G546 Interconnection
Feasibility Study Report
100 MW Wind Generation
Walworth County, Wisconsin

MISO Queue #38605-01

Revision 1

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American Transmission Company, LLC

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System Planning

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1. Summary

This report contains the Feasibility Study Report for the Generation Interconnection Request identified as MISO Project #G546, MISO Queue #38605-01. This study evaluates the impact of a new 100 MW wind farm installation to the 138 kV transmission system in Walworth County, Wisconsin. The requested in-service date for this project is December 1, 2007.

This study identifies the steady state thermal violations and voltage violations caused by the proposed interconnection. For G546 to interconnect as either an Energy Resource (ER) or a Network Resource (NR), it is necessary to complete system upgrades required to resolve injection limits. Injection limits are thermally overloaded facilities that either have a Distribution Factor (DF) of at least 20% in relation to real power injected at the Point of Interconnection (POI) when delivered to all of MISO or they are direct outlets from the generator POI. In order to qualify G546 as a NR, it is necessary to complete all system upgrades identified as a resulted of the Deliverability Study, which will be conducted as part of the Interconnection System Impact Study (ISIS).

The G546 generation is proposed to connect at the North Lake Geneva 138 kV tap on the Sugar Creek - Burlington 138 kV Line (6541). Figure 1.1 shows the existing transmission system for 2008 including the proposed G546 POI. The proposed interconnection **does not** show the ultimate expected substation layout. The final interconnection will depend on the thermal, voltage, and stability analysis performed in the Feasibility Study and the ISIS in addition to operational issues and physical space for the new facilities required for the interconnection.

1.1 Injection Limits

The study identified one steady-state thermal violation for NERC Category A (intact system) events and two steady-state thermal violations for NERC Category B (N-1) events for all the seasonal models studied, as shown in Table A.1 in Appendix A. However, only the two thermal violations for N-1 events meet the criteria for injection limits. These injection limits are:

1. Line 3025, St. Martin - Raymond 138 kV
2. Line 3124, Paris - Albers 138 kV

Without system upgrades to resolve the injection limits, the maximum allowable generation was found to be 21 MW for summer 2008 and 54 MW for winter 2007/08.

1.2 Operation Restrictions

The study identified 12 operating restrictions on G546 for summer 2008, which are based on 6 distinct NERC Category C events (double contingencies) that resulted in 8 distinct limiting elements to be encountered (Table B.1 – Appendix B). The study also identified 20 operating restrictions on G546 for winter 2007/08, which are based on 9 distinct NERC Category C events that resulted in 10 distinct limiting elements to be encountered (Table B.2 – Appendix B). These operation restrictions were identified based on N-2 linear transfer analysis on the winter 2007/08 and summer 2008 models (Table A.2 in Appendix A).

1.3 Network Upgrades

To be determined in the ISIS.

1.4 Required Interconnection Facilities

New interconnection facilities will consist of facilities between the interconnection substation and the generator POI, which is typically the bus side of the disconnecting device on the high side of the 138/34.5 kV substation transformer installed by the G546 customer. Note that the generator POI is also the point of change of ownership.

1.5 Required Power Factor Range at POI

The G546 power factor requirement was identified based on the following criteria:

1 - The voltage magnitude at the POI bus and buses one substation away from the POI bus must not be lower than 0.95 pu under intact system conditions, and must not be lower than 0.90 pu under N-1 contingency conditions.

2 - The interconnecting generator should maintain a voltage schedule of 1.02 pu at the POI for the intact system and also for the system under first contingency conditions.

3 - The interconnecting generator is not required to design a power factor range outside of the 0.95 leading power factor (absorbing reactive power from the Network) to 0.90 lagging power factor (supplying reactive power to the Network).

The power factor requirement calculated for G546 based on these criteria is discussed in Section 3.1.1. Based on the results, G546 will be required to operate between 0.95 leading and 0.90 lagging power factors.

1.6 Further Study

The next step in the Generator Interconnection Request process is for the Generator customer to decide whether to proceed with an ISIS. The ISIS will determine the system upgrades required to resolve all injection limits identified in this report and will include short circuit, transient and dynamic stability, and deliverability studies, as applicable. Limits identified in the ISIS will also need to be resolved to obtain interconnection service. The ISIS will also determine the final interconnection configuration at the G546 interconnection substation.

