August 24, 2009

NRC 2009-0082
10 CFR 50.90

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Point Beach Nuclear Plant, Units 1 and 2
Dockets 50-266 and 50-301
Renewed License Nos. DPR-24 and DPR-27

<u>Transmittal of Background Information to Support</u>
<u>License Amendment Request 261</u>
<u>ATC Interim Operation and Impacts Re-Study</u>

Reference: (1) FPL Energy Point Beach, LLC, Letter to NRC, dated April 7, 2009, License Amendment Request 261, Extended Power Uprate (ML091250564)

To support NRC review of the Point Beach Nuclear Plant (PBNP) License Amendment Request (LAR) 261 (Reference 1) for an Extended Power Uprate (EPU), NextEra Energy Point Beach, LLC (NextEra) is providing the following document:

> G833/G834-J022/J023 Interim Operation and Impacts Re-Study Report, Revision 1, 118 MW Nuclear Generation Increase (59 MW each at Point Beach Generators 1 and 2), Manitowoc County, Wisconsin, dated July 14, 2009.

The study was prepared by American Transmission Company (ATC), the transmission grid owner/operator for PBNP. The report provides the interim operation and impacts re-study required by the Midwest Independent System Operator (MISO) for the PBNP EPU.

In order to address the thermal and stability limits of the transmission grid that will be associated with the implementation of the PBNP EPU, a combination of interim or final requirements including breaker protection improvements, installation of a switching station, line segment upgrades, and operating restrictions will be implemented. These requirements are being addressed to allow PBNP to operate either unit at EPU conditions. Reference (1), Attachment 5, Licensing Report Section 2.3.2, contains a discussion of the Offsite Power System for the proposed EPU.

This letter contains no new commitments and no revisions to existing commitments. The enclosure to this letter is being provided to the NRC in accordance with Commitment 2 of Reference (1). As stated in this commitment, revisions to this report will be provided to the NRC within 45 days of receipt from ATC.

Questions concerning the enclosure should be directed to Mr. Steve Hale, EPU Licensing Manager, at 561/691-2592.

Very truly yours,

NextEra Energy Point Beach, LLC

Larry Meyer
Site Vice President

Enclosure

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW

ENCLOSURE

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

G833/G834-J022/J023
INTERIM OPERATION AND IMPACTS RE-STUDY REPORT
REVISION 1
118 MW NUCLEAR GENERATION INCREASE
(59 MW EACH AT POINT BEACH GENERATORS 1 AND 2)
MANITOWOC COUNTY, WISCONSIN
DATED JULY 14, 2009
AMERICAN TRANSMISSION COMPANY, LLC

102 Pages Follow

AMERICAN TRANSMISSION COMPANY ®

G833/G834-J022/J023
Interim Operation and Impacts Re-Study Report
Revision 1

118 MW Nuclear Generation Increase
(59 MW each at Point Beach Generators 1 and 2)
Manitowoc County, Wisconsin

G833 - MISO Queue #39297-01
J022 - MISO Queue Date (1/16/2009)

G834 - MISO Queue #39297-02
J023 - MISO Queue Date (1/14/2009)

July 14, 2009
American Transmission Company, LLC

Prepared By:
Sun Wook Kang, Planning

Approved By:
David K. Cullum, P.E.
Team Leader – G-T Interconnections & Special Studies

Table of Contents

EXECUTIVE SUMMARY **4**

1. SUMMARY **7**

1.1 INJECTION LIMITS 7
1.2 GENERATING FACILITY OPERATION RESTRICTIONS 8
1.3 GENERATING FACILITY REQUIREMENTS 9
1.4 SYSTEM UPGRADES 10

2. CRITERIA, METHODOLOGY AND ASSUMPTIONS **20**

2.1 STUDY CRITERIA 20
2.2 STUDY METHODOLOGY 20
2.2.1 Competing Generation Requests *20*
2.2.2 A.C. Power Flow Analysis Methods *20*
2.2.3 Stability Analysis *20*
2.3 BASE CASES 21
2.3.1 Power Flow Analysis (Steady State) *21*
2.3.2 Stability Analysis (Dynamics) *21*
2.4 GENERATION FACILITY 22
2.4.1 Generating Facility Modeling *22*
2.4.2 Voltage Sag Criteria *23*

3. ANALYSIS RESULTS **24**

3.1 POWER FLOW ANALYSIS RESULTS 24
3.1.1 Power Factor Capability and Voltage Requirements *24*
3.1.2 Results of Intact System and Single Contingencies (N-1) *24*
3.1.3 Results of Double Contingencies *25*
3.2 STABILITY ANALYSIS RESULTS 26
3.2.1 Results of Primary Clearing of Three-Phase Faults Under Intact System Conditions *27*
3.2.2 Results of Primary Clearing Three-Phase Faults on Two Circuits of a Multiple Circuit Lines *27*
3.2.3 Results of Primary Clearing Three-Phase Faults During a Prior Outage *28*
3.2.4 Results of Three-Phase Fault Delayed (Breaker Failure) Clearing under Intact System Conditions *30*
3.2.5 Point Beach Bus, Generator Step Up and Auxiliary Transformer Faults *32*
3.2.6 Unit Outage *32*
3.2.7 Stability Results Summary *33*

APPENDIX A: POWER FLOW ANALYSIS RESULTS **36**

APPENDIX B: STABILITY ANALYSIS RESULTS **49**

APPENDIX C: COMPETING WIND GENERATORS **74**

APPENDIX D: OPERATING RESTRICTIONS **75**

APPENDIX E: SHORT CIRCUIT / BREAKER DUTY ANALYSIS RESULTS **77**

APPENDIX F: STUDY CRITERIA **80**

APPENDIX G: ESTIMATED ALLOWABLE MW OUTPUT FROM G834 OR G833 UNDER SPRING/FALL OR WINTER EMERGENCY RATINGS **84**

APPENDIX H: SUMMARY TABLE OF STABILITY STUDY RESULT **86**

APPENDIX I: MINIMUM EXCITATION LIMITS AT POINT BEACH AND KEWAUNEE DURING INTERIM PERIODS **90**

APPENDIX J: UNIT RESTRICTION DUE TO STABILITY UNDER PRIOR OUTAGE CONDITIONS IN TABLE ES-3 DURING ONE OF POINT BEACH UNITS OFFLINE 101

Executive Summary

The Impact Study (ISIS) report for Midwest Independent System Operator (MISO) Generation Interconnection Requests identified as Projects G833, Queue #39297-01, and G834, Queue #39297-02, to the 345-kV transmission system in Manitowoc County, Wisconsin, was originally posted in July 2008 and the revision (#3) was posted on December 18, 2008. On January 14 and 16, 2009, the interconnection customer increased the MW output of the original G833/4 by 6 MW per unit (MISO Generator Interconnection Requests J022 and J023) and the original dynamic models of the generators were modified. As a result, the requests became 59 MW increase to each of the Point Beach Nuclear generators for a total increase in plant output of 118 MW. Each generator was studied with a net output, as measured at the low-side of the generator step-up transformer, of 619.56 MW net (642.96 MW gross per unit). The requested commercial operation date is May 31, 2010 for G834/J023 (Point Beach Unit 1) and May 31, 2011 for G833/J022 (Point Beach Unit 2).

Since the requested commercial operation date is earlier than the timeframe to complete the long term Network Upgrade, an interim operation study of the period between the expected commercial operation date and the expected completion date of a long term solution was undertaken to identify the possible unit restrictions and/or additional system upgrades needed during this interim period. This report identifies restrictions due to system thermal limitations (Tables ES-1 and ES-2) and due to angular instability of the Point Beach units and/or other nearby plants (Table ES-3). Information regarding the required system upgrades can be found in Table 1.2.

As a result of the study with the latest data and prior to the long term Network Upgrades, it was also identified that generation instability may occur under fault conditions when Kewaunee and Point Beach units operate at reactive power outputs lower than the outputs shown in Appendix I (Minimum Excitation Limits). Reactive power output from a synchronous machine has an impact on the transient stability of the unit. Typically, a unit tends to be less stable under a fault when the unit produces relatively small reactive power output or absorbs reactive power from transmission system (under-excitation). The results of this interim operation study indicate that a certain level of reactive power output (over-excitation) needs to be maintained to ensure generation stability in anticipation of critical fault conditions. This is primarily due to too many generators with few outlets out of Fox Valley area. Imposition of Minimum Excitation Limits can impact the local transmission system in regard to voltage control. As Appendix I demonstrates, transmission system voltage control will be retained with the proposed limits. Therefore, although ATC and the customer agreed on the unit reactive power output level that is generally consistent with historical levels and corresponds to the low end (352 kV, 1.0203 pu) of the preferred voltage range at the Point Beach power plant, the use of revised Minimum Excitation Limits ensures stable generator operation for system faults.

Table ES-1: Restrictions Due to Thermal (Valid per condition noted)
Maximum 642.96 MW Gross per Point Beach unit
Assumes all competing wind farms at ***full*** output

System Load Level	Season	Restrictions Due to Thermal (U1/U2 gross MW)	Limiting Transmission Line
100%	Winter	None	
	Spring/Fall	None	
	Summer	None	
50%	Winter	None	
	Spring/Fall	None	
	Summer	535 / 537 MW	Point Beach-Sheboygan 345-kV
			Cypress-Arcadian 345-kV

Table ES-2: Restrictions Due to Thermal (Valid per condition noted)
Maximum 642.96 MW Gross per Point Beach unit
Assumes all competing wind farms at ***20%*** output

System Load Level	Season	Restrictions Due to Thermal (U1/U2 gross MW)	Limiting Transmission Line
100%	Winter	None	
	Spring/Fall	None	
	Summer	None	
50%	Winter	None	
	Spring/Fall	None	
	Summer	535 / 537 MW	Point Beach-Sheboygan 345-kV

Table ES-3: Restrictions Due to Stability (Valid any hour of year)
Maximum 642.96 MW Gross per Point Beach unit

Year	Point Beach Unit	Restrictions Due to Stability (gross MW)	Condition	Notes
May 2010-April 2011 (i.e. G834/J023 only)	Unit #1	560 MW	Prior outage of 345-kV line 6832	The operating restrictions are valid only with the stability upgrade in-service which are required by May 2010 in Table 1.2. (R-304 Breaker Replacement at North Appleton)
		580 MW	Prior outage of Point Beach Bus Tie 2-3	
May 2011 – beyond With G833/4 (J022/3) With existing Kewaunee	Unit #2	620 MW	Prior outage of 345-kV line 121	The operating restrictions are valid only with all the stability upgrades in-service required by May 2010 and 2011 in Table 1.2. (Point Beach relay upgrades and Addition of a breaker in series with existing Q-303 breaker at Point Beach)
	Unit #2	620 MW	Prior outage of 345-kV line 151	
	Unit #2	600 MW	Prior outage of 345-kV line R304	
	Both Unit #1 and #2	540 MW per unit	Prior outage of 345-kV line 6832	
	Unit #2	580 MW	Prior outage of SEC31	
	Unit #1	580 MW	Prior outage of Point Beach Bus Tie 2-3	
	Unit #2	620 MW	Prior outage of Point Beach Bus Tie 4-5	
May 2011 – beyond With G833/4 (J022/3) With new Kewaunee	Unit #2	600MW	Prior outage of 345-kV line 6832	The operating restrictions are valid only with all the stability upgrades in-service and with Kewaunee bus reconfiguration project in-service
	Unit #1	580 MW	Prior outage of Point Beach Bus Tie 2-3	

1. Summary

Primarily due to the modification to the original generator models of G833 and G834 supplied by the Interconnection Customer, an extensive stability analysis was performed to identify impact of the modification and to provide interim operating limitations and/or interim system upgrades needed to maximize the output of G833/J022 and G834/J023 until completion of the long term Network Upgrades. Key modifications include:

- In-service date of new generator step-up transformer of Unit 2 (October 2009)
- MW output increased by 6 MW per unit (total 642.96 MW gross per unit)
- Dynamic models of unit 1 and 2

G833/J022 and G834/J023, with an expected in-service date of May 31, 2011 and May 31, 2010, respectively, became 59 MW increases to each of the existing Point Beach nuclear units.

For this interim operation period re-study, no new thermal analysis was performed since the plant impact will not change substantially. No significant impact is expected due to additional 12 MW output increase. Instead, the thermal impact due to the proposed 6 MW increase per unit (J022/23) was assessed based on the formula in Section 1.1 and the results shown in the previous version of the Interim Operation Study report dated Dec. 30, 2008.

The following three different scenarios were studied for the interim period stability analysis:

- Interim 1 scenario representing the period between May 2010 (after G834/J023) and April 2011 (before G833/J022)
- Interim 2 scenarios representing the period between May 2011 (after G833/J022) and the in-service date of a long term solution:
    - Interim 2A: with G833/4-J022/3 and with existing Kewaunee substation
    - Interim 2B: with G833/4-J022/3 and with new Kewaunee substation

Different generation patterns and load levels were considered for each scenario. Consistent with the G833/4 System Impact Study report dated Dec. 18, 2008, both high and low Fox Valley generation scenarios were studied to evaluate stability for the scenarios. More details can be found in Section 2.3.

This re-study assumes the Point Beach generator and turbine improvements submitted for requests J022/23 (MISO queue dates: January 16 and 14, 2009). The limitations and solutions described in this report may not be valid if the Point Beach data changes.

1.1 Injection Limits[1]

No new thermal analysis was performed since the plant impact will not change substantially. No significant impact is expected due to additional 12 MW output increase.

Among the four injection limits identified in the previous interim operation report, only Point Beach-Sheboygan Energy Center and Cypress-Arcadian 345 kV lines are now required to be

[1] See Appendix F, Section F3.1 for a definition of what transmission overloads qualify as injection limits.

mitigated. The Elkhart Lake-Saukville and Elkhart Lake-G611 138 kV lines, which were originally identified in the previous interim operation study report, are no longer injection limits under the new MISO Generation Interconnection Business Practices. The new MISO generation interconnection procedure does not require transmission reinforcement for thermal issues resulting from an outage of generation outlet if distribution factor is below 5%.

