G833/G834 Interim Operation and Impacts Report

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

G833 - MISO Queue #39297-01

G834 - MISO Queue #39297-02

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Executive Summary

The Interconnection System 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 last revision (#3) was posted on December 18, 2008. These requests consist of a 53 MW increase to each of the Point Beach Nuclear generators for a total increase in plant output of 106 MW. Each generator was studied with a net output, as measured at the low-side of the generator step-up transformer, of 612.6 MW net (636 MW gross per unit). The requested commercial operation date is May 31, 2010 for G834 (Point Beach Unit 1) and May 31, 2011 for G833 (Point Beach Unit 2).

The ISIS report identified the Network Upgrades required to interconnect requests G833 and G834 along with a preliminary, good faith estimate of the schedule to implement the required projects of 5 years. Since the requested commercial operation date is earlier than the timeframe to complete the required projects, a study of the period between the expected commercial operation date and the expected completion date of all Network Upgrades 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.

Table ES-1: Restrictions Due to Thermal (Valid per condition noted)
Maximum 636 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	535 / 537 MW	G611 – Elkhart Lake 138-kV
	Summer	535 / 537 MW	Point Beach-Sheboygan 345-kV
			Cypress-Arcadian 345-kV
			G611 – Elkhart Lake 138-kV
			Elkhart Lake-Saukville 138-kV

Table ES-2: Restrictions Due to Thermal (Valid per condition noted)
Maximum 636 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 636 MW Gross per Point Beach unit

Year	Point Beach Unit	Restrictions Due to Stability (gross MW)	Condition	Notes
2010 (i.e. G834 only)	Unit #1	540 MW	Prior outage of 345-kV line L6832	Restriction is 560 MW if North Appleton R-304 circuit breaker is replaced
		560 MW	Prior outage of Point Beach Bus Tie 2-3	Assumes Kewaunee Under-Excited Limit
		620 MW	Prior outage of 345-kV line SEC31	Restriction can be removed if North Appleton R-304 circuit breaker is replaced
2011 until Network Upgrades completed (i.e. After G833)	Unit #1	560 MW	Prior outage of Point Beach Bus Tie 2-3	Assumes Kewaunee Under-Excited Limit
	Unit #2	600 MW	At all times	Restriction can be removed if L111 Special Protection System (SPS) is active at all times
		620 MW	Prior outage of 345-kV line L6832	Assumes Kewaunee Reconfiguration project

1. Summary

The long lead time of the projects required for the G833 and G834 interconnection, as documented in revision 3 of the G833/4 Interconnection System Impact Study (ISIS) report dated December 18, 2008, precipitated the need for this study to identify the interim operating limitations and/or additional system upgrades needed to maximize the output of G833 and G834 before all required Network Upgrades are in service. G833 and G834, with an expected in-service date of May 31, 2011 and May 31, 2010, respectively, are 53 MW increases to each of the existing Point Beach nuclear units.

The Network Upgrades required for G833 and G834 can be found in Appendix D or in the G833/4 ISIS report. ATC reported that it would require at least 5 years after the execution of an Generator to Transmission Interconnection Agreement to implement the Network Upgrades including constructing a new 345-kV switching station and re-conductoring a 138-kV circuit. Without the Network Upgrades, the maximum allowable G833 and G834 generation is zero as indicated in the ISIS report.

For this Interim Operation and Impacts Study report, eight different scenarios with and without G834 or G833 were studied for the steady-state analysis, representing the periods between 2010 (after G834) and 2011 (before G833) and between 2011 (after G833) and the final state as described in the G833/4 ISIS report. Different generation patterns and load levels were considered for each scenario. Consistent with the G833/4 ISIS report, both high and low Fox Valley generation scenarios were studied to evaluate angular stability for the periods between 2010 (after G834) and 2011 (before G833) and between 2011 (after G833) and the final state as described in the G833/4 ISIS report. More details can be found in Section 2.3.

This study assumes the Point Beach generator and turbine improvements submitted for and described in the G833/4 ISIS report posted December 18, 2008. The limitations and solutions described in this report may not be valid if the Point Beach data changes.

1.1 Injection Limits[1]

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

No injection limits were identified in the scenarios with 100% load condition, while four injection limits were identified in the scenarios with 50% load condition for NERC Category B (N-1) events. The four injection limits are

1. Point Beach-Sheboygan Energy Center 345-kV line (L-111)
2. Cypress-Arcadian 345-kV Line (L-CYP31 north)
3. Elkhart Lake-G111 Tap 138-kV Line (4035 north)
4. Elkhart Lake-Saukville 138-kV line (8241)

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

Interim mitigation measures for these injection limits are described in Section 1.4 and are required for the requested interconnection service of G833 and G834 to maximize their power output.

1.2 Generating Facility Operation Restrictions

Thirty-one (31) distinct thermal constraints were found for Category C.3 events and four (4) thermal constraints were found for Category C.5 events, which is the outage of two circuits on a multi-circuit tower. 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 MISO binding constraint procedure, no operating restrictions are listed for these thermal constraints.

1.3 Generating Facility Requirements

There are no changes to the information described in Section 1.3 of posted G833/834 ISIS report, which is dated December 18, 2008.

1.4 System Upgrades

1.4.1 Existing System Upgrades (See Table 1.1)

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

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

Breaker Duty Related
No breaker duty related required upgrades were found prior to the addition of G833 and G834.

1.4.2 System Upgrades and Interim Mitigation Measures Required due to G834 and/or G833 Addition (See Table 1.2)

All four injection limits shown in Table A.1 through A.8 (see the list below) need to be upgraded by the in-service date of the Point Beach unit #1 upgrade, which is May 31, 2010. This assumes all competing generation is on-line at full output.

1. Point Beach-Sheboygan Energy Center 345-kV Line (L-111)
2. Cypress-Arcadian 345-kV Line (L-CYP31)
3. G611 Tap-Elkhart Lake 138-kV Line (Line 4035, southern segment)
4. Elkhart Lake-Saukville 138-kV Line (Line 8241)

The Elkhart Lake-Saukville 138-kV line was not identified in the G833/834 ISIS report as an injection limit due to the required new 345-kV West Switching Station. For the time period examined in this study, this 138-kV line rises meets the injection limit criteria.

1.4.2.1 Additional System Upgrades and Interim Mitigation Measures for Thermal Issues

If it is not feasible to upgrade all four injection limits prior to the commercial operation of G834, it is recommended that the Point Beach-Sheboygan Energy Center 345-kV line be improved to at least a summer emergency rating of 592 MVA (990.8 A). This line appears as an injection limit under single contingency conditions even with reduced output from the competing wind generators (see Appendix C for list and status of these requests).

For the remaining three injection limits (i.e. Cypress-Arcadian 345-kV line, G611 Tap-Elkhart Lake 138-kV line and Elkhart Lake-Saukville 138-kV line), the MISO binding constraint procedure could be used until completion of the improvements to these facilities and/or the previously identified Network Upgrades. More details are described below:

- Cypress-Arcadian 345-kV line:
  Based on the study results, 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/G833 in-service, respectively, under light system load conditions.
    - Required rating:
      A minimum summer emergency rating of 569 MVA (952.3 A) is required for the Cypress-Arcadian 345-kV line. However, the future northern section between Cypress and the new 345-kV West Switching Station will eventually require a minimum summer emergency rating of 675 MVA (1130 A) once the new 345-kV West Switching Station, described in the G833/834 ISIS report, is complete (see Table 1.2).
- G611 Tap-Elkhart Lake 138-kV line:
  Among the competing wind generators, G611 output impacts this line loading the most. Other competing generators such as G427 and G773 provide moderate impact on the line flow. The study results showed that the line would not be overloaded under the worst single contingency condition with G427, G611 and G773 offline (see Appendix C for status of these requests). The summer rating of this line is limited by the 19 miles of line conductor. Although request G611 requires an improved summer emergency line rating of 112 MVA, the G833 and G834 requests require a minimum summer emergency line rating of 132 MVA, which is expected to necessitate re-conductoring of the transmission line and may take several years to complete. Thus, it may be necessary to rely on the MISO binding constraint procedure until completion of this project.
    - Required rating:
      A minimum summer emergency rating of 132 MVA (552.3 A) is required for the G611 Tap-Elkhart Lake 138-kV line segment (see Table 1.2).
- Elkhart Lake-Saukville 138-kV line:
  Similar to the G611 Tap-Elkhart Lake 138-kV line, G611 output impacts this line loading the most. Other generators such as G427 and G773 provide moderate impact on the line flow. The study results showed that the line would not be overloaded under the worst single contingency condition with G611 and G773 offline. The summer rating of this line is limited by the 34 miles of line conductor. It is not known at this time what improvements are required to achieve the required summer emergency line rating of 118

MVA nor is the schedule for completing this improvement project known. It may be necessary to use the MISO binding constraint procedure until completion of this project.

- Required rating: A minimum summer emergency rating of 118 MVA (493.7 A) for the Elkhart Lake-Saukville 138-kV line (see Table 1.2).

One additional upgrade was identified during this study that may be required if competing request G611 is not constructed (see Appendix G).

- Forest Junction-Elkhart Lake 138-kV line:
  Although it is not an injection limit for the assumptions used in the ISIS report or for this study, this line would be an injection limit if G611 is not constructed. The G611 interconnection request is required to improve the summer emergency line rating to 112 MVA. However, G611 is not constructed, this line can overload under the worst single contingency.
  - Required rating: A minimum summer emergency rating of 109.9 MVA (460 A) if G611 is not constructed (see Table 1.2).

Table 1.2 shows the projects and mitigation options required due to G833 and G834.

1.4.2.2 Additional System Upgrades and Interim Mitigation Measures for Stability Issues

To achieve adequate system stability until completion of the identified long term solution, the protection improvements and operating restrictions described below are required.

- For the G834 interconnection in 2010, the following stability upgrades are required:
  a. Kewaunee Transformer T10 345-kV side primary clearing time:
     - Bypassing lockout relay plus maintaining Kewaunee MVAR output above zero ***or*** installing a SEL 421 impedance relay plus maintaining Kewaunee MVAR output above zero is needed for faults on the high side of T10 at Kewaunee. Bypassing lockout relay will reduce the existing 5.5 cycle local primary clearing time to 5.0 cycles while installing a SEL 421 impedance relay will reduce it to 4.0 cycles.
     - Other option could be replacing the existing three 3 cycle Non-Independent Pole Operation (IPO) circuit breakers with new 2 cycle IPO circuit breakers. However, this is not the preferred option because replacing these circuit breakers is part of the 2011 Kewaunee reconfiguration project. Advancing this portion of that project may require significant engineering work to reduce the impact on the 2011 Kewaunee project in addition to potential operating restrictions on the Kewaunee unit during construction.
     - Required Kewaunee T10 345-kV side Primary Clearing Time:
       i. **From** the existing 5.5 cycle primary
       ii. **To** 3.5 cycle primary (the worst event is T-10 fault under L-111 prior outage), **or To** 5.0 cycle primary if MVAR output from Kewaunee can be maintained above zero (e.g., minimum excitation limiter).

b. Breaker R-304 at North Appleton primary clearing time:
   - 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 primary clearing time to 4.5 cycles to permit additional MW output from Point Beach unit #1 under certain prior outage conditions. This project is also one of the Network Upgrades identified in the G833/834 ISIS report.
   - Required North Appleton R-304 Primary Clearing Time:
      i. **From** the existing 6.5 cycle primary
      ii. **To** 4.5 cycle primary
c. Breaker Q-303 at Point Beach breaker failure clearing time:
   - For a breaker failure at Point Beach under a Q-303 fault, install SEL 325 relay with high speed contact option being wired in parallel with the lockout relay and maintain MVAR output at Kewaunee to eliminate potential stability issue. This will reduce the existing 9.0 cycle breaker failure time to 8.25 cycles.
   - Required Point Beach Q-303 Breaker Failure Clearing Times:
      i. **From** the existing 9.0 cycle breaker failure
      ii. **To** 8.25 cycle breaker failure
   - Required Kewaunee unit Minimum Excitation Limiter:
      - As required above, resetting the Minimum Excitation Limit (MEL) of the Kewaunee unit is needed to maintain Kewaunee MVAR output above zero.

- With the above stability upgrades implemented, the following operating restrictions are required on the upgraded Point Beach unit #1 (i.e. G834) prior to operation of G833:
   a. Limit Point Beach unit #1 to 560 MW (gross) under the prior outage of 345-kV line 6832 in anticipation of an R-304 fault at Kewaunee. If the R-304 345 kV breaker at North Appleton is not replaced prior to G834 operation, Point Beach unit #1 needs to be limited to 540 MW (gross).
   b. If the R-304 345-kV breaker at North Appleton is not replaced prior to G834 operation, Point Beach unit #1 needs to be limited to 620 MW (gross) under the prior outage of 345-kV SEC31 in anticipation of an R-304 fault at Kewaunee.
   c. Limit Point Beach unit #1 to 560 MW (gross) under the outage of Point Beach 345-kV bus tie 2-3 or only schedule this bus tie outage during a Point Beach unit #1 outage. A forced outage to this bus tie will require restriction of unit #1.

- For the G833 interconnection (2011), the following stability upgrades are required:
   a. 2011 Kewaunee bus reconfiguration project is proposed to be in-service prior to commercial operation of G833. The Kewaunee project will replace the existing 3 cycle non-IPO circuit breakers at Kewaunee 345 kV with new 2 cycle IPO circuit breakers. This project will achieve 3.5 cycle primary clearing and 8.5 cycle breaker failure clearing times for the 345-kV ATC-owned equipment at Kewaunee. All the bullet items listed below assume these new clearing times at Kewaunee. If this project is delayed, the information below is not valid.
   b. Breaker L111 at Point Beach breaker failure clearing time:
      - Breaker failure events involving the L111 circuit breaker at Point Beach prior to completion of the West Switching Station Network Upgrade requires total

clearing times shorter than can be achieved with high speed relaying and circuit breakers. However, two options exist to obtain all or partial output from the upgraded Point Beach units.