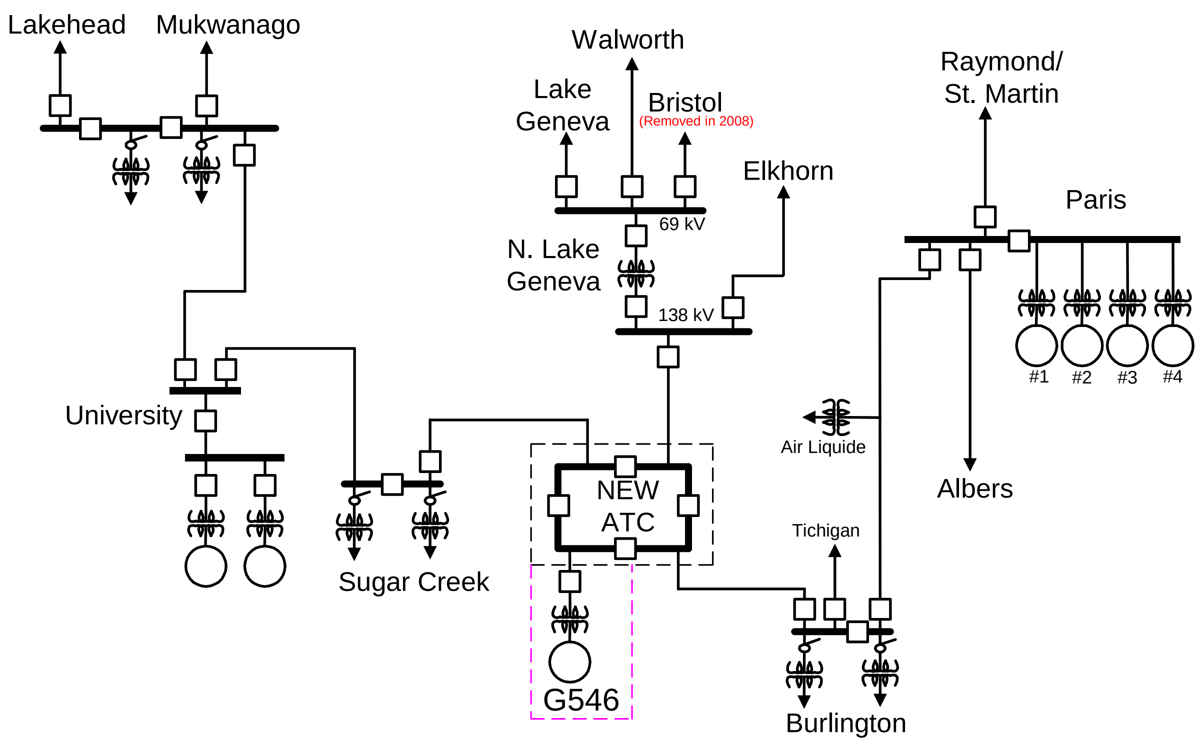

Figure 1.1 – Conceptual One Line Diagram of the System with G546

2. Criteria, Methodology and Assumptions

2.1 Study Criteria

All relevant MISO-adopted NERC Reliability Criteria and the American Transmission Company ("ATC") contingency criteria are to be met for both the thermal and voltage analysis. Details of the analysis criteria applied in this study can be found in the Appendix C.

2.2 Study Methodology

The results of this study are subject to change. The results of the study are based on data provided by the Generator and other ATC system information that was available at the time the study was performed, and the injection study does not guarantee deliverability to the MISO energy market. If there are any significant changes in the generator and controls data, in earlier queue Generator Interconnection Requests, in related Transmission Service Requests, or ATC transmission system development plans, then the results of this study may also change significantly. Therefore, this request is subject to restudy. The Generator is responsible for communicating any significant generation facility data changes in a timely fashion to MISO and ATC prior to commercial operation.

2.2.1 Competing Generation Requests

ATC determined in its sole judgment that no Generator Interconnection Requests with an earlier queue position will impact the G546 study results.

Public information related to the Generator Interconnection Request queue can be found via the MISO web site at **http://oasis.midwestiso.org/documents/ATC/queue.html**.

2.2.2 Linear Transfer Analysis and A.C. Power Flow Analysis Methods

Thermal overloads were identified using linear transfer analysis and then verified with AC power flow solutions. The linear transfer analysis was used to evaluate the intact system, N-1 contingency and certain ATC multiple contingency conditions. The linear transfer analysis utilized adjusted MW ratings to account for reactive power flows and a 5% transmission reserve margin ("TRM"). All AC power flow solutions utilized actual equipment ratings in MVA (i.e. 0% TRM) along with real and reactive power flows. A 5% TRM was factored in the computation of required MVA rating for the limiting elements.

The linear transfer analysis was performed using the Linear Transfer Analysis modules of the Managing and Utilizing System Transmission-6.03 (MUST, Version 6.03) program from Siemens Power Technologies, Inc (PTI). All AC power flow solutions were performed using the Power Flow module of the Power System Simulation/Engineering-29 (PSS/E, Version 29) program from Siemens Power Technologies, Inc (PTI). These programs are accepted industry-wide for power flow analysis.

2.2.3 Base Cases

2.2.3.1 Power flow analysis

Base cases used in the thermal and voltage analysis for this study were developed based upon the predicted topology for the local area for winter 2007/08 and summer 2008. The cases were developed using the January 2006 build of MISO seasonal cases of winter peak 2007/08 and summer peak of 2008. In addition, models for spring 2008 and fall 2008 were obtained from the MISO and used in the power factor requirement analysis. The MISO seasonal cases are accessible through the MISO Extranet. The output of G546 was delivered to all MISO generation for the linear analysis portion of the study.

