sp24
Loss of the Maurine 230/115 kV transformer	324.7	so14
	324.7	sp24
WSD4NU-EB-C1: New Underwood 230 kV East Bus	32.0	so14
	0.0	sp24
C2.HTG4-182: Hettinger 230 kV Breaker Failure 182	305.0	wp15
	307.0	wp24
WSD4MA282C2: Maurine 230 kV Breaker Failure 282	122.0	sp15
	123.0	wp24

Maximum Allowable Injection

A sensitivity analysis was performed to determine the maximum allowable injection for project GI-1401 such that it does not overload those lines included in the list of injection constraints previously presented. For the purposes of this analysis, the above-mentioned upgrades and special protection schemes were not included. Results show that the maximum allowable injection is 6.4 MW (Primary POI) and 11.4 MW (Secondary POI). This analysis was based on DC power flow analysis only. No AC power flow analysis was performed to validate these results. These results were updated based on the previously mentioned system upgrades. See Section 3.5 for details.

POI on Maurine-Newell 115 kV and Upgrading Maurine-POI to 230 kV

For the POI on the Maurine-Newell 115 kV line upgrading the section from the POI to Maurine to 230 kV was studied. The upgrade analyzed consisted of a new 230/115 kV transformer at the POI and converting Maurine-GI-1401 to 230 kV. The transmission system between the POI and Rapid City was retained at the 115 kV level; however, the following modest system improvements were included:

- Upgrade GI-1401 POI – Newell 115 kV line to 134 MVA (normal and emergency)
- Upgrade Newell – Elk Creek – Rapid City 115 kV lines to 134 MVA (normal and emergency)

The above system improvements that bring the rating to 134 MVA will require terminal equipment upgrades and assume that there are no clearance/sag issues.

- Upgrade Rapid City – Dry Creek 115 kV line to 250 MVA (normal and emergency)

As per WAPA, this 115 kV line is new and comprises 556 ACSS conductor – which is capable of a 250 MVA rating.

Maximum allowable injections were calculated. As before, the limiting facility is the POI – Newell 115 kV line that becomes overloaded following contingency WSD4NU-EB-C1 (loss of Maurine - NU 230 kV + NU KV2A + NU - Philip Tap). AC results show that the maximum allowable injections are 99 MW (near-term) and 102 MW (out-year). Upgrading only the POI – Maurine line to 230 kV reduces the maximum allowable injection (previous values without these upgrades were 107.5 MW near-term and 103 MW out-year). The reduction in the maximum allowable injection can be explained as follows. Upgrading the POI – Maurine line to 230 kV “pre-loads” the Maurine – New Underwood 230 kV line slightly higher than before. So loss of the Maurine – New Underwood 230 kV line overloads the underlying 115 kV circuits higher than what was seen previously and this limits the maximum allowable injection.

Therefore, upgrading only the POI to Maurine to 230 kV is not a viable option and does not allow GI-1401 to interconnect any additional amount.

Constrained Interface Analysis

The study evaluated the impact of the proposed project on constrained interfaces in the MAPP and MISO systems. They are provided for informational purposes only, to identify potential third party flow gate issues for the requested delivery component of the transmission.

Short Circuit Analysis

Short-circuit analysis was performed to evaluate the impact of the proposed project on fault currents at nearby substations. A comparison of the post-project fault currents to the minimum breaker capability of the existing breakers at the local substations indicates that there is adequate interrupting capability following the addition of the proposed project.

Stability Analysis

Upon completion of the steady state portion of the study (IFS), the customer informed Western that they wished to reduce the size of their request to 103 MW on the Maurine – Newell 115 kV line. The stability analysis was completed based on this reduction and POI.

No local or regional stability criteria violations were observed for this option. It is concluded that the interconnection of GI-1401 (103 MW on the Maurine – Newell 115 kV line) does not adversely impact system stability.

Cost Estimate for Network Upgrades

Preliminary conceptual cost-estimates associated with the network upgrades required for GI-1401 (325 MW) to interconnect were provided by WAPA and are shown in Tables 5 and 6 below. Tables 7 and 8 provide the conceptual cost-estimate for GI-1401 103 MW (Primary POI) and 51 MW (Secondary POI). Cost-estimates to allow interconnection of 211 MW at the Secondary POI are shown in Table 9. These are non-binding good faith cost estimates for planning purposes and are for information only. These estimates will be further developed and refined in the Facility Study.

Table 1: Steady-State Injection Constraints for Interconnection on Newell – Maurine 115 kV line [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

Table 2: Steady-State Injection Constraints for Interconnection at Maurine 230 kV [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

Table 3: Steady-State Injection Constraints for Interconnection at Maurine – Newell 115 kV Line (Out-Year Cases) [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

Table 4: Steady-State Injection Constraints for Interconnection at Maurine 230 kV (Out-Year Cases) [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

Notes:
1. System intact and post-contingency power flows in excess of 90% of Rate A were flagged.
2. Facilities loaded above 100% of Rate A in the system intact case or above 100% of Rate B in the contingency cases are marked in red.
3. Only the 10 highest loadings for a given monitored element are shown.

Table 5: GI-1401 Conceptual Cost Estimate for Interconnection of 325 MW (Primary Point of Interconnection)

Facility Addition	Quantity		Unit Cost	Total
230 kV Terminal POI (115 kV to 230 kV Upgrade)				
Planning & Design	1		$ 394,350	$ 394,350
Breaker Bay (2000 amp) for 3 breaker ring	3		$ 1,402,000	$ 4,206,000
Service Building, Station Service, Communications	1		$ 650,000	$ 650,000
Transmission Line Approach Spans	1		$ 500,000	$ 500,000
Inspection & Commissioning	1		$ 330,000	$ 330,000
Network Reinforcements				
Upgrade Maurine-GI-1401 POI-Newell 115 kV to 230 kV (954 ACSR)	51.68		$ 301,000	$ 15,555,680
Breaker Bay (2000 amp) at Maurine 230 kV	1		$ 1,402,000	$ 1,402,000
Upgrade Newell - Elk Creek 115 kV to 230 kV (954 ACSR)	26.1		$ 301,000	$ 7,856,100
Newell to 230 kV	1		$ 5,500,000	$ 5,500,000
Elk Creek to 230 kV	1		$ 7,500,000	$ 7,500,000
Upgrade Elk Creek-Rapid City-Dry Creek 115 kV to 230 kV (954 ACSR)	19		$ 301,000	$ 5,719,000
Breaker Bay (2000 amp) at Rapid City	3		$ 1,402,000	$ 4,206,000
Breaker Bay (2000 amp) at Dry Creek/RCDC East	1		$ 1,402,000	$ 1,402,000
Rapid City 230/115 kV Transformer	1		$ 5,000,000	$ 5,000,000
Subtotal of Facility Addition				$60,221,130
Contingency (due to recent increases in energy and steel prices)		15%		$9,033,170
Subtotal of Facility Addition (w/ pricing contingency)				$69,254,300
TOTAL PROJECT ESTIMATE				$69,254,300

Does not include: environmental and land costs
Does not include: economic escalation rates
Does not include terrain factors, access factors or yard expansion if applicable
Does not include: customer line section including take-off structure to customer transformers, generator transformers to wind turbines
Does not include building and associated costs
Does not include construction contract

Table 6: GI-1401 Conceptual Cost Estimate for Interconnection of 325 MW (Secondary Point of Interconnection)

Facility Addition	Quantity		Unit Cost	Total
230 kV Terminal POI				
Planning & Design	1		$ 394,350	$ 394,350
Breaker Bay (2000 amp)	1		$ 1,402,000	$ 1,402,000
Service Building, Station Service, Communications	1		$ 650,000	$ 650,000
Transmission Line Approach Spans	1		$ 500,000	$ 500,000
Inspection & Commissioning	1		$ 330,000	$ 330,000
Network Reinforcements				
Upgrade Maurine-Newell 115 kV to 230 kV (954 ACSR)	51.68		$ 301,000	$ 15,555,680
Breaker Bay (2000 amp) at Maurine 230 kV	1		$ 1,402,000	$ 1,402,000
Upgrade Newell - Elk Creek 115 kV to 230 kV (954 ACSR)	26.1		$ 301,000	$ 7,856,100
Newell to 230 kV	1		$ 5,500,000	$ 5,500,000
Elk Creek to 230 kV	1		$ 7,500,000	$ 7,500,000
Upgrade Elk Creek-Rapid City-Dry Creek 115 kV to 230 kV (954 ACSR)	19		$ 301,000	$ 5,719,000
Breaker Bay (2000 amp) at Rapid City	3		$ 1,402,000	$ 4,206,000
Breaker Bay (2000 amp) at Dry Creek/RCDC East	1		$ 1,402,000	$ 1,402,000
Rapid City 230/115 kV Transformer	1		$ 5,000,000	$ 5,000,000
Subtotal of Facility Addition				$57,417,130
Contingency (due to recent increases in energy and steel prices)		15%		$8,612,570
Subtotal of Facility Addition (w/ pricing contingency)				$66,029,700
TOTAL PROJECT ESTIMATE				$66,029,700