- *Option 1:* The existing 345-kV L111 line Special Protection System (SPS) at Point Beach is designed to avoid angular instability under breaker failure during certain prior outage conditions. When activated, this SPS will commands both the Point Beach L111 line and Bus Tie 1-2 circuit breakers to open in primary clearing time for multi-phase faults. If this SPS was activated for all hours in the year, both G833 and G834 would be permitted to operate a full output except as restricted by other conditions described in this report. Changing the use of the Point Beach L111 SPS would require ReliabilityFirst Corporation approval under NERC Mandatory Reliability Standard PRC-012.
- *Option 2:* For a breaker failure at Point Beach under a L111 fault, install SEL 325 with high speed contact options being wired in parallel with the lockout relay in order to achieve 8.25 cycle breaker failure clearing time. This project is also one of the Network Upgrades identified in the G833/834 ISIS report. However, this improvement would still require restriction on Point Beach unit #2 (i.e. G833) to no more than 600 MW gross for all hours in the year.
- <u>Required Point Beach L111 Breaker Failure Clearing Times:</u>
    i. **From** the existing 9.0 cycle breaker failure
    ii. **To** 8.25 cycle breaker failure and a 600 MW gross restriction on Point Beach Unit #2 (i.e. G833) at all times

c. Breaker L151 at Point Beach breaker failure clearing time:
- For a breaker failure at Point Beach under a L151 fault, install SEL 325 with high speed contact options being wired in parallel with the lockout relay in order to achieve 8.25 cycle breaker failure clearing time. This project is also one of the Network Upgrades identified in the G833/834 ISIS report.
- <u>Required Point Beach L151 Breaker Failure Clearing Times:</u>
    i. **From** the existing 9.0 cycle breaker failure
    ii. **To** 8.25 cycle breaker failure

d. Breaker R-304 at North Appleton primary clearing time:
- If the existing R-304 3 cycle North Appleton 345-kV breaker was not replaced prior to operation of G834, replace this breaker with a 2 cycle IPO circuit breaker to achieve 4.5 cycle primary clearing time. This project is also one of the Network Upgrades identified in the G833/834 ISIS report.
- <u>Required North Appleton R-304 Primary Clearing Times:</u>
    i. **From** the existing 6.5 cycle primary
    ii. **To** 4.5 cycle primary

- <u>With the above stability upgrades implemented</u>, the following operating restrictions are required on the upgraded Point Beach units #1 and #2 (i.e. G834 and G833, respectively) until completion of the Network Upgrades identified in the G833/834 ISIS report:

    a. <u>Until completion of the Network Upgrades identified for G833/834 in the ISIS report, Point Beach unit #2 (i.e. G833) needs to be limited to 600 MW gross or below at all times</u> to be stable with the 8.25 cycle breaker failure clearing time under L111 fault, unless the Point Beach L111 SPS is altered as noted above. The

Network Upgrade of constructing a new 345 kV West Switching Station east of Fond du Lac County as described in the G833/834 ISIS report will mitigate this restriction.

b. Limit Point Beach Unit #2 to 620 MW (gross) under the prior outage of 345-kV line 6832 in anticipation of an R-304 fault at Kewaunee.
c. Limit Point Beach unit #1 to 560 MW (gross) under the outage of Point Beach 345-kV bus tie 2-3 or only schedule this bus tie outage during a Point Beach unit #1 outage. A forced outage to this bus tie will require restriction of unit #1.

- The Point Beach unit upgrade project is not expected to alter any existing or future operating restrictions on the nearby generating units.

Voltage Related
None

Breaker Duty Related
None

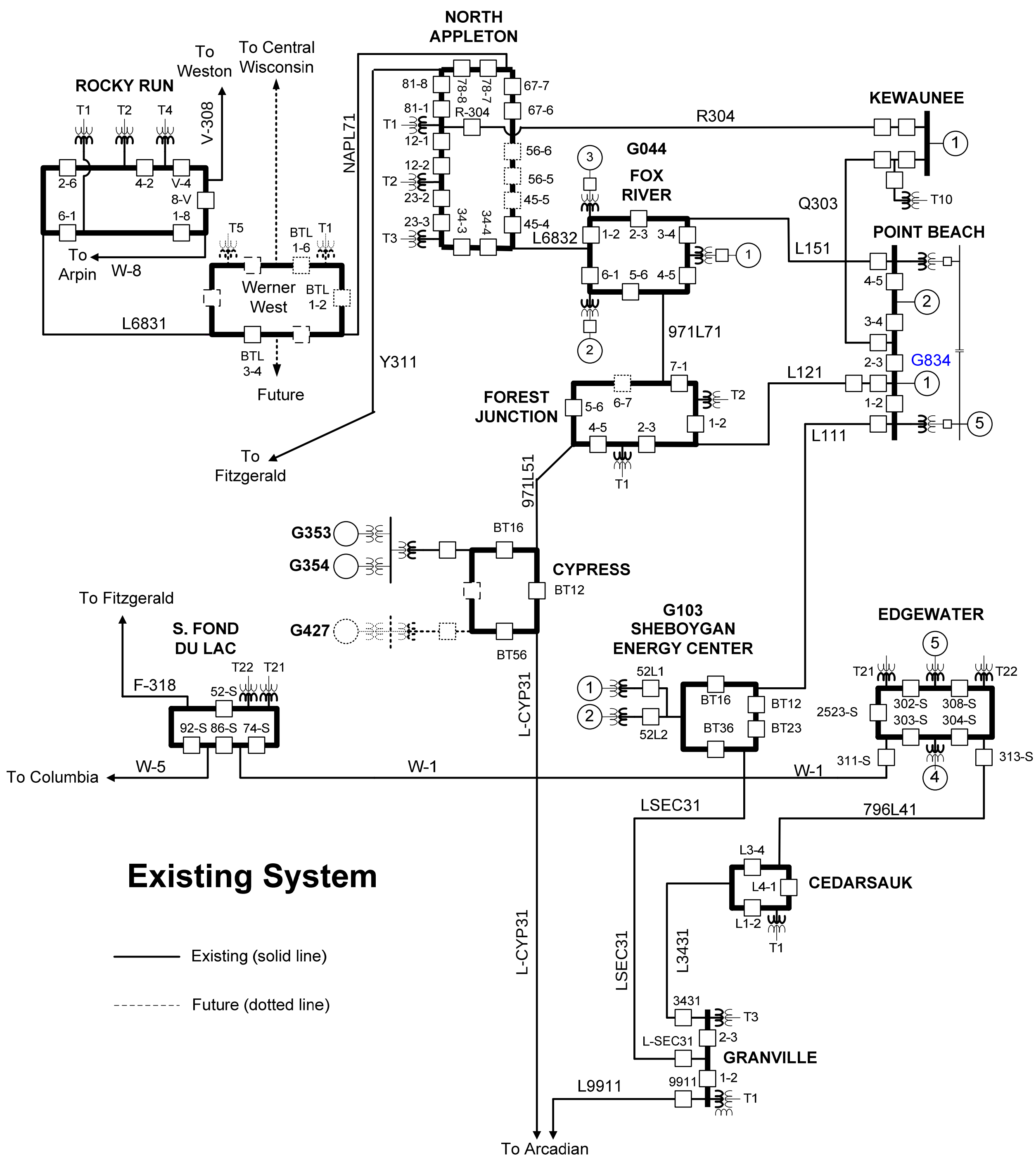

Figure 1.1 – One Line Diagram of the 2010 System with G834 Shown Without Kewaunee Bus Reconfiguration Project

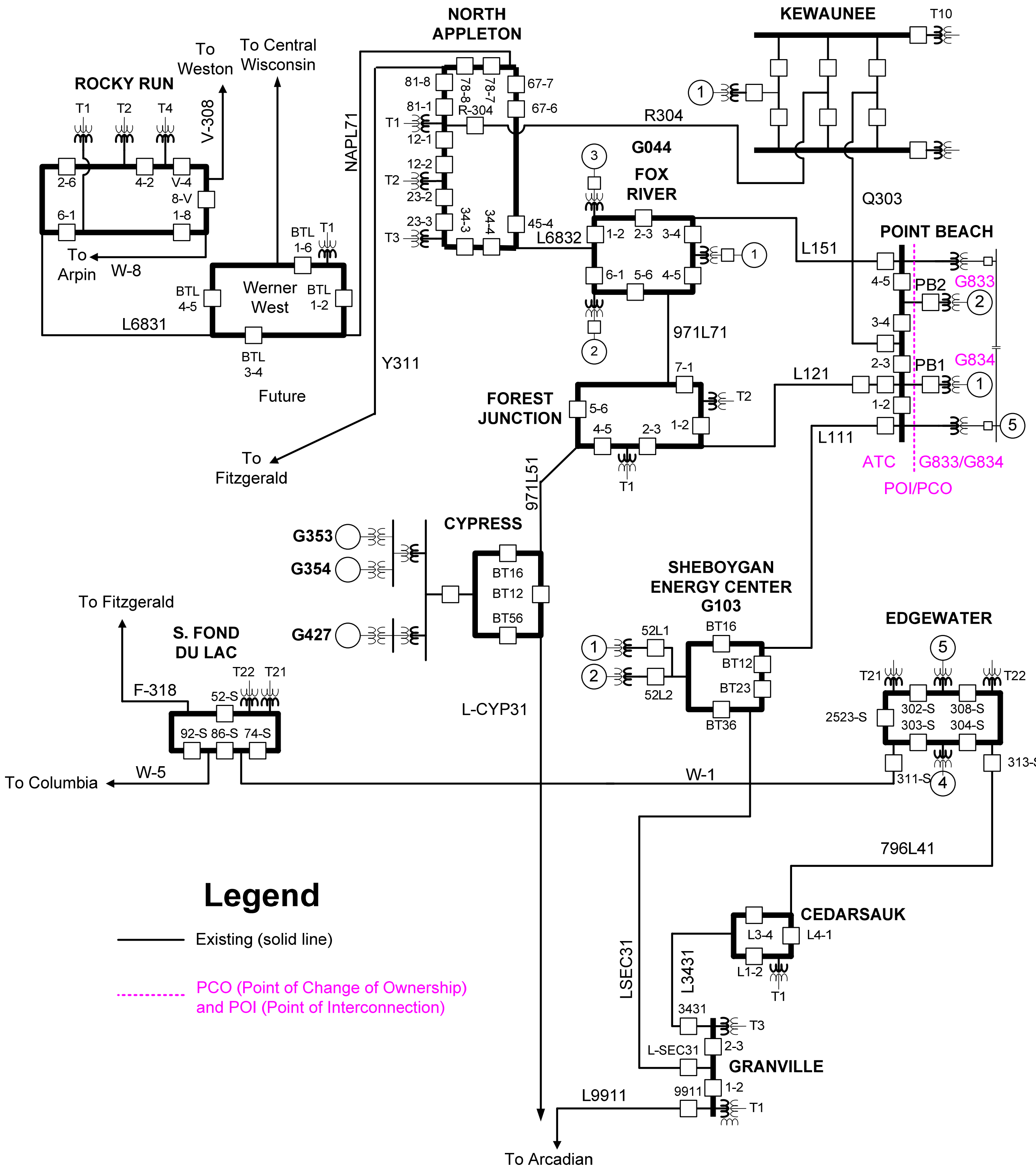

Figure 1.2 – One Line Diagram of the 2011 System with G833 and G834 Shown With Kewaunee Bus Reconfiguration Project and Without new West Switching Station

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

Location	**Facilities**	**Reason**
None		

Table 1.2 – Required Network Upgrades to Address Thermal Issues due to the Addition of G833 and/or G834

Location	Required Upgrade due to G834 (*Without 2011 Kewaunee Bus Reconfiguration, Without West Switching Station*)	Required Upgrade due to G833-834 (*With 2011 Kewaunee Bus Reconfiguration, Without West Switching Station*)	Required Upgrades Shown in G834-833 ISIS Report (*With 2011 Kewaunee Bus Reconfiguration, With West Switching Station*)		
	Facilities	**Facilities**	**Facilities**	**Reason**	**Good Faith Cost Estimate (Y2008)**
Cypress-West Switching Station 345-kV line **(L-CYP31 north)**	See Cypress-Arcadian information below for period without West Switching Station	See Cypress-Arcadian information below for period without West Switching Station	**Item #1** – Increase conductor temperature rating 4° F. look at plan and profile and Patrol to observe any close wire crossings and adjust to obtain a minimum Summer Emergency rating of 675 MVA (1130 A).	Injection Limit	$150,000
Cypress-Arcadian 345-kV line **(CYP31)**	**Item #1** – Increase the line clearance, look at plan and profile and patrol to observe any close wire crossings and adjust to obtain a minimum Summer Emergency rating of 546 MVA (913.7 A). **Mitigation plan** – MISO binding constraints procedure. With less output (Table A.6) from the competing wind generators, this line does not appear to be an injection limit. Based on the required ratings and the percent output of all competing generators in the tables, roughly 52 % output of all competing generators is estimated as the upper bound for not exceeding the existing emergency rating. With the assumption that it is unlikely to have more than 52 % of all competing wind generator output, potential heavy flow issue can be handled by MISO binding constraints procedure.	**Item #1** – Increase the line clearance, look at plan and profile and patrol to observe any close wire crossings and adjust to obtain a minimum Summer Emergency rating of 569 MVA (952.3 A). **Mitigation plan** – use MISO binding constraints procedure until the line uprates. Based on the study result shown in Table A.7 and A.8, roughly 33 % output of all competing generators is estimated as the upper bound for not exceeding the existing emergency rating.		Injection Limit	
Point Beach-Sheboygan Energy Center 345-kV line **(L111)**	**Item #2** – Increase 345 kV line clearance to obtain a minimum Summer Emergency rating of 568 MVA (950.6 A). **Mitigation plan** – MISO binding constraint procedure. Although MISO binding constraint procedure can be used, it is recommended to uprate this line since it is the worst injection limit, and it appears as the injection limit even with less output of the competing wind generator.	**Item #2** – Increase 345 kV line clearance to obtain a minimum Summer Emergency rating of 592 MVA (990.8 A). **Mitigation plan –** Uprate the line.	**Item #2 –** Increase 345 kV line clearance to obtain a minimum Summer Emergency rating of 555 MVA (929 A). Little to no work is expected to be required to increase rating only 4° F. Cost is to review plan and profile and patrol to observe any close wire crossings and adjust accordingly.	Injection Limit	$150,000
Elkhart Lake-G611 Tap 138-kV line (4035 north)	**Item #3a** – Increase the clearance on the 138 kV line to obtain a minimum Summer Emergency rating of 131 MVA (549 A). Or replace the existing conductor with 336 kcmil or T2-4/0 AWG. **Mitigation plan** – MISO binding constraints until the line uprates. Among the competing wind generators, the output of G611 impacts the line flow the most. Other competing wind generators such as G773 and G427 also provide moderate impact on the line flow. With G611, G427 and G773 offline, the line loading can be relieved under the worst contingency condition. G773 and G611's commercial in-service date are 12/01/2010 and 12/31/2010 respectively (per Oct08 G-T status report). G611 interconnection requires uprating the Elkhart Lake-G611 to 112 MVA. Thus, if G611 moves toward construction, additional upgrades of the Elkhart Lake-G611 138-kV line will be needed as part of the project.	**Item #3a** – Increase the clearance on the 138 kV line to obtain a minimum Summer Emergency rating of 132 MVA (552.3 A). Or if it is not feasible, replace the existing 4/0 ACSR conductor with 336 kcmil or T2-4/0 AWG. **Mitigation plan –** MISO binding constraints until the line uprates. See the details described for G834.	**Item #3** – Increase the clearance on the 138 kV line to obtain a minimum Summer Emergency rating of 131 MVA (549 A) by replacing the existing conductor with 336 kcmil or T2-4/0 AWG.	Injection Limit	$5,876,000
G611 Tap-Forest Junction 138-kV line (4035 north) with G611 offline	**Item #3b** – Increase the clearance on the existing 138 kV line (4/0 ACSR) to achieve a minimum Summer Emergency rating of 106 MVA (443.5 A). Or replace the existing conductor with 336 kcmil or T2-4/0 AWG. **Mitigation plan –** MISO binding constraints until the line uprates. With G611 offline, the line may experience	**Item #3b** – Increase the clearance on the existing 138 kV line (4/0 ACSR) to achieve a minimum Summer Emergency rating of 109.9 MVA (460 A). Or replace the existing conductor with 336 kcmil or T2-4/0 AWG. **Mitigation plan –** MISO binding constraints until the line uprates. With G611 offline, the line may experience			

