Interconnection System Impact Study
FINAL REPORT - November 8, 2016

Generator Interconnection Requests No. TI-16-0230 & TI-16-0231
2x 150 MW Wind Energy Generating Facility
In Platte County, Wyoming

Prepared By:

Chris Gilden
Tri-State Generation and Transmission Association, Inc.

Reviewed By:

Mark Stout
Tri-State Generation and Transmission Association, Inc.

TABLE OF CONTENTS

Page No.

NOTE: Appendices are Tri-State Confidential, are available only to the IC and Affected Systems upon request, and are not for posting on OASIS.

1.0 EXECUTIVE SUMMARY

This System Impact Study (SIS) is for Generator Interconnection Requests No. TI-16-0230 and TI-16-0231, two proposed 150 MW wind energy Generating Facilities (GF) located in Platte County, Wyoming. This SIS was prepared in accordance with Tri-State Generation and Transmission Association, Inc. (Tri-State) Generator Interconnection Procedures, and includes steady-state power flow, dynamic, short-circuit, and cost and schedule analyses for interconnection of each GF as a Network and Non-Network Resource of Basin Electric Power Cooperative.

Each proposed GF consists of sixty-nine (69) General Electric 2.0 MW and seven (7) General Electric 1.79 MW wind turbines and one 34.5-345-13.8 kV transformer at the main wind energy generating facility with a primary Point of Interconnection (POI) on the Laramie River Station – Story 345 kV transmission line, 9 miles east of Chugwater, WY (see Figures 1, 2, and 4 for reference).

Two generation dispatch scenarios were studied: 1) local area generation was modeled as in the WECC base case dispatch, 2) WECC rated path 36 (TOT3) was stressed in accordance with a 24-cell generation dispatch matrix.

Steady-state power flow results:

For 2019 Heavy Summer and Light Autumn system conditions, no elements exceeded their emergency thermal limits for the non-stressed TOT3 generation dispatch scenarios.

For 2019 Heavy Summer and Light Autumn system conditions, the post-Project stressed TOT3 scenarios demonstrated overloads on the Terry Ranch-Ault 230 kV line, the Laramie River Station-Stegall 230 kV line, and the 345 kV line section between the Project POI and Wayne Child substation. All three overloads increase with incremental GF injection levels. However, if the TOT3 metering point is moved from the LRS terminal of the LRS – Ault 345 kV line to the Wayne Child substation as is planned, and if current reliability operating limits are maintained, these overloads can be avoided.

Reactive power / voltage regulation:

The GF can meet Tri-State's 0.95 p.f. lag to lead criteria at the generator high-side bus with exception of output levels near 0 MW. Therefore, approximately 11 MVAR of switched shunt reactors (inductors) will be required on each 34.5 kV bus to offset the collector system VARs and meet Tri-State’s VAR neutral requirement.

The Interconnecting Customer is responsible for installing equipment to ensure that the GF can achieve the net 0.95 p.f. lag and lead capability across the near 0 to 300 MW net generation output as measured at the POI. Prior to entering into a Generator Interconnection Agreement, the Customer must provide data that demonstrates compliance with Tri-State's reactive criteria.

Dynamic stability analysis:

Transient stability analysis was completed with the GE 2.0 MW wind turbine dynamic model. The Project did not trip during any of the simulated disturbances and the GF was able to operate at full capacity. Local area generators showed stable performance and remained in synchronism for all contingencies. Acceptable damping and voltage recovery was observed (Appendix B).

Short - Circuit analysis:

Total fault currents are within Tri-State's planned equipment ratings.

The total cost for the 345 kV Interconnection Facilities, as defined in this report, is $9 M. All costs are good faith estimates in 2016 dollars (refer to Figure 4).

The in-service date for this GF will depend on construction of the Interconnection Facilities and Network Upgrades and will be a minimum of 24 months after the execution of a Generator Interconnection Agreement or Engineering and Procurement contract.

NOTE: Pursuant to Section 3.2.2.4 of the Tri-State's Generation Interconnection Procedures, "Interconnection Service does not convey the right to deliver electricity to any customer or point of delivery. In order for an Interconnection Customer to obtain the right to deliver or inject energy beyond the Generating Facility Point of Interconnection or to improve its ability to do so, transmission service must be obtained pursuant to the provisions of the Transmission Provider's Tariff by either Interconnection Customer or the purchaser(s) of the output of the Generating facility." See Tri-State's Open Access Same Time Information System (OASIS) web site for information regarding requests for transmission service, related requirements and contact information.

2.0 BACKGROUND AND SCOPE

On February 29, 2016, the Interconnecting Customer submitted two Generator Interconnection Requests for identical 150 MW wind energy GFs to be located approximately nine (9) miles east of Chugwater, WY. The application was deemed complete on April 14, 2016 and an Interconnection System Study Agreement was executed on May 27, 2016.

This System Impact Study was prepared in accordance with Tri-State's Generator Interconnection Procedures and relevant FERC, NERC, WECC and Tri-State guidelines. The objectives are: 1) to evaluate the steady state performance of the system with the proposed project, 2) identify Interconnection Facilities and Network Upgrades, 3) check the GF's ability to meet Tri-State's voltage regulation and reactive power criteria, 4) assess the dynamic performance of the transmission system under specified stability contingencies, 5) perform a basic short circuit analysis to provide the estimated maximum (N-0) and minimum (N-1) short circuit currents, and 6) provide a preliminary estimate of the costs and schedule for all necessary Interconnection Facilities and Network Upgrades, subject to refinement in a Facilities Study.