For the two remaining injection limits, new required ratings in this report were estimated using the formula given below:

$$\text{New Required Rating} = \text{Old Required Rating} + (\Delta P \times DF/0.95)$$

Where

ΔP : MW output of new G833/J022 and/or G834/J023 – MW output of old G833/J022 and/or G834/J023

DF: Distribution Factor

The injection limits are identified in Tables A.1 through A.8 in Appendix A and are listed below. As mentioned in the previous study report, the thermal study identified no steady-state thermal violations for NERC Category A (intact system) events for all models studied.

For NERC Category B (N-1) events, no injection limits were identified in the scenarios with 100% of system peak load while the two injection limits were identified in the scenarios with a 50% of system peak load condition. The two injection limits are:

1. Point Beach-Sheboygan Energy Center 345 kV line (L111)
2. Cypress-Arcadian 345 kV Line (L-CYP31 north)

As described in the previous interim study report, the thermal upgrades are needed for certain system scenarios but not all scenarios. The most critical upgrade is the improvement required to 345 kV line L111 from Point Beach to Sheboygan Energy Center. Independent of these Interconnection Requests, this line has been identified by ATC for improvement due to MISO energy market impacts.

Interim mitigation measures for these injection limits are described in Section 1.4 and are required for the requested Interconnection Service of G833/J022 and G834/J023 to maximize their power output.

1.2 Generating Facility Operation Restrictions

Various potential thermal constraints are shown in Table A.10 in Appendix A for Category C.3 events. In general, re-dispatching generators in the Fox Valley area may relieve the loadings on the constraints. Since thermal constraints will be mitigated in the day-ahead and real-time market through the MISO binding constraint procedure, no operating restrictions are listed for the thermal constraints.

However, there are restrictions based on the stability analysis. With all stability upgrades assumed in-service and the Minimum Excitation Limiter settings for Point Beach and Kewaunee units modified, generation restrictions identified for each interim period are:

- During Interim 1 period (2010 after G834/J023 – 2011 before G833/J022)
  i. G1 at 560 MW (gross) under prior outage condition of 6832 (North Appleton-Fox River 345 kV line)
  ii. G1 at 580 MW (gross) under prior outage condition of Point Beach Bus Tie 2-3

- During Interim 2A period (Without Kewaunee project, 2011 after G833/J022 – beyond)
  i. G2 at 620 MW (gross) under prior outage of 121 (Point Beach-Forest Junction 345 kV line)
  ii. G2 at 620 MW (gross) under prior outage of 151 (Point Beach-Fox River 345 kV line)
  iii. G2 at 600 MW (gross) under prior outage of R304 (Kewaunee-North Appleton 345 kV line)
  iv. Both G1 and G2 at 540 MW (gross) under prior outage of 6832 (North Appleton-Fox River 345 kV line)
  v. G2 at 580 MW (gross) under prior outage of SEC31 (Sheboygan Energy Center-Granville 345 kV line)
  vi. G1 at 580 MW (gross) under prior outage of Point Beach Bus Tie 2-3
  vii. G2 at 620 MW (gross) under prior outage of Point Beach Bus Tie 4-5

- During Interim 2B period (With Kewaunee project, 2011 after G833/J022 – beyond)
  i. G2 at 600 MW (gross) under prior outage condition of 6832 (North Appleton-Fox River 345 kV line)
  ii. G1 at 580 MW (gross) under prior outage condition of Point Beach Bus Tie 2-3

1.3 Generating Facility Requirements

Point Beach Power System Stabilizers

The existing Point Beach Power System Stabilizers (PSS) are required due to inadequate rotor angle damping under certain system conditions. The G833/J022 and G834/J023 projects will continue to require the use of PSS on the Point Beach units. This study incorporated the modified PSS information supplied by the Interconnection Customer and it assumed that the PSS for each unit was in-service for each simulation. The re-tuning of the PSS should be reviewed and commissioned by experienced professionals. The results of the on site PSS tuning, including the parameters expressed in terms of the appropriate power system stabilizer models in the Siemens PTI PSS/E program, must be provided to ATC prior to the commercial operation of G833/J022 and G834/J023. ATC will then test the performance of the Point Beach units with the tuned parameters in the computer simulations to ensure that rotor angle damping is within criteria.

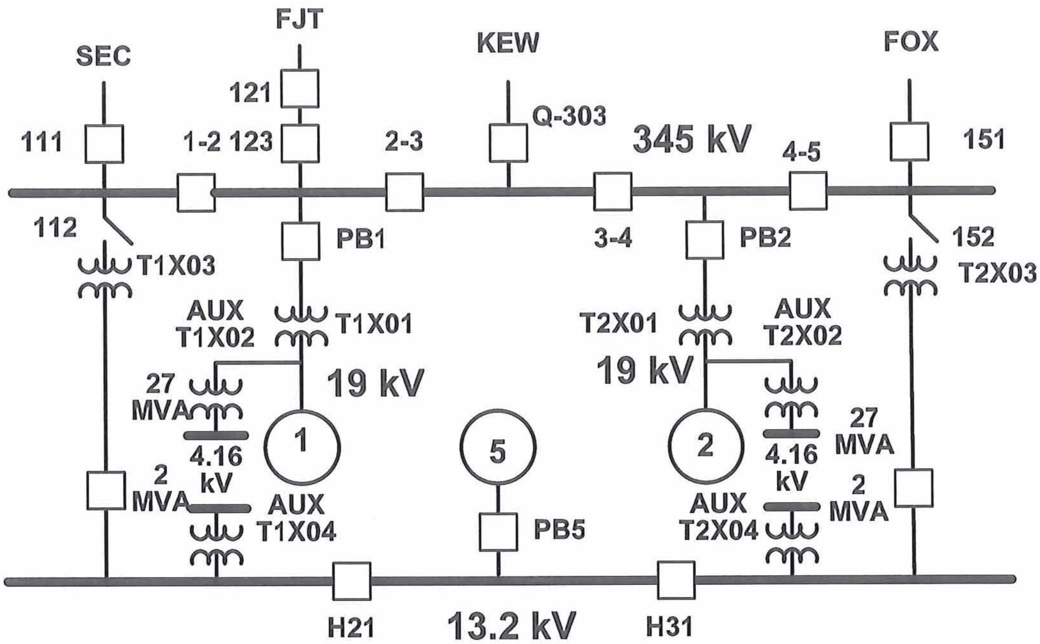

Figure 1.1 – Existing Point Beach Substation Configuration

<u>Reduction of Auxiliary Transformers T1X03 and T2X03 Primary Clearing Times (Table 1.4)</u>
Both the previous G833/4 ISIS study and this interim operation study showed the need for faster primary clearing time for a fault at the high side of T1X03 or at the high side of T2X03 to address potential instability of the generators in the area (see Figure 1.1). As shown in the stability study results for Interim 2A (with existing Kewaunee) and 2B (with new Kewaunee bus configuration) periods, a total clearing time of 4.0 cycles is needed for the auxiliary transformer 345 kV fault primary clearing time under certain outage conditions to avoid instability of generators in the area.

<u>Plant Specific Voltage Requirements</u>
The Point Beach Nuclear has specific 345 kV voltage range requirements. The preferred range is 352 kV (1.020 pu) to 354 kV (1.026 pu), the normal range is 351 kV (1.017 pu) to 358 kV (1.037 pu) and the maximum permissible is 348.5 kV (1.010 pu) to 362 kV (1.049 pu). Any voltage outside the maximum permissible range is a voltage limitation as described in the plant technical specifications.

1.4 System Upgrades

1.4.1 Existing System Upgrades (See Table 1.1)

Injection Upgrades
Analysis prior to G833/J022 and G834/J023 found no required system upgrades due to injection limits.

Voltage Related
Analysis prior to G833/J022 and G834/J023 found no unacceptable voltages.

Breaker Duty Related
No existing over-duty circuit breaker conditions were found prior to be significantly (i.e. ≥1%) impacted due to the addition of G833/J022 and G834/J023. Therefore, no over-dutied circuit breakers are identified in Table 1.1.

1.4.2 System Upgrades and Interim Mitigation Measures Required due to G834/J023 and/or G833/J022 Addition

The stability related upgrades listed in this section are required for increased plant operation during all hours in the year. In addition, the identified stability upgrades do not eliminate all restrictions on the upgraded Point Beach units since operating restrictions will exist during each interim period for certain prior outage conditions. Revised operating restrictions, in addition to the required stability upgrades, can be found at Section 1.2.

In addition to the system upgrades listed below, both Point Beach units and the Kewaunee unit will be required to modify the Minimum Excitation Limit settings on these units to ensure stable operation for a variety of fault conditions. The proposed limits are described in Appendix I.

1.4.2.1 System Upgrades due to Thermal Issues

To accommodate G833/4-J022/3, the following lines need to be uprated by May 1, 2010:

- Point Beach-Sheboygan Energy Center 345-kV line:
  The most critical upgrade is the improvement required to 345 kV line L111 from Point Beach to Sheboygan Energy Center, which has also been independently identified by ATC for improvement due to MISO energy market impacts.
  - Required rating:
    A minimum summer emergency rating of 596 MVA (997.4 A)
  - As an independent economic benefit project, ATC has proposed uprating the line to a summer emergency rating of 1120 MVA which is higher than the required rating for G833/4-J022/3. The proposed in-service date of the line uprate project is April 25, 2010 (ATC Project PR03208).

- Cypress-Arcadian 345-kV line:
  As described in the previous interim operation study report, roughly 52% and 33% of total output from all competing wind generators were estimated as the upper bounds for not exceeding the existing summer emergency rating (488 MVA SE) with G834 in-service and with G834/3-J022/3 in-service, respectively, under light system load conditions.
  - Required rating:
    A minimum summer emergency rating of 572 MVA (957.3 A)
  - In-service date: May 1, 2010

1.4.2.2 System Upgrades due to Stability Issues

- For the G834/J023 interconnection in 2010, the following stability upgrades are required:
  a. Improve primary clearing time at R-304 North Appleton terminal for R-304 fault at Kewaunee:
     - Replace the existing 3 cycle R-304 circuit breaker at North Appleton with new 2 cycle IPO circuit breaker to reduce the existing 6.5 cycle clearing time to 4.5 cycles to permit additional MW output from Point Beach unit #1 under certain prior outage conditions.
     - Required clearing times for R-304 fault at Kewaunee:
       - From the existing 4.5 cycle local primary and 6.5 cycle remote primary,
       - To 4.5 cycle local primary and **4.5** cycle remote.

- For the G833/J022 interconnection in 2011, the following stability upgrades are required:
  a. Improve breaker failure clearing time at L111 Point Beach terminal for L111 fault at Point Beach:
     - Replace the existing Point Beach L111 SBF breaker failure relay with an SEL-352, and replace the existing Line 111 SEL-221F backup relay with an SEL-421.
     - Required clearing times for L111 fault at Point Beach:
       - From the existing 3.5 cycle local primary, 9.0 cycle local delayed, and 4.5 cycle remote primary
       - To 3.5 cycle local primary, **8.0** cycle local delayed, and 4.5 cycle remote primary

  b. Improve breaker failure clearing time at L151 Point Beach terminal for L151 fault at Point Beach:
     - Replace the existing Point Beach L151 SBF breaker failure relay with an SEL-352, and replace the existing Line 151 SEL-221F backup relay with an SEL-421.
     - Required clearing times for L151 fault at Point Beach:
       - From the existing 3.5 cycle local primary, 9.0 cycle local delayed, and 4.5 cycle remote primary
       - To 3.5 cycle local primary, **8.5** cycle local delayed (**8.0** cycle achieved with the upgrade), and 4.5 cycle remote primary

  c. Isolate Q-303 fault at Point Beach in primary time:
     - Add a new Point Beach 345 kV Circuit Breaker in series with the existing Q-303 Circuit Breaker. The upgrade will clear a Q-303 breaker failure at Point Beach in primary time.
     - With the series breaker addition, achieved clearing times for Q-303 fault at Point Beach:
       - From the existing 3.5 cycle local primary, **9.0** cycle local delayed, and 6.5 cycle remote primary (4.5 cycle remote primary with Kewaunee bus reconfiguration project in-service)

    - To 3.5 cycle local primary, **3.5** cycle local delayed (cleared in primary time), and 6.5 cycle remote primary (4.5 cycle remote primary with Kewaunee bus reconfiguration project in-service)

d. Improve breaker failure clearing time of Point Beach Bus Tie 2-3 for a single-line to ground fault on Point Beach Bus 2:
    - Change Relay setting (without Breaker Failure relay replacement) for Failure of Point Beach Bus Tie 2-3 to no more than 11 cycle total breaker failure clearing time for bus faults.
    - Required clearing times for single line to ground fault on Point Beach Bus 2 with failure on Bus Tie breaker 2-3:
        - From the existing 4.75 cycle local primary and **12.5** cycle local delayed
        - To 4.75 cycle local primary and **11.0** cycle local delayed

e. Upgrade back-up relay for better maintenance and operating flexibility during a L121 relay outage at Point Beach.
    - Replace L121 SEL-221F backup relay with SEL-421 to provide better maintenance and operating flexibility during a L121 relay outage.