Location		Required Upgrade due to G834 (*Without 2011 Kewaunee Bus Reconfiguration, Without West Switching Station*)	Required Upgrade due to G833-834 (*With 2011 Kewaunee Bus Reconfiguration, Without West Switching Station*)	Required Upgrades Shown in G834-833 ISIS Report (*With 2011 Kewaunee Bus Reconfiguration, With West Switching Station*)		
		Facilities	**Facilities**	**Facilities**	**Reason**	**Good Faith Cost Estimate (Y2008)**
		overload under certain contingency condition (see Appendix E). G611 interconnection requires uprating the line to 112 MVA.	overload under certain contingency condition (see Appendix G). G611 interconnection requires uprating the line to 112 MVA.			
Elkhart Lake-Saukville 138-kV line (8241)		**Item #4** – Increase the clearance on the 138 kV line to obtain a minimum Summer Emergency rating of 112 MVA (468.6 A) by increasing the line clearance of the existing 477 and 4/0 ACSR line conductors. Or increase the line clearance of the existing 477 kcmil ACSR line conductor and replace the existing 4/0 ACSR conductor with new 477 kcmil ACSR conductor. **Mitigation plan** – MISO binding constraints until the line uprates. Among the competing wind generators, the output of G611 impacts the line flow the most. Other competing wind generators such as G427 also provide moderate impact on the line flow. With G611 and G773 offline, the line loading can be relieved under the worst contingency condition. The commercial in-service dates of G773 and G611 are 12/01/2010 and 12/31/2010 respectively (per Oct08 G-T status report). G611 requires uprating the Elkhart Lake-G611 to 112 MVA. Thus, additional upgrades of the Elkhart Lake-Saukville 138-kV line will be needed in conjunction with the work related to G611.	**Item #4** – Increase the clearance on the 138 kV line to obtain a minimum Summer Emergency rating of 118 MVA (493.7 A) by increasing the line clearance of the existing 477 and 4/0 ACSR line conductors. Or increase the line clearance of the existing 477 kcmil ACSR line conductor and replace the existing 4/0 ACSR conductor with 477 kcmil ACSR conductor. **Mitigation plan –** MISO binding constraints until the line uprates. See the details described for G834.		Injection Limit	
A New 345 kV Switching Station at the Intersection of lines L-CYP31 and W-1. (West Switching Station)				**Item #4** – A 4 (expandable to 6) position 345 kV ring bus connecting lines L-CYP31 (Cypress-Arcadian) and W-1 (Edgewater-South Fond du Lac). Include: Control house, relay protection (ATC standard 345 kV line protection panels plus a bus differential panel with redundant relays), communication and accessories, four 3000A, 50kA, 2 Cycle, GCB (complete IPO installation), four line and twelve maintenance disconnect switches, four dead ends, twelve bus CCVTs, eight line CCVTs, line traps, and tuners; twelve MCOV arresters, jumpers, cables, trench, conduits, and grounds. Assumes transmission line additions <1 mile and falling within PSCW CA guidelines.	Stability Upgrade	$11,919,014
Kewaunee 345 kV Bus	**For T10 high side fault at Kewaunee 345 kV (the worst event is T10 fault under L-111 outage),**	**Item #5** –**Mitigation plan**– Achieve 3.5 cycle local primary, 8.5 cycles, Or achieve 5.0 cycle local primary, 8.5 cycles remote primary if Kewaunee MVAR output can be maintained above zero Option 1: Replace the three existing 3 cycle breakers (Q303, 1099, 3450) plus maintaining MVAR output at Kewaunee above zero, Or Option 2: Installing a 421 impedance relay plus maintaining MVAR output at Kewaunee above zero, Or Option 3: Bypassing lockout relay plus maintaining MVAR output at Kewaunee above zero			Stability Upgrade	
	For R304 fault at Kewaunee 345 kV (the worst event is R304 fault under 6832	**Item #6** –**Mitigation plan** – Achieve 3.5 cycle local primary, 6.5 cycle remote primary, OR Achieve 4.5 cycle local primary, 4.5 cycle remote primary Option 1: Replace the existing 3 cycle non-IPO breakers (R304, 3451) with two new 2 cycle IPO breakers at	**Item #5 - Mitigation plan –** See the row associated with North Appleton 345 kV		Stability Upgrade	

Location		Required Upgrade due to G834 (*Without 2011 Kewaunee Bus Reconfiguration, Without West Switching Station*)	Required Upgrade due to G833-834 (*With 2011 Kewaunee Bus Reconfiguration, Without West Switching Station*)	Required Upgrades Shown in G834-833 ISIS Report (*With 2011 Kewaunee Bus Reconfiguration, With West Switching Station*)		
		Facilities	**Facilities**	**Facilities**	**Reason**	**Good Faith Cost Estimate (Y2008)**
	outage),	Kewaunee Option 2: Limit the gross output of Point Beach G1 to 540 MW under 6832 prior outage. With the existing 3 cycle breaker at North Appleton replaced and 4.5 cycle remote primary clearing time achieved, limit the gross output of Point Beach G1 to 560 MW under 6832 prior outage. Limit the gross output to 620 MW under SEC31 prior outage. But, no limit is required with the existing 3 cycle breaker at North Appleton replaced and 4.5 cycle remote primary clearing time achieved. Generators seem stable with 4.5 local primary and 4.5 remote primary clearing times.				
	For breaker failure at Kewaunee under R304 close-in fault,		**Item #6 - Mitigation plan –** Achieve 3.5 cycle local primary, 8.5 cycle local delayed, 4.5 cycle remote primary. Replace the 3 cycle breaker at North Appleton associated with R304 to achieve 4.5 cycle remote clearing time. According to system protection, local primary and local delayed clearing time will become 3.5 and 8.5 cycles with the proposed Kewaunee bus reconfiguration done.		Stability Upgrade	
	For breaker failure at Kewaunee under Q303 fault,		**Item #7 - Mitigation plan –** Achieve 3.5 cycle local primary, 8.5 cycle local delayed, 4.5 cycle remote primary. According to system protection, local primary and local delayed clearing time will become 3.5 and 8.5 cycles with the proposed Kewaunee bus reconfiguration done.		Stability Upgrade	
	For R304 fault under Q303 prior outage		**Item #8 - Mitigation plan –** See the row associated with North Appleton 345 kV		Stability Upgrade	
	For L121 fault at Point Beach 345 kV under Point Beach bus 2-3 prior outage,	**Item #7 –Mitigation plan** – Achieve 1.5 cycle local primary, 4.5 cycles remote primary, Option 1: limit Point Beach G1 to 560 MW (gross output) under Point Beach bus 2-3 prior outage. Option 2: Take Point Beach bus tie 2-3 out during Point Beach generation refueling outage window.	**Item #9 –Mitigation plan** – Same mitigation options described for G834		Stability Upgrade	
Point Beach 345 kV Bus	**For breaker failure under Q303 fault at Point Beach 345 kV**	**Item #8 –Mitigation plan** – Achieve 3.5 cycle local primary, 7.5 cycles local delayed, and 6.5 cycles remote primary, OR Achieve 3.5 cycle local primary, 8.5 cycles local delayed, and 6.5 cycles remote primary plus maintain Kewaunee MVAR output above zero (see Option 1) Option 1: For 8.5 cycles local delayed time, install SEL 325 with high speed contact option being wired in parallel with the lockout relay and maintain MVAR output at Kewaunee above zero	**Item #10 - Mitigation plan –** Achieve 3.5 cycle local primary, 8.5 cycle local delayed, and 4.5 cycles remote primary. Replace the existing breaker failure relay with a high speed SEL 325 and wire relay to direct trip breaker failure breaker to achieve 8.25 cycle breaker failure clearing time which is the mitigation option for G834 interconnection. There is no need to improve remote clearing time because the proposed Kewaunee bus reconfiguration project will improve the remote clearing time to 4.5 cycles.		Stability Upgrade	
	For breaker failure under L111 fault at Point Beach 345 kV **For breaker failure under**		**Item #11- Mitigation plans –** For breaker failure at Point Beach under L111 fault, achieve 3.5 cycle local primary, 8.25 cycle local delayed, and 4.5 cycle remote primary plus limit Point Beach G2 to 600 MW (gross). Install SEL 325 with high speed contact option being wired in parallel with the lockout relay, plus limit the Point Beach G2 to 600 MW (gross) or below to be stable with 8.25 cycle local delayed	**Item #5[1]** –Point Beach Faults Protection Improvements. Item 5A: Achieve L111 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.[2] Item 5B: Achieve L151 clearing times of 3.5 cycles local primary, 8.5 cycles local delayed and 4.5	Stability Upgrade	$106,592

Location	Required Upgrade due to G834 (*Without 2011 Kewaunee Bus Reconfiguration, Without West Switching Station*)	Required Upgrade due to G833-834 (*With 2011 Kewaunee Bus Reconfiguration, Without West Switching Station*)	Required Upgrades Shown in G834-833 ISIS Report (*With 2011 Kewaunee Bus Reconfiguration, With West Switching Station*)		
	Facilities	**Facilities**	**Facilities**	**Reason**	**Good Faith Cost Estimate (Y2008)**
L151 fault at Point Beach 345 kV		clearing time. For breaker failure at Point Beach under L151 fault, achieve 3.5 cycle local primary, 8.5 cycle local delayed, and 4.5 cycle remote primary. Install SEL 325 with high speed contact option being wired in parallel with the lockout relay to achieve 8.25 cycle local delayed clearing time.	cycles remote primary by reducing local delayed clearing time 0.5 cycles.[2]		
North Appleton 345 kV Bus		**Item #5 - Mitigation plan –** For the R304 fault at Kewaunee under 6832 prior outage, achieve 3.5 cycle local primary and 4.5 cycle remote primary, plus limit Point Beach G2 under the 6832 prior outage condition. Replace the existing North Appleton 345 kV R-304 circuit breaker with a 345 kV, 3000 A, 50 kA, Gas CB to achieve 4.5 cycles remote primary by reducing remote primary by 1.0 cycle as noted. In addition to the breaker replacement, Point Beach G2 needs to be reduced to 620 MW (gross) or below under the 6832 prior outage condition. **Item #8 - Mitigation plan –** For the R304 fault at Kewaunee under Q303 prior outage, achieve 3.5 cycle local primary and 4.5 cycle remote primary, plus limit Kewaunee under the Q303 prior outage condition. Replace the existing North Appleton 345 kV R-304 circuit breaker with a 345 kV, 3000 A, 50 kA, Gas CB to achieve 4.5 cycles remote primary by reducing remote primary by 1.0 cycle as noted. According to the Scope document developed for the 2011 Kewaunee bus reconfiguration project, Kewaunee needs to be reduced to 475 MW (Net) for generation stability in anticipation of R304 fault. In addition, it may need to be further reduced due to thermal overload issue on Kewaunee-East Krok 138 kV line under the Q303 prior outage condition in anticipation of R304 fault. Kewaunee generator appears to be stable with the reduced output and the breaker replacement at North Appleton.	**Item #6[1]** – R-304 Fault at Kewaunee Protection Improvement Achieve R-304 fault clearing times of 3.5 cycles local primary, 8.5 cycles local delayed and 4.5 cycles remote primary by reducing remote primary by 1.0 cycle.[3]	Stability Upgrade	$515,437
			TOTAL		**$18,717,043**

Note 1 – Assumes Kewaunee Bus Reconfiguration ($17,509,123 in 2011 dollars) goes forward. Additional upgrades will be needed to reduce fault clearing times at Kewaunee if the Kewaunee Bus Reconfiguration project does not go forward (See Section 1.4).
Note 2 – Replace existing breaker failure relay with SEL-352 with high speed contacts and wire relay to direct trip breaker failure breakers.
Note 3 – Replace existing North Appleton 345 kV R-304 circuit breaker with a 345 kV, 3000 A, 50 kA, Gas CB.