Figure 1 - Map Of Study Area And Location of GF

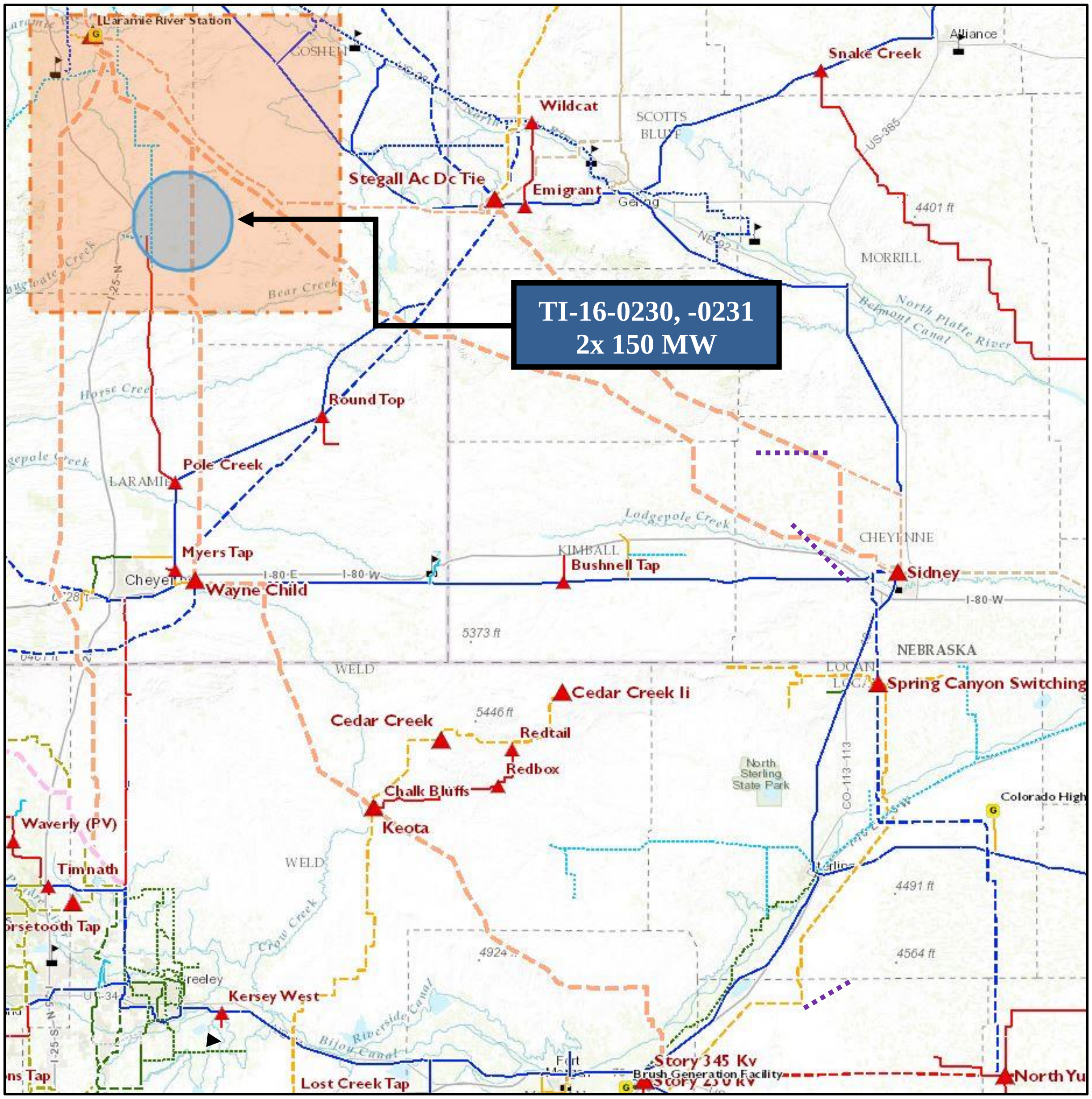
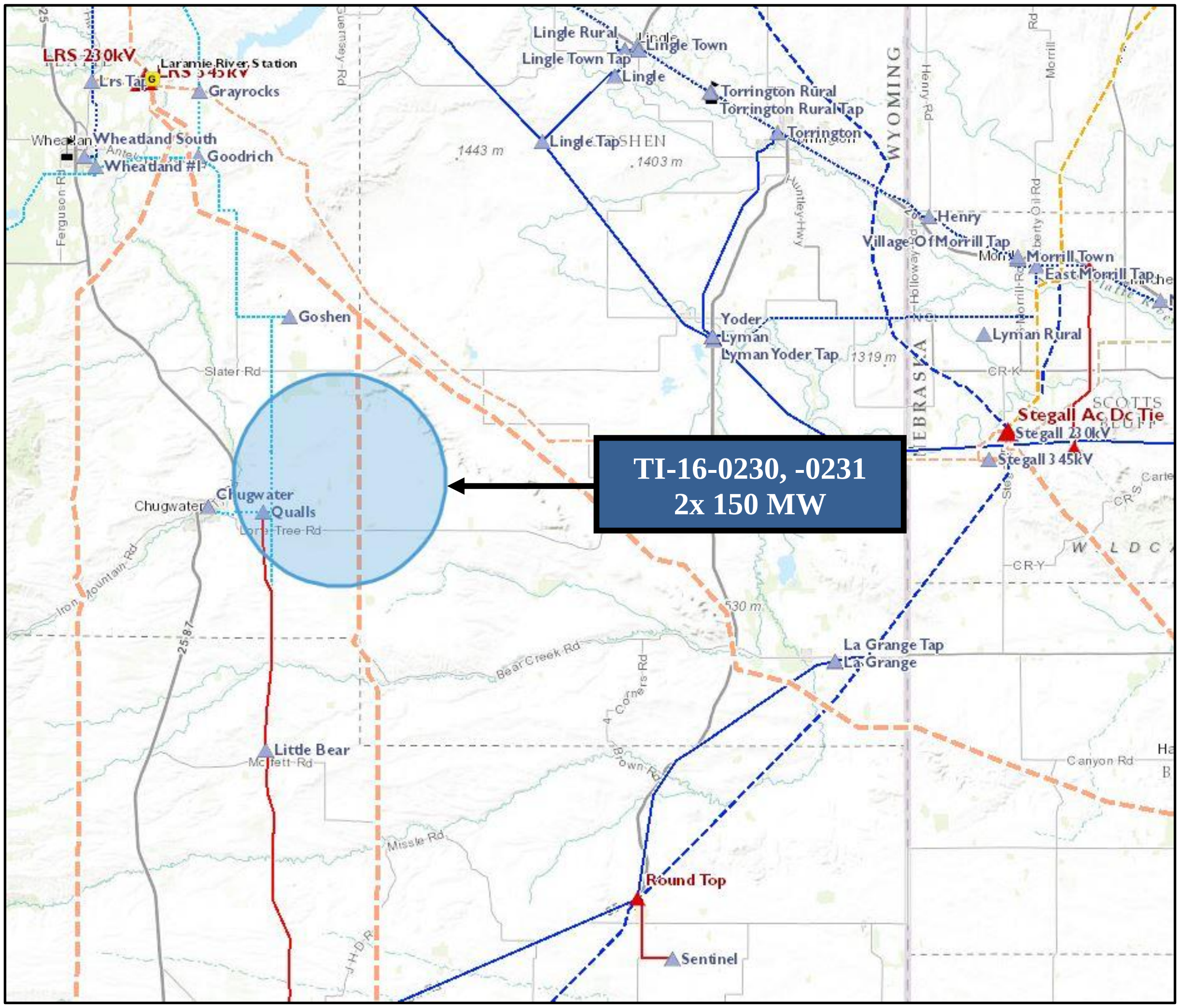


Figure 2 - Map Of Study Area And Location of GF



3.0 GF MODELING DATA

The model consists of two 150 MW equivalent wind turbine generators with two 34.5-345-13.8 kV transformers and a 4 mile 345 kV generator tie line routed from the Project to the Laramie River Station – Story 345 kV POI. See Figures 1, 2, and 4 for further details. Model data is based on information provided by the Customer. The Customer must provide actual data and confirm actual reactive power operating capabilities prior to interconnecting the Project, and ultimately prior to being deemed by Tri-State as suitable for commercial operation.

Generator Data: The study modeled two lumped equivalent generators with a Pmax of 150 MW. Each generator had a reactive capability of 0.900 lag and 0.900 lead, 72.64 to -72.64 MVAR.

Table 1: Generator Data for Steady-State Power Flow Analyses

Unit	Description	
Pmax	Name plate rating (lumped equivalent gen model)	2x 150 MW
Qmin, Qmax	Reactive capability	0.900 lag to 0.900 lead
Et	Terminal voltage	0.69 kV
RSORCE	Synchronous resistance	0.0000 p.u.
XSORCE	Synchronous reactance	1.0000 p.u.

Table 2: Power Flow Data for General Electric 1.79 MW Unit

Unit	Description	[*Manufacturer*]
MBase	Generator MVA base	1.79 MVA
Prated	Generator active power rating (nameplate)	1.79 MW
Vrated	Terminal voltage	0.69 kV
Srated	Unit transformer Rating	2.00 MVA
Xt	Unit Transformer Reactance (on transformer base)	5.75%
Xt/Rt	Unit Transformer X/R ratio	7.5

Table 3: Power Flow Data for General Electric 2.00 MW Unit

Unit	Description	[*Manufacturer*]
MBase	Generator MVA base	2.25 MVA
Prated	Generator active power rating (nameplate)	2.0 MW
Vrated	Terminal voltage	0.69 kV
Srated	Unit transformer Rating	2.25 MVA
Xt	Unit Transformer Reactance (on transformer base)	5.75%
Xt/Rt	Unit Transformer X/R ratio	7.5

34.5 kV Collector System: The wind farm was interconnected to the POI via two 34.5-345-13.8 kV transformers and an equivalent feeder circuit model.

Main GF Substation Transformer: Each substation transformer was modeled with ratings of 102/136/170 MVA and a voltage ratio of 34.5 kV (wye-gnd) - 345 kV (wye-gnd) - 13.8 kV (delta). The transformer impedance was assumed to be 8.5% on the 102 MVA base ONAN rating with X/R of 40.

345 kV Generator Tie Line: The GF to POI line impedance was based on 4 miles of 2C-795 kcmil ACSR. The continuous thermal rating is 1084 MVA with an impedance of R = 0.196E-3, X = 1.996E-3, B = 33.6E-3. All values are in p.u.

4.0 STEADY-STATE POWER FLOW ANALYSIS

The Customer requested that both Projects be studied as Network and Non-Network Resources of Basin Electric Power Cooperative.