2.2.3.2 Deliverability analysis

Deliverability analysis, which is required for G546 to attain Network Resource Interconnection Service, was not performed in this study but will be performed by the MISO at a later date.

2.3 Assumptions

2.3.1 Generation Facility Modeling

The G546 wind farm is to be comprised of seventy (70) 1.5 MW GE wind turbines and was modeled by a lumped representation in this study. The wind farm was modeled as a 100 MW net injection at 0.95 lead power factor (absorbing MVAR) at the Point Of Interconnection (POI) for the power flow analysis. This power factor set-point was determined by the analysis described in Section 3.1.1.

3. Analysis Results

3.1 Power Flow Analysis Results

3.1.1 Determination of the Power Factor Requirement

The G546 power factor requirement was identified based on the following criteria:

1 - The voltage magnitude at the POI bus and buses one substation away from the POI bus must not be lower than 0.95 pu under intact system conditions, and must not be lower than 0.90 pu under N-1 contingency conditions.

2 - The interconnecting generator should maintain a voltage schedule of 1.02 pu at the POI for the intact system and also for the system under first contingency conditions.

3 - The interconnecting generator is not required to design a power factor range outside of the 0.95 leading power factor (absorbing reactive power from the Network) to 0.90 lagging power factor (supplying reactive power to the Network).

Criterion 3 governs the widest range that the interconnecting customer must design to, regardless of the results of the analysis for criterion 1 and 2. A summary of the power factor range calculated in the criterion 1 and 2 analysis is found in Table A.4 in Appendix A.

Although a leading power factor no less than 0.95 at the POI is adequate for most system conditions modeled, criterion 1 results show a violation of system voltage criteria for the intact system condition in Summer 2008 when the Paris generation was not dispatched (Table A.5 in Appendix A). This particular condition will require operation at 0.99 leading power factor.

All generators interconnected with the ATC transmission system must follow voltage schedule instructions. Although the generator may be directed to maintain a different voltage schedule than the standard (cf. *pro forma* LGIA, paragraph 9.6.2), this analysis assumed a voltage schedule of 1.02 per unit. ATC's standard voltage schedule is 1.02 per unit voltage at the POI, although some locations require a higher scheduled voltage due to plant and/or system reliability requirements. The results of the analysis for criterion 2 are shown in Table A.6 in Appendix A. Since criterion 3 governs the widest range of power factor correction, criterion 3 applies for the lagging operating condition.

Based on these results, G546 must be capable of operation between 0.95 leading and 0.90 lagging power factors.

3.1.2 Results of Intact System and Single Contingencies (N-1)

The study identified one steady-state thermal violations due to G546 for NERC Category A (intact system) events and two violations due to G546 for NERC Category B (N-1) events for all study models. Results of the N-1 thermal analysis can be found in Table A.1 in Appendix A. The two N-1 violations meet the criteria of injection limits (cf. Section C.3.2 in Appendix C) and must be mitigated for the generator to connect as either an Energy Resource or a Network Resource. ATC does not currently have any planned or proposed system upgrades that would mitigate these violations. The remaining limit in Table A.1 is not an injection limit and, therefore, is supplied for informational purposes only.

The maximum allowable real power output without system upgrades was determined by calculating the distribution factor for the line using AC analysis and then using linear interpolation to find the output of the plant based on the maximum capacity of the line and the distribution factor. The maximum allowable output without system upgrades is presented in Table A.3 in Appendix A. As shown in this table, the maximum real power output without system upgrades is 21 MW for summer 2008 and 54 MW for winter 2007/08.

Voltage analysis determined that the voltage magnitude at all system buses whose magnitude decreases at least 0.01 p.u. after adding G546 remains above 0.95 p.u. for the NERC Category A events (intact system) and remain above 0.90 p.u. for the NERC Category B events (single contingency). Hence, the study did not identify any voltage limit violations that can be attributed to the addition of G546.

3.1.3 Results of Double Contingencies (N-2)

Thermal and voltage constraints were evaluated for NERC Category C events (N-2 contingencies) in the electrical proximity of G546. The purpose of the N-2 analysis is to reveal potential violations and identify operating restrictions to eliminate the violations under prior outage conditions.

The double contingency constraints are not required to be resolved for the generator to attain either Energy Resource or Network Resource status. All identified operating restrictions will be reviewed in the ISIS.

Thermal violations under a selected number of N-2 contingencies were evaluated using linear transfer analysis. All identified contingencies were verified using AC calculation methods to obtain the distribution factor and required ratings for full plant capacity. The distinct thermal violations identified from all summer and winter models used in the study are listed in Table A.2 in Appendix A. The study identified eight thermal constraints for the summer period and ten thermal constraints for the winter period as a result of local N-2 contingencies. The required operating restrictions due to these thermal constraints are listed in Tables B.1 and B.2 in Appendix B. These operating restrictions will be reviewed in the ISIS.