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 Generator and other ATC system information that was available at the time the study was performed, and the injection study does not guarantee deliverability to the MISO energy market. If there are any significant changes in the generator and controls data, 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 Generator 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

ATC determined in its judgment that five Interconnection Requests with an earlier Queue Position may impact the G833 and G834 study results. G384, G427, G590, G611, and G773 are included in all of the thermal analysis cases. Because of its location on the 138 kV system, G773 was not included in the stability models.

Table 2.1 – Competing Generation Requests

Queue Number	Control Area	MW	Requested In-Service Year
G384	WPS	99	Suspended
G427	WEC	98	Suspended
G590	WEC	98	Suspended
G611	WEC	99	2010
G773	WPS	150	2010

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

Thermal overloads were identified using AC power flow solutions. All AC power flow solutions utilized actual equipment ratings in MVA (i.e. 0% TRM) along with real and reactive power flows. A 5% TRM was factored in the computation of required MVA rating for the limiting elements.

All AC power flow solutions were performed using the Power Flow module of the Power System Simulation/Engineering-29.5.1 (PSS/E, Version 29.5.1) program from Siemens Power Technologies, Inc (PTI). This program is accepted industry-wide for power flow analysis.

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. Simulations were performed with G833 and/or G834 in service to determine the stability impacts that attributed to the additional generation. Any violations of the stability study criteria (in Appendix F) identified with the increased generation in service can be attributed to the G833 and G834 interconnection request and are documented in this report.

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 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)

Base cases used in the thermal and voltage analysis for this study were developed based upon the expected topology for the local area for summer 2010 at 100% and 50% of system peak loading conditions. The cases were developed using the 2006 series of NERC/MMWG base cases with planned and proposed projects added for the time frame studied. The topology representing the ATC service territory was taken from ATC internal planning models and inserted into the NERC/MMWG cases to update the local area model.

The output of the competing wind generators (G384, G427, G590, G611 and G773) was delivered to the WAPA and TVA control areas in an equal distribution.

For the AC analysis portion of the study, half of the output of G833 and/or G834 was delivered to the WAPA control area and the remaining half was delivered to the TVA control area. This dispatch pattern in the AC analysis was used to mimic delivery to the MISO footprint.

The study models correspond to two load levels for the first summer season topology after the expected in-service date of G834 (G833 will be in-service one year after to G834). The study models do not have new 345-kV West Switching station which is one of the long term solutions identified in the G833/834 ISIS report.

The 2010 summer peak case (100% of peak load conditions) and 2010 light load case (50% of peak load conditions), were modified and used to create the scenarios shown in Table 2.2. Note that the new West switching station required for G833/834 (see G833/834 ISIS report) is not modeled in each scenario.

Table 2.2 – Scenarios for Thermal Analysis

Base Case	Scenario #	Assumption	Comment
S2010 at 100% of peak load conditions Without West Switching Station	1	G834 at 100%, G833 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 at 100%, G833 offline, All competing generators at 20% Without 2011 Kewaunee project (representing 2010-2011)	
	3	G834 at 100%, G833 at 100% All competing generators at 20% With 2011 Kewaunee project (representing 2011 and beyond)	
	4	G834 at 100%, G833 at 100% All competing generators at 100% With 2011 Kewaunee project (representing 2011 and beyond)	
S2010 at 50% of peak load conditions Without West Switching Station	5	G834 at 100%, G833 offline All competing generators at 100% Without 2011 Kewaunee project (representing 2010-2011)	
	6	G834 at 100%, G833 offline All competing generators at 20% Without 2011 Kewaunee project (representing 2010-2011)	
	7	G834 at 100%, G833 at 100% All competing generators at 67% With 2011 Kewaunee project (representing 2011 and beyond)	
	8 (N-1 only)	G834 at 100%, G833 at 100% All competing generators at 20% With 2011 Kewaunee project (representing 2011 and beyond)	

Table 2.3 – Load and Generation Level in Each 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

2.3.2 Stability Analysis (Dynamics)

The 2010 50% of system peak load base case used in the stability analysis for this study was developed based upon the ATC 2009 Ten Year Assessment 50% peak load dynamics-ready model from the 2007 Series 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 generator interconnection study methodology. The resulting additional generation was delivered to ComEd (75%) and Northern States Power (25%) control areas.

Four stability scenarios were studied for G833 and/or G834. 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 provide significant impact on stability result. 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 2.4 – Scenarios for Stability Analysis for G834

Scenario #	S2010 at 50% of peak load conditions
1a: use High Gen case 1b: use Low Gen case	W/O 2011 Kewaunee projects, G834 at 100%, G833 offline, All competing generators at 100% (representing 2010-2011)

Table 2.5 – Scenarios for Stability Analysis for G833

Scenario #	S2010 at 50% of peak load conditions
2a: use High Gen case 2b: use Low Gen case	W/ 2011 Kewaunee projects, W/ G834 at 100% assumed, W/O new West Switching Station G833 at 100%, All competing generators at 100% (representing 2011-beyond)

2.4 Generation Facility

2.4.1 Generating Facility Modeling

The G833 and G834 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 636 MW for each unit. The voltage regulation set point of each machine was 102.02% (352 kV) of nominal at the POI to reflect preferred plant operation.

More details can be found in the G833/834 ISIS report.

3. Analysis Results

3.1 Power Flow Analysis Results

The Intact and N-1 thermal analysis in this report used AC analysis under 100% and 50% load conditions with the conceptual West Switching Station in service. The N-2 power flow analysis used AC analysis under 100% and 50% load conditions.

3.1.1 Power Factor Capability and Voltage Requirements

N/A (Details can be found in the G833/834 ISIS report)

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

3.1.2.1 Base Case Analyses

The scenarios shown in Table 2.2 and 2.3 were studied and identified zero transmission element steady-state thermal violation due to G834/G833 for NERC Category B (N-1) events for the summer 2010 100% of system peak load model. Four transmission element steady-state thermal violations due to G834/G833 were identified for NERC Category B (N-1) events for the summer 2010 50% of system peak load model. The transmission elements overloaded meet the criteria of an injection limit. A summary of the thermal violations due to G833 and G834 is presented in Tables A.5, A.6, A.7 and A.8 in Appendix A.

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

- Line LCYP31, 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 LCYP31 out of service
- Line 4035 (southern segment), G611 Tap to Elkhart Lake 138-kV line segment. Approximately 3.5% of the new generation flowing on the line with L111 out of service. Although Line 4035 carries only 3% of the increased generation with L111 out of service, because L111 is a generator outlet, this is an injection limit.
- Line 8241, Elkhart Lake to Saukville 138-kV line. Approximately 3.2 % of the new generation flowing on the line with L111 out of service. Although Line 8241 carries only 3.2% of the increased generation with L111 out of service, because L111 is a generator outlet, this is an injection limit. This limit was not identified in the G833/834 ISIS report due to the need for the 345-kV West Switching Station as a Network Upgrade.
- As shown in Appendix G, the existing Forest Junction-Elkhart Lake 138-kV line may also need to be upgraded although it was not identified as injection limit. The line may overload with L111 out of service if G611 is not constructed. If G611 is constructed, this line will be upgraded to a summer emergency rating of 112 MVA for G611.

In addition to the analysis of the system for the various load and generation levels noted above under summer ratings, a further review was made of the flow on the four injection limits using seasonal ratings. This review did not involve further steady state analysis. Instead, the information presented in the tables in Appendix H is an estimate as footnoted to the tables. This review, however, indicates that with full output from competing generation requests some of the constraints are not expected under these seasonal ratings. It can be inferred from other results in this report that reduction in the output of competing requests may alleviate some of the remaining constraints further.

The maximum allowable real power output without system upgrades was determined by calculating the distribution factor for the element using AC analysis and then using linear interpolation to find the output of the plant based on the maximum capacity of the line and the distribution factor. The maximum allowable output without Network Upgrades for injection limits is presented in Table A.11 in Appendix A.

Voltage analysis shows that no transmission system voltage limits will be violated as a result of the interconnection of G833 and G834 as shown in Table A.13.

3.1.3 Results of Double Contingencies (N-1-1)

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

For Scenario 1 through 7 except Scenario 8, thermal and voltage constraints were evaluated for NERC Category C events (N-1-1 contingencies) in the electrical proximity of G833 and G834 for the summer 2010 100% and 50% of system peak load model. The double contingency constraints are not required to be resolved for the generator to attain either Energy Resource or Network Resource Interconnection Service status. The purpose of the N-1-1 analysis is to reveal potential violations under prior outage conditions.

Thermal violations under a selected number of N-1-1 contingencies were evaluated using AC analysis. The distinct thermal violations identified from the summer 2010 100% and 50% of system peak load model used in the study are listed in Table A.10 in Appendix A.

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 and G834 for the contingencies noted in this N-1-1 analysis.

3.1.3.2 NERC Category C.5 Contingencies

The Transmission System local to the selected Point of Interconnection was reviewed for facilities that could be defined as double contingencies that correspond to NERC Category C.5 events (i.e. two circuits on shared tower). Table 3.1 shows all NERC Category C.5 events that were considered local and potentially limiting the proposed interconnection. Four stead-state thermal constraints were found for Category C.5 events, which is the outage of two circuits on a multi-circuit tower. The Category C.5 violations are shown in Tables A.9, Appendix A.

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[2]

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

Thirty two disturbance scenarios selected and considered as critical events in the G834-3 ISIS report were studied for G834 interconnection, and three disturbance scenarios were studied for G833 interconnection without new West Switching station.

As shown in Appendix B, the selected disturbances were evaluated using the high and low generation cases in Table 2.4 and 2.5. For the analysis, it is assumed that the Point Beach Unit power system stabilizer (PSS) was in-service. For G834 stability analysis, Kewaunee bus reconfiguration is not considered in the models since the project is proposed to be in-service by June 2011. For G833 stability analysis, new West Switching station is not considered in the models.

The selected contingencies include

1. Three-phase fault cleared in primary time with an otherwise intact system (NERC Cat. B);
2. Three-phase fault cleared in primary clearing time with a prior outage of any other transmission element (NERC Cat C); and
3. Three-phase fault cleared in delayed (breaker failure) clearing time with an otherwise intact system (NERC Cat D).

Added to the actual clearing time provided by System Protection, 0.5 and 1.0 cycle planning margins were considered during the simulation for existing and new systems respectively. This planning margin 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 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.

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 fault listed in Table 3.2.1 was simulated as 3-phase faults cleared in primary time under intact system conditions. The only stability problem under intact system conditions was for a fault on the high side of Kewaunee transformer T10 with G384 in-service under low generation scenario. Until long term solution in place, implementing one of the options listed below can eliminate the stability issue:

- Reduce the existing 5.5 cycle local primary clearing time to 5.0 cycle by bypassing lockout relay associated with T10,
- Reduce the existing 5.5 cycle local primary clearing time to 4.0 cycle by installing a 421 impedance relay which will open faster than the existing differential relay under the 3-phae fault at the high side of T10 transformer, or
- Reset Minimum Excitation Limit (MEL) of Kewaunee to maintain Kewaunee MVAR output above zero and to be stable with the existing 5.5 cycle local primary clearing time.

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

Faulted Element	Fault Location	Description
KEW T10 High Side	Kewaunee 345 KV	Kewaunee 345/138 kV Transformer

3.2.2 Results of Primary Fault Clearing During a Prior Outage

3.2.2.1 Stability analysis result with G834

Primary fault clearing under prior outage conditions simulated all of the events listed in Table 3.2.3 under the outages listed in Table 3.2.2 without the proposed Kewaunee bus reconfiguration project.

Table 3.2.2 – Simulated Prior Outage Elements and Faulted Element

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
L6832	Fox River-North Appleton 345 kV Line
971L71	Fox River-Forest Junction 345 kV Line
SEC31	Sheboygan Energy -Granville 345 kV Line
LCYP31	Cypress-Arcadian 345 kV Line
NAPL71	North Appleton-Werner West 345 kV Line
971L51	Forest Junction-Cypress 345 kV Line
Y311	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

Table 3.2.3 – Simulated Single Circuit 3-Phase Faults Cleared in Primary Time

Faulted Element	Fault Location	Description
KEW T10 H*	Kewaunee 345 KV	Kewaunee 345/138 kV Transformer
R304	Kewaunee 345 kV	North Appleton-Kewaunee 345 kV line
L121	Point Beach 345 kV	Point Beach-Forest Junction 345 kV line

11 events with generation instability were found for prior outage scenarios (Table B.2 in Appendix B). Among 11 events, 10 events of the prior outage problems 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.2 in Appendix B.

- Bypass lockout relay for T10 high side fault
- Install 421 impedance relay for T10 high side fault
- Maintain MVAR output at Kewaunee above zero (Minimum Excitation Limiter)
- Replace 345 kV breakers at Kewaunee with new 2.0 cycle IPO breakers
- Replace 345 kV breaker at North Appleton associated with R304

Among the options listed above, replacing 345 kV breakers at Kewaunee is not preferred mitigation option because the breakers may need to be replaced outside generation refueling outage window which is extremely difficult without impacting generating unit, and it may result in either generation reduction or trip in anticipation of next contingency or with next contingency. In addition, it may require significant engineering and project schedule challenges to avoid impact on 2011 Kewaunee project.

L121 fault at Point Beach under the prior outage of Point Beach 345-kV bus 2-3 couldn't be eliminated by the options listed above. For the event, it is recommended to take the bus tie out of service during the generation refueling outage window. Otherwise, operating restriction will be needed to limit Point Beach G1 to 560 MW (gross) during the POB 2-3 prior outage in anticipation of L121 fault.

As shown in Table B.2, Point Beach G1 needs to be limited to 560 MW (gross) under the prior outage of 6832 for R304 fault at Kewaunee with R304 breaker at North Appleton replaced.