1.4.2.3 Upgrades Required due to Voltage
None identified.

1.4.2.4 Upgrades Required due to Breaker Duty
None identified.

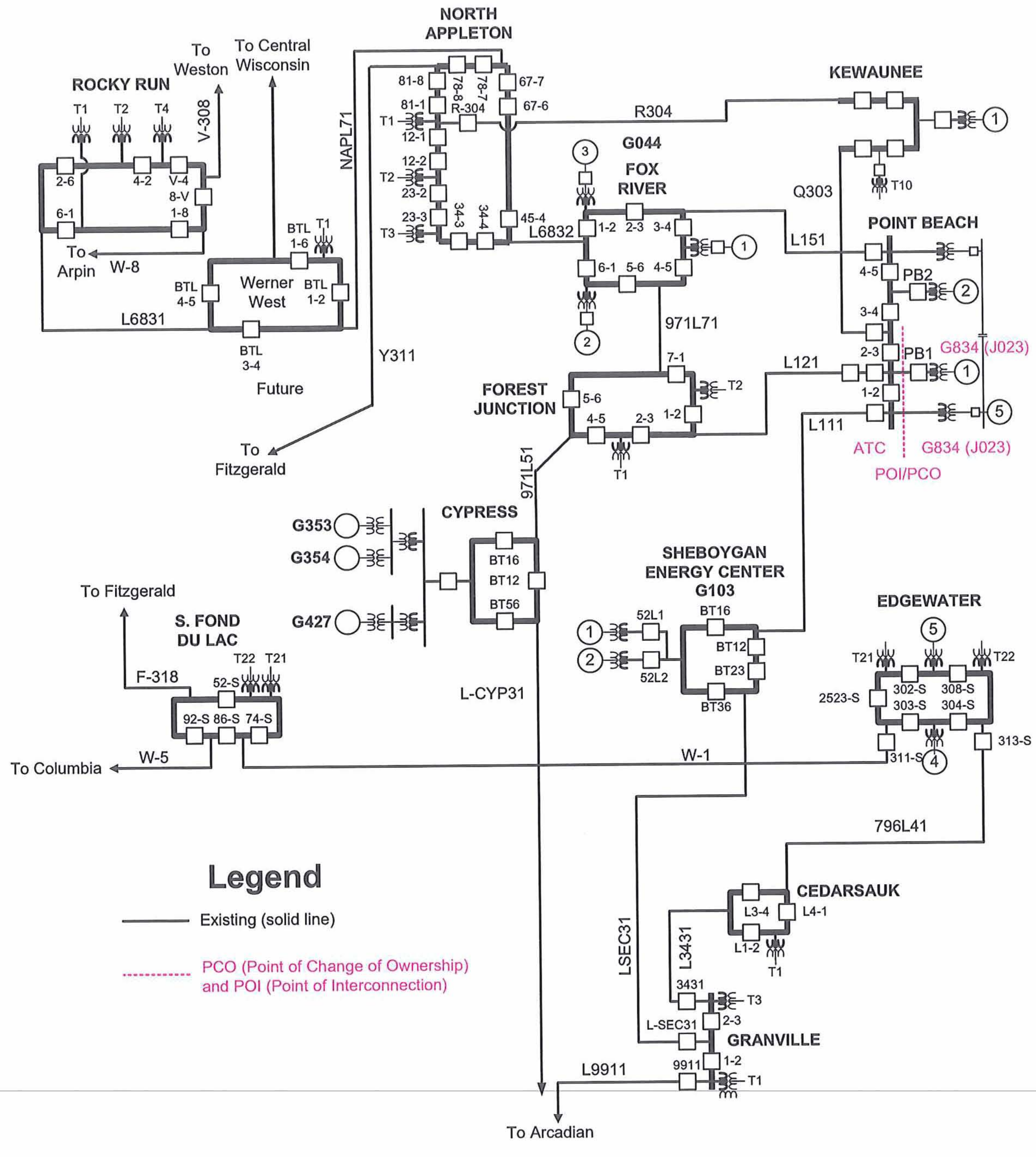

Figure 1.2 – One Line Diagram of the 2010 System with G834 (J023) Shown With existing Kewaunee Substation

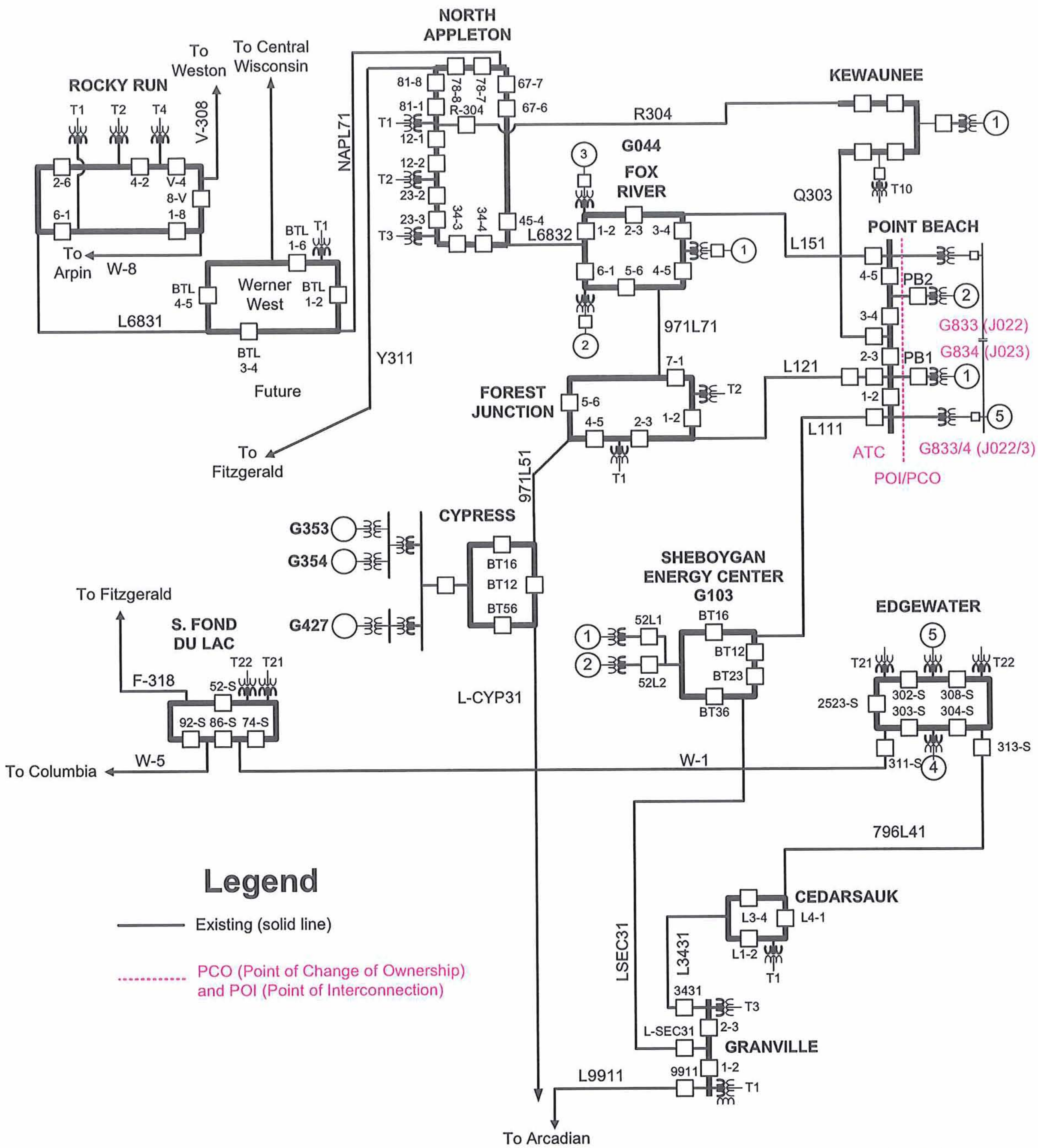

Figure 1.3 – One Line Diagram of the 2011 System with G833 (J022) and G834 (J023) Shown With existing Kewaunee Substation

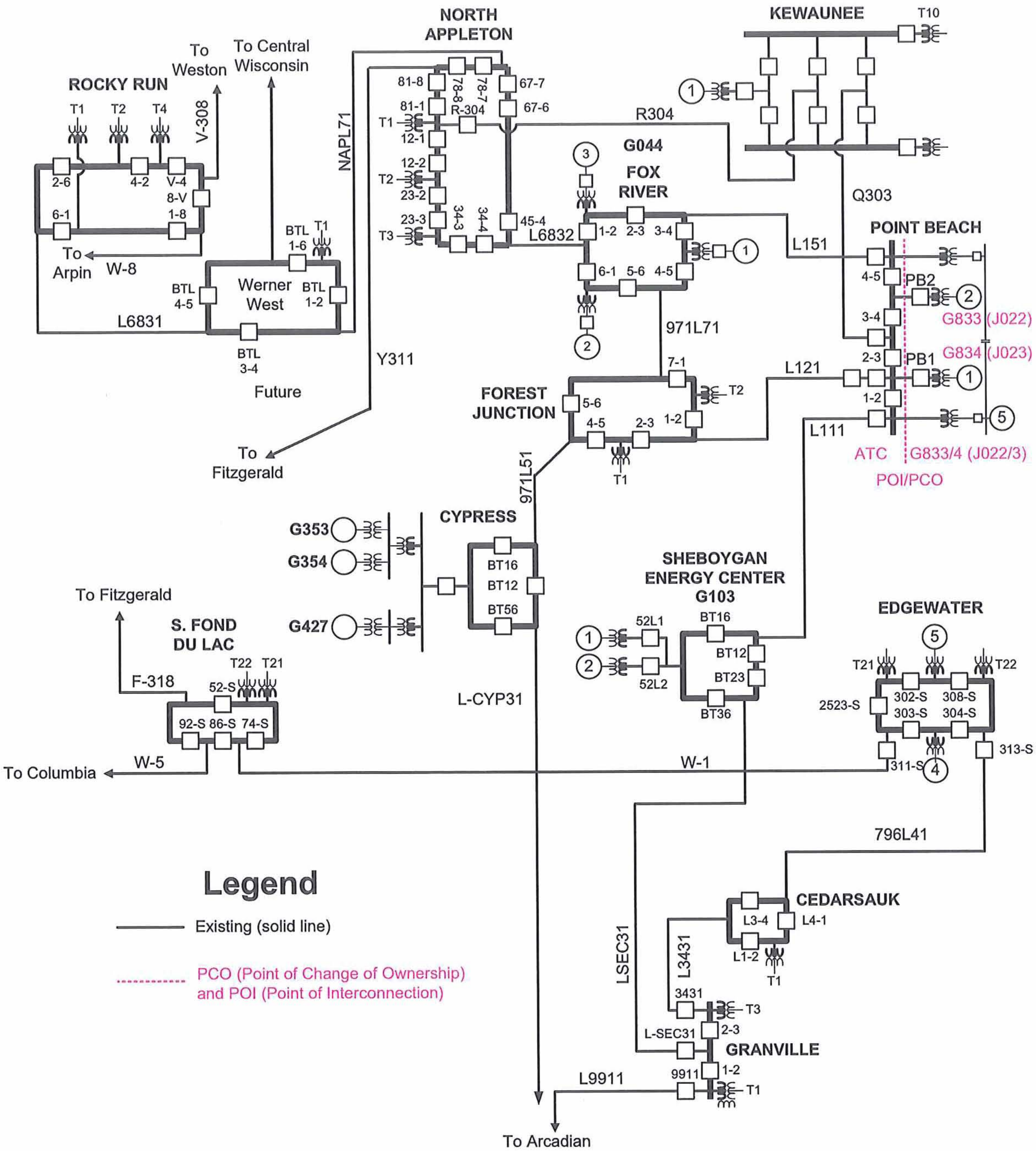

Figure 1.4 – One Line Diagram of the 2011 System with G833 (J022) and G834 (J023) Shown With Kewaunee Bus Reconfiguration Project

Table 1.1– Existing System Upgrades Required before Operation of G833/J022 and/or G834 /J023

Location	Facilities	Reason
None		

Table 1.2 – Required Interim Network Upgrades for Thermal and Stability Issues due to the Addition of G833/J022 and/or G834/J023

Location	Facilities	Reason	In-service Date	Good Faith Cost Estimate (Y2009)
Cypress-Arcadian 345-kV line	**Item #1** –Look at plan and profile and Patrol to observe any close wire crossings and adjust to obtain a minimum Summer Emergency rating of 572 MVA (957.3 A).	Injection Limit	5/1/2010	$1.7 M
Point Beach-Sheboygan Energy Center 345-kV line	**Item #2** – L111 requires a minimum summer emergency rating of 596 MVA (997.4 A). PRF PR03208 requires a minimum summer emergency rating of 1120 MVA with a proposed in-service date of Spring 2010. Completion of PRF PR03208 accomplishes the requirements for G833 and G834.	Injection Limit	5/1/2010	Not required since existing ATC project will satisfy rating needs
North Appleton 345 kV Bus	**Item #3** – R-304 Fault at Kewaunee Protection Improvement - North Appleton R-304 Circuit Breaker Replacement with 2 cycle Circuit Breaker implemented for Independent Pole Operation **(345 kV, 3000 A, 50 kA, Gas CB, IPO)** in order to achieve 4.5 cycles remote primary clearing time. With Kewaunee bus reconfiguration project and Item #3 assumed in-service, R-304 fault clearing times become 3.5[1] cycles local primary, 8.5[1] cycles local delayed and 4.5[2] cycles remote primary by reducing the remote clearing time by 2.0 cycles	Stability Upgrades	5/1/2010	$1 M
Point Beach 345 kV Bus	**Item #4** –Point Beach Faults Protection Improvements. <u>Item 4A:</u> Achieve L111 clearing times of 3.5 cycles local primary, 8.0 cycles local delayed and 4.5 cycles remote primary by reducing local delayed clearing time 1.0 cycles. It requires Point Beach L111 SBF Breaker Failure Relay replacement with an SEL-352, and the existing Line 111 SEL-221F backup relay replacement with an SEL-421. <u>Item 4B:</u> Achieve L151 clearing times of 3.5 cycles local primary, 8.5 cycles local delayed and 4.5 cycles remote primary by reducing local delayed clearing time 0.5 cycles. It requires Point Beach L151 SBF Breaker Failure Relay replacement with an SEL-352, and the existing Line 151 SEL-221F backup relay replacement with an SEL-421 (note 8.0 cycles delayed clearing time can be obtained with Item 4B implemented). <u>Item 4C</u>: Isolate Q-303 line fault in primary time at Point Beach. This requires Point Beach 345 kV Circuit Breaker Addition **(345 kV, 3000 A, 50 kA, Gas CB, IPO)** in series with the existing Q-303 Circuit Breaker to isolate line fault in primary time. <u>Item 4D</u>: Achieve breaker B23 clearing times of 11 cycles local delayed by reducing local delayed clearing time 1 cycle. It requires relay setting change (without Breaker Failure relay replacement) for Failure of Point Beach Bus Tie 2-3 to achieve no more than 11 cycle total breaker failure clearing time for bus faults	Stability Upgrades	5/1/2011	$1.8 M
	<u>Item 4E</u>: Replace L121 SEL-221F backup relay with SEL-421 to provide better maintenance and operating flexibility during a L121 relay outage			
TOTAL				**$ 4.5 M**