Network Resource Interconnection integrates a Generating Facility with a Transmission Provider's Transmission System in a manner comparable to the way the Transmission Provider integrates its own generating facilities to serve its native load customers. Therefore, other Network Resources in the local area are studied at full output to determine if the aggregate of the existing and proposed generation can be delivered to load consistent with the Transmission Provider's reliability criteria and procedures. As a Network Resource, MBPP generation was displaced at Dry Fork Generating Station.

Non-Network resources are studied either (i) pursuant to a Transmission Service Request, or (ii) at full output of the proposed Generating Facility to identify required Network Upgrades, and also at reduced output levels to determine the maximum allowed output without Network Upgrades, other than those required for interconnection of the Customer's facilities. For the Non-Network (Energy Resource) analysis, generation was displaced at Springerville Unit 3.

4.1 Criteria and Assumptions

Siemens PTI PSS/E version 33.5.2 software was used for performing the steady-state power flow analysis with the following study criteria:

1. Tri-State's GIP 2019, Heavy Summer and Light Autumn (PSS/E-v33) base cases were developed from WECC approved seed cases with updates from the latest available loads and resources data, topology (line and transformer ratings, planned and budgeted projects, etc.), and updates received from regional utilities and Affected Systems. These GIP base cases were further updated by Tri-State to reflect appropriate generation dispatching for this study. The following base cases were utilized for the SIS:
    a. 2019 Heavy Summer cases with and without the new GF project.
    b. 2019 Light Autumn cases with and without the new GF project.

2. To stress TOT3, a 24-point generation dispatch matrix utilized in similar studies was used (Table 4). Generation was dispatched in accordance with the matrix cells and flows across TOT3 were stressed by increasing remote generation in the Pacific Northwest, Idaho, and Montana and decreasing generation in Colorado. TOT3 is considered stressed when overload or voltage violations begin to appear in the vicinity of TOT3 under these increased flows. The impact on TOT3 flows due to Project injection levels was then determined using the following methodology:

a. TOT3 was stressed pre-Project.

b. Project injection levels were increased and equivalent generation was displaced at Dry Fork (or Springerville Unit 3) to minimize the impact on TOT3.

Table 4: Pre-Project TOT3 North-South Flows

CPP = 66 MW	300 MW E→W	0 MW E→W	300 MW W→E
LRS = 1140 MW Pawnee = 777 MW	19HS: 1802 19LA: 1754	19HS: 1574 19LA: 1580	19HS: 1032 19LA: 1394
LRS = 570 MW Pawnee = 777 MW	19HS: 1341 19LA: 1356	19HS: 1078 19LA: 1129	19HS: 712 19LA: 890
LRS = 1140 MW Pawnee = 280 MW	19HS: 1835 19LA: 1790	19HS: 1593 19LA: 1583	19HS: 1059 19LA: 1411
LRS = 570 MW Pawnee = 280 MW	19HS: 1364 19LA: 1366	19HS: 1096 19LA: 1139	19HS: 824 19LA: 891
CPP = 266 MW	**300 MW E→W**	**0 MW E→W**	**300 MW W→E**
LRS = 1140 MW Pawnee = 777 MW	19HS: 1798 19LA: 1701	19HS: 1576 19LA: 1578	19HS: 1052 19LA: 1374
LRS = 570 MW Pawnee = 777 MW	19HS: 1346 19LA: 1355	19HS: 1087 19LA: 1145	19HS: 833 19LA:889
LRS = 1140 MW Pawnee = 280 MW	19HS: 1814 19LA: 1792	19HS: 1576 19LA: 1609	19HS:1047 19LA: 1385
LRS = 570 MW Pawnee = 280 MW	19HS: 1319 19LA: 1370	19HS: 1086 19LA: 1158	19HS: 819 19LA: 898

3. Power flow (P0) solution parameters were as follows: Transformer LTC Taps – stepping; Area Interchange Control – disabled; Phase Shifters and DC Taps – adjusting; and Switched Shunts - enabled.
4. Power flow contingencies (P1-P7) utilized the following solution settings: Transformer LTC Taps – locked taps; Area Interchange Control – disabled; Phase Shifters and DC Taps – non-adjusting; and Switched Shunts – locked all. (Not allowing these voltage regulating solution parameters to adjust provides worst case results.)
5. All buses, lines and transformers with nominal voltages greater than or equal to 69 kV in the Tri-State and surrounding areas were monitored in all study cases for N-0 and N-1 system conditions.

6. Nearby study areas (PacifiCorp, Tri-State, WAPA, and XE/PSCo) were investigated using the same overload criteria.
7. This analysis assumes that the GF controls the high voltage bus at the POI and should not negatively impact any controlled voltage buses on the transmission system.
8. Post-contingency power transfer capability is subject to voltage constraints as well as equipment ratings. The Project was tested against NERC/WECC reliability criteria with additions/exceptions as listed in the following Table 5:

Table 5: Voltage Criteria

Tri - State Voltage Criteria for Steady State Power Flow Analysis		
Conditions	**Operating Voltages**	**Delta-V**
Normal (P0)	0.95 - 1.05	-
Contingency (P1)	0.90 - 1.10	8%
Contingency (P2-P7)	0.90 - 1.10	-

4.2 Voltage Regulation and Reactive Power Criteria

1. The GF must be capable of either producing or absorbing VAR as measured at the POI to achieve a 0.95 power factor (p.f.), across the range of near 0% to 100% of facility MW rating, as calculated on the basis of nominal generator high-side bus voltage (1.0 p.u. V).
2. The GF may be required to either produce VAR or absorb VAR from .90 p.u. V to 1.10 p.u. V at the POI, with typical target regulating voltage being 1.03 p.u. V.
3. The GF is required to supply a portion of the VAR on a continuously adjustable or dynamic basis. The amount of continuously adjustable VAR shall be equivalent to a minimum of 0.95 p.f. produced or absorbed at the high side of the generator substation bus across the full range (0 to 100%) of rated MW output. The remaining VAR required to meet the 0.95 p.f. net criteria may be achieved with switched reactive devices.
4. The GF may utilize switched capacitors or reactors as long as the individual step size results in less than 3% change at the POI operating bus voltage. This step change voltage magnitude shall be calculated based on the minimum system (N-1) short circuit POI bus MVA level as supplied by Tri-State.
5. When the GF is not producing any real power (near 0 MW), the VAR exchange at the POI shall be near 0 MVAR, i.e., VAR neutral.

4.3 Steady-State Power Flow Results

The purpose of the steady state power flow analysis is to determine the impacts that the Project will have on the performance of the transmission system under various system conditions. System intact and contingency analysis was performed. The transmission system was analyzed prior to the interconnection of the Project to determine any pre-existing loading or voltage violations. The Project was then interconnected and the contingency analysis was repeated. The results were compared to determine if the existing system is negatively affected by the Project.

1. N-0 (System Intact, Category P0) Study Results:

   For both the 2019 Heavy Summer and 2019 Light Autumn cases, and for both stressed and non-stressed TOT3 conditions, the proposed Project generation (300 MW) can be added with no thermal or voltage violations with all lines in-service.

2. N-1 and N-1-1 (Category P1-P7) Study Results:

   Results for P1-P7 contingencies using the non-stressed TOT3 2019 Heavy Summer and 2019 Light Autumn cases are shown in Tables 6 and 7 below. With the 2019 Heavy Summer and 2019 Light Autumn cases, there were no elements that exceeded their normal thermal limits for any contingency using the non-stressed cases.

   Results for P1-P7 contingencies using the stressed TOT3 2019 Heavy Summer and 2019 Light Autumn cases are shown in Tables 8-11 below. Tables 8 and 9 contain the results when modeled as an Energy Resource; Tables 10 and 11 contain the results when modeled as a Network Resource of Basin Electric Power Cooperative.

   As indicated in Tables 8-11, the post-Project stressed TOT3 scenarios demonstrated overloads on the Terry Ranch-Ault 230 kV line, the Laramie River Station-Stegall 230 kV line, and the 345 kV line section between the Project POI and Wayne Child substation, whether the GF is an Energy Resource or a Network Resource. The overloads were observed for several cells of the 24-cell generation dispatch matrix used to stress the system.