Does not include: environmental and land costs
Does not include: economic escalation rates
Does not include terrain factors, access factors or yard expansion if applicable
Does not include: customer line section including take-off structure to customer transformers,
generator transformers to wind turbines
Does not include building and associated costs
Does not include construction contract

Table 7: GI-1401 Conceptual Cost Estimate for Interconnection of 103 MW (Primary Point of Interconnection)

Facility Addition	Quantity		Unit Cost	Total
115 kV Terminal POI				
Planning & Design	1		$ 394,350	$ 394,350
Breaker Bay (2000 amp) for 3 breaker ring	3		$ 836,000	$ 2,508,000
Service Building, Station Service, Communications	1		$ 650,000	$ 650,000
Transmission Line Approach Spans	1		$ 500,000	$ 500,000
Inspection & Commissioning	1		$ 330,000	$ 330,000
Network Reinforcements**				
Upgrade Maurine-GI-1401 POI-Newell 115 kV to 134 MVA (normal/emergency)*				
CTs	1		$ 60,000	$ 60,000
Jumpers	2		$ 40,000	$ 80,000
Newell Bus Work	1		$ 2,000,000	$ 2,000,000
Upgrade Newell-Elk Creek-Rapid City 115 kV to 134 MVA (normal/emergency)*				
Elk Creek CTs	4		$ 20,000	$ 80,000
Jumpers	2		$ 40,000	$ 80,000
Elk Creek Bus Work	1		$ 750,000	$ 750,000
Rapid City CTs	1		$ 20,000	$ 20,000
Subtotal of Facility Addition				$7,452,350
Contingency (due to recent increases in energy and steel prices)		15%		$1,117,853
Subtotal of Facility Addition (w/ pricing contingency)				$8,570,203
TOTAL PROJECT ESTIMATE				$8,570,203

Does not include: environmental and land costs
Does not include: economic escalation rates
Does not include terrain factors, access factors or yard expansion if applicable
Does not include: customer line section including take-off structure to customer transformers, generator transformers to wind turbines
Does not include building and associated costs
Does not include construction contract
* Assumes that no structures need to be raised due to clearance issues at 134 MVA. A Thermal Study of the line must be completed prior to interconnecting.
** Assumes no additional cost to achieve 250 MVA (normal and emergency) rating on Rapid City-Dry Creek 115 kV

Table 8: GI-1401 Conceptual Cost Estimate for Interconnection of 51 MW (Secondary Point of Interconnection)

Facility Addition	Quantity		Unit Cost	Total
230 kV Terminal POI				
Planning & Design	1		$ 394,350	$ 394,350
Breaker Bay (2000 amp)	1		$ 1,402,000	$ 1,402,000
Service Building, Station Service, Communications	1		$ 650,000	$ 650,000
Transmission Line Approach Spans	1		$ 500,000	$ 500,000
Inspection & Commissioning	1		$ 330,000	$ 330,000
Network Reinforcements**				
Upgrade Maurine-Newell 115 kV to 134 MVA (normal/emergency)*				
CTs	1		$ 60,000	$ 60,000
Jumpers	2		$ 40,000	$ 80,000
Newell Bus Work	1		$ 2,000,000	$ 2,000,000
Upgrade Newell-Elk Creek-Rapid City 115 kV to 134 MVA (normal/emergency)*				
Elk Creek CTs	4		$ 20,000	$ 80,000
Jumpers	2		$ 40,000	$ 80,000
Elk Creek Bus Work	1		$ 750,000	$ 750,000
Rapid City CTs	1		$ 20,000	$ 20,000
Subtotal of Facility Addition				$ 6,346,350
Contingency (due to recent increases in energy and steel prices)		15%		$ 951,953
Subtotal of Facility Addition (w/ pricing contingency)				$ 7,298,303
TOTAL PROJECT ESTIMATE				$ 7,298,303

Does not include: environmental and land costs
Does not include: economic escalation rates
Does not include terrain factors, access factors or yard expansion if applicable
Does not include: customer line section including take-off structure to customer transformers, generator transformers to wind turbines
Does not include building and associated costs
Does not include construction contract
* Assumes that no structures need to be raised due to clearance issues at 134 MVA. A Thermal Study of the line must be completed prior to interconnecting.
** Assumes no additional cost to achieve 250 MVA (normal and emergency) rating on Rapid City-Dry Creek 115 kV

Table 9: GI-1401 Conceptual Cost Estimate for Interconnection of 211 MW (Secondary Point of Interconnection)

Facility Addition	Quantity	Unit Cost	Total
230 kV Terminal POI			
Planning & Design	1	$ 394,350	$ 394,350
Breaker Bay (2000 amp)	1	$ 1,402,000	$ 1,402,000
Service Building, Station Service, Communications	1	$ 650,000	$ 650,000
Transmission Line Approach Spans	1	$ 500,000	$ 500,000
Inspection & Commissioning	1	$ 330,000	$ 330,000
Network Reinforcements**			
Upgrade Maurine-Newell 115 kV to 134 MVA (normal/emergency)*			
CTs	1	$ 60,000	$ 60,000
Jumpers	2	$ 40,000	$ 80,000
Newell Bus Work	1	$ 2,000,000	$ 2,000,000
Upgrade Newell-Elk Creek-Rapid City 115 kV to 134 MVA (normal/emergency)*			
Elk Creek CTs	4	$ 20,000	$ 80,000
Jumpers	2	$ 40,000	$ 80,000
Elk Creek Bus Work	1	$ 750,000	$ 750,000
Rapid City CTs	1	$ 20,000	$ 20,000
Upgrade Maurine 230/115 kV Transformer to 250-300 MVA	1	$ 5,530,000	$ 5,530,000
Shunt Capacitor at Newell 115 kV (minimum total of 51 Mvar)	1	$ 800,000	$ 800,000
Subtotal of Facility Addition			$12,676,350
Contingency (due to recent increases in energy and steel prices)	15%		$1,901,453
Subtotal of Facility Addition (w/ pricing contingency)			$14,577,803
TOTAL PROJECT ESTIMATE			$14,577,803

Does not include: environmental and land costs, economic escalation rates, terrain factors, access factors or yard expansion if applicable

Does not include: customer line section including take-off structure to customer transformers,
generator transformers to wind turbines

Does not include building and associated costs

Does not include construction contract

* Assumes that no structures need to be raised due to clearance issues at 134 MVA. A Thermal Study of the line must be completed prior to interconnecting.

** Assumes no additional cost to achieve 250 MVA (normal and emergency) rating on Rapid City-Dry Creek 115 kV

Table 10: GI-1401 Conceptual Cost Estimate for Interconnection of 325 MW (Secondary Point of Interconnection) with SPS

Facility Addition	Quantity		Unit Cost	Total
230 kV Terminal POI				
Planning & Design	1		$ 394,350	$ 394,350
Breaker Bay (2000 amp)	1		$ 1,402,000	$ 1,402,000
Service Building, Station Service, Communications	1		$ 650,000	$ 650,000
Transmission Line Approach Spans	1		$ 500,000	$ 500,000
Inspection & Commissioning	1		$ 330,000	$ 330,000
Network Reinforcements**				
SPS	3		$ 200,000	$ 600,000
Metering & Instrumentation	3		$ 80,000	$ 240,000
Studies	1		$ 100,000	$ 100,000
Subtotal of Facility Addition				$4,216,350
Contingency (due to recent increases in energy and steel prices)		15%		$632,453
Subtotal of Facility Addition (w/ pricing contingency)				$4,848,803
TOTAL PROJECT ESTIMATE				$4,848,803

Does not include: environmental and land costs
Does not include: economic escalation rates
Does not include terrain factors, access factors or yard expansion if applicable
Does not include: customer line section including take-off structure to customer transformers, generator transformers to wind turbines
Does not include building and associated costs
Does not include construction contract

LEGAL NOTICE

TABLE OF CONTENTS

1 INTRODUCTION

1.1 DESCRIPTION OF PROJECT

Western Area Power Administration (WAPA) commissioned ABB Inc. to perform an Interconnection System Impact Study for the interconnection of a 325 MW wind farm queued in the WAPA/BEPC/Heartland Integrated System "IS" generator interconnection queue with a queue number of GI-1401.

The primary point of interconnection of this project is on the Maurine – Newell 115 kV line, approximately twenty-seven miles from Maurine. An alternate or secondary point of interconnection at the Maurine 230 kV bus was also studied. Figure 1 shows a diagram of the transmission system in the vicinity of the proposed project.

The projected in-service date for the GI-1401 project is Q4 2017 or Q1 2018.