Note 1 – Clearing times at Kewaunee with Kewaunee Bus Reconfiguration in-service
Note 2 – Clearing time achieved by implementing item #3

Table 1.3 – Required Interconnection Facilities for G833/J022 and G834/J023

Entity	Facilities	Cost Estimate (Y2009)
Transmission Owner	None.	NA
G833 (J022) and G834 (J023) Interconnection Customer	Minimum Excitation Limiter setting changes are documented in Appendix I. **Note:** These facilities are to be provided by the generator interconnection customer. Hence, cost estimate is not applicable.	NA

Table 1.4 – Recommended Facilities Due To Third Party Impact of G833/J022 and G834/J023

Entity	Facilities	Cost Estimate (Y2009)
G833 (J022) and G834 (J023) Interconnection Customer	Recommended improvements to the Point Beach substation design. Add 345 kV, 3000A, 50 kA, 2 cycle gas Circuit Breakers on the high side of Point Beach auxiliary transformers T1X03 and T2X03 with adequate primary and breaker failure relaying. Reduce Auxiliary Transformer T1X03 primary fault clearing time from 5.1 cycles to 4.0 cycles and Auxiliary Transformer T2X03 from 5.1 cycles to 4.0 cycles. **Note:** These facilities are to be provided by the generator interconnection customer. Hence, cost estimate is not applicable.	NA

Table 1.5 – Required Improvements due to Third Party Impacts

Entity	Facilities	Cost Estimate (Y2009)
Kewaunee unit	Minimum Excitation Limiter setting changes are documented in Appendix I. **Note:** No cost estimate is identified for Third Party impacts.	NA

2. Criteria, Methodology and Assumptions

2.1 Study Criteria

All relevant MISO-adopted NERC Reliability Criteria and the American Transmission Company contingency criteria are to be met for thermal, voltage and angular stability analysis. Details of the analysis criteria used in this study can be found in Appendix F.

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 Interconnection Customer 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, earlier queue Generator Interconnection Requests, 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 Interconnection Customer is responsible for communicating any significant generating facility data changes in a timely fashion to MISO and ATC prior to commercial operation.

2.2.1 Competing Generation Requests

Competing generation requests can be found in Appendix C.

Public information related to the MISO Interconnection Request queue can be found at:
http://www.midwestmarket.org/page/Generator%20Interconnection
and the Interconnection Requests specific to the ATC footprint can be found at:
http://oasis.midwestiso.org/documents/ATC/Cluster_8_Queue.html.

2.2.2 A.C. Power Flow Analysis Methods

No thermal analyses were performed based on the reasons described in Section 1.1.

2.2.3 Stability Analysis

ATC recently conducted extensive stability analysis of the area near the Point Beach generators and determined that there were no generation limitations for intact and single outage conditions, with the existing Power System Stabilizers (PSS) in service, and prior to requests G833/J022 and G834/J023. Simulations were performed with G833/J022 and/or G834/J023 in service to determine the stability impacts that attributed to the additional generation with the latest dynamic data submitted to MISO for J022/J023. Any violations of the stability study criteria (in Appendix F) identified with the increased generation in service can be attributed to the G833/J022 and G834/J023 interconnection request and are documented in this report.

For the analysis, the Power System Stabilizers are assumed in-service. Simulated/tested clearing times shown in each table in Appendix B contains the required planning margin described in Section 3.2.

The stability and grid disturbance performance analysis was performed using the Dynamics Simulation and Power Flow modules of the Power System Simulation/Engineering-29 (PSS/E, Version 29.5.1) program from Siemens Power Technologies, Inc (PTI). This program is accepted industry-wide for dynamic stability analysis.

2.3 Base Cases

2.3.1 Power Flow Analysis (Steady State)

No thermal analyses were performed based on the reasons shown in Section 1.1.

2.3.2 Stability Analysis (Dynamics)

The 2010 50% of system peak load base case used in the stability analysis was developed based upon the ATC 2009 Ten Year Assessment 50% peak load dynamics-ready model from the 2007 Series NERC MMWG cases. The ATC area was replaced with the 2010 planned and proposed projects and load and generation was set to expected levels. All local and competing generators were dispatched at full output in accordance with ATC's generator interconnection study methodology. The resulting additional generation was delivered to ComEd (75%) and Northern States Power (25%) control areas.

Two stability scenarios per each interim period were studied for G833/4-J022/3 interim operations. Specifically, high local generation and low local generation models were created. Only the wind generator (G427) located at Cypress 345-kV substation was considered as the competing generator for stability analysis based on the assumption that other wind generators connected at 138 kV would not significantly impact the stability results. For the high generation scenario, in addition to Point Beach and all local generation (Kewaunee, Fox River, Sheboygan Energy, South Fond du Lac and Cypress) were modeled with maximum generation. Weston Units 3 and 4 were also in service. For the low generation scenario, the same dispatch was used except that the Fox Energy, Sheboygan Energy, Cypress and South Fond du Lac were modeled as off-line.

Table 2.3.1 – Key generation status for Interim Period 1 (May 2010~April 2011, with G834 and without G833, without Kewaunee bus reconfiguration)

Units	Low Generation Scenario	High Generation Scenario
Point Beach Unit 1 (G834)	642.96 MW (Gross)	642.96 MW (Gross)
Point Beach Unit 2 (G833)	537 MW (Gross)	537 MW (Gross)
Kewaunee	603 MW (Gross)	603 MW (Gross)
Cypress	0 MW	258 MW
South Fond du Lac generators	0 MW	352 MW
Fox Energy Center	0 MW	632 MW
Sheboygan Energy Center	0 MW	346.8 MW

Table 2.3.2 – Key generation status for Interim Period 2 (May 2011~until completion of long term project, with G834 and with G833, with Kewaunee bus reconfiguration)

Units	Low Generation Scenario	High Generation Scenario
Point Beach Unit 1 (G834)	642.96 MW (Gross)	642.96 MW (Gross)
Point Beach Unit 2 (G833)	642.96 MW (Gross)	642.96 MW (Gross)
Kewaunee	603 MW (Gross)	603 MW (Gross)
Cypress	0 MW	258 MW
South Fond du Lac generators	0 MW	352 MW
Fox Energy Center	0 MW	632 MW
Sheboygan Energy Center	0 MW	346.8 MW

2.4 Generation Facility

2.4.1 Generating Facility Modeling

The G833/J022 and G834/J023 projects are increases to the existing capacity of Point Beach generating units and are modeled by changing the existing representation in the planning cases so that the total gross real power is 642.96 MW and a new machine base of 684 MVA for each unit.

Prior to performing the stability analysis, ATC investigated and reviewed historical reactive power outputs from both the Point Beach and Kewaunee plants. Reactive power output from a synchronous machine has an impact on the transient stability of the unit. Therefore, for the interim study, ATC wanted to review the assumptions for building the study models. ATC selected a unit reactive power output level that is generally consistent with historical levels and corresponds to the low end of the preferred voltage range at the Point Beach power plant.

As a result, 352 kV (1.0203 pu) is assumed as the voltage schedule of both the Point Beach and Kewaunee generating units. The voltage schedule is consistent with the lowest value of the preferred voltage range of Point Beach (see Attachment H of OP 2A Revision 64). Table 2.4.1 shows the MVAR output (gross) from the Point Beach and Kewaunee units in each scenario.

This re-study used the latest dynamic model data of J022/J023 submitted by the Interconnection Customer to MISO on February 9 2009.

After the units are physically modified and prior to initial unit synchronization, final generator dynamic models should be provided so that operational studies confirming the results of this study can be completed.

Table 2.4.1 – MVAR outputs (gross) from Point Beach and Kewaunee

Stability Study Cases	MVAR outputs (gross) from Point Beach and Kewaunee with 352 kV voltage schedule assumed	
	Low Generation Scenario	High Generation Scenario
Interim 1 (with G834/J023 and without G833/J022, without Kewaunee project)	47.4 MVAR at Point Beach G1 47.4 MVAR at Point Beach G2 30.4 MVAR at Kewaunee	75.6 MVAR at Point Beach G1 75.6 MVAR at Point Beach G2 62.2 MVAR at Kewaunee
Interim 2a (with G833/J022 and G834/J023, without Kewaunee project)	60.1 MVAR at Point Beach G1 60.1 MVAR at Point Beach G2 35.8 MVAR at Kewaunee	85.7 MVAR at Point Beach G1 85.7 MVAR at Point Beach G2 68.2 MVAR at Kewaunee
Interim 2b (with G833/J022 and G834/J023, with Kewaunee project)	58.6 MVAR at Point Beach G1 58.6 MVAR at Point Beach G2 27.3 MVAR at Kewaunee	83.8 MVAR at Point Beach G1 83.8 MVAR at Point Beach G2 59.9 MVAR at Kewaunee

2.4.2 Voltage Sag Criteria

Based on the voltage sag criteria information provided by the Interconnection Customer on March 13 2009, 19 kV and 345 kV bus voltage relay settings at Point Beach were also modeled and monitored during for the dynamic stability study.

Table 2.4.2 – 19 and 345 kV bus voltage relay settings at Point Beach

Bus KV		Drop Out Voltage	Reset Voltage	Minimum Time Delay
19 kV		84.6%	86.2%	1.5 seconds
345 kV	1st criteria	74.3%	75.7%	1.0 second
	2nd criteria	94.1%	95.7%	1.5 seconds

3. Analysis Results

3.1 Power Flow Analysis Results

No new thermal analysis was performed since the plant impact will not change substantially. No significant impact is expected due to additional 12 MW output increase.

Appendix A, which is based on the previous version of the report, was revised using the formula given below:

$$\text{New Required Rating} = \text{Old Required Rating} + (\Delta P \times DF/0.95)$$

Where

ΔP : MW output of new G833/J022 and/or G834/J023 – MW output of old G833/J022 and/or G834/J023

DF: Distribution Factor

3.1.1 Power Factor Capability and Voltage Requirements

No power factor analysis was completed for this interim operation study.

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

3.1.2.1 Base Case Analyses

No new thermal analysis was performed since the plant impact will not change substantially. No significant impact is expected due to additional 12 MW output increase.

Among the four injection limits identified in the previous interim operation report, only the Point Beach-Sheboygan Energy Center and Cypress-Arcadian 345 kV lines are now required. Since L111 (Point Beach-Sheboygan Energy Center 345 kV line) will be uprated as an independent economic benefit project (1120 MVA SE with ATC Project PR03208 assumed in-service), required ratings are given but these are lower than those required for ATC Project PR03208. Therefore, for all practical purposes, the only thermal upgrade required for G833/4 interconnection is the Cypress-Arcadian 345 kV line. Although an upgrade to the Cypress-Arcadian 345 kV line is noted, the overload of this 345 kV line only occurs for specific conditions whereas the interim upgrades needed for stability are required for all hours in the year.

The Elkhart Lake-Saukville and Elkhart Lake-G611 138 kV lines that were originally identified in the previous interim operation study report are no longer injection limits under the new MISO Generation Interconnection Business Practice Manual (BPM). The new MISO generation interconnection procedure does not require transmission reinforcement for thermal issue resulting from an outage of a generation outlet if distribution factor is below 5%.

The two injection upgrades found with 50% system peak load modeled were

- Line L-CYP31, Cypress to Arcadian 345 kV. Approximately 20% of the increased generation will flow on this line, with Line L111 Point Beach to Sheboygan Energy Center 345-kV out of service.
- Line L111, Point Beach to Sheboygan Energy 345 kV. Approximately 24% of the increased generation flowing on this line with L-CYP31 out of service

The revised maximum allowable real power output without system upgrades is presented in Table A.11 in Appendix A.

No study was performed for voltage analysis since no significant impact is expected due to 12 MW increase from the original request (G833/4). Thus, it is expected that no transmission system voltage limits will be violated as a result of the interconnection of J022 and J023. See also Table A.13.

3.1.3 Results of Double Contingencies

3.1.3.1 NERC Category C.3 Contingencies (N-1-1)

Table A.10 in Appendix A was revised due to additional 12 MW output increase.

The results of this analysis are supplied for information only since no operating restrictions will be created for thermal N-1-1 limits. In the day-ahead and real-time market, MISO will utilize a binding constraint procedure to mitigate transmission system overloads. This process may result in curtailment of generation and could affect G833/J022 and G834/J023 for the contingencies noted in this N-1-1 analysis.

3.1.3.2 NERC Category C.5 Contingencies (N-2)

Table A.9 in Appendix A was revised due to additional 12 MW output increase.

NERC Category C.5 events (i.e. two circuits on shared tower) evaluated are shown in Table 3.1.