   As Tables 9 and 11 indicate, the Terry Ranch-Ault 230 kV line is fully loaded in the Light Autumn pre-Project cases. This is a consequence of stressing TOT3 flows to a maximum. In order to accommodate the Project injection, the power flow analysis should demonstrate that the post-Project loading on this line is not worse than the pre-Project loading and that no other system elements are overloaded. However, the analysis found that the post-Project loadings on the Terry Ranch-Ault line were greater than the pre-Project loadings (approximately 5 - 9 %).

   When analyzing the above overload, it was noted that the methodology used to stress the system did not adjust TOT3 flows post-Project, and therefore the results may overstate actual line flows across TOT3. This is particularly true considering that system operators will keep TOT3 flows within system reliability limits. This issue was discussed with the Western Area Power Administration, owner of the Terry Ranch-Ault 230 kV line. The TOT3 metering point on the LRS-Story 345 kV line is currently located at the LRS terminal but will be moved south of the Wayne Child POI once the Wayne Child project is completed. With this relocation of the TOT3 metering point, any amount of Project injection results in increased measured TOT3 flows. However, if the study methodology subsequently reduces TOT3 flows to pre-Project limits (consistent with anticipated system operator actions) then the Terry Ranch-Ault 230 kV line overload and the Project POI to Wayne Child overload do not appear.

As Tables 12-15 indicate, reducing TOT3 flows to pre-Project limits does not fully avoid a potential overload of the LRS-Stegall 230 kV line for a loss of the Project POI to Wayne Child 345 kV line section. However, as discussed in item 6 below, Project curtailment will occur anytime a section of the 345 kV line is out of service. This overload can be ignored by leveraging the 30-minute 550 MVA emergency rating of the Laramie River Station-Stegall 230 kV line until curtailment occurs.

3. Steady-state voltage violations:

   With an operating voltage range between 0.90 p.u. to 1.10 p.u., under single contingency outage conditions there were no voltage violations with the GF at full output.

4. Steady-state contingency voltage deviation:

   Each Balancing Authority's ΔV requirement was applied as per Table 5. There were no ΔV violations at any of the monitored buses.

5. Reactive power required at the generator high-side bus:

   At 150 MW output, the VAR capability required at the generator high-side bus ranges from 98.6 MVAR produced (0.95 p.f. lag) to 98.6 MVAR absorbed (0.95 p.f. lead). This is the net MVAR to be produced or absorbed by the GF, depending upon the applicable range of voltage conditions at the POI.

   The unit data provided by the Customer shows a reactive capability of 0.900 p.f. lag to 0.900 p.f. lead. Utilizing only the GF capability supplied by the Customer, a steady-state analysis was performed for the generator high-side bus voltage established by the dispatch in the power flow cases. For reference, Table 16 shows the net VAR flow at several levels of GF output and at fixed voltage levels of 0.95 p.u. and 1.05 p.u. for a simulated 'infinite' grid.

   The results show that this GF can meet Tri-State's 0.95 p.f. lag to lead criteria at the generator high-side bus with exception of output levels less than 50 MW while absorbing reactive power, and at output levels near 0 MW for VAR neutral requirements. Approximately 11 MVAR of switched shunt reactors (inductors) will be required on each 34.5 kV bus to offset the collector system VARs and meet Tri-State's VAR neutral criteria (less than 2 MVAR flow at 0 MW output at the high side of the generator substation).

6. The existing LRS generation is currently restricted to 680 MW during an outage of either the LRS-Story or LRS-Ault 345 kV lines. This is required to maintain system reliability in the event of an outage on the remaining LRS 345 kV line. The proposed Project will be curtailed prior to curtailing the existing LRS units based on current ownership rights in the MBPP system. Note that for full Project output, this report

identifies a potential overload of the LRS-Stegall 230 kV line for a loss of the Project POI to Wayne Child 345 kV line section of the LRS-Story 345 kV line. Based on the above 680 MW restriction, this potential overload would exist above the normal 478 MVA line rating but below the 30-minute 550 MVA emergency line rating until such time that system operators can curtail generation for this line outage.

7. Energy Resource Interconnection Service permits delivery of the Project output using the existing non-firm capacity of the transmission system on an as available basis. Energy Resource Interconnection Service does not, in and of itself, convey any right to deliver the GF output to any specific customer or point of delivery. There currently is no firm transmission capacity available north to south across the TOT3 path.

Table 6: 2019 Heavy Summer Non-Stressed TOT3

AFFECTED ELEMENT	CONTINGENCY	Normal/Emergency* Rating (MVA)	Pre-Project Loading (%)	Post-300 MW Project Loading (%)	Delta (%)	Maximum Project Output w/out Additional NU (MW)	Owner	Notes – Limiting Elements
No thermal elements triggered.								

(*) Indicates Emergency Rating

Table 7: 2019 Light Autumn Non-Stressed TOT3

AFFECTED ELEMENT	CONTINGENCY	Normal/Emergency* Rating (MVA)	Pre-Project Loading (%)	Post-300 MW Project Loading (%)	Delta (%)	Maximum Project Output w/out Additional NU (MW)	Owner	Notes – Limiting Elements
No thermal elements triggered								

(*) Indicates Emergency Rating

Table 8: 2019 Heavy Summer Stressed TOT3 (Energy Resource)

AFFECTED ELEMENT	CONTINGENCY	Normal/Emergency* Rating (MVA)	Pre-Project Loading (%)	Post-300 MW Project Loading (%)	Delta (%)	Maximum Project Output w/out Additional NU (MW)	Owner	Notes – Limiting Elements
Laramie River Station-Stegall 230	Project POI-Wayne Child 345	478.0	87.6	103.7	16.1	225	MBPP	Conductor
Terry Ranch-Ault 230 1	Laramie River Station-Ault 345	457.0	96.4	104.5	8.1	120	WAPA	Conductor
Project POI-Wayne Child 345	Laramie River Station-Ault 345	1195.0	86.4	101.8	15.4	270	MBPP	Bus
Weld_LM-Boomerang 115	Ft.Lupton-St.Vrain 230 1 & 2	121.7	100.0	102.0	2.0	0	WAPA	Conductor

(*) Indicates Emergency Rating

Table 9: 2019 Light Autumn Stressed TOT3 (Energy Resource)

AFFECTED ELEMENT	CONTINGENCY	Normal/Emergency* Rating (MVA)	Pre-Project Loading (%)	Post-300 MW Project Loading (%)	Delta (%)	Maximum Project Output w/out Additional NU (MW)	Owner	Notes – Limiting Elements
Terry Ranch-Ault 230	Laramie River Station-Ault 345	457.0	100.5	109.1	8.6	0	WAPA	Conductor
Project POI-Wayne Child 345	Laramie River Station-Ault 345	1195.0	89.7	104.6	14.9	210	MBPP	Bus

(*) Indicates Emergency Rating

Table 10: 2019 Heavy Summer Stressed TOT3 (Network Resource)

`AFFECTED ELEMENT	CONTINGENCY	Normal/Emergency* Rating (MVA)	Pre-Project Loading (%)	Post-300 MW Project Loading (%)	Delta (%)	Maximum Project Output w/out Additional NU (MW)	Owner	Notes – Limiting Elements
Laramie River Station-Stegall 230	Project POI-Wayne Child 345	478.0†	87.6	105.1	16.1	200	MBPP	Conductor
Terry Ranch-Ault 230	Laramie River Station-Ault 345	457.0	96.4	101.2	4.8	250	WAPA	Conductor
Weld_LM-Boomerang 115	Ft.Lupton-St.Vrain 230 1 & 2	121.7	100.0	101.2	1.2	0	WAPA	Conductor

(*) Indicates Emergency Rating

(†) Laramie River Station-Stegall 230 kV has a 30-minute 550 MVA Emergency Rating

Table 11: 2019 Light Autumn Stressed TOT3 (Network Resource)

AFFECTED ELEMENT	CONTINGENCY	Normal/Emergency* Rating (MVA)	Pre-Project Loading (%)	Post-300 MW Project Loading (%)	Delta (%)	Maximum Project Output w/out Additional NU (MW)	Owner	Notes – Limiting Elements
Terry Ranch-Ault 230	Laramie River Station-Ault 345	457.0	100.6	105.9	5.3	0	WAPA	Conductor
Project POI-Wayne Child 345	Laramie River Station-Ault 345	1195.0	89.7	102.9	14.9	250	MBPP	Bus

