AMERICAN TRANSMISSION COMPANY
THE ENERGY ACCESS COMPANY

Interconnection System Impact Study 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

Revision 3

December 17, 2008

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Executive Summary

This Interconnection System Impact Study report documents the system impacts and required upgrades needed to interconnect 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. 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).

Revision 1 includes the MISO Deliverability Analysis results that indicate than no upgrades are needed for G833 and G834 Network Resource Interconnection Service (NRIS) operation. Revision 2 changed the requirement to add 345 kV high side breakers to auxiliary transformers T1X03 and T2X03 to a recommendation to add these breakers and further explained the benefits of these breakers. Revision 3 includes stability simulation results for Point Beach GSU and Auxiliary Transformer faults based on fault clearing times provided by staff at Point Beach in response to a request by ATC.

This study has identified the Interconnection Facilities and Network Upgrades to facilitate the requested interconnection for Energy Resource Interconnection Service (ERIS). Deliverability analysis has shown that no upgrades are needed for NRIS operation. For ERIS, the good faith estimate of cost for the Network Upgrades identified in this report is approximately $18.7 million. The preliminary, good faith estimate of schedule indicates that all of the Network Upgrades can be in-service within 5 years of an executed Interconnection Agreement.

Although there are no required Interconnection Facilities for this project, ATC recommends that the Interconnection Customer reduce the primary fault clearing time for Point Beach auxiliary transformer T1X03 from 5.1 cycles to 4.75 cycles and for auxiliary transformer T2X03 from 5.1 cycles to 4.25 cycles to prevent these faults from causing the Point Beach and Kewaunee generators to lose synchronism. ATC also recommends installing 345 kV circuit breakers on the high side of each of these two 345/13.2 kV auxiliary transformers to prevent a breaker failure event during auxiliary transformer faults from tripping Point Beach generation. Section 1.3 describes the reliability benefits of these recommendations.

The Interconnection Customer must commission updated optimal settings for the existing Point Beach Power System Stabilizers (PSSs) as described in Section 1.4 of this report.

The next step in the Generator Interconnection Request process is for the customer to decide whether or not to proceed to an Interconnection Facilities Study. An Interconnection Facilities Study will specify in more detail the time and cost of the equipment, engineering, procurement and construction of the system upgrades identified in the ISIS report.