Table 3.1 – NERC Category C.5 Events Reviewed[1]

Contingency Pairs	
Point Beach – Forest Junction 345-kV (Line 121)	Forest Junction – Meeme – Howards Grove 138-kV (Line 971K51)
Point Beach – Sheboygan Energy 345-kV (Line 111)	Forest Junction – Meeme – Howards Grove 138-kV (Line 971K51)
Point Beach – Sheboygan Energy 345-kV (Line 111)	Howards Grove – PM4 – Holland 138-kV (Line HOLG21)
Sheboygan Energy – Granville 345-kV (Line L-SEC31)	Howards Grove – PM4 – Holland 138-kV (Line HOLG21)
Sheboygan Energy – Granville 345-kV (Line L-SEC31)	Holland – Charter Industrial – Saukville 138-kV (Line 8222)
Cypress – Arcadian 345-kV (Line L-CYP31)	Saukville – Maple – Germantown 138-kV (Line 2642) Germantown – Bark River 138-kV (Line 2661)

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit tower.

3.2 Stability Analysis Results

The stability analysis in this study was done for the following grid disturbance scenarios:

1. Three-phase fault cleared in primary time with an otherwise intact system (NERC Cat. B);
2. Single line-to-ground fault on both circuits of a double circuit structure with an otherwise intact system (NERC Cat. C);
3. Single line-to-ground fault on a bus with an otherwise intact system (NERC Cat. C);
4. Three-phase fault cleared in primary clearing time with a prior outage of any other transmission element (NERC Cat C); and
5. Three-phase fault cleared in delayed clearing time (e.g., breaker failure condition or zone 2 trip due to communication-based protection system failure) with an otherwise intact system (NERC Cat D).

In general, for any grid disturbance, the proposed generation's dynamic response must not degrade the system stability performance. Recent stability analysis of the area near Point Beach, prior to requests G833/J022 and G834/J023, found no stability problems for (a) three-phase fault cleared in primary time with an otherwise intact system, (b) single line-to-ground fault on both circuits of a double circuit structure with an otherwise intact system, and (c) three-phase fault cleared in delayed clearing time with an otherwise intact system.

For the G833/J022 and G834/J023 analysis, it is assumed that the Power System Stabilizers are in-service for all simulations.

For existing system components, actual existing breaker clearing times were simulated. Wherever clearing times faster than existing settings are required, a notation is made. For new system components, the clearing times used in this study are as follows:

Primary Clearing (Local):	3.5 cycles,
Delayed Clearing (Local Breaker Failure):	9.0 cycles,
Primary Clearing (Remote End):	4.5 cycles

A planning margin of 1.0 cycle is required between any studied (simulated/tested) clearing time and the maximum expected clearing time of the system protection equipment (i.e. relay and circuit breaker operation). This 1.0 cycle is added to the local primary clearing time for primary clearing simulations and the local breaker failure time for breaker failure simulations. If a fault is cleared using Independent Pole Operation (IPO) breakers, it is assumed that only one phase of the breaker will fail, so that after the primary clearing time, a three phase to ground fault will become a single line-to-ground fault until it is cleared by the breaker failure relaying. No margin is added to the primary clearing times during breaker failure simulations.

As shown in Appendix B, the disturbances were evaluated using the high and low generation cases described in Table 2.3.1 and 2.3.2. The following three different scenarios were studied for the interim period stability analysis:

- Interim 1 scenario representing the period between May 2010 (after G834/J023) and April 2011 (before G833/J022)

- Interim 2 scenarios representing the period between May 2011 (after G833/J022) and the in-service date of the long term Network Upgrade:
  - o Interim 2A: with G833/4-J022/3 and with existing Kewaunee substation
  - o Interim 2B: with G833/4-J022/3 and with new Kewaunee substation

In addition to examining angular stability of the generation, voltage recovery at Point Beach was also monitored to ensure acceptable performance under Point Beach's requirements. These requirements for 345 kV and 19 kV voltage are listed in Table 2.4.2.

Results of the stability analysis are summarized in Appendix B.

3.2.1 Results of Primary Clearing of Three-Phase Faults Under Intact System Conditions

The 13 faults listed in Table 3.2.1 were simulated as 3-phase faults cleared in primary time under intact system conditions. No stability problem under intact system conditions was identified under Interim 1, 2A or 2B. These results are summarized in Table B.1 in Appendix B.

Table 3.2.1 – Simulated Single Circuit 3-Phase Faults Cleared in Primary Time

Faulted Element	Fault Location	Description
L111	Point Beach 345 kV	Point Beach-Sheboygan Energy 345 kV Line
L121	Point Beach 345 kV	Point Beach-Forest Junction 345 kV Line
L151	Point Beach 345 kV	Point Beach-Fox River 345 kV Line
Q-303	Point Beach 345 kV	Point Beach-Kewaunee 345 kV Line
Q-303	Kewaunee 345 kV	Point Beach-Kewaunee 345 kV Line
R-304	Kewaunee 345 kV	Kewaunee-North Appleton 345 kV Line
L151	Fox River 345 kV	Point Beach-Fox River 345 kV Line
L6832	Fox River 345 kV	Fox River-North Appleton 345 kV Line
971L71	Fox River 345 kV	Fox River-Forest Junction 345 kV Line
L111	Sheboygan Energy 345 kV	Point Beach-Sheboygan Energy 345 kV Line
L-SEC31	Sheboygan Energy 345 kV	Sheboygan Energy-Granville 345 kV Line
L-CYP31	Cypress 345 kV	Cypress-Arcadian 345 kV Line
KEW T10 H	Kewaunee 345 KV	Kewaunee 345/138 kV Transformer

3.2.2 Results of Primary Clearing Three-Phase Faults on Two Circuits of a Multiple Circuit Lines

The transmission system near Point Beach contains eight double circuit lines of concern (Table 3.2.2). Three phase faults were simulated on both ends of the double circuit, for a total of sixteen simulated events. No stability problem under intact system conditions was identified under Interim 1, 2A or 2B. These results are summarized in Table B.2 in Appendix B.

Table 3.2.2 – Simulated Intact System Double Circuit 3-Phase Faults

Fault 1		Fault 2	
Element	Location	Element	Location
111–Pt. Beach -Sheboygan Energy 345 kV	38.5% from POB	971K51-Forest Jct.-Howard's Grove 138 kV	33.9% from FJT
111-Pt. Beach -Sheboygan Energy 345 kV	16.3% from SEC	971K51-Forest Jct.-Howard's Grove 138 kV	6.3% from HOG
111-Pt. Beach -Sheboygan Energy 345 kV	SEC	HOGL21-Howard's Grove-Holland 138 kV	46.8% from HOL
111-Pt. Beach -Sheboygan Energy 345 kV	15.7% from SEC	HOGL21-Howard's Grove-Holland 138 kV	12.3% from HOG

Fault 1	Fault 2		
Element	Location	Element	Location
121-Pt. Beach -Forest Junction 345 kV	FJT	971K51-Forest Jct.-Howard's Grove 138 kV	FJT
121-Pt. Beach -Forest Junction 345 kV	42.3% from FJT	971K51-Forest Jct.-Howard's Grove 138 kV	33.9% from FJT
L-SEC31-Sheboygan Energy-Granville 345 kV	GVL	3431-Granville-Saukville 345 kV	GVL
L-SEC31-Sheboygan Energy-Granville 345 kV	26.7% from GVL	3431-Granville-Saukville 345 kV	25.3% from SAU
L-SEC31-Sheboygan Energy-Granville 345 kV	43.5% from GVL	8231-Sukville-Barton 138 kV	36.4% from BRT
L-SEC31-Sheboygan Energy-Granville 345 kV	48.3% from GVL	8231-Sukville-Barton 138 kV	36.4% from SAU
L-CYP31-Cypress-Arcadian 345 kV	32.0% from ADN	2642-Saukville-Germantown 138 kV	34.2% from SAU
L-CYP31-Cypress-Arcadian 345 kV	16.6% from ADN	2642-Saukville-Germantown 138 kV	GER
L-CYP31-Cypress-Arcadian 345 kV	10.8% from ADN	2661-Germantown-Bark River 138 kV	31.5% from GER
L-CYP31-Cypress-Arcadian 345 kV	16.6% from ADN	2661-Germantown-Bark River 138 kV	GER
L-CYP31-Cypress-Arcadian 345 kV	10.8% from ADN	9911-Granville-Arcadian 345 kV	45.4% from GVL
L-CYP31-Cypress-Arcadian 345 kV	ADN	9911-Granville-Arcadian 345 kV	ADN

3.2.3 Results of Primary Clearing Three-Phase Faults During a Prior Outage

Primary fault clearing under prior outage conditions simulated all of the events listed in Table 3.2.1 under the outages listed in Table 3.2.3.

Table 3.2.3 – Simulated Prior Outage Elements

Element	Description
L111	Point Beach-Sheboygan Energy 345 kV Line
L121	Point Beach-Forest Junction 345 kV Line
L151	Point Beach-Fox River 345 kV Line
Q-303	Point Beach-Kewaunee 345 kV Line
R-304	Kewaunee-North Appleton 345 kV Line
L6832	Fox River-North Appleton 345 kV Line
971L71	Fox River-Forest Junction 345 kV Line
L-SEC31	Sheboygan Energy -Granville 345 kV Line
L-CYP31	Cypress-Arcadian 345 kV Line
NAPL71	North Appleton-Werner West 345 kV Line
971L51	Forest Junction-Cypress 345 kV Line
Y-311	North Appleton-Fitzgerald 345 kV Line
T10	Kewaunee 345/138 kV Transformer
POB 1-2, 2-3, 3-4, 4-5	Point Beach 345 kV Breakers 1-2, 2-3, 3-4, 4-5
FOX 1-2, 2-3, 3-4, 4-5, 5-6, 6-1	Fox River 345 kV Breakers 1-2, 2-3, 3-4, 4-5, 5-6, 6-1
SEC BT12, BT23, BT36, BT16	Sheboygan Energy 345 kV Breakers BT12, BT23, BT36, BT16
CYP BT16, BT12, BT56	Cypress 345 kV Breakers BT16, BT12, BT56
FJT 1-2, 2-3, 4-5, 5-6, 7-1	Forest Junction 345 kV Breakers 1-2, 2-3, 4-5, 5-6, 7-1

Interim 1 (with G834/J023, with existing Kewaunee):

For interim 1, three events with generation instability were found for prior outage scenarios (Table B.3 in Appendix B). These events could be eliminated by one or more of the mitigation options listed below. Specific mitigation options for each event can be found in Table B.3 in Appendix B.

- North Appleton R-304 breaker replacement with 2 cycle circuit breaker
- Point Beach G1 reduction under prior outage conditions

To minimize generation restriction under Point Beach 345-kV bus 2-3 prior outage condition in anticipation of L121 fault, it is recommended to take the bus tie out of service during a Point Beach G1 refueling outage window. Otherwise, an operating restriction will be needed to limit Point Beach G1 to 580 MW (gross) during the POB 2-3 prior outage in anticipation of a L121 fault at Point Beach.

With the North Appleton R-304 breaker replaced, Point Beach G1 will need to be restricted to 560 MW (gross) under the prior outage of 6832 (North Appleton-Fox River 345 kV line) in anticipation of R-304 fault at Kewaunee

Interim 2A (with G834/J023 and G833/J022, with existing Kewaunee):

For interim 2A, eleven events with generation instability were found for prior outage scenarios (Table B.3 in Appendix B). These events could be eliminated by one or more of the mitigation options listed below. Specific mitigation options for each event can be found in Table B.3 in Appendix B.

- North Appleton R-304 breaker replacement with 2 cycle circuit breaker, which is already required for Interim 1.
- Point Beach G1 and/or G2 reduction under prior outage conditions

With the stability upgrades and thermal upgrades assumed in-service, Point Beach G1 and/or G2 will still need to be restricted during the following prior outage conditions in anticipation of a next critical contingency:

- G2 at 620 MW (gross) under the prior outage of 121 (Point Beach-Forest Junction 345 kV line)
- G2 at 620 MW (gross) under the prior outage of 151 (Point Beach-Fox River 345 kV line)
- G2 at 600 MW (gross) under the prior outage of R-304 (Kewaunee-North Appleton 345 kV line)
- Both G1 and G2 at 540 MW (gross) under the prior outage of 6832 (North Appleton-Fox River 345 kV line)
- G2 at 580 MW (gross) under the prior outage of L-SEC31 (Sheboygan Energy Center-Granville 345 kV line)
- G1 at 580 MW (gross) under the prior outage of Point Beach Bus Tie 2-3
- G2 at 620 MW (gross) under the prior outage of Point Beach Bus Tie 4-5

Interim 2B (with G834/J023 and G833/J022, with new Kewaunee Substation):

The Kewaunee Bus Reconfiguration project is assumed in-service for Interim 2B. The planned Kewaunee Bus Reconfiguration project will replace the existing 3 cycle non-IPO breakers at Kewaunee 345 kV with new 2 cycle IPO breakers. According to ATC System Protection, 3.5 cycles, 8.5 cycles, and 4.5 cycles will be achieved with the Kewaunee project as local primary, local delayed(breaker failure), and remote primary time respectively. The new clearing times at Kewaunee were considered for the simulations discussed in this section. The original 2011 in-service date of the project may need to be deferred roughly by 18 months due to project schedule constraints.

For interim 2B, two events with generation instability were found for prior outage scenarios (Table B.3 in Appendix B). These events could be eliminated by one or more of the mitigation options listed below. Specific mitigation options for each event can be found in Table B.3 in Appendix B.

- North Appleton R-304 breaker replacement with 2 cycle circuit breaker, which is already required for Interim 1 and 2A.
- Point Beach G1 and G2 reduction under prior outage conditions

With the stability upgrades and thermal upgrades assumed in-service, Point Beach G1 and/or G2 will still need to be restricted during the following prior outage conditions in anticipation of a next critical contingency:

- G2 at 600 MW (gross) under prior outage condition of 6832 (North Appleton-Fox River 345 kV line)
- G1 at 580 MW (gross) under prior outage condition of Point Beach Bus Tie 2-3

3.2.4 Results of Three-Phase Fault Delayed (Breaker Failure) Clearing under Intact System Conditions

Delayed (breaker failure) 3-phase fault clearing under otherwise intact system was simulated for the events listed in Table 3-2-4.