(*) Indicates Emergency Rating

Table 12: 2019 Heavy Summer Stressed TOT3 (Energy Resource) – Limited TOT3 Analysis

`AFFECTED ELEMENT	CONTINGENCY	Normal/Emergency* Rating (MVA)	Pre-Project Loading (%)	Post-300 MW Project Loading (%)	Delta (%)	Maximum Project Output w/out Additional NU (MW)	Owner	Notes – Limiting Elements
Laramie River Station-Stegall 230	Project POI-Wayne Child 345	478.0†	87.6	103.1	15.5	300	MBPP	Conductor

(*) Indicates Emergency Rating
(†) Laramie River Station-Stegall 230kV has a 30-minute 550 MVA Emergency Rating

Table 13: 2019 Light Autumn Stressed TOT3 (Energy Resource) – Limited TOT3 Analysis

`AFFECTED ELEMENT	CONTINGENCY	Normal/Emergency* Rating (MVA)	Pre-Project Loading (%)	Post-300 MW Project Loading (%)	Delta (%)	Maximum Project Output w/out Additional NU (MW)	Owner	Notes – Limiting Elements
Terry Ranch-Ault 230	Laramie River Station-Ault 345	457.0	100.7	102.1	1.4	300	WAPA	Conductor

(*) Indicates Emergency Rating

Table 14: 2019 Heavy Summer Stressed TOT3 (Network Resource) – Limited TOT3 Analysis

`AFFECTED ELEMENT	CONTINGENCY	Normal/Emergency* Rating (MVA)	Pre-Project Loading (%)	Post-300 MW Project Loading (%)	Delta (%)	Maximum Project Output w/out Additional NU (MW)	Owner	Notes – Limiting Elements
Laramie River Station-Stegall 230	Project POI-Wayne Child 345	478.0†	87.6	104.6	17.0	300	MBPP	Conductor

(*) Indicates Emergency Rating
(†) Laramie River Station-Stegall 230kV has a 30-minute 550 MVA Emergency Rating

Table 15: 2019 Light Autumn Stressed TOT3 (Network Resource) – Limited TOT3 Analysis

`AFFECTED ELEMENT	CONTINGENCY	Normal/Emergency* Rating (MVA)	Pre-Project Loading (%)	Post-300 MW Project Loading (%)	Delta (%)	Maximum Project Output w/out Additional NU (MW)	Owner	Notes – Limiting Elements
Terry Ranch-Ault 230	Laramie River Station-Ault 345	457.0	100.7	102.0	1.3	300	WAPA	Conductor

(*) Indicates Emergency Rating

**Table 16: Reactive Power Delivered to the WTG Bus and at POI Bus
Project Size: 150 MW, GE V116/GS 3.3, 76 Units**

Infinite Grid Voltage (p.u.)	P, Q, V At Gen Equiv MV			Net P, Q, V, PF At Gen HV Bus					
	Pgen (MW)	Qgen (MVAR)	Voltage (p.u.)	P (MW)	Q (MVAR)	PF at Gen HV Bus	Voltage (p.u.)	MVAR to meet PF Reqd at Gen HV Bus of 0.95	MVAR Short(-) or Excess(+)
0.95	0.0	0.0	0.9742	0	9.0	-	0.9656	0.0	**-9.0**
0.95	50.0	24.2	1.0110	49.7	30.5	0.852	0.9750	16.3	14.2
0.95	100.0	48.3	1.0415	98.8	46.5	0.905	0.9819	32.5	14.0
0.95	150.0	72.4	1.0670	147.6	57.9	0.931	0.9865	48.5	9.4
1.05	0.0	0.0	1.0768	0	11.0	-	1.0585	0	**-11.0**
1.05	50.0	-24.2	1.0485	49.8	-16.1	0.952	1.0587	-16.3	**-0.2**
1.05	100.0	-48.5	1.0132	98.9	-49.7	0.894	1.0470	-32.5	17.2
1.05	150.0	-72.8	0.9684	147.2	-91.8	0.849	1.0316	-48.6	43.2

5.0 DYNAMIC STABILITY ANALYSIS

5.1 Criteria and Assumptions

5.1.1 NERC/WECC Dynamic Criteria

General Electric PSLF version 19.01 was used for dynamic stability analysis. Dynamic stability analysis was performed in accordance with the requirements of NERC standard TPL-001-4 and dynamic performance criteria in TPL-001-WECC-CRT-3. These criteria are described below.

- Voltage shall recover to above 80% of pre-contingency voltage within 20 seconds for all P1-P7 events.
- After rising above 80% of pre-contingency voltage, voltage shall neither dip below 70% pre-contingency voltage for more than 30 cycles nor remain below 80% pre-contingency voltage for more than 2 seconds for all P1-P7 events.
- For contingencies without a fault (P2.1 category event), voltage shall neither dip below 70% pre-contingency voltage for more than 30 cycles nor remain below 80% pre-contingency voltage for more than 2 seconds.
- All oscillations that do not show positive damping within 30 seconds after the start of the studied event shall be deemed unstable.

In addition, the NERC TPL-001-4 standard also requires the simulation of automatic operations such as high-speed reclosing and relay loadability.

5.1.2 Voltage Ride-Through Requirements

1. The GF shall be able to meet the dynamic response LVRT requirements consistent with the latest NERC/WECC criteria, Tri-State's GIP (Appendix G) and FERC Order 661a for LVRT.
2. Generating plants are required to remain in service during faults, three-phase or single line-to-ground (SLG) whichever is worse, with normal clearing times of approximately 4 to 9 cycles, SLG faults with delayed clearing and subsequent post-fault voltage recovery to pre-fault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the circuit breaker clearing times of the affected system to which the IC facilities are interconnecting. The maximum clearing time the generating plant shall be required to withstand for a fault shall be 9 cycles. After which, if the fault remains following the location-specific normal clearing time for faults, the generating plant may disconnect from the transmission system. A generating plant shall remain interconnected during a fault on the transmission system for a voltage level as low as zero volts, as measured at the POI. The IC may not disable low voltage ride through equipment while the plant is on-line.
3. This requirement does not apply to faults that may occur between the generator terminals and the POI.
4. LVRT requirements may be met by the performance of the generators or by installing additional equipment, such as a Static VAR Compensator, or by a combination of generator performance and additional equipment.

5.2 Base Case Model Assumptions

1. Ride-through characteristics of the GF were based upon data in the default model for GE 2.0 MW wind turbines.
2. The GF was modeled using data provided by the IC. Two equivalent collector systems were modeled with one 345/34.5 kV substation transformer for each collector system.

5.3 Methodology

1. The 2019 Heavy Summer and 2019 Light Autumn cases were utilized with the GF in service.
2. System stability was observed by monitoring local voltage and frequency at six (6) busses which function to estimate regional performance. Stability is determined from the performance criteria discussed above.
3. Three-phase faults (3LG) were simulated for all category P1 contingencies and Single Line-to-Ground (SLG) faults for all category P4 contingencies. Contingencies used to evaluate the wind farm's compliance with NERC/WECC criteria for dynamic stability are listed in the following table.