Figure 1: Geographic Location of Project GI-1401 [CEII]

2 STUDY METHODOLOGY

2.1 *STEADY-STATE ANALYSIS*

The purpose of steady-state analysis is to analyze the impact of the proposed project on transmission system facilities under steady-state conditions. It involves two distinct analyses: thermal analysis and voltage analysis.

A "study area" was defined to represent the areas of interest which included: WAPA (area 652), GRE (615), OTP (620), XEL (600), MDU (661), NPPD (640) and MEC (635).

2.1.1 Thermal Analysis

Transmission facilities rated 100 kV and above in the study area were monitored. For the purposes of this analysis, Rate A is the continuous facility rating and Rate B is the emergency rating.

System Intact Analysis:

The incremental impact of the proposed project on thermal loading of transmission facilities under system intact conditions was evaluated by comparing transmission system power flows with and without the proposed project. For this purpose, full ac power flow solutions were used.

The criteria to flag thermal overloads is 100% of continuous facility rating (Rate A in the power flow model). MAPP DRS Guidelines [2] were used to identify Significantly Affected Facilities (SAF). According to these guidelines, all overloaded facilities that have a TDF (Transfer Distribution Factor) greater than 5% of the generation additions (without plant vs. with plant) were flagged as SAF.

Contingency Analysis:

The contingency list included single branch outages in the monitored systems, plus Category B and Category C outages in the Dakotas, Minnesota and Nebraska. Contingencies were solved with phase shifters, switched shunts and transformer taps enabled. Thermal violations were flagged based on the Rate A data for facilities (from the power flow model). Post-contingency power flows in excess of 100% of Rate A were flagged. Facility loadings with and without the proposed project were tabulated and compared.

As in the system intact analysis, MAPP DRS Guidelines were used to identify Significantly Affected Facilities (SAF). Facilities with a TDF greater than 3% were included in the SAF list.

2.1.2 Voltage Analysis

Voltages at buses rated 100 kV and above inside the study area were monitored for possible pre- and post-contingency voltage violations in accordance with reference [1]. In accordance with MAPP DRS Guidelines, those buses having a voltage deviation greater than 0.01 pu (without plant vs. with plant) are considered significantly affected. Examinations of voltage collapse issues were also conducted.

2.1.3 Criteria for Identifying and Mitigating Interconnection Constraints

SAFs in the electrical vicinity of the Maurine and Newell substations are considered to be interconnection constraints. These constraints will limit the ability of the proposed project to inject power into the grid. Transmission upgrades will be required to resolve these constraints.

2.1.4 Constrained Interface Analysis

The purpose of the constrained interface analysis is to calculate the impact of the proposed project on specified constrained interfaces in the MAPP and MISO transmission systems. The MAPP DFCALC constrained interface analysis program was used for this purpose.

2.2 SHORT-CIRCUIT ANALYSIS

The purpose of short-circuit analysis is to determine fault current levels at the point of interconnection, both before and after the addition of the proposed project. Three-phase and single-line-to-ground faults were simulated at the point of interconnection and the impact of the proposed project on the increase in fault currents was determined.

3 STEADY STATE ANALYSIS

3.1 MODEL DEVELOPMENT

The pre-project cases for this analysis were developed by WAPA based on the 2013 MRO series models. These cases were developed using the 6-digit UMTAG package dated 01-22-2014. Cases were developed for the following study years and system conditions.

- 2014 Summer Off-Peak (so14)
- 2015 Summer Peak (sp15)
- 2015 Winter Peak (wp15)
- 2024 Summer Peak (sp24)
- 2024 Winter Peak (wp24)

The out-year cases include the following major transmission lines that are not included in the near-term cases:

- Ellendale – Big Stone 345 kV line
- Big Stone – Brookings County 345 kV line
- Antelope Valley – Tioga 345 kV line
- Bison – Alexandria – Quarry – Monticello 345 kV line (included in 2015 and 2024 cases, but not in the 2014 case)

Prior-queued projects included in these cases are listed in Table 3-1. It should be noted that this is not an all-inclusive list.

The corresponding post-project cases were developed by adding the proposed GI-1401 wind farm and dispatching it to the MISO footprint to the east of the Twin Cities.

Two sets of pre- and post-project cases were developed to evaluate the impact of the proposed project.

- Interconnection Cases: These cases include prior-queued generation projects that have been approved for interconnection (as of the time of the study) – these projects may (or may not) have rights to deliver power to the transmission system.

- Transmission Rights Cases: These cases include prior-queued projects that have been approved for both interconnection and delivery service i.e., projects that have transmission rights (as of the time of the study).

Both the initial Interconnection Cases and the Transmission Rights Cases were provided by WAPA. Modeling assumptions for the following prior-queued projects were updated to create the final pre-project Interconnection and Transmission Rights Cases.

- GI-0515: Disconnected (project withdrawn from the IS generation interconnection queue)
- GI-1301: Dispatch adjusted to 90 MW (as per IS queue)

The Transmission Rights Cases were further developed according to comments from MEC and MDU. In all cases, a wind farm at Macksburg was added and dispatched according to seasonal projections (information provided by MEC). This wind farm was added at bus ‘DEY 415 W’, and its dispatch for each case was assigned as follows:

- Summer Off-Peak, near-term: 41.9 MW
- Summer Peak, near-term and out-year: 23.9 MW
- Winter Peak, near-term and out-year: 41.9 MW

Additionally, dispatches of the wind farms at SHD and LGR were adjusted for each case (information provided by MEC). These adjustments are as follows:

- Summer Off-Peak, near-term: SHD dispatch adjusted from 500 MW to 0 MW (wind farm not in service in 2014), LGR dispatch adjusted from 250 MW to 87.5 MW
- Summer Peak, near-term and out-year: SHD dispatch adjusted from 500 MW to 100 MW, LGR dispatch adjusted from 250 MW to 51.1 MW
- Winter Peak, near-term and out-year: adjusted from 500 MW to 175.2 MW, LGR dispatch adjusted from 250 MW to 87.5 MW

In both out-year cases (summer peak and winter peak), generators and other facilities connected to Council Bluffs and Neal were removed as these units are to be retired (information provided by MEC).

In all near-term and out-year cases, dispatches at Diamond Willow and Cedar Hills were adjusted to 30 MW and 19.5 MW, respectively (information provided by MDU).

The proposed project will be required to mitigate injection constraints seen in the Transmission Rights Cases; constraints in Interconnection Cases are "for information only."

The single-line diagrams for the pre- and post-project Transmission Rights Cases are shown in Appendix A.

Table 3-1: Prior-queued Projects

Project Name/Project Queue Number	Location/Description	Size (MW)
GI-0515	Eagle Butte 115 kV	113
GI-0619	Leland Olds - Groton 345 kV	150
GI-0708	Culbertson	120
G645	Ladish 1 (Ladish 115 kV)	99
G788	Ladish 115 kV	
G752	Hettinger 230 kV	150
G723	Heskett 115 kV	7
J003	Baker 115 kV	19.5
GI-0614A	Culbertson Waste Heat	7.5
GI-0508	Ecklund (Wilton 1)	49.5
GI-0615	Ecklund (wilton 2)	49.5
GI-0715	Hilken 230 kV (Baldwin; Wilton 3)	100
GI-0727	Bismarck-Garrison 230 kV	102.4
GI-0926	Dickinson-Mandan 230 kV	200
GI-1001	Glenham-Bismarck 230 kV	99
GI-1007	Antelope Valley 345 kV	172.5
GI-1105, GI-1205, GI-1207	Stateline 115 kV	150
GI-1202, GI-1204, GI-1208	Hay Butte 115 kV	150
GI-1212	Wolf Point-Circle 115 kV	75
GI-1301	Summit – Watertown 115 kV line	90
GI-1309	Redfield NW 115 kV	19.5

3.2 *STEADY STATE ANALYSIS RESULTS*

Contingency analysis was performed in two steps as described below:

First, a DC power flow analysis (DCCC) was performed in order to identify Significantly Affected Facilities (SAF) and limiting contingencies. This step was performed on both the Interconnection Cases and Transmission Rights Cases and utilized contingencies described in Section 2.1.1.

Next, limiting contingencies in the Transmission Rights DC power flow analysis results were selected for further evaluation with full AC power flow solution. In addition, single contingencies on branches connected to the following buses were also simulated using AC analysis.

- Maurine 230 kV
- Maurine 115 kV
- Newell 115 kV
- Elk Creek 115 kV
- Rapid City 115 kV
- Ellsworth 115 kV
- New Underwood 115 kV

3.2.1 DC Power Flow Results

The DC power flow results for the Primary and Secondary POI Interconnection Cases are shown in Appendix D and are for information only.

The DC power flow results for the Transmission Rights Cases are also shown in Appendix D. Results are given for all cases, and the injection constraints are highlighted in yellow.