3.2.2.2 Stability analysis result with G833, with Kewaunee Bus Reconfiguration, and without new West Switching Station

The proposed 2011 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 2011 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 with the 2011 Kewaunee bus reconfiguration project assumed in-service prior to G833 interconnection.

Among the stability issues in Table B.5, 2 events with generation instability were simulated to identify operating restriction to Kewaunee and Point Beach G2. The two events are listed in Table 3.2.5 under the outages listed in Table 3.2.4.

Table 3.2.4 – Simulated Prior Outage Elements and Faulted Element

Element	Description
L6832	Fox River-North Appleton 345 kV Line
Q303	Kewaunee-Point Beach 345 kV Line

Table 3.2.5 – Simulated Single Circuit 3-Phase Faults Cleared in Primary Time

Faulted Element	Fault Location	Description
R304	Kewaunee 345 kV	North Appleton-Kewaunee 345 kV line

The study results show that Kewaunee unit will be stable for R304 fault under the prior outage of Q303 as long as it limits its output to 500 MW (gross) during the prior outage condition, which is consistent with the stability limit identified in the study of the 2011 Kewaunee Bus Reconfiguration project.

The stability issue for R304 fault under the prior outage of 6832 can be eliminated as long as the R304 breaker at North Appleton is replaced prior to G833 and Point Beach G2 is limited to 620 MW (gross).

For the stability issue due to L121 fault under the prior outage of Point Beach 345-kV bus 2-3, it is recommended either limiting Point Beach G1 to 560 MW (gross) under the bus tie outage or taking the bus tie outage during Point Beach generation refueling outage window, which is the mitigation option for G834 under the same event.

3.2.3 Results of Three-Phase Fault Delayed Clearing under Intact System Conditions

3.2.3.1 Stability analysis result with G834 (Breaker failure issue)

Delayed 3-phase fault clearing under otherwise intact system was simulated for the events listed in Table 3.2.4 without the proposed Kewaunee bus reconfiguration. Among 3 events identified as critical events in G833/834 ISIS report, only the breaker failure at Point Beach under Q303 fault resulted in generation instability if existing breaker clearing times (3.5 cycle primary local, 9.0 cycles delayed local and 6.5 cycles primary remote) were modeled. For the Q-303 fault, reducing the local delayed clearing time to 7.5 cycles eliminated the generator instability. Since 7.5 cycle delayed clearing time is not feasible to achieve, it is recommended to

- install SEL 325 with high speed contact option being wired in parallel with the lockout in order to improve the clearing time to 8.25 cycles, and <u>reset Minimum Excitation Limit (MEL) of Kewaunee to maintain Kewaunee MVAR output above zero which is needed even for the existing system condition.</u>

Table B.3 presents results for three phase faults with breaker failure.

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

3.2.3.2 Stability analysis result with G833 (Breaker failure issue), with Kewaunee Bus Reconfiguration, and without new West Switching Station

Delayed 3-phase fault clearing under otherwise intact system was evaluated for the events listed in Table 3.2.5 with the proposed Kewaunee Bus Reconfiguration. As mentioned in the previous section, with the 2011 Kewaunee project done, 3.5 cycles, 8.5 cycles, and 4.5 cycles will be achieved at Kewaunee 345 kV as local primary, local delayed(breaker failure), and remote primary time respectively. As shown in Table B.6, the stability issue with Q303 breaker failure at Kewaunee is eliminated with the 2011 Kewaunee Bus Reconfiguration project modeled. All the simulations discussed in this section assumed the new clearing times at Kewaunee.

The stability issue with R304 breaker failure at Kewaunee can be eliminated with R304 breaker at North Appleton replaced and 345-kV breakers at Kewaunee replaced. The R304 breaker replacement at North Appleton will improve the existing 6.5 cycle remote clearing time to 4.5 cycles.

For L111 breaker failure at Point Beach, the stability issue can be eliminated by installing SEL 325 with high speed contact option being wired in parallel with the lockout in order to improve the clearing time to 8.25 cycles and <u>by maintaining the Point Beach G2 output to 600 MW (gross) or below at all times</u>. Long term solution is constructing new West Switching station.

For L151 breaker failure at Point Beach, the stability issue can be eliminated by installing SEL 325 with high speed contact option being wired in parallel with the lockout in order to improve the clearing time to 8.25 cycles.

For Q303 breaker failure at Point Beach, the stability issue can be eliminated by installing SEL 325 with high speed contact option being wired in parallel with the lockout in order to improve the clearing time to 8.25 cycles, which is the mitigation option for G834 under the same event.

Table B.6 presents results for three phase faults with breaker failure.

Table 3.2.5 – 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
Q303	Point Beach 345 kV	Point Beach-Kewaunee 345 kV line
Q303	Kewaunee 345 kV	Point Beach-Kewaunee 345 kV line
R304	Kewaunee 345 kV	Kewaunee-North Appleton 345 kV line

3.2.4 Stability Results Summary

Prior to G834 interconnection, the following stability upgrade and operating restrictions are needed:

- Bypassing lockout relay plus maintaining Kewaunee MVAR output above zero is needed for the stability issue related to T10 high side fault at Kewaunee, or installing a 421 impedance relay plus maintaining Kewaunee MVAR output above zero. Bypassing lockout relay will reduce the existing 5.5 cycle local primary clearing time to 5.0 cycles, while installing 421 impedance relay will reduce it to 4.0 cycles.
- Operating restrictions are needed to prepare for certain stability issues under prior outage conditions with G834 in-service:
    - Limit Point Beach G1 to 540 MW (gross) under the prior outage of 6832 (North Appleton-Fox River 345 kV) in anticipation of R304 (Kewaunee-North Appleton 345 kV) fault at Kewaunee. It can go up to 560 MW (gross) if the existing 3 cycle breaker at North Appleton associated with R304 can be replaced with new breaker to achieve 4.5 cycle remote primary clearing time before G834 in place.
    - Limit Point Beach G1 to 620 MW (gross) under the prior outage of SEC31 (Sheboygan Energy Center-Granville 345 kV) in anticipation of R304 fault at Kewaunee. If the existing 3 cycle breaker at North Appleton associated with R304 can be replaced with new breaker to achieve 4.5 cycle remote primary clearing time before G834 in place, the limit under SEC31 prior outage can be eliminated.
    - Limit Point Beach G1 to 560 MW (gross) under the outage of Point Beach 345-kV bus tie 2-3, or allow the bus tie outage during Point Beach generation refueling outage window.
- Replace the existing 3 cycle breaker at North Appleton associated with R304 with new breaker to reduce the existing 6.5 cycle remote primary clearing time to 4.5 cycles since the breaker replacement will allow additional MW output from Point Beach G1, and it is also one of the long term solutions identified for G833/834 interconnection.
- For the breaker failure at Point Beach under Q303 fault, it is needed to install SEL 325 with high speed contact option being wired in parallel with the lockout relay and to maintain MVAR output at Kewaunee to eliminate potential stability issue. It will reduce the existing 9.0 cycle local delayed clearing time to 8.25 cycles.
- As required above, resetting Minimum Excitation Limit (MEL) of Kewaunee unit is needed to maintain Kewaunee MVAR output above zero. Absorbing MVAR from transmission system can result in Kewaunee unit trip under the Q303 breaker failure at Point Beach even with the existing system condition.

Prior to G833 interconnection, the following stability upgrade and operating restrictions are needed:

- 2011 Kewaunee bus reconfiguration project needs to be in service prior to G833 interconnection, which will replace the existing 3 cycle non-IPO breakers at Kewaunee 345 kV with new 2 cycle IPO breakers. According to System Protection, 3.5 cycles, 8.5 cycles, and 4.5 cycles will be achieved with the 2011 Kewaunee project as local primary, local delayed(breaker failure), and remote primary time respectively. All the bullet items listed below assume the new clearing times at Kewaunee.

- For the breaker failure at Point Beach under L111 (Point Beach-Sheboygan Energy Center 345 kV) fault, install SEL 325 with high speed contact options being wired in parallel with the lockout relay in order to reduce the existing 9.0 cycle local delayed clearing time to 8.25 cycle. However, Point Beach G2 needs to be limited to 600 MW or below at all times to be stable with 8.25 cycle local delayed clearing time. Long term solution is constructing new 345 kV West Switching Station at east of Fond du Lac County.
- For the breaker failure under L151 (Point Beach-Fox River 345 kV) fault at Point Beach, install SEL 325 with high speed contact options being wired in parallel with the lockout relay in order to reduce the existing 9.0 cycle local delayed clearing time to 8.25 cycle.
- If the existing 3 cycle North Appleton 345-kV breaker associated with R304 was not replaced prior to G834 interconnection, replace it with new breaker to achieve 4.5 cycle remote primary clearing time. It eliminates stability issues under certain fault events:
  - R304 fault at Kewaunee under 6832 prior outage with Point Beach G2 limited to 620 MW (gross)
  - breaker failure at Kewaunee under R304 fault
  - R304 fault at Kewaunee under Q303 prior outage with Kewaunee limited to 500 MW (gross). The limit to Kewaunee under Q303 prior outage is not due to Point Beach Uprates.

Appendix A: Power Flow Analysis Results

Table A.1 – Identified Thermal Violations in Scenario 1 Due to G834
Summer 2010 (100% Load) Delivery to MISO for NERC Category A and B events (TDF>3%)
G833 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 SE	Pleasant Prairie 345-kV bus tie 2-3	6.2	2010S	No	No[3]
Elkhart Lake-G611 138-kV line	96 SE	102 SE	Sheboygan Energy Center-Granville 345-kV line	3.5	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 calculations using AC analysis in PSS/E dispatching 50% of G834 or G833 to TVA area and 50% to WAPA as a proxy for MISO delivery.
3. An operating guide is available to mitigate the Bain 345/138 kV transformer for Pleasant Prairie 345-kV bus tie outage.
4. Line rating is limited by the clearance of the existing line (28.4 mile). It is being increased to 112 MVA due to requirements of G611 and G92 generation interconnection studies.

Table A.2 – Identified Thermal Violations in Scenario 2 Due to G834
Summer 2010 (100% Load) Delivery to MISO for NERC Category A and B events (TDF>3%)
G833 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 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 calculations using AC analysis in PSS/E dispatching 50% of G834 or G833 to TVA area and 50% to WAPA as a proxy for MISO delivery.
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 (Assume G834 online)
Summer 2010 (100% Load) Delivery to MISO for NERC Category A and B events (TDF>3%)
G833 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 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 calculations using AC analysis in PSS/E dispatching 50% of G834 or G833 to TVA area and 50% to WAPA as a proxy for MISO delivery.
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 (Assume G834 online)
Summer 2010 (100% Load) Delivery to MISO for NERC Category A and B events (TDF>3%)
G833 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 SE	Pleasant Prairie 345-kV bus tie 2-3	6.3	2010S	No	No[3]
Elkhart Lake-G611 138-kV line	96 SE	106 SE	Sheboygan Energy Center-Granville 345-kV line	3.4	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 calculations using AC analysis in PSS/E dispatching 50% of G834 or G833 to TVA area and 50% to WAPA as a proxy for MISO delivery.
3. An operating guide is available to mitigate the Bain 345/138 kV transformer for Pleasant Prairie 345-kV bus tie outage.
4. Line 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.

Table A.5 – Identified Thermal Violations in Scenario 5 Due to G834
Summer 2010 (50% Load) Delivery to MISO for NERC Category A and B events (TDF>3%)
G833 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	568 SE	Cypress-Arcadian 345-kV line	23.4	2010S	Yes	No[3]
Cypress-Arcadian 345-kV line	488 SE	546 SE	Point Beach-Sheboygan Energy Center 345-kV line	19.8	2010S	Yes	No[4]
Elkhart Lake-G611 138-kV line	96 SE	131 SE	Point Beach-Sheboygan Energy Center 345-kV line	3.5	2010S	Yes	No[5]
Elkhart Lake-Saukville 138-kV line	88 SE	112 SE	Point Beach-Sheboygan Energy Center 345-kV line	3.2	2010S	Yes	No[6]

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 calculations using AC analysis in PSS/E dispatching 50% of G834 or G833 to TVA area and 50% to WAPA as a proxy for MISO delivery.
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.
5. Line 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.
6. 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). Required rating should be able to be met by increasing line clearance.

Table A.6 – Identified Thermal Violations in Scenario 6 Due to G834
Summer 2010 (50% Load) Delivery to MISO for NERC Category A and B events (TDF>3%)
G833 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	498 SE	Cypress-Arcadian 345-kV line	24.0	2010S	Yes	No[3]
Elkhart Lake-G611 138-kV line	96 SE	98 SE	Point Beach-Sheboygan Energy Center 345-kV line	3.4	2010S	Yes	No[4]
Cypress-Arcadian 345-kV line	488 SE	449 SE	Point Beach-Sheboygan Energy Center 345-kV line	N/A	2010S	No	N/A

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 calculations using AC analysis in PSS/E dispatching 50% of G834 or G833 to TVA area and 50% to WAPA as a proxy for MISO delivery.
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 (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.

Table A.7 – Identified Thermal Violations in Scenario 7 Due to G833 (Assume G834 online)
Summer 2010 (50% Load) Delivery to MISO for NERC Category A and B events (TDF>3%)
G833 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	560 SE	Cypress-Arcadian 345-kV line	23.2	2010S	Yes	No[3]
Cypress-Arcadian 345-kV line	488 SE	527 SE	Point Beach-Sheboygan Energy Center 345-kV line	19.9	2010S	Yes	No[4]
Elkhart Lake-G611 138-kV line	96 SE	122 SE	Point Beach-Sheboygan Energy Center 345-kV line	3.5	2010S	Yes	No[5]
Elkhart Lake-Saukville 138-kV line	88 SE	103 SE	Point Beach-Sheboygan Energy Center 345-kV line	3.1	2010S	Yes	No[6]

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 calculations using AC analysis in PSS/E dispatching 50% of G834 or G833 to TVA area and 50% to WAPA as a proxy for MISO delivery.
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.
5. Line 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.
6. 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). Required rating should be able to be met by increasing line clearance.