Table 3-2-4 – Simulated 3-Phase Faults Cleared in Delayed Time

Faulted Element	Fault Location	Description
L111	Point Beach 345 kV	Point Beach-Sheboygan Energy 345 kV Line
L151	Point Beach 345 kV	Point Beach-Fox River 345 kV Line
Q-303	Point Beach 345 kV	Point Beach-Kewaunee 345 kV Line
R-304	North Appleton 345 kV	North Appleton-Kewaunee 345 kV Line
L121	Forest Junction 345 kV	Forest Junction-Point Beach 345 kV Line
971L51	Forest Junction 345 kV	Forest Junction-Cypress 345 kV Line
971L71	Forest Junction 345 kV	Forest Junction-Fox River 345 kV Line
L151	Fox River 345 kV	Point Beach-Fox River 345 kV Line
L6832	Fox River 345 kV	Fox River-North Appleton 345 kV Line
971L71	Fox River 345 kV	Fox River-Forest Junction 345 kV Line
L111	Sheboygan Energy 345 kV	Point Beach-Sheboygan Energy 345 kV Line
L-SEC31	Sheboygan Energy 345 kV	Sheboygan Energy-Granville 345 kV Line
L-CYP31	Cypress 345 kV	Cypress-Arcadian 345 kV Line
971L51	Cypress 345 kV	Cypress-Forest Junction 345 kV Line
Q-303*	Kewaunee 345 kV	Point Beach-Kewaunee 345 kV Line
R-304*	Kewaunee 345 kV	Kewaunee-North Appleton 345 kV Line
KEW T10 H*	Kewaunee 345 KV	Kewaunee 345/138 kV Transformer

*Breaker Failure Scenario Only Possible with New Kewaunee Bus Configuration

Interim 1 (with G834/J023, with existing Kewaunee):
No stability problems were found due to breaker failure scenarios evaluated.

Interim 2A (with G834/J023 and G833/J022, with existing Kewaunee):
For interim 2A, three events with generation instability were found for breaker failure scenarios (Table B.4 in Appendix B). These events could be eliminated by the mitigation options listed below. More details can be found in Table B.4 in Appendix B.

- For fault on L111 at Point Beach with breaker failure,
    - Point Beach L111 SBF Breaker Failure Relay replacement with an SEL-352 and the existing Line 111 SEL-221F backup relay replacement with an SEL-421.
- For fault on L151 at Point Beach with breaker failure,
    - Point Beach L151 SBF Breaker Failure Relay replacement with an SEL-352 and the existing Line 151 SEL-221F backup relay replacement with an SEL-421
- For fault on Q-303 at Point Beach with breaker failure,
    - Point Beach 345 kV Circuit Breaker Addition in series with the existing Q-303 Circuit Breaker to isolate line fault in primary time[2]

With the stability upgrades and thermal upgrades assumed in-service, generation restriction at Point Beach G1 and G2 will not be needed under intact conditions.

Interim 2B (with G834/J023 and G833/J022, with new Kewaunee Substation):
For interim 2B, four events with generation instability were found for breaker failure scenarios (Table B.4 in Appendix B). These events could be eliminated by the mitigation options listed below. More details can be found in Table B.4 in Appendix B.

- For fault on L111 at Point Beach with breaker failure,
    - Point Beach L111 SBF Breaker Failure Relay replacement with an SEL-352 and the existing Line 111 SEL-221F backup relay replacement with an SEL-421, which is already required for Interim 2A
- For fault on L151 at Point Beach with breaker failure,
    - Point Beach L151 SBF Breaker Failure Relay replacement with an SEL-352 and the existing Line 151 SEL-221F backup relay replacement with an SEL-421, which is already required for Interim 2A
- For fault on Q-303 at Point Beach with breaker failure,
    - Point Beach 345 kV Circuit Breaker Addition in series with the existing Q-303 Circuit Breaker to isolate line fault in primary time, which is already required for Interim 2A
- For fault on R-304 at Kewaunee with breaker failure,
    - North Appleton R-304 Circuit Breaker Replacement with 2 cycle Circuit Breaker implemented for Independent Pole Operation, which is already required for Interim 1 and Interim 2A.

[2] It is proposed if installing a series breaker is feasible. If it is not feasible, replace existing Position 131 SBF breaker failure relay with an SEL-352, and replace the existing Line Q-303 SEL-221F backup relay with an SEL-421 in order to improve existing breaker failure clearing time. With the relays upgraded, Point Beach G2 will need to be restricted to 600 MW at all times (with 8.0 cycle BF clearing time, previously 580 MW with 8.25 BF clearing time) from May 2011 until completion of the Kewaunee reconfiguration project (roughly 18 months)

With the stability upgrades and thermal upgrades assumed in-service, generation restriction at Point Beach G1 and G2 will not be needed under intact conditions.

3.2.5 Point Beach Bus, Generator Step Up and Auxiliary Transformer Faults

3.2.5.1 Point Beach 345 kV Bus Fault Clearing

Interim 1 (with G834/J023, with existing Kewaunee):
No stability problems were found due to breaker failure scenarios evaluated.

Interim 2A (with G834/J023 and G833/J022, with existing Kewaunee):
For interim 2A, one event with generation instability was found (Table B.5 in Appendix B). The event could be eliminated by the mitigation option listed below. More details can be found in Table B.5 in Appendix B.

- For single-line-to-ground fault at Point Beach 345 kV bus 2 with breaker failure at the bus tie 2-3,
    - Relay setting change (without Breaker Failure relay replacement) for failure of Point Beach Bus Tie 2-3 to no more than 11 cycle total breaker failure clearing time for bus faults

Interim 2B (with G834/J023 and G833/J022, with new Kewaunee Substation):
No stability problems were found due to breaker failure scenarios evaluated.

3.2.5.2 Generator Step-Up (GSU) Transformer Fault Clearing (T1X01 and T2X01)

No stability problems were found in the three interim scenarios due to single-line-to-ground (intact system with delayed clearing) and three phase (primary clearing under both intact and prior outage conditions) GSU faults (see Tables B.6 and B.8 in Appendix B).

3.2.5.3 Auxiliary Transformer Fault Clearing (T1X03 and T2X03)

No stability problems were found in the three interim scenarios due to single-line-to-ground (intact system with delayed clearing) auxiliary transformer faults (see Table B.7 in Appendix B).

For three phase (primary clearing under both intact and prior outage conditions) T1X03 and T2X03 faults,

- Interim 1: no stability problems were found
- Interim 2A: 11 events with generation instability were found (Table B.9 in Appendix B). Generator stability can be maintained for all N-1 conditions if T1X03 clearing time is reduced to 4.0 cycles and T2X03 clearing time is reduced to 4.0 cycles.
- Interim 2B: 10 events with generation instability were found (Table B.9 in Appendix B). Generator stability can be maintained for all N-1 conditions if T1X03 clearing time is reduced to 4.0 cycles and T2X03 clearing time is reduced to 4.0 cycles.

3.2.6 Unit Outage

Kewaunee and Point Beach unit outages were also simulated (Table B.10 in Appendix B) and no stability problems were found for the three interim scenarios.

3.2.7 Stability Results Summary

The improvements in system stability required for G833/J022 and G834/J023 are provided by reductions in fault clearing times described in this report.

- For the G834/J023 interconnection in 2010, the following stability upgrades are required:
  a. Improve primary clearing time at R-304 North Appleton terminal for R-304 fault at Kewaunee:
     - Replace the existing 3 cycle R-304 circuit breaker at North Appleton with new 2 cycle IPO circuit breaker to reduce the existing 6.5 cycle clearing time to 4.5 cycles to permit additional MW output from Point Beach unit #1 under certain prior outage conditions.
     - Required clearing times for R-304 fault at Kewaunee:
       - From the existing 4.5 cycle local primary and 6.5 cycle remote primary,
       - To 4.5 cycle local primary and **4.5** cycle remote.

- For the G833/J022 interconnection in 2011, the following stability upgrades are required:
  b. Improve breaker failure clearing time at L111 Point Beach terminal for L111 fault at Point Beach:
     - Replace the existing Point Beach L111 SBF breaker failure relay with an SEL-352, and replace the existing Line 111 SEL-221F backup relay with an SEL-421.
     - Required clearing times for L111 fault at Point Beach:
       - From the existing 3.5 cycle local primary, 9.0 cycle local delayed, and 4.5 cycle remote primary
       - To 3.5 cycle local primary, **8.0** cycle local delayed, and 4.5 cycle remote primary

  c. Improve breaker failure clearing time at L151 Point Beach terminal for L151 fault at Point Beach:
     - Replace the existing Point Beach L151 SBF breaker failure relay with an SEL-352, and replace the existing Line 151 SEL-221F backup relay with an SEL-421.
     - Required clearing times for L151 fault at Point Beach:
       - From the existing 3.5 cycle local primary, 9.0 cycle local delayed, and 4.5 cycle remote primary
       - To 3.5 cycle local primary, **8.5** cycle local delayed (**8.0** cycle achieved with the upgrade), and 4.5 cycle remote primary

  d. Isolate Q-303 fault at Point Beach in primary time:
     - Add a new Point Beach 345 kV Circuit Breaker in series with the existing Q-303 Circuit Breaker. The upgrade will clear a Q-303 breaker failure at Point Beach in primary time.
     - With the series breaker addition, achieved clearing times for Q-303 fault at Point Beach:

- From the existing 3.5 cycle local primary, **9.0** cycle local delayed, and 6.5 cycle remote primary (4.5 cycle remote primary with Kewaunee bus reconfiguration project in-service)
- To 3.5 cycle local primary, **3.5** cycle local delayed (cleared in primary time), and 6.5 cycle remote primary (4.5 cycle remote primary with Kewaunee bus reconfiguration project in-service)

e. Improve breaker failure clearing time of Bus Tie 2-3 for a single-line to ground fault on Point Beach Bus 2:
   - Change Relay setting (without Breaker Failure relay replacement) for Failure of Point Beach Bus Tie 2-3 to no more than 11 cycle total breaker failure clearing time for bus faults.
   - Required clearing times for single line to ground fault on Point Beach bus 2 with failure of bus tie breaker 23:
     - From the existing 4.75 cycle local primary and **12.5** cycle local delayed
     - To 4.75 cycle local primary and **11.0** cycle local delayed

f. Upgrade back-up relay for better maintenance and operating flexibility during a L121 relay outage at Point Beach.
   - Replace L121 SEL-221F backup relay with SEL-421 to provide better maintenance and operating flexibility during a L121 relay outage.

With the stability upgrades assumed in-service and the Minimum Excitation Limiter settings for Point Beach and Kewaunee units modified, generation restrictions identified for each interim period are

- During Interim 1 period (May 2010 after G834/J023 – April 2011 before G833/J022)
  i. G1 at 560 MW (gross) under prior outage condition of 6832 (North Appleton-Fox River 345 kV line)
  ii. G1 at 580 MW (gross) under prior outage condition of Point Beach Bus Tie 2-3

- During Interim 2A period (May 2011 after G833/J022 – beyond without Kewaunee project)
  i. G2 at 620 MW (gross) under prior outage of 121 (Point Beach-Forest Junction 345 kV line)
  ii. G2 at 620 MW (gross) under prior outage of 151 (Point Beach-Fox River 345 kV line)
  iii. G2 at 600 MW (gross) under prior outage of R304 (Kewaunee-North Appleton 345 kV line)
  iv. Both G1 and G2 at 540 MW (gross) under prior outage of 6832 (North Appleton-Fox River 345 kV line)
  v. G2 at 580 MW (gross) under prior outage of SEC31 (Sheboygan Energy Center-Granville 345 kV line)
  vi. G1 at 580 MW (gross) under prior outage of Point Beach Bus Tie 2-3
  vii. G2 at 620 MW (gross) under prior outage of Point Beach Bus Tie 4-5

- During Interim 2B period (May 2011 after G833/J022 – beyond <u>with</u> Kewaunee project)

i. G2 at 600 MW (gross) under prior outage condition of 6832 (North Appleton-Fox River 345 kV line)
ii. G1 at 580 MW (gross) under prior outage condition of Point Beach Bus Tie 2-3

Appendix A: Power Flow Analysis Results

***Note that no thermal analysis was performed as described in this report. However, the tables in Appendix A were updated based on the formula shown in Section 3.1 and the new MISO Generation Interconnection Procedures.**

Scenarios for Thermal Analysis

Base Case	Scenario #	Assumption	Comment
S2010 at 100% of peak load conditions	1	G834/J023 at 100%, G833/J022 offline, All competing generators at 100% Without 2011 Kewaunee project (representing 2010-2011)	Note: For each scenario, cases with "***before***" and "***after***" G-T were studied to assess the impact of the new generators.
	2	G834/J023 at 100%, G833/J022 offline, All competing generators at 20% Without 2011 Kewaunee project (representing 2010-2011)	
	3	G834/J023 at 100%, G833/J022 at 100% All competing generators at 20% With 2011 Kewaunee project (representing 2011 and beyond)	
	4	G834/J023 at 100%, G833/J022 at 100% All competing generators at 100% With 2011 Kewaunee project (representing 2011 and beyond)	
S2010 at 50% of peak load conditions	5	G834/J023 at 100%, G833/J022 offline All competing generators at 100% Without 2011 Kewaunee project (representing 2010-2011)	
	6	G834/J023 at 100%, G833/J022 offline All competing generators at 20% Without 2011 Kewaunee project (representing 2010-2011)	
	7	G834/J023 at 100%, G833/J022 at 100% All competing generators at 67% With 2011 Kewaunee project (representing 2011 and beyond)	
	8 (N-1 only)	G834/J023 at 100%, G833/J022 at 100% All competing generators at 20% With 2011 Kewaunee project (representing 2011 and beyond)	

Load and Generation Level in Each Scenario

Scenario	Case	Load level	G834	G833	All competing generation	2011 Kewaunee project
Scenario 1	Summer 2010	100%	100%	offline	100%	No
Scenario 2		100%	100%	offline	20%	No
Scenario 3		100%	100%	100%	20%	Yes
Scenario 4		100%	100%	100%	100%	Yes
Scenario 5		50%	100%	offline	100%	No
Scenario 6		50%	100%	offline	20%	No
Scenario 7		50%	100%	100%	67%	Yes
Scenario 8		50%	100%	100%	20%	Yes

Table A.1 – Identified Thermal Violations in Scenario 1 Due to G834/J023 Summer 2010 (100% Load) Delivery to MISO for NERC Category A and B events (TDF>5%) G833/J022 offline, All Competing Generation at 100%, without 2011 Kewaunee Projects

Limiting Element	Existing Rating (MVA)[1]	Required Rating (MVA)[1,2]	Worst Contingency	TDF (%)	Case	Injection Limit	Solution Planned
Bain 345/138-kV transformer	382 SE	452.4 SE	Pleasant Prairie 345-kV bus tie 2-3	6.2	2010S	No	No[3]

Notes:
1. SN – Summer Normal, SE – Summer Emergency, WN – Winter Normal and WE – Winter Emergency.
2. Includes provision for 5% TRM. The required ratings are estimated values using the formula described in Section 3.1.
3. An operating guide is available to mitigate the Bain 345/138 kV transformer for Pleasant Prairie 345-kV bus tie outage.