3.2.2 Near-Term Power Flow Results (AC Analysis)

The AC power flow results for near-term transmission rights cases are shown in Tables 3-2 and 3-3 (Primary POI) and in Table 3-4 (Secondary POI). These tables show the Significantly Affected Facilities associated with the interconnection of the proposed project.

<u>Thermal Analysis</u>

Table 3-2 shows injection constraints near the Primary POI on the following monitored elements:

1. GI-1401 POI – Maurine 115 kV Line
2. GI-1401 POI – Newell 115 kV Line
3. Newell – Elk Creek 115 kV Line
4. Elk Creek – Rapid City 115 kV Line
5. Faith – Eagle Butte 115 kV Line
6. Maurine 230/115 kV Transformer
7. Rapid City – Ellsworth 115 kV Line
8. Rapid City – Rushmore 115 kV Line

Table 3-4 shows injection constraints near the Secondary POI on the following monitored elements:

1. Maurine – Newell 115 kV Line
2. Newell – Elk Creek 115 kV Line
3. Elk Creek – Rapid City 115 kV Line
4. Hettinger 230/115 kV Transformer

5. Maurine 230/115 kV Transformer
6. Maurine – New Underwood 230 kV Line

These lines become overloaded for various Category B and Category C contingencies based on their Rate B emergency rating. Many of these contingencies induce thermal overloads in the local 115 kV bus network around each POI, which is primarily due to the inability of those lines tying these buses to handle the full output of the 325 MW wind farm. In general, the power attempts to route to the nearest 230 kV outlet, and in most cases this is the line tying Bison, Maurine, New Underwood, and Wayside buses. As a result, many lines in the area south of Newell become overloaded.

Voltage Analysis

Voltage analysis and thermal analysis for near-term cases were performed concurrently. Buses in the local area whose voltages were adversely impacted following the addition of the wind farm with impacts greater than 0.01 p.u. were considered significantly affected. Those buses which continued to exhibit 0.01 p.u. voltage deviations for near-term Transmission Rights cases are given in Tables 3-5 and 3-6.

In addition to the voltage violations shown in these tables, the following contingencies resulted in voltage collapse:

- Loss of GI-1401 POI – Maurine 115 kV line
- Loss of GI-1401 POI – Newell – Elk Creek 115 kV line
- Loss of Elk Creek – Rapid City 115 kV line

Voltage collapse is a consequence of reactive power deficiency in the 115 kV transmission system between the Maurine, Newell, Elk Creek, Rapid City, and New Underwood substations. See section 3.4 for details.

Secondary POI cases exhibited similar voltage collapse issues for the following contingencies:

- Contingency WSD4MA282C2 (simultaneous loss of Maurine – New Underwood 230 kV line and Bison 230 kV bus)
- Contingency WSD4NU-WB-C1 (simultaneous loss of New Underwood – RCDC East 230 kV line, New Underwood – Wayside 230 kV line, and one of the New Underwood 230/115/13.8 kV transformers)

These issues are also associated with reactive power deficiencies in the local system. See section 3.4 for further details.

Table 3-2: Significantly Affected Facilities for Primary Point of Interconnection, Thermal Analysis (Near-Term Transmission Rights Cases; System Intact Conditions) [CEII]

MONITORED FACILITY	RATING (MVA)		LOADING (MVA)		TDF	CASE
	RATE A	RATE B	PRE-PROJECT	POST-PROJECT		

Table 3-3: Significantly Affected Facilities for Primary Point of Interconnection, Thermal Analysis (Near-Term Transmission Rights Cases; Contingency Case Conditions) [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

Table 3-4: Significantly Affected Facilities for Secondary Point of Interconnection, Thermal Analysis (Near-Term Transmission Rights Cases; Contingency Case Conditions) [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

<u>Notes</u>:
1. Injection constraints are highlighted in yellow.
2. Facilities loaded above 100% of Rate A in the system intact case or above 100% of Rate B in the contingency cases are marked in red.
3. Only the 10 most limiting contingencies are shown for each overloaded facility.

Table 3-5: Significantly Affected Facilities for Primary Point of Interconnection, Voltage Analysis (Near-Term Transmission Rights Cases; System Intact Conditions) [CEII]

Bus #	Bus Name	Base kV	Pre-Project	Post-Project	DV	Case

Bus #	Bus Name	Base kV	Pre-Project	Post-Project	DV	Case

Table 3-6: Significantly Affected Facilities for Primary Point of Interconnection, Voltage Analysis (Near-Term Transmission Rights Cases; Contingency Case Conditions) [CEII]

Bus #	Bus Name	Base kV	Contingency	Pre-Project	Post-Project	DV	Case

3.2.3 Out-Year Power Flow Results (ACCC)

The AC power flow results for the out-year transmission rights cases are shown in Table 3-7 (Primary POI) and Table 3-8 (Secondary POI).

Thermal Analysis

Table 3-7 shows injection constraints near the Primary POI on the following monitored elements:

1. GI-1401 POI – Maurine 115 kV Line
2. GI-1401 POI – Newell 115 kV Line
3. Newell – Elk Creek 115 kV Line
4. Elk Creek – Rapid City 115 kV Line
5. Maurine 230/115 kV Transformer

Table 3-8 shows injection constraints near the Secondary POI on the following monitored elements:

1. Newell – Elk Creek 115 kV Line
2. Elk Creek – Rapid City 115 kV Line
3. Hettinger 230/115 kV Transformer
4. Maurine 230/115 kV Transformer
5. Maurine – Newell 115 kV Line

These lines become overloaded for various Category B and Category C contingencies based on their Rate B emergency rating. As in the near-term case examinations, the local area around each POI is largely a 115 kV bus network, and the output of the 325 MW wind farm overloads those lines in the system due to their low MVA ratings as power seeks to flow toward the nearest 230 kV outlets.

Voltage Analysis

As in the near-term cases, the Primary POI out-year Transmission Rights Cases exhibited extensive base case and post-project voltage violations while the Secondary POI Cases did not. These violations for the Transmission Rights Cases are summarized in Tables 3-9 and 3-10 for the post-project cases.

Table 3-7: Significantly Affected Facilities for <u>Primary</u> Point of Interconnection

(Out-Year Transmission Rights Cases; Contingency Case Conditions) [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

Table 3-8: Significantly Affected Facilities for Secondary Point of Interconnection (Out-Year Transmission Rights Cases; Contingency Case Conditions) [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

Notes:
1. Injection constraints are highlighted in yellow.
2. Facilities loaded above 100% of Rate B in the contingency cases are marked in red.
3. Only the 10 most limiting contingencies are shown for each overloaded facility.

Table 3-9: Significantly Affected Facilities for Primary Point of Interconnection, Voltage Analysis (Out-Year Base Cases) [CEII]

Bus #	Bus Name	Base kV	Pre-Project	Post-Project	DV	Case

Bus #	Bus Name	Base kV	Pre-Project	Post-Project	DV	Case

Table 3-10: Significantly Affected Facilities for Primary Point of Interconnection, Voltage Analysis (Out-Year Transmission Rights Cases; Contingency Case Conditions) [CEII]

Bus #	Bus Name	Base kV	Contingency	Pre-Project	Post-Project	DV	Case

3.3 Sensitivity Analysis

A sensitivity was performed to determine the maximum allowable injection for project GI-1401 such that it does not overload the aforementioned lines based on their normal (Rate A) and emergency (Rate B) ratings under system-intact and contingency conditions, respectively. The analysis was performed using the transmission rights cases for the primary and secondary points of interconnection in both near-term and out-year systems. For the purposes of this sensitivity, DC power flow analysis was used. No AC power flow analysis was performed to validate these results.

Near-term Transmission Rights Cases

Results show that the maximum allowable injection (FCITC) for interconnection at the Primary POI is 6.4 MW for near-term cases based on the 2015 summer peak case. This is based on the post-contingency loading on the GI-1401 POI – Newell 115 kV line following the outage of the New Underwood – Maurine 230 kV line, the outage of the New Underwood 230/115 kV transformer, and the outage of the New Underwood – Philip Tap 230 kV Line. See below.

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	FCITC (MW)
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		
CEII							

The maximum allowable injection for interconnection at the Secondary POI is 11.4 MW for near-term cases; this calculation was determined from 2015 summer peak results. This is based on the post-contingency loading on the Maurine – Newell 115 kV line following the outage of the Maurine – New Underwood 230 kV line and the Maurine – Bison 230 kV Line. See below.

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	FCITC (MW)
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		
CEII							

Out-year Transmission Rights Cases

The maximum allowable injection for interconnection at the Primary POI is 9.6 MW for out-year cases; this calculation was determined from 2024 summer peak results. This is based on the same contingency as in the near-term Transmission Rights examination: outage of the New Underwood – Maurine 230 kV line, the outage of the New Underwood 230/115 kV transformer, and the outage of the New Underwood – Philip Tap 230 kV Line. As was the case in the near-term case, the limiting element is the GI-1401 POI – Newell 115 kV line under contingency conditions. See below.