Table A.8 – Identified Thermal Violations in Scenario 8 Due to G833 (Assume G834 online)
Summer 2010 (50% Load) Delivery to MISO for NERC Category A and B events (TDF>3%)
G833 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	519 SE	Cypress-Arcadian 345-kV line	23.5	2010S	Yes	No[3]
Cypress-Arcadian 345-kV line	488 SE	472 SE	Point Beach-Sheboygan Energy Center 345-kV line	20.3	2010S	No	No[4]
Elkhart Lake-G611 138-kV line	96 SE	102 SE	Point Beach-Sheboygan Energy Center 345-kV line	3.5	2010S	Yes	No[5]
Elkhart Lake-Saukville 138-kV line	88 SE	85 SE	Point Beach-Sheboygan Energy Center 345-kV line	3.2	2010S	No	No[6]

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 calculations using AC analysis in PSS/E dispatching 50% of G834 or G833 to TVA area and 50% to WAPA as a proxy for MISO delivery.
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.
5. Line 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.
6. 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). 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>3%)

Limiting Element	Existing Rating[1]	Required Rating[1,2]	Worst Double Contingency	TDF (%)	Scenario	Potential Solution Identified
Elkhart Lake-G611 Tap 138-kV line	96 SE	109 SE	Granville-Sheboygan Energy Center 345-kV line Howards Grove-Plymouth #4-Holland 138-kV line	3.78	Scenario 1	No[3]
		114 SE		3.85	Scenario 4	
		142 SE		3.88	Scenario 5	
		107 SE	Point Beach-Sheboygan Energy Center 345-kV line Howards Grove-Plymouth #4-Holland 138-kV line	3.78	Scenario 6	
		132 SE		3.85	Scenario 7	
Cypress-Arcadian 345-kV line	488 SE	569 SE	Point Beach-Sheboygan Energy Center 345-kV line Howards Grove-Plymouth #4-Holland 138-kV line	20.61	Scenario 5	No[4]
		549 SE		20.73	Scenario 7	
Elkhart Lake-Saukville 138-kV line	88 SE	121 SE	Point Beach-Sheboygan Energy Center 345-kV line Howards Grove-Plymouth #4-Holland 138-kV line	3.47	Scenario 5	No[5]
		90 SE		3.47	Scenario 6	
		112 SE		3.44	Scenario 7	
Point Beach-Sheboygan Energy Center 345-kV line	488 SE	570 SE	Cypress-Arcadian 345-kV line Saukville-Maple-Germantown-Bark River 138-kV line	23.67	Scenario 5	No[6]
		500 SE		24.08	Scenario 6	
		562 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 calculations using AC analysis in PSS/E dispatching 50% of G834 or G833 to TVA area and 50% to WAPA as a proxy for MISO delivery.
3. Line 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.
4. 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.
5. 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.
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.

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>3%)

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	1156 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	1064 SE	Point Beach 345-kV bus 4-5 North Appleton-Fox River 345-kV line	56.73	scenario 1	No[4]
		1072 SE		56.63	scenario 2	
		1050 SE		54.06	scenario 3	
		1051 SE		54.27	scenario 4	
		955 SE		57.24	scenario 5	
		966 SE		54.79	scenario 7	
		960 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	687 SE	Forest Junction 345/138-kV transformer #2 North Appleton-Fox River 345-kV line	15.92	scenario 1	No[5]
		744 SE		15.71	scenario 2	
		722 SE		15.10	scenario 3	
Forest Junction 345/138-kV transformer #2	675 SE	686 SE	Forest Junction 345/138-kV transformer #1 North Appleton-Fox River 345-kV line	15.92	scenario 1	No[5]
		743 SE		15.71	scenario 2	
		722 SE		15.00	scenario 3	
Point Beach-Sheboygan Energy Center 345-kV line	488 SE	633 SE	Point Beach 345-kV bus 2-3 Point Beach-Forest Junction 345-kV line	97.04	scenario 1	No[6]
		633 SE		97.14	scenario 2	
		633 SE		97.35	scenario 6	
		679 SE	Cypress-Arcadian 345-kV line Edgewater-Cedarsauk 345-kV line	24.18	scenario 5	
		671 SE		23.85	scenario 7	
Cypress-Arcadian 345-kV line	488 SE	545 SE	Granville-Sheboygan Energy Center 345-kV line North Appleton-Fox River 345-kV line	23.37	scenario 1	No[7]
		565 SE		23.44	scenario 4	
		650 SE	Point Beach 345-kV bus 1-2 Edgewater-Cedarsauk 345-kV line	21.12	scenario 5	
		555 SE		22.04	scenario 6	
		632 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	519 SE	Cypress-Arcadian 345-kV line Granville 345-kV bus tie 1-2	16.84	scenario 1	No[8]
		574 SE		16.84	scenario 5	
		512 SE		17.24	scenario 6	
		565 SE		16.67	scenario 7	
Granville 138-kV bus tie 5-6	539 SE	593 SE		23.47	scenario 5	No[9]
		577 SE		22.19	scenario 7	
Neevin-Woodenshoe 138-kV line	332 SE	399 SE	Granville-Sheboygan Energy Center 345-kV lineNorth Appleton-Fitzgerald 345-kV line	13.98	scenario 1	No[10]
		341 SE		13.88	scenario 2	
		355 SE		13.65	scenario 3	
		413 SE		14.06	scenario 4	
		341 SE		14.90	scenario 5	
		333 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	409 SE	North Appleton-Fox River 345-kV line North Appleton-Kewaunee 345-kV line	13.57	scenario 1	No[11]
		448 SE		13.37	scenario 2	
Forest Junction-Kaukauna Central Tap 138-kV line	293 SE	406 SE		10.51	scenario 1	No[12]
		358 SE		10.41	scenario 2	
		363 SE		10.10	scenario 3	
		412 SE		10.52	scenario 4	
Kaukauna Central-Kaukauna Central Tap 138-kV line	191 SE	193 SE		5.73	scenario 3	No[13]
		219 SE		5.94	scenario 4	
Kaukauna Central Tap-Meadows 138-kV line	169 SE	189 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	316 SE	Granville-Sheboygan Energy Center 345-kV line North Appleton-Fitzgerald 345-kV line	13.88	scenario 1	No[15]
		330 SE		13.85	scenario 4	
		301 SE	Point Beach 345-kV bus 1-2 North Appleton-Fitzgerald 345-kV line	14.29	scenario 5	
		292 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	300 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	387 SE	North Appleton-Fox River 345-kV line North Appleton-Kewaunee 345-kV line	9.39	scenario 1	No[17]
		344 SE		9.39	scenario 2	
		349 SE		9.27	scenario 3	
		392 SE		9.38	scenario 4	
Darboy-Forest Junction 138-kV line	293 SE	400 SE		9.39	scenario 1	
		365 SE		16.22	scenario 2	
		370 SE		16.46	scenario 3	
		406 SE		9.38	scenario 4	
Lake Park-City Limits 138-kV line	293 SE	341 SE		9.49	scenario 1	No[18]
		298 SE		9.59	scenario 2	
		303 SE		9.48	scenario 3	
		346 SE		9.58	scenario 4	
Kewaunee-East Krok 138-kV line	287 SE	337 SE		8.88	scenario 1	No[19]
		317 SE		8.78	scenario 2	
		393 SE		10.83	scenario 3	
		406 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	337 SE	North Appleton-Fox River 345-kV line North Appleton-Kewaunee 345-kV line	8.88	scenario 1	No[20]
		326 SE		6.15	scenario 4	
Melissa-Tayco 138-kV line	143 SE	158 SE		4.39	scenario 2	Yes[21]
		161 SE		4.27	scenario 3	
		181 SE		4.37	scenario 4	
Melissa-Meadows 138-kV line	169 SE	181 SE		4.37	scenario 4	No[22]
Forest Junction-Fox River 345-kV line	1096 SE	1224 SE	North Appleton-Fox River 345-kV line Point Beach 345-kV bus tie 3-4	97.08	scenario 3	No[23]
		1224 SE		96.15	scenario 4	
Elkhart Lake-G611 Tap 138-kV line	96 SE	101 SE	Cypress-Arcadian 345-kV line Granville-Sheboygan Energy Center 345-kV line	5.00	scenario 3	No[24]
		141 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	
		163 SE		5.00	scenario 7	
Elkhart Lake-Saukville 138-kV line	88 SE	107 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	
		140 SE		4.38	scenario 7	
North Appleton-Kewaunee 345-kV line	1071 SE	1166 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	534 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	180 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	
		186 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]
		188 SE		5.52	scenario 7	
Meyer Rd-Mullet River Tap-Lyndon 138-kV line	169 SE	190 SE		5.92	scenario 5	No[30]
		176 SE		5.42	scenario 7	
Fredonia-Lyndon 138-kV line	169 SE	179 SE		5.41	scenario 5	No[31]
		166 SE		5.21	scenario 7	
Edgewater-Saukville 345-kV line	653 SE	697 SE		13.98	scenario 5	No[32]
		691 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]
		102 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 calculations using AC analysis in PSS/E dispatching 50% of G834 or G833 to TVA area and 50% to WAPA as a proxy for MISO delivery.
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 and G833 in Each Scenario without Network Upgrades for Injection Limits

Limiting Element	Worst Contingency	Scenario[1]	G833 and G834 Maximum Output (MW)[2]
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
Elkhart Lake-G611 138-kV line	Point Beach-Sheboygan Energy Center 345-kV line		0
Elkhart Lake-Saukville 138-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 only)
Elkhart Lake-G611 138-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 7	0
Cypress-Arcadian 345-kV line	Point Beach-Sheboygan Energy Center 345-kV line		0
Elkhart Lake-G611 138-kV line	Point Beach-Sheboygan Energy Center 345-kV line		0
Elkhart Lake-Saukville 138-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
Elkhart Lake-G611 138-kV line	Point Beach-Sheboygan Energy Center 345-kV line		0

Notes:
1. See Table 2.2 and 2.3 for the details of each scenario
2. G833-4 ISIS report shows 0 MW allowed.

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

Limiting Element	Existing Rating (MVA)[1]	Required Rating (MVA)[1,2]		Worst Contingency
		From Table A.5 to A.8	From G833/834 ISIS report	
Point Beach-Sheboygan Energy Center 345-kV line	488 SE	568 SE (A.5)	516 SE	Cypress-Arcadian 345-kV line
Cypress-Arcadian 345-kV line	488 SE	546 SE (A.5)	579 SE (north) 513 SE (south)	Point Beach-Sheboygan Energy Center 345-kV line
Elkhart Lake-G611 138-kV line	96 SE	131 SE (A.5)	131 SE	Point Beach-Sheboygan Energy Center 345-kV line
Elkhart Lake-Saukville 138-kV line	88 SE	112 SE (A.5)	N/A	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. The required ratings are calculations using AC analysis in PSS/E dispatching 50% of G834 or G833 to TVA area and 50% to WAPA as a proxy for MISO delivery.

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

Limiting Element	Worst Contingency	Voltage (p.u.)		Scenarios	ΔV (p.u.)	Potential Solution Identified
		Before G834-3	After G834-3			
None identified	-	-	-	-	-	-

Appendix B: Stability Analysis Results

Table B.1-G834 Stability Results for Faults Clearing in Primary Time under Intact System Conditions

Item Number	Element Faulted	Fault Location	Remote Location	Kewaunee Substation	Tested Clearing Cycles	High Gen Model		Low Gen Model		Mitigation Options					Long term solution identified in G834-3 ISIS report
						Before G834	After G834	Before G834	After G834						
					Local/Remote	Units Tripped	Units Tripped	Units Tripped	Units Tripped	Bypass lock out relay at T10+	Install 421 impedance relay++	Maintain MVAR output at Kewaunee above zero	Replacing breakers	Limit G834 under prior outage condition	2011 Kewaunee bus reconfiguration
1	T10 – Kewaunee 345/138 kV Transformer	KWH	KWL	Existing	6.0*/8.5 (before G834) 6.5*/8.5 (after G834)	OK	OK	OK	K Stable at 6.0/8.5 Stable at 6.5/8.5 with maintaining Kewaunee Var output above 0	Yes	Yes	Yes Stable at 6.5/8.5	Yes	Yes	Yes

Note: Without 2011 Kewaunee Bus Reconfiguration, G834 at 100%, G833 offline, All Competing Generators at 100%, PSS of Point Beach In Service.
Tripped Units: K-Kew, P1-POB G1, P2-POB G2, P-POB G1 & G2, F1-FOX CT1, F2-FOX CT2, Fs-FOX ST, S1-SEC 1, S2-SEC 2, S-SEC 1&2
Clearing times (Cycles) include 1.0 cycle margin on faulted end clearing time
* 0.5 and 1.0 cycle planning margins were added to the actual clearing time for the existing and new systems respectively.
+ Bypassing lockout relay will reduce the tested clearing time roughly by 0.5 cycle
++ Installing a 421 impedance relay will reduce the tested clearing time roughly by 1.5 cycle

Table B.2-G834 Stability Results for Faults Clearing in Primary Time under Prior Outage Conditions