Voltage violations under a selected number of N-2 contingencies were not evaluated for this interconnection. However, all double contingencies listed in Table A.2 in Appendix A were evaluated using AC methods to ensure that the power flow solution for the identified N-2 contingencies did not diverge.

Appendix A: Power Flow Analysis Results

Table A.1 – Identified Thermal Violations Due to G546
With Delivery to MISO for System Intact Conditions and N-1 Contingencies (TDF>3%)

Limiting Element	Existing Rating (MVA)	Required Rating (MVA)[1]	Worst Contingency	TDF (%)	Case[2]	Injection Limit[3]	Solution Planned
St. Martin - Raymond 138 kV Line 3025	218 SN	222.9	System Intact	17.0 %	2008 Sb	No	No[4]
St. Martin - Raymond 138 kV Line 3025	300 SE	314.8	Albers - Paris 138 kV	27.3 %	2008 Sb	Yes	No[4]
Albers – Paris 138 kV Line 3124	279 SE	306.0 339.5	Paris – Raymond 138 kV	32.7 % 36.6 %	2008 Sb 2007 Wb	Yes	No[5]

Notes:

1. Includes provision for 5% TRM. The required ratings are calculations using PSS/E, dispatching 75% of G546 to CE area and 25% to NSP as a proxy for MISO delivery.
2. (2007Wb) – 2007/08 MISO Winter Peak Case with all local generation dispatched at P_{MAX}, (2008Sb) - 2008 MISO Summer Peak Case with all local generation dispatched at P_{MAX}.
3. Injection limits are defined as having a TDF greater than 20%. These limits need to be corrected prior to the customer generating. Overloads with a TDF less than 20% are for informational purposes only.
4. Substation jumper limit at St. Martin.
5. Line conductor limit.

Table A.2 – Identified Thermal Violations under N-2 Contingencies
Summer and Winter Delivery to MISO

Limiting Element	Existing Rating (MVA)	Required Rating[1,2] (MVA)	Worst Double Contingency	TDF (%)	Solution Planned for Limiting Element
North Lake Geneva 138 – 69 kV XFMR	100 WE	104.5 Wb	Whitewater – University 138 kV Line 4453 Burlington – G546 138 kV Line 6541	24.5	No
Whitewater – University 138 kV Line 4453	272 SE 316 WE	309.2 S 309.2 Sb 357.1 Wb	North Lake Geneva – G546 138 kV Line 6541 Burlington – G546 138 kV Line 6541	93.8 93.6 43.5	No
North Lake Geneva – G546 138 kV Line 6541	228 SE 228 WE	308.1 S 308.0 Sb 317.2 Wb	Whitewater – University 138 kV Line 4453 Burlington – G546 138 kV Line 6541	100.0 100.0 99.5	No
Janesville – Townline Road 138 kV Line X-7	239 SE	244.1 Sb	Rock River - Venture 138 kV Line X-24 Townline Road - Tripp 138 kV Line X-32	-3.1	No
Viking - Tripp 138 kV Line X-32	256 SE	276.2 Sb	Wempletown – Rockdale 345 kV Line W-4F Janesville - Russell 138 kV Line X-21	3.5	No
Townline Road – Tripp 138 kV Line X-32	256 SE	287.8 Sb	Wempletown – Rockdale 345 kV Line W-4F Janesville - Russell 138 kV Line X-21	3.5	No
Burlington – G546 138 kV Line 6541	238 SE 292 WE	311.1 S 310.8 Sb 323.6 Wb	Whitewater – University 138 kV Line 4453 North Lake Geneva – G546 138 kV Line 6541	100.0 100.0 100.0	No
Paris - Raymond 138 kV Line 3025	300 SE 367 WE	329.9 S 393.1 Sb 417.5 Wb	Whitewater – University 138 kV Line 4453 Albers - Paris 138 kV Line 3124	33.8 34.8 42.3	No
St. Martin – Raymond 138 kV Line 3025	300 SE 367 WE	319.6 S 382.8 Sb 417.5 Wb	Whitewater – University 138 kV Line 4453 Albers - Paris 138 kV Line 3124	33.9 34.9 42.3	No
Bain – Kenosha 345 kV Line 63151	287 WE	343.8 Wb	Zion – Pleasant Prairie 345 kV Line 2221 Albers – Kenosha 345 kV Line 9352	10.6	No
Albers – Kenosha 138 kV Line 9352	272 WE	307.23 Wb	Zion – Pleasant Prairie 345 kV Line 2221 Bain – Kenosha 345 kV Line 63151	14.7	No
Albers – Paris 138 kV Line 3124	322 WE	429.6 Wb	Whitewater - University Line 4453 Paris – Raymond 138 kV Line 3025	47.7	No
Lakeview – Zion 138 kV Line 28201	292 WE	316.7 Wb	Zion – Pleasant Prairie 345 kV Line 2221 Zion – Arcadian 345 kV Line 2222	17.4	No
Kenosha – Lakeview 138 kV Line 9341	329 WE	346.5 Wb	Zion – Pleasant Prairie 345 kV Line 2221 Pleasant Prairie – Racine 345 kV Line 631	12.2	No