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	FCITC (MW)
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		
CEII							

The maximum allowable injection for interconnection at the Secondary POI is 17.5 MW for out-year cases; this calculation was determined from 2024 summer peak results. This is based on the post-contingency loading on the Maurine – Newell 115 kV line following the same limiting contingency from the Primary POI results for out-year cases. See below.

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	FCITC (MW)
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		
CEII							

3.4 ANALYSIS OF EVENTS THAT RESULT IN VOLTAGE COLLAPSE

While performing steady-state analysis, a number of instances of voltage collapse were observed for some select contingencies in Transmission Rights Cases for each POI. While thermal overloads contribute significantly to voltage sags across the local area in proximity of the GI-1401 Primary and Secondary POIs, QV analysis was performed to examine if sufficient reactive power exists under these conditions. In each case, select buses which were deemed to exhibit reactive deficiency (critical buses) were monitored. These buses were selected based on engineering judgment. This analysis was performed using only the 2015 summer peak case. Those contingencies are summarized as follows:

1. Outage of GI-1401 POI – Newell – Elk Creek 115 kV lines (Newell 115 kV is a tap)
2. Outage of Elk Creek – Rapid City 115 kV line
3. Outage of GI-1401 POI – Maurine 115 kV line
4. WSD4MA282C2: Loss of Maurine – Bison – Hettinger 230 kV line + Loss of Maurine – New Underwood 230 kV line
5. WSD4NU-WB-C1: Loss of New Underwood – Rapid City 230 kV line + Loss of New Underwood – Wayside 230 kV line + New Underwood 230/115 kV Transformer #1

Contingencies 1, 2, and 3 cause voltage collapses in cases with the wind plant connected at the Primary POI, and contingencies 4 and 5 cause voltage collapses in cases with the wind plant connected the Secondary POI. Results of QV analysis for each contingency are given below.

Figure 3.1: QV curves at Maurine 230 kV bus and Maurine 115 kV bus for contingency 1, 2015 summer peak pre-project case [CEII]

Figure 3.2: QV curves at Maurine 230 kV bus and Maurine 115 kV bus for contingency 1, 2015 summer peak post-project case [CEII]

Figure 3.3: QV curves at Maurine 230 kV bus and Maurine 115 kV bus for contingency 2, 2015 summer peak pre-project case [CEII]

Figure 3.4: QV curves at Maurine 230 kV bus and Maurine 115 kV bus for contingency 2, 2015 summer peak post-project case [CEII]

Figure 3.5: QV curves at Newell 115 kV bus and Elk Creek 115 kV bus for contingency 3, 2015 summer peak pre-project case [CEII]

Figure 3.6: QV curves at Newell 115 kV bus and Elk Creek 115 kV bus for contingency 3, 2015 summer peak post-project case [CEII]

Figure 3.7: QV curves at Faith 115 kV bus and Newell 115 kV bus for contingency 4, 2015 summer peak pre-project case [CEII]

Figure 3.8: QV curves at Faith 115 kV bus and Newell 115 kV bus for contingency 4, 2015 summer peak post-project case [CEII]

[CEII Removed]

Figure 3.9: QV curves at Elk Creek 115 kV bus, Rapid City 115 kV bus, Rushmore 115 kV bus, and Ellsworth 115 kV bus for contingency 5, 2015 summer peak pre-project case [CEII]

Figure 3.10: QV curves at Elk Creek 115 kV bus, Rapid City 115 kV bus, Rushmore 115 kV bus, and Ellsworth 115 kV bus for contingency 5, 2015 summer peak post-project case [CEII]

[CEII Removed]

3.5 *MITIGATION OF STEADY STATE VIOLATIONS*

Results of Section 3.2 show the following injection constraints for the near-term Transmission Rights Cases:

<u>Primary POI</u>
1. GI-1401 POI – Maurine 115 kV Line
2. GI-1401 POI – Newell 115 kV Line
3. Newell – Elk Creek 115 kV Line
4. Elk Creek – Rapid City 115 kV Line
5. Faith – Eagle Butte 115 kV Line
6. Maurine 230/115 kV Transformer
7. Rapid City – Ellsworth 115 kV Line
8. Rapid City – Rushmore 115 kV Line

<u>Secondary POI</u>
1. Newell – Elk Creek 115 kV Line
2. Elk Creek – Rapid City 115 kV Line
3. Hettinger 230/115 kV Transformer
4. Maurine 230/115 kV Transformer
5. Maurine – Newell 115 kV Line
6. Maurine – New Underwood 230 kV Line

Results of Section 3.2 show the following injection constraints for the out-year Transmission Rights Cases:

<u>Primary POI</u>
1. GI-1401 POI – Maurine 115 kV Line
2. GI-1401 POI – Newell 115 kV Line
3. Newell – Elk Creek 115 kV Line
4. Elk Creek – Rapid City 115 kV Line
5. Maurine 230/115 kV Transformer

<u>Secondary POI</u>
1. Newell – Elk Creek 115 kV Line
2. Elk Creek – Rapid City 115 kV Line
3. Hettinger 230/115 kV Transformer
4. Maurine 230/115 kV Transformer
5. Maurine – Newell 115 kV Line

Mitigation is necessary in order to accommodate the entire requested amount of 325 MW from the wind farm. This would involve system upgrades to prevent thermal overloads.

3.5.1 Modest System Improvements

A limited investigation was performed to determine whether modest system improvements could mitigate the injection constraints described above. The improvements included the following:

- Upgrade Maurine – Newell 115 kV line to 134 MVA (normal and emergency)
- Upgrade Newell – Elk Creek – Rapid City 115 kV lines to 134 MVA (normal and emergency)

The above system improvements to 134 MVA will require terminal equipment upgrades and assume there are no clearance/sag issues.

- Upgrade Rapid City – Dry Creek 115 kV line to 250 MVA (normal and emergency). As per WAPA, this 115 kV line is new and comprises 556 ACSS conductor.

The analysis was performed using the transmission rights cases for the primary and secondary points of interconnection in both near-term and out-year systems. DC power flow analysis was used and AC power flow analysis was subsequently performed to validate the results and to determine the true maximum allowable injection.

3.5.1.1 Primary POI

Near-term Transmission Rights Cases

DC power flow results show that the maximum allowable injection (FCITC) for interconnection at the Primary POI is 113.7 MW for near-term cases based on the 2015 summer peak case, and AC analysis results in a maximum allowable injection of 107.5 MW. This is based on the post-contingency loading on the GI-1401 POI – Newell 115 kV line following the outage of the New Underwood – Maurine 230 kV line, the outage of the New Underwood 230/115 kV transformer, and the outage of the New Underwood – Philip Tap 230 kV Line. See below.

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	FCITC, DC Analysis (MW)	Maximum Allowable Injection, AC Analysis
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT			
CEII								

Out-year Transmission Rights Cases

A similar analysis was performed with the out-year cases for the Primary POI, and it was determined that the maximum allowable injection is 117.5 MW based on the 2024 summer peak case. AC analysis results in a maximum injection of 103.0 MW. This result stems from limitations due to the same monitored element and contingency pair as the near-term case, POI – Newell 115 kV line and contingency WSD4NU-EB-C1, respectively. See below.

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	FCITC, DC Analysis (MW)	Maximum Allowable Injection, AC Analysis
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT			
CEII								

3.5.1.2 Secondary POI

<u>Near-term Transmission Rights Cases</u>

The maximum allowable injection for interconnection at the <u>Secondary POI</u> is 63.4 MW for near-term cases based on DC analysis; this calculation was determined from 2015 summer peak results. This is based on the post-contingency loading on the Maurine 230/115 kV transformer following the outage of the New Underwood – Maurine 230 kV line, the outage of New Underwood 230/115 kV transformer NU KV2A, and the outage of the New Underwood – Philip Tap 230 kV line. AC power flow results yield a final maximum allowable injection of 57 MW. See below.

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	FCITC, DC Analysis (MW)	Maximum Allowable Injection, AC Analysis (MW)
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT			
CEII								

However, if it is assumed that the Maurine 230/115 kV transformer is upgraded to eliminate the above constraint, the next most limiting element is the Maurine – Newell 115 kV line. Again, in the event of the loss of the New Underwood – Maurine 230 kV line, the outage of New Underwood 230/115 kV transformer NU KV2A, and the outage of the New Underwood – Philip Tap 230 kV line, the maximum allowable injection becomes 225.3 MW based on DC analysis, and AC analysis indicates a maximum injection of 200 MW. See below.