Event	Faulted	Fault	Prior	Existing Clearing Tested Clearing Cycle (Local/Remote)		High Gen		Low Gen		Mitigation Options					Long term solution identified in G834-3 ISIS report
#	Element	Location	Outage	Before G834	After G834	Before G834	After G834	Before G834	After G834	Bypass lock out relay at T10[+]	Install 421 impedance relay[++]	Maintain MVAR output at Kewaunee above zero	Replacing breakers at Kewaunee 345 kV	Limit G834 under prior outage condition	2011 Kewaunee bus reconfiguration
2	R-304	KEW	L-111	5.0/6.5	5.5/6.5	OK	OK	OK	OK						
3	T-10	KEW	L-111	6.0/8.5	6.5/8.5	OK	OK	OK	K Stable at 4.5/6.5 [#]Maintaining VAR output around 0 works for 6.0/8.5	Replacing breakers plus maintaining MVAR output at Kewaunee above zero Installing impedance relay or bypassing lockout relay plus maintaining MVAR output at Kewaunee above zero				Yes	West Switching station and Kewaunee bus reconfiguration (breaker replacement)
4	R-304	KEW	L-121	5.0/6.5	5.5/6.5	OK	OK	OK	OK						
5	T-10	KEW	L-121	6.0/8.5	6.5/8.5	OK	OK	OK	OK						
6	R-304	KEW	L-151	5.0/6.5	5.5/6.5	OK	OK	OK	OK						
7	T-10	KEW	L-151	6.0/8.5	6.5/8.5	OK	OK	OK	OK						
8	R-304	KEW	6832	5.0/6.5	5.5/6.5	OK	P,K,F,S Stable at 4.5/6.5	OK	OK				Yes	Yes Limit the Gross output of Point Beach G1 to 540 MW (gross) to be stable With the existing 3 cycle breaker at North Appleton (associated with R304) replaced and 4.5 cycle remote primary clearing time achieved, limit the Gross output of Point Beach G1 to 560 MW (gross) to be stable	Yes
9	T-10	KEW	6832	6.0/8.5	6.5/8.5	OK	OK	OK	OK						
10	T-10	KEW	971L71	6.0/8.5	6.5/8.5	OK	OK	OK	K Stable at 6.0/8.5 [#]Stable at 6.5/8.5 with maintaining Kewaunee Var output above 0	Yes	Yes	Yes Stable at 6.5/8.5	Yes	Yes	Yes
11	R-304	KEW	SEC31	5.0/6.5	5.5/6.5	OK	P,K, S Stable at 5.0/6.5 Or Stable at 5.0/4.5	OK	OK				Yes	Yes Limit the Gross output of Point Beach G1 to 620 MW (gross) to be stable But, no limit is required with the existing 3 cycle breaker at North Appleton replaced and 4.5 cycle remote primary clearing time achieved. Generators seem stable with 4.5 local primary and 4.5 remote primary clearing times.	Yes
12	T-10	KEW	SEC31	6.0/8.5	6.5/8.5	OK	P,K,F,S Stable at 6.0/6.5	OK	K Stable at 6.0/8.5 [#]Maintaining VAR output around 0 does not work for 6.5/8.5	Yes	Yes		Yes	Yes	Yes
13	R-304	KEW	CYP31	5.0/6.5	5.5/6.5	OK	OK	OK	OK						
14	T-10	KEW	CYP31	6.0/8.5	6.5/8.5	OK	OK	OK	K Stable at 6.0/8.5 [#]Stable at 6.5/8.5 with maintaining Kewaunee Var	Yes	Yes	Yes Stable at 6.5/8.5	Yes	Yes	Yes

									output above 0						
15	R-304	KEW	T10	5.0/6.5	5.5/6.5	OK	OK	OK	OK						
16	R-304	KEW	NAPL71	5.0/6.5	5.5/6.5	OK	OK	OK	OK						
17	T-10	KEW	NAPL71	6.0/8.5	6.5/8.5	OK	K Stable at 6.0/8.5	OK	K Stable at 6.0/8.5	Yes	Yes		Yes	Yes	Yes
18	R-304	KEW	971L51	5.0/6.5	5.5/6.5	OK	OK	OK	OK						
19	T-10	KEW	971L51	6.0/8.5	6.5/8.5	OK	OK	OK	K Stable at 6.0/8.5 #Stable at 6.5/8.5 with maintaining Kewaunee Var output above 0	Yes	Yes	Yes Stable at 6.5/8.5	Yes	Yes	Yes
20	R-304	KEW	L311	5.0/6.5	5.5/6.5	OK	OK	OK	OK						
21	T-10	KEW	L311	6.0/8.5	6.5/8.5	OK	K Stable at 6.0/8.5	OK	K Stable at 6.0/8.5 #Maintaining VAR output around 0 does not work for 6.5/8.5	Yes	Yes		Yes	Yes	Yes
22	R-304	KEW	POB12	5.0/6.5	5.5/6.5	OK	OK	OK	OK						
23	T-10	KEW	POB12	6.0/8.5	6.5/8.5	OK	OK	OK	K Stable at 6.0/8.5 #Maintaining VAR output around 0 does not work for 6.5/8.5	Yes	Yes		Yes	Yes	Yes
24	L121	POB	POB23	4.5/4.5	5.0/4.5	OK	P1 Stable at 4.0/4.5	OK	P1 Stable at 2.5/4.5 #Maintaining VAR output around 0 does not work for 5.0/4.5					Yes Limit the Gross output of Point Beach G1 to 560 MW (gross) to be stable	No solution. An OP Guide is needed for the POB 2-3 bus tie outage, Or Take the bus tie outage during generation refueling outage window
25	R-304	KEW	POB23	5.0/6.5	5.5/6.5	OK	OK	OK	OK						
26	T-10	KEW	POB23	6.0/8.5	6.5/8.5	OK	OK	OK	OK						
27	T-10	KEW	POB34	6.0/8.5	6.5/8.5	OK	OK	OK	OK						
28	R-304	KEW	POB45	5.0/6.5	5.5/6.5	OK	OK	OK	OK						
29	T-10	KEW	POB45	6.0/8.5	6.5/8.5	OK	OK	OK	OK						

Note: Without 2011 Kewaunee Bus Reconfiguration, G834 at 100%, G833 offline, All Competing Generators at 100%, PSS of Point Beach In Service.
Tripped Units: K-Kew, P1-POB G1, P2-POB G2, P-POB G1 & G2, F1-FOX CT1, F2-FOX CT2, Fs-FOX ST, S1-SEC 1, S2-SEC 2, S-SEC 1&2
Clearing times (Cycles) include 0.5 and 1.0 cycle margin on faulted end clearing time for the existing and new systems respectively
Tested after adjusting the voltage schedule (adjusting less than 0.1 %) at Kewaunee Unit so the VAR output can be around zero from Kewaunee Unit.
+ Bypassing lockout relay will reduce the tested clearing time roughly by 0.5 cycle
++ Installing a 421 impedance relay will reduce the tested clearing time roughly by 1.5 cycle

Table B.3-G834 Stability Results for 3-Phase Faults Cleared in Delayed (Breaker Failure) Time under Intact Conditions

Event Number	Element Faulted	Fault Location	Remote Location	Event Notes	Tested Clearing Cycle (Local/Remote)*	High Generation Base: Before G834	High Generation Base: After G834	Low Generation Base: Before G834	Low Generation Base: After G834	Mitigation Options: Maintain MVAR output at Kewaunee above zero	Mitigation Options: Install faster SEL 325 rely to reduce 8.25 cycles of required clearing time	Long term solution
30	L111	POB	SEC	T1X03 Tripped, Aux Moved	3.5/9.5/4.5 (before G834) 3.5/10.0/4.5 (after G834)	OK	OK	OK	OK			
31	L151	POB	FOX	T2X03 Tripped, Aux Moved	3.5/9.5/4.5 (before G834) 3.5/10.0/4.5 (after G834)	OK	OK	OK	OK			
32	Q303	POB	KEW	Trip T10 Primary, Delay POB Split	3.5/9.5/6.5 (before G834) 3.5/10.0/6.5 (after G834)	OK	K Stable at 3.5/9.75/6.5 (9.25 CCT can be achieved with a high speed SEL 325 installed)	K Stable at 3.5/8.75/6.5 Stable at 3.5/10.0/6.5 with maintaining Kewaunee VAR output above 0	K Stable at 3.5/8.5/6.5 Stable at 3.5/9.5/6.5 with maintaining Kewaunee VAR output above 0	Installing SEL 325 will reduce the clearing time to 8.25 cycles. In addition to installing SEL 325, maintaining VAR output at Kewaunee above zero is needed to further reduce the clearing time.		West Substation (identified in G834-3 ISIS report), Plus maintain VAR output at Kewaunee above zero Plus install SEL 325

Note: Without 2011 Kewaunee Bus Reconfiguration, G834 at 100%, G833 offline, All Competing Generators at 100%, PSS of Point Beach In Service.
Tripped Units: K-Kew, P1-POB G1, P2-POB G2, P-POB G1 & G2, F1-FOX CT1, F2-FOX CT2, Fs-FOX ST, S1-SEC 1, S2-SEC 2, S-SEC 1&2
Clearing times (Cycles) include 1.0 cycle margin on faulted end clearing time
* According to ATC Protection, the existing breaker failure time for Q303 fault at Point Beach is 9.0 cycle (=10.0 cycle with 1.0 cycle planning margin considered)

Table B.4-G833 Stability Results for Faults Clearing in Primary Time under Intact System Conditions
With Proposed Kewaunee Bus Reconfiguration, Without West Switching Station
(Per G833-834 ISIS report)

NONE

Table B.5--G833 Stability Results for Faults Clearing in Primary Time under Prior Outage Conditions
With Proposed Kewaunee Bus Reconfiguration, Without West Switching Station
(Per G833-834 ISIS report)

Event #	Faulted Element	Fault Location	Prior Outage	Existing Clearing Time	Existing Clearing High Gen		Existing Clearing Low Gen		Tested Clearing Time	Tested Clearing High Gen		Tested Clearing Low Gen		Mitigation Option
					Existing	West SS	Existing	West SS		Existing	West SS	Existing	West SS	
1	R-304	KEW	Q-303	4.5/6.5	K	K*	K	K*	4.5/4.5	K	K*	K	K*	Study result shows that Kewaunee generator is stable with 500 MW (Gross or ~ Net 475 MW) output with the tested clearing time. According to the Scope document developed for the 2011 Kewaunee bus reconfiguration project, Kewaunee needs to be reduced to <u>475 MW (Net) for generation stability in anticipation of R304 fault</u>. In addition, it may need to be further reduced due to thermal overload issue on Kewaunee-East Krok 138 kV line under the Q303 prior outage condition in anticipation of R304 fault. 4.5 cycle remote clearing time will be achieved by replacing the 3 cycle breaker at North Appleton.
2	Q-303	POB	R-304	4.5/4.5	K	K**	K	K**	n/a					N/A
3	Q-303	KEW	R-304	4.5/4.5	K	K**	K	K**	n/a					N/A
4	R-304	KEW	6832	4.5/6.5	P, K, F, S	none	none	none	4.5/4.5	P, K, F	none	none	none	Replace the 3 cycle breaker at North Appleton associated with R304 to achieve 4.5 cycle remote clearing time, plus limit Point Beach G2 to 620 MW (gross) under the prior outage of line 6832. Long term solution is constructing new West Switching Station
5	L-121	POB	POB23	4.5/4.5	P1*	P*1	P1*	P1*	n/a					Limit Point Beach G1 to 560 MW (gross) under the bus tie outage or take the bus tie outage during Point Beach generation refueling outage window

Notes: (1) Tripped Units - K-KEW, P1-POB 1, P2-POB 2, P- POB 1 & 2, F1-Fox CT1, F2-Fox CT2, Fs-Fox ST, F-Fox CT1, CT2 & ST, S1-SEC 1, S2-SEC 2, S-SEC 1 & 2.
(2) Clearing Times (Cycles) Include 1.0 Cycle Margin on Faulted End Clearing Time
K* - Stable with Kewaunee Net Generation ≤ 500 MW.
K** - Stable with Kewaunee Net Generation ≤ 475 MW.
P1* - Stable with West Switching Station and Kewaunee Net Generation ≤ 550 MW. Stable at Full Generation with East Switching Station, w/ or w/o West Switching Station.

Table B.6--G833 Stability Results for Faults Clearing in 3-Phase Faults Cleared in Delayed Time under Intact Conditions With Proposed Kewaunee Substation Configuration, Without West Switching Station (Per G833-834 ISIS report)

Event	Element	Fault	Remote	Event	Existing	High Generation Base		High Generation – West SS		Low Generation Base		Low Generation – West SS		Mitigation options
Number	Faulted	Location	Location	Notes	CCT*	3.5/9.5/4.5	Existing	3.5/9.5/4.5	Existing	3.5/9.5/4.5	Existing	3.5/9.5/4.5	Existing	
1	L111	POB	SEC	T1X03 Tripped, Aux Moved	3.5/10.0/4.5	P, K*	P, K, Fs		none	P, K**	PK	none	PK	Replace the existing breaker failure relay with a high speed SEL 325 and wire relay to direct trip breaker failure breaker to achieve 8.25 cycle breaker failure clearing time plus limit Point Beach G2 to 600 MW (gross). Stable at 8.25 cycles with 600 MW (gross output from POB G2) Long term solution will be constructing a new West Switching Station
2	L151	POB	FOX	T2X03 Tripped, Aux Moved	3.5/10.0/4.5		none		none	none	PK	none	PK	Replace the existing breaker failure relay with a high speed SEL 325 and wire relay to direct trip breaker failure breaker to achieve 8.25 cycle breaker failure clearing time
3	Q303	POB	KEW	Delay POB Split	3.5/10.0/6.5		none		none	none	P2	none	none	Replace the existing breaker failure relay with a high speed SEL 325 and wire relay to direct trip breaker failure breaker to achieve 8.25 cycle breaker failure clearing time. It was the mitigation option for G834 interconnection. There is no need to improve remote clearing time because Kewaunee bus reconfiguration project will improve the remote clearing time to 4.5 cycles.
4	Q303	KEW	POB	Trip T10 Primary, Delay POB Split	3.5/10.0/4.5		none		none	none	K	none	K	According to protection, breaker failure clearing time will become 8.5 cycles with the proposed Kewaunee bus reconfiguration project done
5	R-304	KEW	NAP	Split NAP Primary, T10 Trips in BF	3.5/10.0/6.5		none		none	none	PK	none	PK	Replace the 3 cycle breaker at North Appleton associated with R304 to achieve 4.5 cycle remote clearing time. According to protection, breaker failure clearing time will become 8.5 cycles with the proposed Kewaunee bus reconfiguration

* - Stable at 9.25 cycles at bus and 9.5 cycles 10% down the line.
** - Stable at 9.0cycles at bus.