Table A.2 – Identified Thermal Violations in Scenario 2 Due to G834/J023 Summer 2010 (100% Load) Delivery to MISO for NERC Category A and B events (TDF>5%) G833/J022 offline, All Competing Generation at 20%, without 2011 Kewaunee Projects

Limiting Element	Existing Rating (MVA)[1]	Required Rating (MVA)[1,2]	Worst Contingency	TDF (%)	Case	Injection Limit	Solution Planned
Bain 345/138-kV transformer	382 SE	423.4 SE	Pleasant Prairie 345-kV bus tie 2-3	6.3	2010S	No	No[3]

Notes:
1. SN – Summer Normal, SE – Summer Emergency, WN – Winter Normal and WE – Winter Emergency.
2. Includes provision for 5% TRM. The required ratings are estimated values using the formula described in Section 3.1.
3. An operating guide is available to mitigate the Bain 345/138 kV transformer for Pleasant Prairie 345-kV bus tie outage.

Table A.3 – Identified Thermal Violations in Scenario 3 Due to G833/J022 (Assume G834/J023 online) Summer 2010 (100% Load) Delivery to MISO for NERC Category A and B events (TDF>5%) G833/J022 at 100%, All Competing Generation at 20%, with 2011 Kewaunee Projects

Limiting Element	Existing Rating (MVA)[1]	Required Rating (MVA)[1,2]	Worst Contingency	TDF (%)	Case	Injection Limit	Solution Planned
Bain 345/138-kV transformer	382 SE	429.8 SE	Pleasant Prairie 345-kV bus tie 2-3	6.3	2010S	No	No[3]

Notes:
1. SN – Summer Normal, SE – Summer Emergency, WN – Winter Normal and WE – Winter Emergency.
2. Includes provision for 5% TRM. The required ratings are estimated values using the formula described in Section 3.1.
3. An operating guide is available to mitigate the Bain 345/138 kV transformer for Pleasant Prairie 345-kV bus tie outage.

Table A.4 – Identified Thermal Violations in Scenario 4 Due to G833/J022 (Assume G834/J023 online) Summer 2010 (100% Load) Delivery to MISO for NERC Category A and B events (TDF>5%) G833/J022 at 100%, All Competing Generation at 100%, with 2011 Kewaunee Projects

Limiting Element	Existing Rating (MVA) [1]	Required Rating (MVA)[1,2]	Worst Contingency	TDF (%)	Case	Injection Limit	Solution Planned
Bain 345/138-kV transformer	382 SE	458.8 SE	Pleasant Prairie 345-kV bus tie 2-3	6.3	2010S	No	No[3]

Notes:

1. SN – Summer Normal, SE – Summer Emergency, WN – Winter Normal and WE – Winter Emergency.
2. Includes provision for 5% TRM. The required ratings are estimated values using the formula described in Section 3.1.
3. An operating guide is available to mitigate the Bain 345/138 kV transformer for Pleasant Prairie 345-kV bus tie outage.

Table A.5 – Identified Thermal Violations in Scenario 5 Due to G834/J023 Summer 2010 (50% Load) Delivery to MISO for NERC Category A and B events (TDF>5%) G833/J022 offline, All Competing Generation at 100%, without 2011 Kewaunee Projects

Limiting Element	Existing Rating (MVA) [1]	Required Rating (MVA)[1,2]	Worst Contingency	TDF (%)	Case	Injection Limit	Solution Planned
Point Beach-Sheboygan Energy Center 345-kV line	488 SE	569.5 SE	Cypress-Arcadian 345-kV line	23.4	2010S	Yes	No[3]
Cypress-Arcadian 345-kV line	488 SE	547.3 SE	Point Beach-Sheboygan Energy Center 345-kV line	19.8	2010S	Yes	No[4]

Notes:

1. SN – Summer Normal, SE – Summer Emergency, WN – Winter Normal and WE – Winter Emergency.
2. Includes provision for 5% TRM. The required ratings are estimated values using the formula described in Section 3.1.
3. Line rating is limited by the clearance of the existing line (51.07 mile, 120 F for SN/SE, 2156 ACSR). Required rating should be able to be met by increasing line clearance.
4. Line rating is limited by the clearance of the existing line (79.2 mile, 120 F for SN/SE, 2156 ACSR). Required rating should be able to be met by increasing line clearance.

Table A.6 – Identified Thermal Violations in Scenario 6 Due to G834/J023 Summer 2010 (50% Load) Delivery to MISO for NERC Category A and B events (TDF>5%) G833/J022 offline, All Competing Generation at 20%, without 2011 Kewaunee Projects

Limiting Element	Existing Rating (MVA) [1]	Required Rating (MVA)[1,2]	Worst Contingency	TDF (%)	Case	Injection Limit	Solution Planned
Point Beach-Sheboygan Energy Center 345-kV line	488 SE	499.52 SE	Cypress-Arcadian 345-kV line	24.0	2010S	Yes	No[3]

Notes:

1. SN – Summer Normal, SE – Summer Emergency, WN – Winter Normal and WE – Winter Emergency.
2. Includes provision for 5% TRM. The required ratings are estimated values using the formula described in Section 3.1.
3. Line rating is limited by the clearance of the existing line (51.07 mile, 120 F for SN/SE, 2156 ACSR). Required rating should be able to be met by increasing line clearance.

Table A.7 – Identified Thermal Violations in Scenario 7 Due to G833/J022 (Assume G834/J023 online) Summer 2010 (50% Load) Delivery to MISO for NERC Category A and B events (TDF>5%) G833/J022 at 100%, All Competing Generation at 67%, with 2011 Kewaunee Projects

Limiting Element	Existing Rating (MVA) [1]	Required Rating (MVA) [1,2]	Worst Contingency	TDF (%)	Case	Injection Limit	Solution Planned
Point Beach-Sheboygan Energy Center 345-kV line	488 SE	563.0 SE	Cypress-Arcadian 345-kV line	23.2	2010S	Yes	No[3]
Cypress-Arcadian 345-kV line	488 SE	529.5 SE	Point Beach-Sheboygan Energy Center 345-kV line	19.9	2010S	Yes	No[4]

Notes:
1. SN – Summer Normal, SE – Summer Emergency, WN – Winter Normal and WE – Winter Emergency.
2. Includes provision for 5% TRM. The required ratings are estimated values using the formula described in Section 3.1.
3. Line rating is limited by the clearance of the existing line (51.07 mile, 120 F for SN/SE, 2156 ACSR). Required rating should be able to be met by increasing line clearance.
4. Line rating is limited by the clearance of the existing line (79.2 mile, 120 F for SN/SE, 2156 ACSR). Required rating should be able to be met by increasing line clearance.

Table A.8 – Identified Thermal Violations in Scenario 8 Due to G833/J022 (Assume G834/J023 online) Summer 2010 (50% Load) Delivery to MISO for NERC Category A and B events (TDF>5%) G833/J022 at 100%, All Competing Generation at 20%, with 2011 Kewaunee Projects

Limiting Element	Existing Rating (MVA) [1]	Required Rating (MVA) [1,2]	Worst Contingency	TDF (%)	Case	Injection Limit	Solution Planned
Point Beach-Sheboygan Energy Center 345-kV line	488 SE	522.0 SE	Cypress-Arcadian 345-kV line	23.5	2010S	Yes	No[3]
Cypress-Arcadian 345-kV line	488 SE	474.6 SE	Point Beach-Sheboygan Energy Center 345-kV line	20.3	2010S	No	No[4]

Notes:
1. SN – Summer Normal, SE – Summer Emergency, WN – Winter Normal and WE – Winter Emergency.
2. Includes provision for 5% TRM. The required ratings are estimated values using the formula described in Section 3.1.
3. Line rating is limited by the clearance of the existing line (51.07 mile, 120 F for SN/SE, 2156 ACSR). Required rating should be able to be met by increasing line clearance.
4. Line rating is limited by the clearance of the existing line (79.2 mile, 120 F for SN/SE, 2156 ACSR). Required rating should be able to be met by increasing line clearance.

Table A.9 – Identified Thermal Violations Under Select NERC Category C.5 events In Each Scenario With Delivery to MISO for NERC Category C.5 events (TDF>5%)

Limiting Element	Existing Rating[1]	Required Rating[1,2]	Worst Double Contingency	TDF (%)	Scenario	Potential Solution Identified
Cypress-Arcadian 345-kV line	488 SE	570.3 SE	Point Beach-Sheboygan Energy Center 345-kV line Howards Grove-Plymouth #4-Holland 138-kV line	20.61	Scenario 5	No[3]
		551.6 SE		20.73	Scenario 7	
Point Beach-Sheboygan Energy Center 345-kV line	488 SE	571.5 SE	Cypress-Arcadian 345-kV line Saukville-Maple-Germantown-Bark River 138-kV line	23.67	Scenario 5	No[4]
		501.5 SE		24.08	Scenario 6	
		564.9 SE		23.23	Scenario 7	

1. SN – Summer Normal, SE – Summer Emergency, WN – Winter Normal and WE – Winter Emergency.
2. Includes provision for 5% TRM. The required ratings are estimated values using the formula described in Section 3.1.
3. Line rating is limited by the clearance of the existing line (79.2 mile, 120 F for SN/SE, 2156 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
4. Line rating is limited by the clearance of the existing line (51.07 mile, 120 F for SN/SE, 2156 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.

Table A.10 – Identified Thermal Violations under Select NERC Category C.3 events In Each Scenario With Delivery to MISO for NERC Category C.3 events (TDF>5%)

Limiting Element	Existing Rating[1]	Required Rating[1,2]	Worst Double Contingency	TDF (%)	Scenario	Potential Solution Identified
Kewaunee-North Appleton 345-kV line	1071 SE	1159 SE	Granville-Sheboygan Energy Center 345-kV line North Appleton-Fox River 345-kV line	42.45	scenario 1	No[3]
Point Beach-Forest Junction 345-kV line	883 SE	1068 SE	Point Beach 345-kV bus 4-5 North Appleton-Fox River 345-kV line	56.73	scenario 1	No[4]
		1076 SE		56.63	scenario 2	
		1057 SE		54.06	scenario 3	
		1058 SE		54.27	scenario 4	
		959 SE		57.24	scenario 5	
		973 SE		54.79	scenario 7	
		964 SE	Point Beach-Fox River 345-kV line North Appleton-Kewaunee 345-kV line	57.04	scenario 6	
Forest Junction 345/138-kV transformer #1	675 SE	688 SE	Forest Junction 345/138-kV transformer #2 North Appleton-Fox River 345-kV line	15.92	scenario 1	No[5]
		745 SE		15.71	scenario 2	
		724 SE		15.10	scenario 3	
Forest Junction 345/138-kV transformer #2	675 SE	687 SE	Forest Junction 345/138-kV transformer #1 North Appleton-Fox River 345-kV line	15.92	scenario 1	No[5]
		744 SE		15.71	scenario 2	
		724 SE		15.00	scenario 3	
Point Beach-Sheboygan Energy Center 345-kV line	488 SE	639 SE	Point Beach 345-kV bus 2-3 Point Beach-Forest Junction 345-kV line	97.04	scenario 1	No[6]
		639 SE		97.14	scenario 2	
		639 SE		97.35	scenario 6	
		681 SE	Cypress-Arcadian 345-kV line Edgewater-Cedarsauk 345-kV line	24.18	scenario 5	
		674 SE		23.85	scenario 7	
Cypress-Arcadian 345-kV line	488 SE	546 SE	Granville-Sheboygan Energy Center 345-kV line North Appleton-Fox River 345-kV line	23.37	scenario 1	No[7]
		568 SE		23.44	scenario 4	
		651 SE	Point Beach 345-kV bus 1-2 Edgewater-Cedarsauk 345-kV line	21.12	scenario 5	
		556 SE		22.04	scenario 6	
		635 SE		21.15	scenario 7	