Table 17: List of Dynamic Stability Contingencies

	Fault Description	Reclosing?	Fault Type	Duration
1	P1.1 - LRS U3		3LG	3 Cycles
2	P1.1 - Craig U1		3LG	3 Cycles
3	P1.1 - Craig U3		3LG	3 Cycles
4	P1.1 - JM Shafer ST1		3LG	3 Cycles
5	P1.1 - JM Shafer U3, ST2		3LG	3 Cycles
6	P1.1 - Chugwater Wind Farm		3LG	3 Cycles
7	P1.1 - Pawnee		3LG	4 Cycles
8	P1.2 - LRS-Dave Johnson 230 kV CKT 1		3LG	3 Cycles
9	P1.2 - LRS-Ault 345 kV CKT 1		3LG	3 Cycles
10	P1.2 - LRS-Chugwater 345 kV CKT 1		3LG	3 Cycles
11	P1.2 - Chugwater-Wayne Child 345 kV CKT 1		3LG	3 Cycles
12	P1.2 - Wayne Child-Keota 345 kV CKT 1		3LG	3 Cycles
13	P1.2 - Ault-Owl Creek 115 kV CKT 1		3LG	4 Cycles
14	P1.2 - Ault-Owl Creek 115 kV CKT 1	X	3LG	4 Cycles
15	P1.2 - Owl Creek-Cheyenne 115 kV CKT 1		3LG	4 Cycles
16	P1.2 - Craig-Ault 345 kV CKT 1		3LG	3 Cycles
17	P1.2 - N. Yuma-Spring Canyon 230 kV CKT 1		3LG	4 Cycles
18	P1.2 - N. Yuma-Spring Canyon 230 kV CKT 1	X	3LG	4 Cycles
19	P1.2 - N. Yuma-Story 230 kV CKT 1		3LG	4 Cycles
20	P1.2 - N. Yuma-Story 230 kV CKT 1	X	3LG	4 Cycles
21	P1.2 - Story-Beaver CK_TS 230/115 kV CKT 1		3LG	4 Cycles
22	P1.2 - Story-Beaver CK_PS 230 kV CKT 1		3LG	4 Cycles
23	P1.2 - Story-Pawnee 230 kV CKT 1		3LG	4 Cycles
24	P1.2 - Story-Henry Lake 230 kV CKT 1		3LG	4 Cycles
25	P1.2 - Story-Keota 345 kV CKT 1		3LG	3 Cycles
26	P1.2 - Ault-Carey 230 kV CKT 1		3LG	4 Cycles
27	P1.2 - Ault-Carey 230 kV CKT 1	X	3LG	4 Cycles
28	P1.2 - Henry Lake-Ft. Lupton 230 kV CKT 1		3LG	4 Cycles
29	P1.2 - Henry Lake-Ft. Lupton 230 kV CKT	X	3LG	4 Cycles
30	P1.2 - Henry Lake-Cherokee 230 kV CKT 1		3LG	4 Cycles
31	P1.2 - Archer-Wayne Child 230 kV CKT 1		3LG	4 Cycles
32	P1.3 - Lar.Rivr XFMR 345/230 kV		3LG	3 Cycles
33	P1.3 - Craig XFMR 345/230 kV		3LG	3 Cycles
34	P1.3 - Story XFMR 1 345/230 kV		3LG	3 Cycles
35	P1.3 - N.Yuma XFMR 230/115 kV		3LG	3 Cycles
36	P1.3 - B.CRK_PS XFMR 230/115 kV		3LG	3 Cycles

37	P1.3 - Keota XFMR 1 345/115 kV		3LG	3 Cycles
38	P1.4 - Lar.Rivr 50 MVAR Cap SVD		3LG	10 Cycles
39	P1.4 - Story 50 MVAR Reactor SVD		3LG	10 Cycles
40	P4.2 - LRS-Dave Johnson 230 kV CKT 1 Stuck CB-382		1LG	18 Cycles
41	P4.2 - LRS-Dave Johnson 230 kV CKT 1 Stuck CB-386		1LG	18 Cycles
42	P4.2 - LRS-Dave Johnson 230 kV CKT 1 Stuck CB-1H268		1LG	18 Cycles
43	P4.2 - LRS-Dave Johnson 230 kV CKT 1 Stuck CB-1H244		1LG	18 Cycles
44	P4.2 - Ault-LRS 345 kV CKT 1 Stuck CB-1092		1LG	15 Cycles
45	P4.2 - Ault-LRS 345 kV CKT 1 Stuck CB-1096		1LG	15 Cycles
46	P4.2 - Ault-LRS 345 kV CKT 1 Stuck CB-2996		1LG	15 Cycles
47	P4.2 - Ault-LRS 345 kV CKT 1 Stuck CB-3092		1LG	15 Cycles
48	P4.2 - LRS-Chugwater 345 kV CKT 1 Stuck Project-CB		1LG	15 Cycles
49	P4.2 - LRS-Chugwater 345 kV CKT 1 Stuck CB-2796		1LG	15 Cycles
50	P4.2 - LRS-Chugwater 345 kV CKT 1 Stuck CB-2892		1LG	15 Cycles
51	P4.2 - Chugwater-Wayne Child 345 kV CKT 1 Stuck Project-CB		1LG	15 Cycles
52	P4.2 - Chugwater-Wayne Child 345 kV CKT 1 Stuck WC-CB		1LG	15 Cycles
53	P4.2 - Craig-Ault 345 kV CKT 1 Stuck CB-896		1LG	15 Cycles
54	P4.2 - Craig-Ault 345 kV CKT 1 Stuck CB-762		1LG	15 Cycles
55	P4.2 - Craig-Ault 345 kV CKT 1 Stuck CB-692		1LG	15 Cycles
56	P4.2 - Craig-Ault 345 kV CKT 1 Stuck CB-696		1LG	15 Cycles
57	P4.2 - Story-Pawnee 230 kV CKT 1 Stuck CB-286		1LG	18 Cycles
58	P4.2 - Story-Pawnee 230 kV CKT 1 Stuck CB-382		1LG	18 Cycles
59	P4.2 - Story-Henry Lake 230 kV CKT 1 Stuck CB-586		1LG	18 Cycles
60	P4.2 - Story-Henry Lake 230 kV CKT 1 Stuck CB-682		1LG	18 Cycles
61	P4.2 - Story-Henry Lake 230 kV CKT 1 Stuck CB-982		1LG	18 Cycles
62	P4.2 - Story-Henry Lake 230 kV CKT 1 Stuck CB-1082		1LG	18 Cycles
63	P4.2 - Story-Keota 345 kV CKT 1 Stuck CB-2096		1LG	15 Cycles
64	P4.2 - Story-Keota 345 kV CKT 1 Stuck CB-2192		1LG	15 Cycles
65	P4.2 - Story-Keota 345 kV CKT 1 Stuck CB-296		1LG	15 Cycles
66	P4.2 - Story-Keota 345 kV CKT 1 Stuck CB-596		1LG	15 Cycles

5.4 Results

Transient stability results identified that the Project does not require additional mitigation and is compliant with the NERC/WECC criteria. Simulation results for both summer and autumn show that:

1. The Project did not trip during any of the simulated disturbances and the GF was able to operate at full capacity (300 MW).

2. Local area generators showed stable performance and remained in synchronism for all contingencies.
3. Acceptable damping and voltage recovery was observed.

Study conclusions for summer and light autumn cases are shown in the following table.

Table 18: Dynamic Stability Contingency Results

	Fault Description	19HS Stability?	19LA Stability?
1	P1.1 - LRS U3	Stable	Stable
2	P1.1 - Craig U1	Stable	Stable
3	P1.1 - Craig U3	Stable	Stable
4	P1.1 - JM Shafer ST1	Stable	Stable
5	P1.1 - JM Shafer U3, ST2	Stable	Stable
6	P1.1 - Chugwater Wind Farm	Stable	Stable
7	P1.1 - Pawnee	Stable	Stable
8	P1.2 - LRS-Dave Johnson 230 kV CKT 1	Stable	Stable
9	P1.2 - LRS-Ault 345 kV CKT 1	Stable	Stable
10	P1.2 - LRS-Chugwater 345 kV CKT 1	Stable	Stable
11	P1.2 - Chugwater-Wayne Child 345 kV CKT 1	Stable	Stable
12	P1.2 - Wayne Child-Keota 345 kV CKT 1	Stable	Stable
13	P1.2 - Ault-Owl Creek 115 kV CKT 1	Stable	Stable
14	P1.2 - Ault-Owl Creek 115 kV CKT 1	Stable	Stable
15	P1.2 - Owl Creek-Cheyenne 115 kV CKT 1	Stable	Stable
16	P1.2 - Craig-Ault 345 kV CKT 1	Stable	Stable
17	P1.2 - N. Yuma-Spring Canyon 230 kV CKT 1	Stable	Stable
18	P1.2 - N. Yuma-Spring Canyon 230 kV CKT 1	Stable	Stable
19	P1.2 - N. Yuma-Story 230 kV CKT 1	Stable	Stable
20	P1.2 - N. Yuma-Story 230 kV CKT 1	Stable	Stable
21	P1.2 - Story-Beaver CK_TS 230/115 kV CKT 1	Stable	Stable
22	P1.2 - Story-Beaver CK_PS 230 kV CKT 1	Stable	Stable
23	P1.2 - Story-Pawnee 230 kV CKT 1	Stable	Stable
24	P1.2 - Story-Henry Lake 230 kV CKT 1	Stable	Stable
25	P1.2 - Story-Keota 345 kV CKT 1	Stable	Stable
26	P1.2 - Ault-Carey 230 kV CKT 1	Stable	Stable
27	P1.2 - Ault-Carey 230 kV CKT 1	Stable	Stable
28	P1.2 - Henry Lake-Ft. Lupton 230 kV CKT 1	Stable	Stable
29	P1.2 - Henry Lake-Ft. Lupton 230 kV CKT	Stable	Stable
30	P1.2 - Henry Lake-Cherokee 230 kV CKT 1	Stable	Stable
31	P1.2 - Archer-Wayne Child 230 kV CKT 1	Stable	Stable