Appendix C: Competing Wind Generators

Queue Number	Control Area	MW	Commercial Operation Date (From 10-31-08 status report)	Geographical Location
G384	WPS	99	TBD (suspended)	Kewaunee-Mishicot 138 kV line
G427	WEC	98	TBD (suspended)	Cypress 345 kV Substation
G590	WEC	98	TBD (suspended)	Tecumseh Rd 138 kV Substation
G611	WEC	99	12-31-2010	Elkhart Lake-Forest Junction 138 kV line
G773	WPS	150	12-01-2010 In Facilities Study Stage	Forest Junction-Lost Dauphin 138 kV line

Appendix D: Network Upgrades for G833/834 per ISIS Report

Location	Facilities	Reason	Good Faith Cost Estimate (Y2008)	Worst contingencies
Cypress-West Switching Station 345-kV line (L-CYP31 north)	**Item #1** – Increase conductor temperature rating 4° F. look at plan and profile and Patrol to observe any close wire crossings and adjust to obtain a minimum Summer Emergency rating of 675 MVA (1130 A).	Injection Limit	$150,000	100% load - North Appleton-Fox River 345 kV line (6832) 50% load- POB-SEC (111)
Point Beach-Sheboygan Energy Center 345-kV line (L111)	**Item #2** – Increase 345 kV line clearance to obtain a minimum Summer Emergency rating of 555 MVA (929 A). Little to no work is expected to be required to increase rating only 4° F. Cost is to review plan and profile and patrol to observe any close wire crossings and adjust accordingly.	Injection Limit	$150,000	50% load – Cypress-West Switching station
Elkhart Lake-G611 Tap 138-kV line (4035 south)	**Item #3** – Increase the clearance on the 138 kV line to obtain a minimum Summer Emergency rating of 131 MVA (549 A) by replacing the existing conductor with 336 kcmil or T2-4/0 AWG.	Injection Limit	$5,876,000	100% load - Granville-Sheboygan Energy 345 kV line (L-SEC31) 50% load-POB-SEC (111)
A New 345 kV Switching Station at the Intersection of lines L-CYP31 and W-1. (West Switching Station)	**Item #4** – A 4 (expandable to 6) position 345 kV ring bus connecting lines L-CYP31 (Cypress-Arcadian) and W-1 (Edgewater-South Fond du Lac). Include: Control house, relay protection (ATC standard 345 kV line protection panels plus a bus differential panel with redundant relays), communication and accessories, four 3000A, 50kA, 2 Cycle, GCB (complete IPO installation), four line and twelve maintenance disconnect switches, four dead ends, twelve bus CCVTs, eight line CCVTs, line traps, and tuners; twelve MCOV arresters, jumpers, cables, trench, conduits, and grounds. Assumes transmission line additions <1 mile and falling within PSCW CA guidelines.	Stability Upgrades	$11,919,014	Stability: Fault L111 with Breaker Failure
Point Beach 345 kV Bus	**Item #5**[1] –Point Beach Faults Protection Improvements. Item 5A: Achieve L111 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.[2] Item 5B: 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.[2]	Stability Upgrades	$106,592	Stability: Fault L111 or L151 with Breaker Failure
North Appleton 345 kV Bus	**Item #6**[1] – R-304 Fault at Kewaunee Protection Improvement Achieve R-304 fault clearing times of 3.5 cycles local primary, 8.5 cycles local delayed and 4.5 cycles remote primary by reducing remote primary by 1.0 cycle.[3]	Stability Upgrades	$515,437	Stability: Fault R-304 with Breaker Failure
	TOTAL		**$18,717,043**	

Appendix E: Impact of G427, G611 and G773 on Saukville-Elkhart Lake-G611-Forest Junction 138 kV line

(Before and After G834, using Scenario 5)

CASE	Limiting Element	Existing Rating (MVA)	Contingency	Before G834 MVA	After G834 MVA	DF	REQ'D RATING	% Loading	Allowable MW	Status of Competing Wind Generators
2010S	Elkhart Lake-G611-Forest Junction 138-kV line*	96	Point Beach-Sheboygan Energy Center345-kV line	97.1	100.6	3.6%	105.89	110.3%	-165.2	Without G611
2010S	Elkhart Lake-Saukville 138-kV line	88	Point Beach-Sheboygan Energy Center345-kV line	83.2	86.6	3.5%	91.15	103.6%	11.52	Without G611
2010S	Cypress-Arcadian 345-kV line	488	Point Beach-Sheboygan Energy Center345-kV line	484.6	505.40	21.2%	532	109.0%	-98.94	Without G611
2010S	Elkhart Lake-G611-Forest Junction 138-kV line	96	Point Beach-Sheboygan Energy Center345-kV line	94.5	98	3.6%	103.15	107.5%	-92.4	Without G611 and G427
2010S	Elkhart Lake-Saukville 138-kV line	88	Point Beach-Sheboygan Energy Center345-kV line	80.6	84	3.5%	88.42	100.5%	86.47	Without G611 and G427
2010S	Cypress-Arcadian 345-kV line	488	Point Beach-Sheboygan Energy Center345-kV line	444.8	465.4	21.0%	489.89	100.4%	89.43	Without G611 and G427
2010S	Elkhart Lake-G611-Forest Junction 138-kV line	96	Point Beach-Sheboygan Energy Center345-kV line		91		95.78	99.8%		Without G611 G427, G773
2010S	Elkhart Lake-Saukville 138-kV line	88	Point Beach-Sheboygan Energy Center345-kV line		77.1		81.15	92.2%		Without G611 G427, G773
2010S	Cypress-Arcadian 345-kV line	488	Point Beach-Sheboygan Energy Center345-kV line		436.1		459.05	94.1%		Without G611 G427, G773
2010S	Elkhart Lake-G611 138-kV line	96	Point Beach-Sheboygan Energy Center 345-kV line	120.8	124.2	3.5%	130.73	136.2%	-853.17	With all competing generation
2010S	Elkhart Lake-Saukville 138-kV line	88	Point Beach-Sheboygan Energy Center 345-kV line	102.5	105.6	3.2%	111.15	126.3%	-597.48	With all competing generation
2010S	Cypress-Arcadian 345-kV line	488	Point Beach-Sheboygan Energy Center 345-kV line	498.7	518.1	19.8%	545.36	111.8%	-177.30	With all competing generation

*Note: G611 interconnection requires uprating the Elkhart Lake-G611-Forest Junction 138 kV line to 112 MVA.

Appendix F: Study Criteria

Study Criteria

F.1 Contingencies

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

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

For power flow analysis, contingencies include:

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

F.2 Monitored Elements

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

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

A Transmission Reliability Margin (TRM) of 5% must be applied to the MVA ratings of each monitored ATCLLC element. Violations reported will be based upon the adjusted MVA rating.

F.3 Thermal Loading Criteria

F.3.1 Injection Violations

Generation injection violations include: 1) thermal violations of the transmission elements that connect the Generator to the rest of the transmission network (outlet congestion); 2) thermal violations of the transmission elements that have a transfer distribution factor (TDF) ≥ 20% anywhere in the studied system in relation to real power injected at the Point of Interconnection (POI) when delivered to all of MISO; or 3) thermal violations created by the loss of a transmission element connected to the generator interconnection substation.

F.3.2 Operating Restriction Calculation

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

F.4 Steady State Under Voltage Criteria

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

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

F.4.2 N-2 Contingency Evaluation

Power flow solutions must converge for a selected number of N-2 contingencies in the electrical proximity of the studied Generator. Divergence of a power flow solution indicates potential voltage collapse. A “fix” must be identified for any non-converging power flow simulation and may include generator operating restrictions. [Note: Non-convergence may be due to solution settings such as switched shunt operation and/or LTC action.]

F.5 Angular Stability Criteria

Critical Clearing Time (CCT) is a period relative to the start of a fault, within which all generators in the system remain stable (synchronized). CCT is obtained from simulation. Maximum Expected Clearing Time (MECT) determines a period of time that is needed to clear a fault using the existing system facilities. MECT is dictated by the existing system facilities. In any contingency, if the computed CCT is less than the MECT plus a margin determined by ATC (1.0 cycle for studies using estimated generator data and 0.5 cycles for studies using confirmed generator data), it is considered an unstable situation and is unacceptable. Otherwise, it is considered acceptable transient stability performance.

Longer time-domain simulations must be performed on faults cleared at the CCT to examine dynamic stability. Simulations will typically cover 20 seconds of system dynamics and machine angle oscillations must meet the damping criteria in the ATC Planning Criteria.

Note that ATC stability criteria and NERC stability criteria differ on the study assumptions used for breaker failure analysis. ATC study criterion models breaker failure by modeling a three-phase fault during the primary time, reduced to SLG fault if the failed breaker is an Independent Pole Operated (IPO) breaker during delayed clearing and cleared at the end of the delayed clearing time. On the other hand, NERC study criterion assumes a single line-to-ground fault for the entire breaker failure analysis. Hence, the CCT computed from ATC stability criteria is always less than or equal to the value computed using the NERC study criteria. This report assumes ATC stability criteria unless otherwise stated.

The time-domain simulations must also be reviewed for compliance with the transient and dynamic voltage standards in the ATC Planning Criteria. Voltages of all transmission system buses must recover to be at least 70% of the nominal system voltages immediately after fault removal and 80% of the nominal system voltages in 2.0 second after fault removal.

Appendix G: Loading on Forest Junction-Elkhart Lake 138 kV line with G611 offline

(After G833 with G834 assumed on-line, using Scenario 5)

CASE	Limiting Element	Existing Rating (MVA)	Contingency	After G833 MVA	DF	REQ'D RATING	% Loading	Status of Competing Wind Generators
2010S	Forest Junction-Elkhart Lake 138-kV line*	96	Point Beach-Sheboygan Energy Center345-kV line	104.4		109.9	114.5%	Without G611

*Note: G611 interconnection requires uprating the Elkhart Lake-G611-Forest Junction 138 kV line to 112 MVA.

Appendix H: Estimated Allowable MW Output from G834 or G833
Under Spring/Fall or Winter Emergency Ratings

- Allowable output from G834 between 2010 and 2011 (before G833 in service) with Spring/Fall emergency ratings considered

Limiting Element	Spring/Fall Existing Rating (MVA)	Contingency	PRE MVA[1]	POST MVA[1]	% Loading	DF	REQ'D RATING	Allowable MW
Point Beach-Sheboygan Energy Center 345-kV line	968	Cypress-Arcadian 345-kV line	516.2	539.1	58.62%	23.37%	567.4736842	1726.340611
Cypress-Arcadian 345-kV line	968	Point Beach-Sheboygan Energy Center 345-kV line	498.7	518.1	56.34%	19.80%	545.3684211	2126.195876
Elkhart Lake-G611 138-kV line	117	Point Beach-Sheboygan Energy Center 345-kV line	120.8	124.2	111.74%	3.47%	130.7368421	-278.1470588
Elkhart Lake-Saukville 138-kV line	117	Point Beach-Sheboygan Energy Center 345-kV line	102.5	105.6	95.01%	3.16%	111.1578947	273.4516129

- Allowable output from G834 between 2010 and 2011 (before G833 in service) with Winter emergency rating considered

Limiting Element	Winter Existing Rating (MVA)	Contingency	PRE MVA[1]	POST MVA[1]	% Loading	DF	REQ'D RATING	Allowable MW
Point Beach-Sheboygan Energy Center 345-kV line	1311	Cypress-Arcadian 345-kV line	516.2	539.1	43.29%	23.37%	567.4736842	3120.80786
Cypress-Arcadian 345-kV line	1076	Point Beach-Sheboygan Energy Center 345-kV line	498.7	518.1	50.68%	19.80%	545.3684211	2644.484536
Elkhart Lake-G611 138-kV line	136	Point Beach-Sheboygan Energy Center 345-kV line	120.8	124.2	96.13%	3.47%	130.7368421	242.1176471
Elkhart Lake-Saukville 138-kV line	136	Point Beach-Sheboygan Energy Center 345-kV line	102.5	105.6	81.73%	3.16%	111.1578947	844.0645161

1. Pre and Post MVA flow were estimated and obtained from Table A.5

- Allowable output from G833 beyond 2011 (w/ G834 assumed in service) with Spring/Fall emergency ratings considered

Limiting Element	Spring/Fall Existing Rating (MVA)	Contingency	PRE MVA²	POST MVA³	% Loading	DF	REQ'D RATING	Allowable MW
Point Beach-Sheboygan Energy Center 345-kV line	968	Cypress-Arcadian 345-kV line	539.1	563	61.22%	24.90%	592.6	1528.4
Cypress-Arcadian 345-kV line	968	Point Beach-Sheboygan Energy Center 345-kV line	518.7	540.5	58.78%	22.71%	568.9	1765.4
Elkhart Lake-G611 138-kV line	117	Point Beach-Sheboygan Energy Center 345-kV line	124.2	125.4	112.82%	1.25%	132.0	-1044.0
Elkhart Lake-Saukville 138-kV line	117	Point Beach-Sheboygan Energy Center 345-kV line	105.6	111.7	100.49%	6.35%	117.6	87.3

- Allowable output from G833 beyond 2011 (w/ G834 assumed in service) with Winter emergency rating considered

Limiting Element	Winter Existing Rating (MVA)	Contingency	PRE MVA²	POST MVA³	% Loading	DF	REQ'D RATING	Allowable MW
Point Beach-Sheboygan Energy Center 345-kV line	1311	Cypress-Arcadian 345-kV line	539.1	563	45.20%	24.90%	592.6	2837.2
Cypress-Arcadian 345-kV line	1076	Point Beach-Sheboygan Energy Center 345-kV line	518.7	540.5	52.88%	22.71%	568.9	2217.2
Elkhart Lake-G611 138-kV line	136	Point Beach-Sheboygan Energy Center 345-kV line	124.2	125.4	97.06%	1.25%	132.0	400.0
Elkhart Lake-Saukville 138-kV line	136	Point Beach-Sheboygan Energy Center 345-kV line	105.6	111.7	86.46%	6.35%	117.6	371.4

2. Pre MVA flow was estimated from Table A.5
3. Post MVA flow was estimated from the case (Scenario 5 with G833/834 and all wind 100%, with 2011 Kewaunee modeled) which was used to calculated required ratings shown in Column 3 of Table 1.2

Note: The results shown in the above tables are based on 50% peak load cases.