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	FCITC, DC Analysis (MW)	Maximum Allowable Injection, AC Analysis (MW)
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT			
CEII								

<u>Out-year Transmission Rights Cases</u>

The maximum allowable injection for Secondary POI out-year cases is 51 MW based on AC power flow analysis. This result is again based upon the post-contingency loading on the Maurine 230/115 kV transformer under contingency WSD4NU-EB-C1, a result similar to that of the near-term case analysis. At this injection level however, low voltage violations exist in the local 115 kV system (summarized below). Subsequent analysis determined that shunt compensation of at least 38 MVAr is required to mitigate the low voltage violations. See below.

Bus Number	Bus Name	Base kV	V (pu)	V (kV)
	ELKCRK 7	115.0	0.844	97.1
	NEWELL 7	115.0	0.863	99.3
	NUNDRWD7	115.0	0.858	98.6
	WICKSVL7	115.0	0.879	101.1
	RAPIDCY8	69.0	0.832	57.4
	ELSWRTH7	115.0	0.846	97.3
	NUNDRWD4	230.0	0.863	198.4
	RAPIDCY7	115.0	0.845	97.2
	RUSHMRE7	115.0	0.842	96.8

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	FCITC, DC Analysis (MW)	Maximum Allowable Injection, AC Analysis (MW)
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT			
CEII								

As in the near-term analysis, it was assumed that the Maurine transformer can be easily upgraded, and the next most-limiting element is the Maurine – Newell 115 kV line that becomes overloaded following contingency WSD4NU-EB-C1. Under this assumption, the maximum allowable injection is 204.0 MW based on AC analysis. However, without reactive power compensation, this level of injection results in voltage collapse for the above-mentioned contingency. Shunt compensation of at least 65 MVAr is required at the Newell 115 kV bus to mitigate the voltage collapse condition and address low voltage violations. Included in this compensation is the 38 MVAr described in the preceding paragraph.

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	FCITC, DC Analysis (MW)	Maximum Allowable Injection, AC Analysis (MW)
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT			
CEII								

3.5.2 Upgrade Maurine to Rapid City 115 kV Network to 230 kV

An other mitigation option evaluated was re-conductoring and converting Maurine to Rapid City to 230 kV. The mitigation option includes the following:

1. Upgrade GI-1401 POI – Maurine 115 kV line to 230 kV, and connecting this line to the Maurine 230 kV bus.
2. Upgrade GI-1401 POI – Newell 115 kV line to 230 kV
3. Upgrade Newell – Elk Creek 115 kV line to 230 kV
4. Remove Elk Creek – Rapid City 115 kV line and the Rapid City – Dry Creek 115 kV line. Replace these lines with an Elk Creek – Rapid City East 230 kV line, and assume this line will use the same right-of-way as the existing 115 kV lines.
5. Add 230/115 kV transformer at Rapid City

For simulation purposes, the lines were assumed to be 954 ACSR with a 300 MVA rating (note that this is a proxy rating to facilitate determination of the worst-case facility loadings and consequently the rating requirements). The Rapid City transformer was assumed to have the same impedance and rating as the New Underwood 230/115 kV transformer. A limited set of contingencies were simulated in the local area to assess the effectiveness of this mitigation option.

3.5.2.1 Primary POI

Contingency analysis thermal violation results for the Primary POI are given in Table 3-11. There were no voltage violations to report. Also, none of the contingencies exhibited voltage collapse. Under system intact conditions, the highest loading of the 230 kV lines requires a minimum normal (Rate A) rating of 220 MVA. As shown in the table, a maximum post-project MVA loading of 316.9 MVA results from the loss of the POI – Elk Creek 230 kV line. Therefore, a minimum emergency (Rate B) rating of 317 MVA is required for the new 230 kV lines.

Further analysis was performed to assess robustness of this mitigation option. The 200 MW DC line at Rapid City is defined in the provided models as flowing east to west, dictating much of the power flow behavior around the region in the proximity of the POI. This flow direction was reversed for purposes of this examination, with flows directed from Rapid City DC West (Bus 659303) to Rapid City DC East (Bus 659268). In addition, the 150 MW flows at Miles City DC were reversed in an effort to force overall power flows between New Underwood – Maurine – Bison – Hettinger from south to north. Results are summarized in Table 3-12. Results indicate the need to upgrade the Rapid City – Rushmore 115 kV line to a rating of at least 130 MVA. Additionally, there were no voltage violations to report in this examination.

Table 3-11: Thermal violations summary for mitigation option, Primary POI [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)	CASE
	RATE A	RATE B		POST-PROJECT	

Table 3-12: Thermal violations summary for mitigation option, RCDC flows reversed, Primary POI [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)	CASE
	RATE A	RATE B		POST-PROJECT	

An alternate 115 kV system upgrade scheme was considered consisting of a new 230/115 kV transformer at the POI, and a new line between the POI 230 kV bus and the Maurine 230 kV bus. This scheme assumed no change in the GI-1401 POI (i.e., it remained connected at the 115 kV bus).The transmission system between the POI and Rapid City was retained at the 115 kV level; however, modest system improvements described in Section 3.5.1 of the report were included. Maximum allowable injections were calculated. As before, the limiting facility is the POI – Newell 115 kV line that becomes overloaded following contingency WSD4NU-EB-C1 (loss of Maurine - NU 230 kV + NU KV2A + NU - Philip Tap). AC results show that the maximum allowable injections are 99 MW (near-term) and 102 MW (out-year). Upgrading the POI – Maurine line to 230 kV reduces the maximum allowable injection (previous values without these upgrades were 107.5 MW near-term and 103 MW out-year). The reduction in the maximum allowable injection can be explained as follows. Upgrading the POI – Maurine line to 230 kV “pre-loads” the Maurine – New Underwood 230 kV line slightly higher than before. So loss of the Maurine – New Underwood 230 kV line overloads the underlying 115 kV circuits higher than what was seen previously and this limits the maximum allowable injection.

3.5.2.2 Secondary POI

Similar analysis was performed considering the Secondary POI. Contingency analysis thermal violation results for the Secondary POI are given in Table 3-13. As in the Primary POI case, there were no voltage violations and none of the contingencies exhibited voltage collapse. As shown in the table, a maximum post-project MVA loading of 317.6 MVA results from the loss of the POI – Elk Creek 230 kV line, so a minimum emergency (Rate B) rating of 318 MVA is required for the new lines.

Table 3-13: Thermal violations summary for mitigation option, Secondary POI [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)	CASE
	RATE A	RATE B		POST-PROJECT	

Again DC flows were reversed as previously described to assess the option's robustness when considering the Secondary POI, yet no lines were overloaded based on existing ratings, and there were no voltage violations to report.

3.5.3 Addition of Maurine – Philip Tap 230 kV Line with Modest System Improvements

System performance was investigated for a mitigation scheme consisting of a new 230 kV line from Maurine to Philip Tap and the modest system improvements described in Section 3.5.1. This approach considered interconnection at the Secondary POI only. For modeling purposes, the new 230 kV line was assumed to be 954 ACSR with a 300 MVA rating as in previous analysis. A limited set of contingencies were chosen to examine the effectiveness of these upgrades.

A DC analysis was performed to determine the most limiting contingencies for this network configuration, and other limiting contingencies were also selected based on prior experience. DC FCITCs were determined, and AC analysis was subsequently performed to verify the results. A summary of these results, which includes the DC and AC FCITCs, is given in Table 3-14.

Table 3-14: Thermal violations summary and FCITCs for network with Maurine – Philip Tap 230 kV line addition and modest network improvements, Secondary POI [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE	DC FCITC RATE A/B (MW)	AC FCITC RATE A/B (MW)
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT				

Results indicate that the maximum injection is approximately 173.0 MW. However, if it is assumed that the new Maurine – Philip Tap 230 kV line and the Maurine 230/115 kV transformer can be sized appropriately, it is possible to interconnect the full 325 MW requested. A more detailed AC analysis was performed at the 325 MW injection level. See Tables 3-15 and 3-16. Results show that additional upgrades are necessary to interconnect at the full 325 MW. In particular, analysis determined the need for a 53 MVAr capacitor at the Newell 115 kV bus. This stems from an examination of contingency WSD4NU-EB-C1 (Loss of New Underwood - Maurine 230 kV line + NU 230/115 kV KV2A transformer + New Underwood - Philip Tap 230 kV line). This contingency resulted in low voltage violations throughout the local 115 kV system between Maurine and New Underwood, and the 53 MVAr capacitor was shown to be effective in mitigating these violations.