Notes:

1. (Wb) – 2007/08 MISO Winter Peak Case with all local generation dispatched at P_{MAX}, (Sb) - 2008 MISO Summer Peak Case with all local generation dispatched at P_{MAX}, (S) - 2008 MISO Summer Peak Case with Paris, Rock River and Riverside Energy Center dispatched at less than P_{MAX} .
2. Includes provision for 5% TRM. The required ratings are calculations using PSS/E, dispatching 75% of G546 to CE area and 25% to NSP as a proxy for MISO delivery.

Table A.3 – Maximum Allowable Generation for G546 without System Upgrades

Limiting Element	Worst Contingency	Model Description[1]	G546 Maximum MW[2]	Max MW with Planned and Proposed Projects[2,3]	Injection Limit
St. Martin - Raymond 138 kV Line 3025	Base Case	2008 Sb	73.0 MW	73.0 MW	No
St. Martin - Raymond 138 kV Line 3025	Albers - Paris 138 kV 3124	2008 Sb	48.3 MW	48.3 MW	Yes
Albers – Paris 138 kV Line 3124	Paris – Raymond 138 kV 3025	2008 Sb 2007 Wb	21.4 MW 54.5 MW	21.4 MW 54.5 MW	Yes

Notes:

1. (2007Wb) – 2007/08 MISO Winter Peak Case with all local generation dispatched at P_{MAX}, (2008Sb) – 2008 MISO Summer Peak Case with all local generation dispatched at P_{MAX}.
2. Includes provision for 5% TRM. The maximum output calculated using PSS/E, dispatching 75% of G546 to CE area and 25% to NSP as a proxy for MISO delivery. The maximum output calculated for this generator is based on no upgrades being performed on the transmission system.
3. Planned and Proposed projects from ATC's 2005 Ten Year Assessment report.

Table A.4 – Calculated G546 Power Factor Range
Based on Criterion 1 and 2 (cf. Section 3.1.1 and Tables A.5 and A.6)

Generator	Leading Power Factor (Absorbing MVAr from the System)	Lagging Power Factor (Providing MVAr to the System)
G546	96.4%	79.6%

Table A.5 – G546 Power Factor to maintain 0.95 p.u. local bus voltage for intact system and 0.90 p.u. local bus voltage for N-1 contingency conditions

	Winter 2007		Summer 2008		Summer 2008 (Paris Not Dispatched)		Spring 2008		Fall 2008	
Contingency	G546 MVAr at POI	Power Factor at POI	G546 MVAr at POI	Power Factor at POI	G546 MVAr at POI	Power Factor at POI	G546 MVAr at POI	Power Factor at POI	G546 MVAr at POI	Power Factor at POI
None (Intact System)	-59.0	0.861 Lead	-101.8	0.700 Lead	-27.3	0.964 Lead	-81.4	0.775 Lead	-109.1	0.675 Lead
G546 – North Lake Geneva 6541	-128.1	0.615 Lead	-147.5	0.561 Lead	-89.8	0.744 Lead	-120.7	0.637 Lead	-120.3	0.639 Lead
G546 – Burlington 6541	-78.2	0.787 Lead	-135.1	0.594 Lead	-133.5	0.599 Lead	-100.0	0.707 Lead	-125.9	0.621 Lead
G546 – Sugar Creek 6541	-121.7	0.634 Lead	-161.4	0.526 Lead	-93.2	0.731 Lead	-135.8	0.592 Lead	-172.1	0.502 Lead
Sugar Creek – University 6552	-102.2	0.699 Lead	-130.0	0.609 Lead	-63.2	0.845 Lead	-116.3	0.651 Lead	-151.2	0.551 Lead
University – Whitewater 4453	-103.6	0.694 Lead	-183.4	0.478 Lead	-115.6	0.654 Lead	-117.7	0.647 Lead	-152.6	0.548 Lead
White Water – Mukwonago 77353	-144.4	0.569 Lead	-207.1	0.434 Lead	-132.7	0.601 Lead	-161.3	0.527 Lead	-195.8	0.454 Lead
Whitewater – Lakehead 4434	-122.8	0.631 Lead	-202.5	0.442 Lead	-133.1	0.600 Lead	-118.8	0.643 Lead	-147.6	0.560 Lead
Burlington – Paris 8962	-98.7	0.711 Lead	-99.4	0.709 Lead	-98.7	0.711 Lead	-114.0	0.659 Lead	-151.0	0.552 Lead
N. Lake Geneva – Elkhorn X-55	-114.1	0.659 Lead	-132.9	0.601 Lead	-76.6	0.793 Lead	-124.7	0.625 Lead	-123.4	0.629 Lead

Notes:

1. Power Factor requirement is based on 100 MW net injection from G546 at POI.
2. Lagging power factor corresponds to generator supplying (+) reactive power to the transmission system. Conversely, Leading power factor corresponds to generator absorbing (–) reactive power from the transmission system.