32	P1.3 - Lar.Rivr XFMR 345/230 kV	Stable	Stable
33	P1.3 - Craig XFMR 345/230 kV	Stable	Stable
34	P1.3 - Story XFMR 1 345/230 kV	Stable	Stable
35	P1.3 - N.Yuma XFMR 230/115 kV	Stable	Stable
36	P1.3 - B.CRK_PS XFMR 230/115 kV	Stable	Stable
37	P1.3 - Keota XFMR 1 345/115 kV	Stable	Stable
38	P1.4 - Lar.Rivr 50 MVAR Cap SVD	Stable	Stable
39	P1.4 - Story 50 MVAR Reactor SVD	Stable	Stable
40	P4.2 - LRS-Dave Johnson 230 kV CKT 1 Stuck CB-382	Stable	Stable
41	P4.2 - LRS-Dave Johnson 230 kV CKT 1 Stuck CB-386	Stable	Stable
42	P4.2 - LRS-Dave Johnson 230 kV CKT 1 Stuck CB-1H268	Stable	Stable
43	P4.2 - LRS-Dave Johnson 230 kV CKT 1 Stuck CB-1H244	Stable	Stable
44	P4.2 - Ault-LRS 345 kV CKT 1 Stuck CB-1092	Stable	Stable
45	P4.2 - Ault-LRS 345 kV CKT 1 Stuck CB-1096	Stable	Stable
46	P4.2 - Ault-LRS 345 kV CKT 1 Stuck CB-2996	Stable	Stable
47	P4.2 - Ault-LRS 345 kV CKT 1 Stuck CB-3092	Stable	Stable
48	P4.2 - LRS-Chugwater 345 kV CKT 1 Stuck Project-CB	Stable	Stable
49	P4.2 - LRS-Chugwater 345 kV CKT 1 Stuck CB-2796	Stable	Stable
50	P4.2 - LRS-Chugwater 345 kV CKT 1 Stuck CB-2892	Stable	Stable
51	P4.2 - Chugwater-Wayne Child 345 kV CKT 1 Stuck Project-CB	Stable	Stable
52	P4.2 - Chugwater-Wayne Child 345 kV CKT 1 Stuck WC-CB	Stable	Stable
53	P4.2 - Craig-Ault 345 kV CKT 1 Stuck CB-896	Stable	Stable
54	P4.2 - Craig-Ault 345 kV CKT 1 Stuck CB-762	Stable	Stable
55	P4.2 - Craig-Ault 345 kV CKT 1 Stuck CB-692	Stable	Stable
56	P4.2 - Craig-Ault 345 kV CKT 1 Stuck CB-696	Stable	Stable
57	P4.2 - Story-Pawnee 230 kV CKT 1 Stuck CB-286	Stable	Stable
58	P4.2 - Story-Pawnee 230 kV CKT 1 Stuck CB-382	Stable	Stable
59	P4.2 - Story-Henry Lake 230 kV CKT 1 Stuck CB-586	Stable	Stable
60	P4.2 - Story-Henry Lake 230 kV CKT 1 Stuck CB-682	Stable	Stable
61	P4.2 - Story-Henry Lake 230 kV CKT 1 Stuck CB-982	Stable	Stable
62	P4.2 - Story-Henry Lake 230 kV CKT 1 Stuck CB-1082	Stable	Stable
63	P4.2 - Story-Keota 345 kV CKT 1 Stuck CB-2096	Stable	Stable
64	P4.2 - Story-Keota 345 kV CKT 1 Stuck CB-2192	Stable	Stable
65	P4.2 - Story-Keota 345 kV CKT 1 Stuck CB-296	Stable	Stable
66	P4.2 - Story-Keota 345 kV CKT 1 Stuck CB-596	Stable	Stable

6.0 SHORT-CIRCUIT ANALYSIS

Short-circuit analysis was performed for 3-phase-to-ground and single-line-to-ground faults at the 345 kV POI bus, using the Aspen OneLiner model. Faults were applied with and without the Project generation. Model assumptions are as follows.

6.1 Assumptions and Methodology

1. The model used is shown in Figure 3 below.

2. The Point of Interconnection is on the Laramie River Station – Story 345 kV transmission line, 32 miles south of Laramie River Station. The line impedance of the sections between LRS, the Project POI and Story 345 kV were provided by Tri-State Power System Planning.

3. A collector system for an output of 300 MW was modeled with two 345/34.5/13.8 kV, 102/126/170 MVA transformers with voltage ratios of 34.5 kV (wye-gnd) - 345 kV (wye-gnd) - 13.8 kV (delta).

    a. Zero Sequence impedance of the 345/34.5 kV transformers was modeled using data provided by the Customer.

    b. The transformer delta windings were all modeled to lag the high side phase angles.

    c. The zero sequence impedance of the 345 kV tie line and the 34.5 kV collector systems were modeled from the one-line drawing provided by the Customer (reference Figure 4).

    d. The system was modeled with and without the planned 345/230 kV autotransformer at Wayne Child Substation. The Wayne Child transformer has a planned in-service date of 4Q2019.

6.2 Results

Table 19 lists results for the 345 kV bus faults at the POI with contributions from each of the 345 kV sources into the bus faults. The system impedances for the faulted buses for each configuration are also included (see Figure 3 below). The results indicate that the GF increases the fault duty by approximately 1368 Amperes at the 345 kV POI bus prior to installation of the Wayne Child 345/230 kV autotransformer. The results indicate that the GF increases the fault duty by approximately 1397 Amperes at the 345 kV POI bus after installation of the Wayne Child transformer. The resultant total fault currents are within existing and planned equipment ratings.