As in previous analysis, Rapid City DC flows were reversed to examine the robustness of this mitigation option i.e., Rapid City DC is modeled at 200 MW west to east. There were no voltage violations in this case, though limited thermal violations were found. These violations are given in Table 3-17. These violations necessitate an additional upgrade of the Rapid City – Rushmore 115 kV line to a rating of at least 98 MVA to mitigate thermal violations in the near-term case. The complete set of upgrades needed for interconnection of the full 325 MW using this mitigation approach are summarized below:

- Modest 115 kV system improvements described in Section 3.5.1
- Add Maurine – Philip Tap 230 kV line (rating > 322 MVA)
- Upgrade Maurine 230/115 kV transformer (rating > 151 MVA)
- Terminal equipment replacements at Philip 230 kV to get the rating up to 177 MVA at a minimum
- Add 53 MVAr shunt capacitor at Newell 115 kV
- Upgrade Rapid City – Rushmore 115 kV line (rating > 98 MVA)

Table 3-15: Thermal violations summary for network with Maurine – Philip Tap 230 kV line addition and modest network improvements with 325 MW of injection, Secondary POI [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)	CASE	
	RATE A	RATE B		POST-PROJECT		
						<< With 53 MVAr capacitor at Newell 115 kV (see Note 2 below)
						<< See Note 1 below. Corresponding pre-project loading is 122.4 MVA
						<< See Note 1 below. Corresponding pre-project loading is 160.0 MVA

MA2NU-MATX: Loss of Maurine - New Underwood 230 kV line + Maurine 230/115 kV transformer
WSD4NU-EB-C1: Loss of New Underwood - Maurine 230 kV line + NU 230/115 kV KV2A transformer + New Underwood - Philip Tap 230 kV line
WSD4NU-WB-C1: Loss of New Underwood – Rapid City 230 kV line + Loss of New Underwood – Wayside 230 kV line + New Underwood 230/115 kV kV1A

Notes:

1. Contingency WSD4NU-WB-C1 initially resulted in voltage collapse in the post-project out-year case. This is due to reactive power deficiency in the Elk Creek / Rapid City / Rushmore / Ellsworth area. The contingency was solved by adding a 85 MVAr shunt capacitor at the Elk Creek 115 kV bus.

Contingency WSD4NU-WB-C1 also resulted in voltage collapse in the pre-project out-year case. This is due to reactive power deficiency in the Elk Creek / Rapid City / Rushmore / Ellsworth area. The contingency was solved by adding a 94 MVAr shunt capacitor at the Elk Creek 115 kV bus.

Based on the resulting loadings (see table above), it is concluded that Project GI-1401 does not aggravate system performance following contingency WSD4NU-WB-C1. Shunt capacitor additions at Elk Creek 115 kV are not associated with the addition of Project GI-1401.

2. Contingency WSD4NU-EB-C1 resulted in low voltage violations in the out-year case as shown in the above table.
Addition of a 53 MVAr shunt capacitor at the Newell 115 kV bus was shown to be effective in mitigating the out-year low voltage violations.

Table 3-16: Voltage violations summary for network with Maurine – Philip Tap 230 kV line addition and modest network improvements with 325 MW of injection, Secondary POI

Bus #	Bus Name	Base kV	Contingency	Post-Project Voltage (pu)	Case
	ELKCRK 7	115.0	WSD4NU-EB-C1	0.8490	s02-sp24aa-115up-MA-PTAP
	ELSWRTH7	115.0	WSD4NU-EB-C1	0.8501	s02-sp24aa-115up-MA-PTAP
	NEWELL 7	115.0	WSD4NU-EB-C1	0.8725	s02-sp24aa-115up-MA-PTAP
	NUNDRWD4	230.0	WSD4NU-EB-C1	0.8694	s02-sp24aa-115up-MA-PTAP
	NUNDRWD7	115.0	WSD4NU-EB-C1	0.8613	s02-sp24aa-115up-MA-PTAP
	RAPIDCY7	115.0	WSD4NU-EB-C1	0.8492	s02-sp24aa-115up-MA-PTAP
	WICKSVL7	115.0	WSD4NU-EB-C1	0.8783	s02-sp24aa-115up-MA-PTAP
	RUSHMRE7	115.0	WSD4NU-EB-C1	0.8462	s02-sp24aa-115up-MA-PTAP

WSD4NU-EB-C1: Loss of New Underwood - Maurine 230 kV line + NU 230/115 kV KV2A transformer + New Underwood - Philip Tap 230 kV line

MA230-115XF: Loss of Maurine 230/115 kV transformer

MA2PT-MATX: Loss of Maurine - Philip Tap 230 kV line + Maurine 230/115 kV transformer

Notes:

1. Contingency WSD4NU-WB-C1 initially resulted in voltage collapse in the post-project out-year cases.
   This is due to reactive power deficiency in the Elk Creek / Rapid City / Rushmore / Ellsworth area.
   The contingency was solved by adding a 85 MVAr shunt capacitor at the Elk Creek 115 kV bus. No post-contingency voltage violations were observed.

2. Contingency WSD4NU-EB-C1 resulted in low voltage violations in the out-year case as shown in the above table.
   Addition of a 53 MVAr shunt capacitor at the Newell 115 kV bus was shown to be effective in mitigating the out-year low voltage violations.

Table 3-17: Thermal violations summary for network with Maurine – Philip Tap 230 kV line addition and modest network improvements, RCDC flows reversed, Secondary POI
[CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)	CASE
	RATE A	RATE B		POST-PROJECT	

3.5.4 Special Protection Scheme (SPS)

The application of a SPS was investigated to evaluate the possibility of running back or tripping GI-1401 to mitigate adverse system impacts following contingencies in the local area. Analysis was performed at both the primary and secondary POIs.

3.5.4.1 Primary POI

Table 3-2 indicates that interconnection of GI-1401 at the primary POI causes thermal overloads on the Newell – Elk Creek 115 kV line and the Maurine transformer under system intact conditions. If these system intact overloads are not mitigated through either system reinforcements and/or a reduction in the size of the proposed interconnection, the application of a SPS is not possible.

Results of Section 3.5.1 show that modest system improvements limit the allowable injection to 103 MW. These results were further reviewed to determine if interconnection above 103 MW is possible with a SPS. It was concluded that the application of a SPS is not practical for interconnection at the primary POI (with or without the conversion of the POI-Maurine line from 115 kV to 230 kV) because a run-back or tripping of GI-1401 would be required for a large number of contingencies. See below for a summary of contingencies requiring SPS action. Near-term and out-year results are given in Table 3-18 and 3-19, respectively.

3.5.4.2 Secondary POI

Tables 3-4 and 3-8 were reviewed to determine the applicability of a SPS at the secondary POI. Results indicate that GI-1401 would require run-backs or tripping for the following contingencies:

- Loss of Maurine – New Underwood 230 kV line
- WSD4NU-EB-C1
- C2.HTG4-182

Furthermore, run-backs are required to address the voltage collapse problems and associated thermal overloads following contingency WSD4MA282C2. Additional analysis would have been performed as part of the stability studies to determine the speed of SPS action relative to the speed of voltage collapse if the customer had proceeded at the Secondary POI following review of the IFS.

From the perspective of steady-state analysis, it is concluded that interconnection at the secondary POI is possible provided that the SPS is designed to run-back or trip GI-1401 as appropriate for the contingencies listed above. Additional analysis was performed to determine whether a SPS would be required to address the voltage collapse and thermal overloads following contingency WSD4NU-WB-C1 (as shown in Section 3.4, this contingency resulted in voltage collapse in the pre- and post-project cases). This analysis showed that GI-1401 does not aggravate post-contingency voltages and thermal overloads over and above those found in the pre-project case, so a SPS would not be effective for this contingency.

Table 3-18: Summary of contingencies requiring SPS action (Primary POI, near-term transmission rights cases) [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE	DC FCITC RATE A/B	AC FCITC RATE A/B	RUN-BACK	
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT						
											<< See Note 1
											Below

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE	DC FCITC RATE A/B	AC FCITC RATE A/B	RUN-BACK
	RATE A	RATE B		PRE-	POST-					

<< See Note 2 Below

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE	DC FCITC RATE A/B	AC FCITC RATE A/B	RUN-BACK
	RATE A	RATE B		PRE-	POST-					

<< See Note 3 Below

Notes:
1. Lowest Contingency Case FCITC: 113.7 MW
2. Lowest System Intact FCITC: 256.3 MW
3. Max. Injection 325 MW

Table 3-19: Summary of contingencies requiring SPS action (Primary POI, out-year transmission rights cases) [CEII]

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE	DC FCITC RATE A/B	AC FCITC RATE A/B	RUN-BACK	
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT						
											<< See Note 4
											Below

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT		

DC FCITC RATE A/B	AC FCITC RATE A/B	RUN-BACK

<< See Note 5 Below

MONITORED FACILITY	RATING (MVA)		CONTINGENCY	LOADING (MVA)		TDF	CASE	DC FCITC RATE A/B	AC FCITC RATE A/B	RUN-BACK
	RATE A	RATE B		PRE-PROJECT	POST-PROJECT					

<< See Note 6 Below

Notes:
4. Lowest Contingency Case FCITC: 117.5 MW
5. Lowest System Intact FCITC: 259.8 MW
6. Max. Injection 325 MW

4 CONSTRAINED INTERFACE ANALYSIS

The purpose of this task was to determine if the GI-1401 project would adversely impact the regional constrained interfaces (PTDF and OTDF interfaces) of the MRO system. The analysis was performed for interconnection at the Primary POI. The NMORWG DFCALC IPLAN program was used to calculate the TDFs on the near-term and out-year summer peak transmission rights power flow models with and without the proposed project. The mitigation described in Section 3.5 was not included in the models used for this analysis.