Table A.6 – G546 Power Factor to maintain 1.02 p.u. voltage at POI for intact system and N-1 contingency system conditions

	Winter 2007		Summer 2008		Spring 2008		Fall 2008	
Contingency	G546 MVAr at POI	Power Factor at POI	G546 MVAr at POI	Power Factor at POI	G546 MVAr at POI	Power Factor at POI	G546 MVAr at POI	Power Factor at POI
None (Intact System)	+62.8	0.846 Lag	+57.5	0.867 Lag	+44.3	0.914 Lag	+27.8	0.964 Lag
G546 – North Lake Geneva 6541	+17.5	0.985 Lag	+20.7	0.979 Lag	+24.2	0.970 Lag	+12.0	0.992 Lag
G546 – Burlington 6541	+54.4	0.878 Lag	+45.8	0.909 Lag	+31.3	0.954 Lag	+27.1	0.965 Lag
G546 – Sugar Creek 6541	+32.4	0.951 Lag	+30.2	0.957 Lag	+14.0	0.990 Lag	-1.7	1.000 Unity
Sugar Creek – University 6552	+45.3	0.910 Lag	+51.3	0.890 Lag	+27.2	0.965 Lag	+10.9	0.994 Lag
University – Whitewater 4453	+43.5	0.917 Lag	+68.1	0.827 Lag	+25.5	0.969 Lag	+9.2	0.996 Lag
White Water – Mukwonago 77353	+60.1	0.857 Lag	+59.2	0.861 Lag	+38.9	0.932 Lag	+22.4	0.976 Lag
Whitewater – Lakehead 4434	+75.8	0.796 Lag	+58.8	0.862 Lag	+60.4	0.856 Lag	+43.4	0.917 Lag

Notes:

1. Power Factor requirement is based on 100 MW net injection from G546 at POI.
2. Lagging power factor corresponds to generator supplying (+) reactive power to the transmission system. Conversely, Leading power factor corresponds to generator absorbing (–) reactive power from the transmission system.

Appendix B: Operation Restrictions

Table B.1 – Summary of Identified Summer Operating Restrictions on G546 due to Thermal Constraints

Prior outage	Allowable G546 MW Output[1,2]	Worst Next Contingency	Most Limiting Element	Existing MVA Rating	TDF %
Rock River – VNT 138 kV Line X-24	0 Sb	Townline Road – Tripp 138 kV Line X-32	Janesville – Townline 138 kV Line X-7	239 SE	-3.1 Sb
Townline Road – Tripp 138 kV Line X-32	0 Sb	Rock River – VNT 138 kV Line X-24	Janesville – Townline 138 kV Line X-7	239 SE	-3.1 Sb
Janesville – Russell 138 kV Line X-21	0 Sb	Wempletown – Rockdale 345 kV Line W-4F	Viking – Tripp 138 kV Line X-32	256 SE	3.4 Sb
			Townline Road – Tripp 138 kV Line X-32	256 SE	3.5 Sb
Wempletown – Rockdale 345 kV Line W-4F	0 Sb	Janesville – Russell 138 kV Line X-21	Viking – Tripp 138 kV Line X-32	256 SE	3.4 Sb
			Townline Road – Tripp 138 kV Line X-32	256 SE	3.5 Sb
Whitewater – University 138 kV Line 4453	24.1 S 24.2 Sb	Burlington – G546 138 kV Line 6541	North Lake Geneva - G546 138 kV Line 4453	228 SE	100.0 S 100.0 Sb
Burlington – G546 138 kV Line 6541	24.1 S 24.2 Sb	Whitewater – University 138 kV Line 4453	North Lake Geneva - G546 138 kV Line 4453	228 SE	100.0 S 100.0 Sb
Whitewater – University 138 kV Line 4453	30.8 S 30.9 Sb	North Lake Geneva - G546 138 kV Line 4453	Burlington – G546 138 kV Line 4453	238 SE	100.0 S 100.0 Sb
North Lake Geneva - G546 138 kV Line 4453	30.8 S 30.9 Sb	Whitewater – University 138 kV Line 4453	Burlington – G546 138 kV Line 4453	238 SE	100.0 S 100.0 Sb
Whitewater – University 138 kV Line 4453	16.0 S 0 Sb	Albers – Paris 138 kV Line 3124	Paris – Raymond 138 kV Line 3025	300 SE 300 SE	33.8 S 34.8 Sb
	45.0 S 0 Sb		St. Martin – Raymond 138 kV Line 3025	300 SE 300 SE	33.9 S 34.8 Sb
Albers – Paris 138 kV Line 3124	16.0 S 0 Sb	Whitewater – University 138 kV Line 4453	Paris – Raymond 138 kV Line 3025	300 SE 300 SE	33.8 S 34.8 Sb
	45.0 S 0 Sb		St. Martin – Raymond 138 kV Line 3025	300 SE 300 SE	33.9 S 34.8 Sb
Burlington – G546 138 kV Line 6541	62.3 S 62.2 Sb	North Lake Geneva - G546 138 kV Line 6541	Whitewater – University 138 kV Line 4453	272 SE	93.8 S 93.5 Sb
North Lake Geneva - G546 138 kV Line 6541	62.3 S 62.2 Sb	Burlington – G546 138 kV Line 6541	Whitewater – University 138 kV Line 4453	272 SE	93.8 S 93.5 Sb