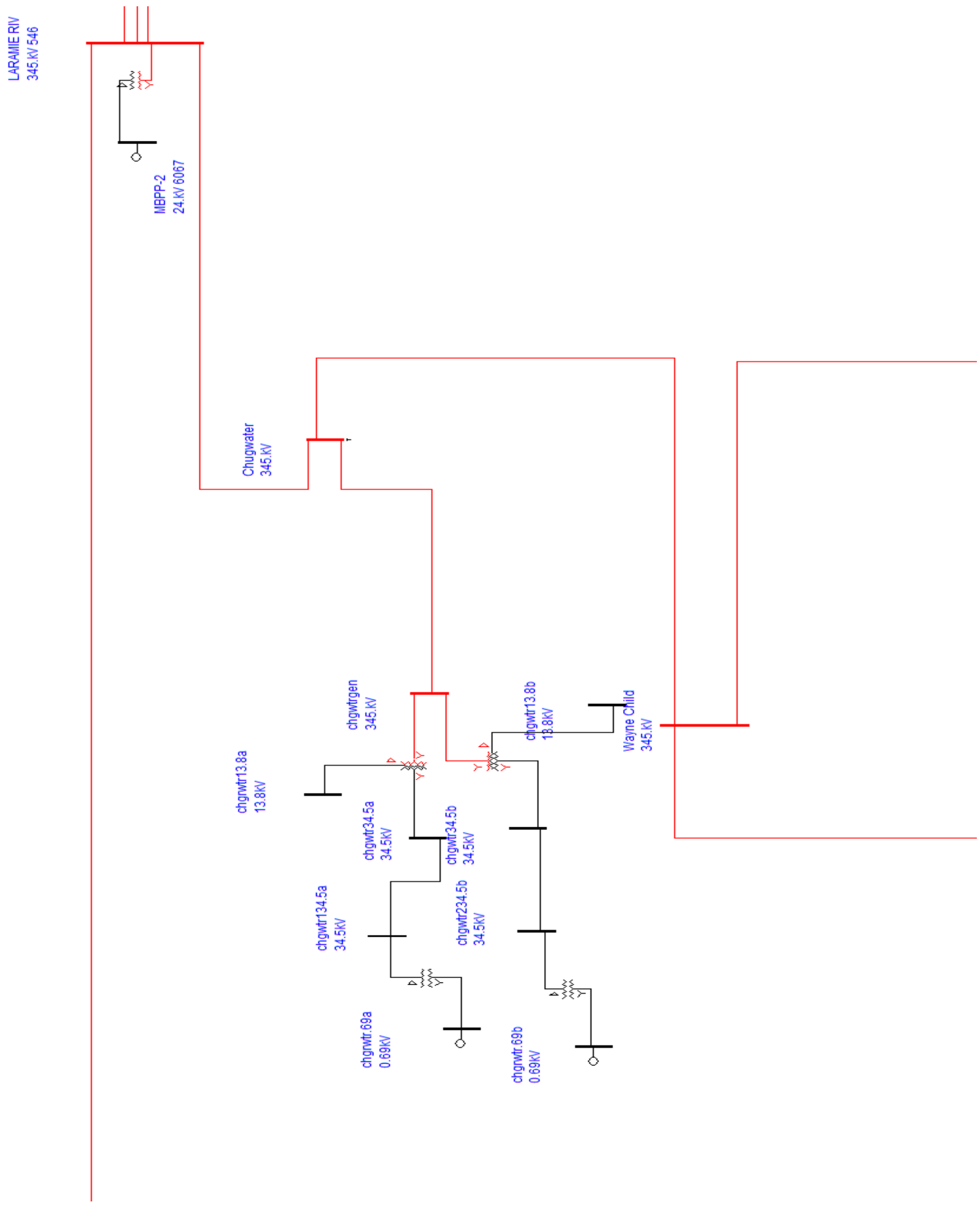
Table 19: Short Circuit Results – Without Transformer at Wayne Child

System Condition	POI 345kV Bus Total 3-Ph Fault (	LRS to POI 345kV 3-Ph Fault	POI to Wayne Child 345kV 3-Ph Fault	Gen HV to POI 3-Ph Fault	POI 345kV Bus Total SLG Fault	LRS to POI 345kV SLG Fault	POI to Wayne Child 345kV SLG Fault	Gen HV to POI SLG Fault	Thevinin System Equivalent Impedance R + jX p.u. 100 MVA, 345 kV base
POI 345kV Bus Fault w/o 300 MW generation N-0	**7698**	5904	1795		**6001**	4470	1531		Z1(pos) = 0.00113 + j 0.0217 Z0(zero) = 0.0095 + j 0.0394
345kV POI Bus Fault w/o 300 MW generation LRS - POI 345kV Out	1825		1825		1472		1472		Z1(pos) = 0.00592 + j0.09152 Z0(zero) = 0.0367+ j 0.1546
345kV POI Bus Fault w/o 300 MW generation POI-Wayne Child 345kV Ou	5934	5934			4551	4551			Z1(pos) = 0.00139 + j 0.02817 Z0(zero) = 0.01281 + j 0.05287
POI 345kV Bus Fault with 300 MW generation N-0	**8104**	5904	1795	405	**7369**	3646	1249	2510	Z1(pos) =0.00106 + j 0.0208 Z0(zero) = 0.0062 + j 0.03168
345kV POI Bus Fault with 300 MW generation LRS - POI 345kV Out	2230		1825	405	2472		825	1658	Z1(pos) =0.00444 + j 0.07713 Z0(zero) = 0.01014 + j 0.0785
345kV POI Bus Fault with 300 MW generation POI-Wayne Child 345kV Out	6339	5934		405	5900	3512		2418	Z1(pos) = 0.00127 + j 0.0266 Z0(zero) = 0.00737 + j 0.0398

Table 20: Short Circuit Results – With Transformer at Wayne Child

System Condition	POI 345kV Bus Total 3-Ph Fault	LRS to POI 345kV 3-Ph Fault	POI to Wayne Child 345kV 3-Ph Fault	Gen HV to POI 3-Ph Fault	POI 345kV Bus Total SLG Fault	LRS to POI 345kV SLG Fault	POI to Wayne Child 345kV SLG Fault	Gen HV to POI SLG Fault	Thevinin System Equivalent Impedance R + jX p.u. 100 MVA, 345 kV base
POI 345kV Bus Fault w/o 300 MW generation N-0	**9177**	5718	3459		**7149**	4462	2687		Z1(pos) = 0.001 + j 0.01821 Z0(zero) = 0.00784 + j 0.0331
345kV POI Bus Fault w/o 300 MW generation LRS - POI 345kV Out	3689		3689		2780		2780		Z1(pos) = 0.00304 + j 0.04527 Z0(zero) = 0.02022 + j 0.088
345kV POI Bus Fault w/o 300 MW generation POI-Wayne Child 345kV Ou	5942	5942			4553	4553			Z1(pos) = 0.00139 + j 0.02813 Z0(zero) = 0.0128 + j 0.0529
POI 345kV Bus Fault with 300 MW generation N-0	**9582**	5718	3459	405	**8546**	3747	2256	2581	Z1(pos) =0.00094 + j 0.01756 Z0(zero) = 0.00545 + j 0.02746
345kV POI Bus Fault with 300 MW generation LRS - POI 345kV Out	4094		3689	405	4043		1896	2166	Z1(pos) =0.00261 + j 0.04144 Z0(zero) = 0.00873 + j 0.0568
345kV POI Bus Fault with 300 MW generation POI-Wayne Child 345kV Out	6347	5942		405	5905	3516		2420	Z1(pos) = 0.00127 + j 0.0266 Z0(zero) = 0.00737 + j 0.03983

Figure 3: Short-Circuit Model One-Line Diagram



7.0 SCOPE, COST AND SCHEDULE

This project will interconnect to the Laramie River Station – Story 345 kV transmission line via a Customer owned 4 mile radial transmission line. (Figure 4, One-Line Diagram).

The following cost estimate is only for the 345 kV facilities that interconnect with the Laramie River Station – Story 345 kV transmission line (represented by a three breaker 345 kV ring in Figure 4). Costs for the Customer's radial 345 kV transmission line and its 345-34.5 kV substation facilities are not included. The estimate includes land rights, permitting, design, procurement, construction and overheads. The estimate does not include costs to mitigate any transmission line thermal overloads discussed in this report.

Note that the Customer will be responsible for constructing the radial 345 kV transmission line to its substation yard and for providing the primary protection (relaying and interrupting device) for the Customer's step-up transformers located in its 345-34.5-13.8 kV substation yard. Equipment in the Transmission Provider's 345 kV yard will only provide backup protection for the Customer's 345-34.5-13.8 kV main transformers in the event of equipment failure or malfunction at the Customer's facility.

The Customer is responsible for providing a communication channel, such as fiber optic cable (OPGW) on its radial 345 kV transmission line to provide for SCADA, metering, and protective relaying. The Customer is required to install redundant communications based line relaying, that provides instantaneous protection for the entire line. The Customer must also provide access to analog, indicating, control and data circuits as required, to integrate the Project into the design and operation of the Transmission Provider's control system.

The total cost for the 345 kV facilities noted above is $9 M. These facilities are considered Network Upgrades and are reimbursable. All costs are good faith estimates based on assumptions as stated in this SIS report. All estimates are in 2016 dollars.

It is estimated that it will take a minimum of 24 months after execution of a Generator Interconnection Agreement or Engineering and Procurement contract to complete the engineering, design, procurement, construction, and testing activities identified in the scope of work for this Project.

Figure 4: 345 kV Chugwater Station One-Line Diagram