The interface and flow-gate definitions were obtained from the definition files "ties-MRO-2013series-2014-new.txt" for near-term cases and "ties-MRO-2013series-2024-new.txt" for out-year cases. Flows on some of the remote interfaces/flowgates could not be monitored due to topology differences between the case and the interface definitions. These flowgates are remote from the area of interest and no further effort was made to reconcile these differences.

Table 4-1 compares the interface flows for the near-term cases with and without the proposed project. The table shows the transfer distribution factor (in percent) for the 325 MW net power transfer from the proposed project to the sink. For the PTDF interfaces, impacts > 5% and for OTDF interfaces, impacts > 3% from pre-project condition are shown in this table. Similar results for out-year cases are shown in Table 4-2.

Mitigation may be required if it is determined that there is insufficient or no available transfer capability (ATC) on the affected MAPP constrained interfaces. This is an issue that should be addressed with the system impact study for delivery service should the proposed project go forward.

Table 4-1: Impact of GI-1401 on Constrained Interfaces (Near-Term) [CEII]

INTERFACE	MW FLOW		Δ	TDF
	PRE- PROJECT	POST-PROJECT	MW	
PTDF INTERFACES				
OTDF INTERFACES				

Table 4-2: Impact of GI-1401 on Constrained Interfaces (Out-Year) [CEII]

INTERFACE	MW FLOW		Δ	TDF
	PRE-PROJECT	POST-PROJECT	MW	
PTDF INTERFACES				
OTDF INTERFACES				

5 SHORT CIRCUIT ANALYSIS

Short-circuit calculations were performed to determine the impact of the GI-1401 project on fault current levels in the transmission system. Both points of interconnection were considered in this analysis, i.e., the Primary POI is twenty-seven miles from the Maurine 115 kV bus on the Maurine – Newell 115 kV line, and the Secondary POI is directly connected to the Maurine 230 kV bus.

5.1 MODEL DEVELOPMENT

The pre- and post-project cases for this analysis were developed starting from the post-project short-circuit case used in the GI-1301 System Impact Study. See reference [3]. These short-circuit models were developed starting from Case "2012-post-GI-1301-poi2-v29.sav."

The proposed project was then added as specified to develop the post-project cases. The mitigation described in Section 3.5 was <u>not</u> included in the models used for this analysis.

5.2 SHORT CIRCUIT ANALYSIS ASSUMPTIONS

Activity ASCC in PSS/E was used to calculate the fault current at selected buses in the vicinity of the proposed project (see Section 5.3). Flat assumptions (1 p.u. voltage at all buses) were used to derive the fault current levels.

5.3 SHORT CIRCUIT ANALYSIS RESULTS

All buses 69 kV and above in WAPA, XEL, GRE and OTP were studied. Buses where the fault currents increased by 100 A or more (post-project vs. pre-project) were retained. Results for the Primary POI are tabulated in Table 5-1; results for the Secondary POI are tabulated in Table 5-2.

Table 5-1: Comparison of Pre- and Post-Project Fault Currents for Primary Point of Interconnection [CEII]

BUS #	BUS NAME	kV	MINIMUM BREAKER RATING AMP	PRE-PROJECT		POST-PROJECT		CHANGE	
				3PH AMP	SLG AMP	3PH AMP	SLG AMP	3PH AMP	SLG AMP

Table 5-2: Comparison of Pre- and Post-Project Fault Currents
for <u>Secondary</u> Point of Interconnection [CEII]

BUS #	BUS NAME	kV	MINIMUM BREAKER RATING AMP	PRE-PROJECT		POST-PROJECT		CHANGE	
				3PH AMP	SLG AMP	3PH AMP	SLG AMP	3PH AMP	SLG AMP

6 STABILITY ANALYSIS

The purpose of this analysis was to determine whether the MAPP system would meet stability criteria following commissioning of the proposed project. Local and regional contingencies were simulated under 2016 summer off-peak conditions. Stability analysis was performed at the Primary POI (Maurine-Newell 115 kV) with the project size reduced to 103 MW.

6.1 MODEL DEVELOPMENT

The pre- and post-project cases for this analysis were developed starting from the cases included in the November 11, 2014 Stability Package developed by BEPC and WAPA. This package utilizes PTI PSS/E^{TM} Rev 32.1 and Version 11.1 of the Intel Visual Fortran Compiler.

The pre-project case for this analysis was developed from a 2016 high-transfer summer off-peak case developed by BEPC. Several modifications were made to this case prior to use in this study. The following is a summary of some of the relevant assumptions that went into developing this case:

- North Dakota Coal Field generators are modeled at URGE levels
- South Dakota hydros are modeled at URGE levels
- South Dakota wind units in the electrical vicinity of Maurine and New Underwood substations are dispatched at 100% of nameplate – these included projects G752 (150 MW wind farm at Hettinger) and GI-1209 (99 MW wind farm on Ft. Randall – Lake Platte 230 kV line)
- All other wind in ND and SD is generally modeled at 20% of nameplate.
- Peaking units are modeled off-line (these include Groton, Culbertson, Pioneer, Lonesome Creek etc.)
- Southwest Minnesota Wind is modeled at 1500 MW.
- HVDC line flows are modeled as follows:
    - Square Butte – Arrowhead DC: 550 MW
    - Rapid City DC (RCDC): 200 MW East to West
    - Miles City Converter Station (MCCS): 150 MW West to East

  Note: A separate stability case was developed with the RCDC and MCCS flows reversed.

The following major transmission projects are included in the case:

- Bemidji – Grand Rapids 230 kV line
- Center – Grand Forks 345 kV line
- Fargo – St. Cloud – Monticello 345 kV lines
- Brookings – Hampton County 345 kV line
- Riel 345 kV substation

Flows on the major interfaces in Northern MAPP were modeled as follows:

- Manitoba Hydro Export (MHEX): Approx. 2175 MW in the north to south direction
- Minnesota – Wisconsin Export (MWEX): Approx. 1611 MW in the west to east direction

- Flows on the North Dakota Export (NDEX) interface were not constrained.

After developing the pre-project case, two post-project cases were developed by adding project GI-1401 on the Maurine-Newell 115 kV line and dispatching it at 103 MW against the MISO footprint east of the Twin Cities. Power output and Pmax were both adjusted to 103.7 MW.

[CEII]

The two post-project cases are:

- Case *a13-s716aa.sav:* GI-1401 dispatched at 103.7 MW, RCDC: 200 MW E → W; MCCS: 150 MW W → E (these assumptions bias the flow on the Hettinger – Bison – Maurine 230 kV line in a north to south direction)

- Case *b13-s716aa.sav:* GI-1401 dispatched at 103.7 MW, RCDC: 200 MW W → E; MCCS: 150 MW E → W (these assumptions bias the flow on the Maurine – Bison – Hettinger 230 kV line in a south to north direction)

Case summaries of the pre- and post-project cases are attached in Appendix E. In addition, the genlist spreadsheets for these cases are also attached.

6.2 FAULT DEFINITIONS

Stability analysis was performed on the cases derived in the previous section to determine the impact of proposed project. A limited number of faults were run. These included critical regional faults in Northern MAPP (see Table 6-1) and local faults in the project vicinity (see Table 6-2). Local faults were developed assuming a new 115 kV three-breaker ring bus at the Primary POI.

Table 6-1: List of Faults for Stability Analysis – Regional Disturbances [CEII]

Fault ID	Fault Definition

Fault ID	Fault Definition

Table 6-2: List of Faults for Stability Analysis, GI-1401 at 103 MW – Local Disturbances [CEII]

Fault ID	Fault Definition

Fault ID	Fault Definition

6.3 Simulation Results

[CEII]

Table 6-3: Local area stability results [CEII]

Fault ID	Case a13-a716aa	Case b13-s716aa

6.4 CONCLUSIONS

Results of the stability analysis indicate that the interconnection of GI-1401 (103 MW on the Maurine – Newell 115 kV line) does not adversely impact system stability.

7 REFERENCES

[1] “MAPP Members Reliability Criteria and Study Procedures Manual”, Version 1.1, September 2013.

[2] “MAPP Design Review Subcommittee Policies and Procedures”, Prepared by MAPP Design Review Subcommittee Members, Version 2.2b, March 2013.

[3] “Interconnection System Impact Study Report for Project GI-1301”, Prepared by ABB Inc., May 15, 2014.