Notes:

1. N-2 contingencies were analyzed by linear transfer analysis for the winter 2007/08 and summer 2008 models and re-run with PSS/E AC analysis. G546 was analyzed with 75% of the output going to the CE area and 25% to NSP as a proxy for MISO delivery.
2. S – 2008 Summer Peak case with Paris, Rock River, and Riverside dispatched at less than P_{MAX}. Sb – 2008 Summer Peak case with all local generation dispatched at P_{MAX}.

Table B.2 – Summary of Identified Winter Operating Restrictions on G546 due to Thermal Constraints

Prior outage	Allowable G546 MW Output[3,4]	Worst Next Contingency	Most Limiting Element	Existing MVA Rating	TDF %
Whitewater – University 138 kV Line 4453	0 Wb	Albers – Paris 138 kV Line 3124	Paris – Raymond 138 kV Line 3025	367 WE	42.3 Wb
	0 Wb		St. Martin – Raymond 138 kV Line 3025	367 WE	42.3 Wb
Albers – Paris 138 kV Line 3124	0 Wb	Whitewater – University 138 kV Line 4453	Paris – Raymond 138 kV Line 3025	367 WE	42.23 Wb
	0 Wb		St. Martin – Raymond 138 kV Line 3025	367 WE	42.23 Wb
Zion - Pleasant Prairie 345 kV Line 2221	0 Wb	Albers – Kenosha 138 kV Line 9352	Bain – Kenosha 138 kV Line 63151	287 WE	10.6 Wb
Albers – Kenosha 138 kV Line 9352	0 Wb	Zion - Pleasant Prairie 345 kV Line 2221	Bain – Kenosha 138 kV Line 63151	287 WE	10.6 Wb
Zion - Pleasant Prairie 345 kV Line 2221	0 Wb	Bain – Kenosha 138 kV Line 63151	Albers – Kenosha 138 kV Line 9352	272 WE	14.7 Wb
Bain – Kenosha 138 kV Line 63151	0 Wb	Zion - Pleasant Prairie 345 kV Line 2221	Albers – Kenosha 138 kV Line 9352	272 WE	14.7 Wb
Whitewater – University 138 kV Line 4453	0 Wb	Paris – Raymond 138 kV Line 3025	Albers – Paris 138 kV Line 3124	322 WE	47.7 Wb
Paris – Raymond 138 kV Line 3025	0 Wb	Whitewater – University 138 kV Line 4453	Albers – Paris 138 kV Line 3124	322 WE	47.7 Wb
Zion - Pleasant Prairie 345 kV Line 2221	0 Wb	Pleasant Prairie – Racine 138 kV Line 631	Kenosha – Lakeview 138 kV Line 9341	292 WE	12.2 Wb
Pleasant Prairie – Racine 138 kV Line 631	0 Wb	Zion - Pleasant Prairie 345 kV Line 2221	Kenosha – Lakeview 138 kV Line 9341	292 WE	12.2 Wb
Zion - Pleasant Prairie 345 kV Line 3025	0 Wb	Zion - Arcadian 345 kV Line 2222	Lakeview – Zion 138 kV Line 28201	292 WE	17.4 Wb
Zion - Arcadian 345 kV Line 2222	0 Wb	Zion - Pleasant Prairie 345 kV Line 3025	Lakeview – Zion 138 kV Line 28201	292 WE	17.4 Wb
Albers – Paris 138 kV Line 3124	10.2 Wb	Paris – Raymond 138 kV Line 3025	Whitewater – University 138 kV Line 4453	316 WE	43.5 Wb
Paris – Raymond 138 kV Line 3025	10.2 Wb	Albers – Paris 138 kV Line 3025	Whitewater – University 138 kV Line 4453	316 WE	43.5 Wb
Whitewater – University 138 kV Line 4453	14.8 Wb	Burlington – G546 138 kV Line 6541	North Lake Geneva - G546 138 kV Line 6541	228 WE	99.5 Wb
Burlington – G546 138 kV Line 6541	14.8 Wb	Whitewater – University 138 kV Line 4453	North Lake Geneva - G546 138 kV Line 6541	228 WE	99.5 Wb
Whitewater – University 138 kV Line 4453	70.1 Wb	North Lake Geneva - G546 138 kV Line 6541	Burlington – G546 138 kV Line 6541	292 WE	100 Wb
North Lake Geneva - G546 138 kV Line 6541	70.1 Wb	Whitewater – University 138 kV Line 4453	Burlington – G546 138 kV Line 6541	292 WE	100.0 Wb
Burlington – G546 138 kV Line 6541	82.9 Wb	Whitewater – University 138 kV Line 4453	North Lake Geneva T31 Transformer 138-69 kV	100 WE	24.5 Wb
Whitewater – University 138 kV Line 4453	82.9 Wb	Burlington – G546 138 kV Line 6541	North Lake Geneva T31 Transformer 138-69 kV	100 WE	24.5 Wb