Limiting Element	Existing Rating[1]	Required Rating[1,2]	Worst Double Contingency	TDF (%)	Scenario	Potential Solution Identified
Granville 345/138-kV transformer #1	478 SE	520 SE	Cypress-Arcadian 345-kV line Granville 345-kV bus tie 1-2	16.84	scenario 1	No[8]
		575 SE		16.84	scenario 5	
		513 SE		17.24	scenario 6	
		567 SE		16.67	scenario 7	
Granville 138-kV bus tie 5-6	539 SE	594 SE		23.47	scenario 5	No[9]
		580 SE		22.19	scenario 7	
Neevin-Woodenshoe 138-kV line	332 SE	400 SE	Granville-Sheboygan Energy Center 345-kV lineNorth Appleton-Fitzgerald 345-kV line	13.98	scenario 1	No[10]
		342 SE		13.88	scenario 2	
		357 SE		13.65	scenario 3	
		415 SE		14.06	scenario 4	
		342 SE		14.90	scenario 5	
		335 SE	Point Beach-Sheboygan Energy Center 345-kV line North Appleton-Fitzgerald 345-kV line	14.48	scenario 7	
Kewaunee 345/138-kV transformer T10	390 SE	410 SE	North Appleton-Fox River 345-kV line North Appleton-Kewaunee 345-kV line	13.57	scenario 1	No[11]
		449 SE		13.37	scenario 2	
Forest Junction-Kaukauna Central Tap 138-kV line	293 SE	407 SE		10.51	scenario 1	No[12]
		359 SE		10.41	scenario 2	
		364 SE		10.10	scenario 3	
		413 SE		10.52	scenario 4	
Kaukauna Central-Kaukauna Central Tap 138-kV line	191 SE	194 SE		5.73	scenario 3	No[13]
		220 SE		5.94	scenario 4	
Kaukauna Central Tap-Meadows 138-kV line	169 SE	190 SE		4.48	scenario 4	No[14]

Limiting Element	Existing Rating[1]	Required Rating[1,2]	Worst Double Contingency	TDF (%)	Scenario	Potential Solution Identified
Mears Corners-Woodenshoe 138-kV line	287 SE	317 SE	Granville-Sheboygan Energy Center 345-kV line North Appleton-Fitzgerald 345-kV line	13.88	scenario 1	No[15]
		332 SE		13.85	scenario 4	
		302 SE	Point Beach 345-kV bus 1-2 North Appleton-Fitzgerald 345-kV line	14.29	scenario 5	
		294 SE	Point Beach-Sheboygan Energy Center 345-kV line North Appleton-Fitzgerald 345-kV line	14.27	scenario 7	
Sunset Point-Mears Corners 138-kV line	287 SE	302 SE	Granville-Sheboygan Energy Center 345-kV line North Appleton-Fitzgerald 345-kV line	13.75	scenario 4	No[16]
Lake Park-Darboy 138-kV line	293 SE	388 SE	North Appleton-Fox River 345-kV line North Appleton-Kewaunee 345-kV line	9.39	scenario 1	No[17]
		345 SE		9.39	scenario 2	
		350 SE		9.27	scenario 3	
		393 SE		9.38	scenario 4	
Darboy-Forest Junction 138-kV line	293 SE	401 SE		9.39	scenario 1	
		366 SE		16.22	scenario 2	
		372 SE		16.46	scenario 3	
		407 SE		9.38	scenario 4	
Lake Park-City Limits 138-kV line	293 SE	342 SE		9.49	scenario 1	No[18]
		299 SE		9.59	scenario 2	
		304 SE		9.48	scenario 3	
		347 SE		9.58	scenario 4	
Kewaunee-East Krok 138-kV line	287 SE	338 SE		8.88	scenario 1	No[19]
		318 SE		8.78	scenario 2	
		394 SE		10.83	scenario 3	
		407 SE		10.83	scenario 4	

Limiting Element	Existing Rating[1]	Required Rating[1,2]	Worst Double Contingency	TDF (%)	Scenario	Potential Solution Identified
G773-Lost Dauphin 138-kV line	287 SE	338 SE	North Appleton-Fox River 345-kV line North Appleton-Kewaunee 345-kV line	8.88	scenario 1	No[20]
		327 SE		6.15	scenario 4	
Melissa-Tayco 138-kV line	143 SE	158 SE		4.39	scenario 2	Yes[21]
		162 SE		4.27	scenario 3	
		182 SE		4.37	scenario 4	
Melissa-Meadows 138-kV line	169 SE	182 SE		4.37	scenario 4	No[22]
Forest Junction-Fox River 345-kV line	1096 SE	1236 SE	North Appleton-Fox River 345-kV line Point Beach 345-kV bus tie 3-4	97.08	scenario 3	No[23]
		1236 SE		96.15	scenario 4	
Elkhart Lake-G611 Tap 138-kV line	96 SE	102 SE	Cypress-Arcadian 345-kV line Granville-Sheboygan Energy Center 345-kV line	5.00	scenario 3	No[24]
		142 SE		5.10	scenario 4	
		174 SE		5.10	scenario 5	
		134 SE	Cypress-Arcadian 345-kV line Point Beach 345-kV bus 1-2	5.00	scenario 6	
		164 SE		5.00	scenario 7	
Elkhart Lake-Saukville 138-kV line	88 SE	108 SE	Granville-Sheboygan Energy Center 345-kV line Cypress-Arcadian 345-kV line	4.58	scenario 4	No[25]
		150 SE	Point Beach 345-kV bus 1-2 Cypress-Arcadian 345-kV line	4.49	scenario 5	
		114 SE		4.69	scenario 6	
		141 SE		4.38	scenario 7	
North Appleton-Kewaunee 345-kV line	1071 SE	1171 SE	Granville-Sheboygan Energy Center 345-kV line North Appleton-Fox River 345-kV line	41.35	scenario 4	No[26]
Granville 345/138-kV transformer #1	478 SE	536 SE	Granville 345-kV bus tie 1-2 Cypress-Arcadian 345-kV line	16.77	scenario 4	No[27]
G590-Tecumseh Rd 138-kV line	169 SE	181 SE	Granville-Sheboygan Energy Center 345-kV line Cypress-Arcadian 345-kV line	5.10	scenario 4	No[28]
		203 SE		5.31	scenario 5	
		187 SE		4.90	scenario 7	

Limiting Element	Existing Rating	Required Rating	Worst Double Contingency	TDF (%)	Scenario	Potential Solution Identified
Meyer Rd-Tecumseh Rd 138-kV line	169 SE	202 SE	Point Beach 345-kV bus 1-2 Cypress-Arcadian 345-kV line	6.12	scenario 5	No[29]
		189 SE		5.52	scenario 7	
Meyer Rd-Mullet River Tap-Lyndon 138-kV line	169 SE	190 SE		5.92	scenario 5	No[30]
		177 SE		5.42	scenario 7	
Fredonia-Lyndon 138-kV line	169 SE	179 SE		5.41	scenario 5	No[31]
		167 SE		5.21	scenario 7	
Edgewater-Saukville 345-kV line	653 SE	698 SE		13.98	scenario 5	No[32]
		693 SE		13.75	scenario 7	
G611 Tap-Forest Junction 138-kV line	96 SE	117 SE	Cypress-Arcadian 345-kV line Point Beach-Sheboygan Energy Center 345-kV line	5.20	scenario 6	No[33]
		103 SE	Point Beach 345-kV bus 1-2 Cypress-Arcadian 345-kV line	4.69	scenario 7	

1. SN – Summer Normal, SE – Summer Emergency, WN – Winter Normal and WE – Winter Emergency.
2. Includes provision for 5% TRM. The required ratings are estimated values using the formula described in Section 3.1.
3. Line rating is limited by the trap (1071 MVA SE) and breakers (1132 MVA SE) at Kewaunee. A project is proposed for reconfiguring the existing Kewaunee switchyard by June 2011 which includes rebuilding the existing 345 kV substation.
4. Line rating is limited by the clearance of the existing line (30.75 mile, 146F, 167F, 275F for SE, 2156 ACSR).
5. Transformer rating is limited by the transformer (500/676 MVA for SN/SE).
6. Line rating is limited by the clearance of the existing line (51.07 mile, 120 F for SN/SE, 2156 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
7. Line rating is limited by the clearance of the existing line (79.2 mile, 120 F for SN/SE, 2156 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
8. Transformer rating is limited by the transformer (504 MVA SE) and the equipment such as CT (478 MVA) and breaker associated with the transformer.
9. Rating is limited by the conductors (539 MVA SE) and breaker (566 MVA SE).
10. Line rating is limited by the clearance of the existing line (4.04 mile, 200/230F for SN/SE, 795 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
11. Transformer rating is limited by the transformer (504 MVA SE). Re-dispatching generation in the area will relieve the loading on the transformer. A project is proposed for reconfiguring the existing Kewaunee switchyard by June 2011 which includes adding a second 345/138 kV transformer in parallel with the existing T10 transformer.
12. Line rating is limited by the clearance of the existing line (9.25 mile, 200/200F for SN/SE, 795 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
13. Line rating is limited by the switch (199 MVA SE) at Kaukauna Central Tap and the 336 ACSR jumper (191 MVA SE) at Kaukauna Central.

14. Line rating is limited by the clearance of the existing line (7.83 mile, 200/200F for SN/SE, 336 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
15. A line clearance study may be needed to validate line ratings. It is assumed that the rating is limited by the clearance of the line.
16. A line clearance study may be needed to validate line ratings. It is assumed that the rating is limited by the clearance of the line.
17. The rating of Lake Park-Darboy-Forest Junction 138 kV line is limited by the line clearance (11.73 mile, 200F SN/SE, 795 ACSR) and jumpers (332 MVA SE) at Lake Park. Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
18. The rating of Lake Park-City Limits 138 kV line is limited by the line clearance (2.25 mile, 200F SN/SE, 795 ACSR) and jumper (332 MVA SE) at Lake Park and jumper (300 MVA SE) at City Limits. Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
19. The rating of the line is limited by the line conductor and terminal equipment such as CTs, meters, traps, switches and East Krok breaker.
20. The line rating is being validated. There is potential for a higher line rating than the required ratings.
21. A project is being proposed to uprate the line to 198 MVA SE for near term. A provisional project is scheduled for 2016 to uprate the line to 229 MVA SE.
22. A line clearance study may be needed. It is assumed that the rating is limited by the clearance of the existing line (1.07 mile, 336ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
23. The rating is limited by the clearance of the existing line (11.32 mile, 108F SN/SE, 2156 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
24. The rating is limited by the clearance of the existing line (28.4 mile, 167F for SN/SE, 4/0 ACSR Penguin). It is being increased to 112 MVA due to requirements of G611 and G92 generation interconnection studies.
25. Line rating is limited by the clearance of the existing line (26.6 mile – 120 F for SN/SE – 477 ACSR, 7.13 mile – 167 F for SN/SE - 4/0 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
26. Line rating is limited by the trap (1071 MVA SE) and breakers (1132 MVA SE) at Kewaunee. A project is proposed for reconfiguring the existing Kewaunee switchyard by June 2011 which includes rebuilding the existing 345 kV substation.
27. Transformer rating is limited by the transformer (504 MVA SE) and the equipment such as CT (478 MVA) and breaker associated with the transformer.
28. The rating is limited by the clearance of the existing line (200F SN/SE, 336 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
29. The rating is limited by the clearance of the existing line (5 mile, 200F SN/SE, 336 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
30. The rating is limited by the clearance of the existing line (18.93 mile, 200F SN/SE, 336 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
31. The rating is limited by the clearance of the existing line (12.94 mile, 200F SN/SE, 336 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
32. Line rating is limited by the clearance of the existing line (26.6 mile – 120 F for SN/SE – 477 ACSR, 7.13 mile – 167 F for SN/SE - 4/0 ACSR). Re-dispatching generation in the Fox Valley area may relieve the loading on the line.
33. Line rating is limited by the clearance of the existing line (28.4 mile, 167F for SN/SE, 4/0 ACSR).

Table A.11-Maximum Allowable Generation for G834/J023 and G833/J022 in Each Scenario without Network Upgrades for Injection Limits

Limiting Element	Worst Contingency	Scenario	G833/J022 and G834/J023 Maximum Output (MW)[1]
None	None	Scenario 1 through 4	106
Point Beach-Sheboygan Energy Center 345-kV line	Cypress-Arcadian 345-kV line	Scenario 5	0
Cypress-Arcadian 345-kV line	Point Beach-Sheboygan Energy Center 345-kV line		0
Point Beach-Sheboygan Energy Center 345-kV line	Cypress-Arcadian 345-kV line	Scenario 6	14.6 (G834 /J023 only)
Point Beach-Sheboygan Energy Center 345-kV line	Cypress-Arcadian 345-kV line	Scenario 7	0
Cypress-Arcadian 345-kV line	Point Beach-Sheboygan Energy Center 345-kV line		0
Point Beach-Sheboygan Energy Center 345-kV line	Cypress-Arcadian 345-kV line	Scenario 8	0

Notes:
1. G833-4 ISIS report dated Dec. 18, 2008 shows 0 MW allowed.

Table A.12-Identified Thermal Violation Due to G834/J023 and G833/J022 in Each Scenario without Network Upgrades for Injection Limits

Limiting Element	Existing Rating (MVA)[1]	Required Rating (MVA)[1,2]		Worst Contingency
		From Revised Table A.5 to A.8	From previous G833/834 ISIS report	
Point Beach-Sheboygan Energy Center 345-kV line	488 SE	569.5 SE (A.5)	516 SE	Cypress-Arcadian 345-kV line
Cypress-Arcadian 345-kV line	488 SE	547.3 SE (A.5)	579 SE (north) 513 SE (south)	Point Beach-Sheboygan Energy Center 345-kV line

Notes:
1. SN – Summer Normal, SE – Summer Emergency, WN – Winter Normal and WE – Winter Emergency.
2. Includes provision for 5% TRM.

Table A.13-Identified Voltage Violation Due to G834/J023 and G833/J022 in Each Scenario

No steady-state analysis was performed because of the reasons described in Section 1.1