Notes:

3. N-2 contingencies were analyzed by linear transfer analysis for the winter 2007/08 and summer 2008 models and re-run with PSS/E AC analysis. G546 was analyzed with 75% of the output going to the CE area and 25% to NSP as a proxy for MISO.
4. Wb – 2007/08 Winter Peak case with all local generation dispatched to P_{MAX}.

Appendix C: Study Criteria

Study Criteria

C.1 Contingencies

For stability analysis, a set of branches in the vicinity of the generator/power plant of concern is selected as contingencies, based on engineering judgment. Fault analysis is performed for the following six categories of contingency conditions:

1. Three-phase fault cleared in primary time with an otherwise intact system.
2. Three-phase fault cleared in delayed clearing time (i.e. breaker failure conditions) with an otherwise intact system.
3. Three-phase fault cleared in primary clearing time with a pre-existing outage of any other transmission element.
4. Single Line Ground (SLG) bus section fault cleared in primary clearing time with an otherwise intact system.
5. SLG internal breaker fault cleared in primary clearing time with an otherwise intact system.
6. SLG fault of double circuits on common tower cleared in primary time with an otherwise intact system.

For power flow analysis, contingencies include:

1. N-1 contingencies – all lines and transformers operated at 69kV and above in the following control areas/zones: ATC Planning Zones 1-5 and ties to those zones, and all branches of voltage level 69kV and above in the Dairyland Power Cooperative, Northern States Power Control Area, Commonwealth Edison, and Alliant West control areas.
2. Selected N-2 and multiple contingencies that ATC has determined to be significant.

C.2 Monitored Elements

C.2.1 Intact System, N-1, N-2, and Special Multiple Contingency Evaluation Using Linear Transfer Analysis Method

All load carrying elements operated at 69kV and above in the following control areas/zones were studied:ATC Planning Zones 1-5 and ties to those zones, and all branches of voltage level 69kV and above in the Dairyland Power Cooperative, Northern States Power Control Area, Commonwealth Edison, and Alliant West control areas.

A Transmission Reliability Margin (TRM) of 5% was applied to MVA ratings of all monitored elements. Thermal violations are reported based upon the TRM adjustment of MVA ratings.

C.3 Thermal Loading Criteria

C.3.1 Injection Violations

Generation injection violations include 1) thermal violations of the transmission elements that connect the Generator to the rest of the transmission network (outlet congestion); 2) thermal violations of the transmission elements that have TDF ≥ 20% anywhere in the studied system.

C.3.2 Operation Restriction Calculation

$$\text{Allowable Generation Output} = \frac{\text{Equipment Rating} - [\text{Line Flow} - (\text{Generation Output} * \text{TDF})]}{\text{TDF}}$$

C.4 Steady State Voltage Criteria

C.4.1 Intact System, N-1 and Special Multiple Contingency Evaluation Using ACCC

Under intact system conditions, the voltage magnitude of all transmission system buses with a decrease of 0.01 p.u. due to the Generator must not be lower than 0.95 p.u. Under contingency conditions, the voltage magnitude of all transmission system buses with a decrease of 0.01 p.u. due to the Generator must not be lower than 0.90 p.u.

C.4.2 N-2 Contingency Evaluation

Power flow solutions must converge for a selected number of N-2 contingencies in the electrical proximity of the studied Generator. Divergence of a power flow solution indicates potential voltage collapse.

C.5 Angular Stability Criteria

Critical Clearing Time (CCT) is a period relative to the start of a fault, within which all generators in the system remain stable (synchronized). CCT is obtained from simulation. Maximum Expected Clearing Time (MECT) determines a period of time that is needed to clear a fault using the existing system facilities. MECT is dictated by the existing system facilities. In any contingency, if the computed CCT is less than the MECT plus a margin determined by ATC (1.0 cycle in this study), it is considered an unstable situation and is unacceptable. Otherwise, it is considered acceptable stability performance.

In the context of angular stability analysis, voltages of all transmission system buses must recover to at least 70% of the nominal system voltage immediately after fault removal and 80% of the nominal system voltage within 0.5 second after fault removal.