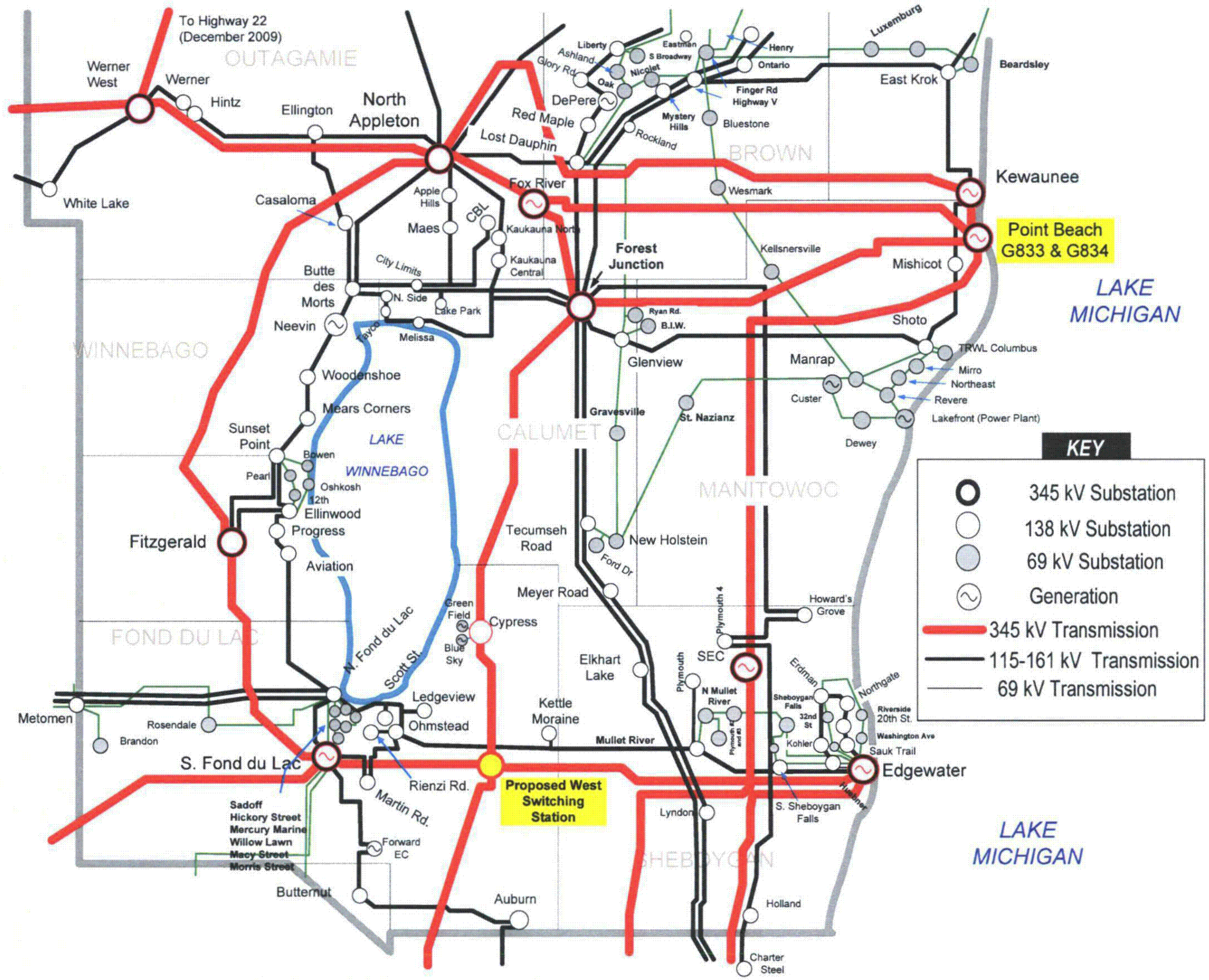

Figure 1 – G833 and G834 Proposed Interconnection at the Point Beach 345 kV Substation and Surrounding System (as expected in 2010) with Proposed West Switching Station.

1. Summary

This study report is a revision of Revision 2 of the posted G833/G834 System Impact Study Report dated August 13, 2008 for the Midwest Independent System Operator (MISO) Generation Interconnection Requests identified as Projects G833 and G834, Queue #39297-01 and #39297-02. This study evaluates the impact of the proposed 106 MW increase in generation at the Point Beach nuclear plant which is connected to the 345 kV transmission system in Manitowoc County, Wisconsin. The customer has requested the following dates for the various stages of interconnection:

- Interconnection Facilities In-Service (Backfeed) Date: Existing facility, not applicable.
- Initial Synchronization Date: Not supplied.
- Commercial Operation Date: May 31, 2010 for G834 and May 31, 2011 for G833.

Revision 1 included the following changes:

- Updates to the Executive Summary, Sections 1, 1.4, 1.6, 2.3.3 and 3.4, Appendix E and Table 1.2 to reflect completion of the deliverability analysis.

Revision 2 included the following changes:

- Updates to Sections 1.3 and 3.2.5, Figure 1.1 and Table 1.4 and adding Figure 1.2 to reflect that the addition of 345-kV high side circuit breakers to transformers T1X03 and T2X03 are recommendations and not requirements.

Revision 3 includes the following changes:

- Updates to Sections 1.3, 2.4.1, 3.2.1 and 3.2.5, Figure 1.1, and Tables 1.4, C-9 and C-10, and adding Tables C-11 to C-13 to incorporate Point Beach supplied clearing times for faults on the Generator Step Up and Auxiliary Transformers.

The Large Generator Interconnection Procedures permit the Interconnection Customer to request specific Backfeed, Initial Synchronization and Commercial Operation Dates. G833 and G834 involve increasing output from existing generators and the required Interconnection Facilities already exist. The Interconnection Facilities Study process will include a high-level evaluation of any known scheduled outage requirements. The scheduled outage requirements and associated evaluations will continue to be refined as project implementation details progress.

The proposed increase in Point Beach generation will be obtained by increasing the thermal power of the reactor. This will require the rewinding of the stator and rotor of the existing Point Beach generators. No changes to the Point Beach substation layout or system topography are required to "interconnect" the increased generation since the units are already connected to the transmission grid. Figure 1.1 shows the expected 345 kV transmission system topology near the Point Beach substation for the 2011 time frame, including the required 345 kV switching station east of Fond du Lac that eliminates stability issues found with the increased Point Beach generation.

Note that Figure 1.1 shows the existing substation layout for the existing Generating Facilities. Figure 1.1 provides a conceptual, equivalent depiction of the Interconnection Customer's

Generating Facilities. The Interconnection Customer will need to supply Generating Facility diagrams for the Large Generator Interconnection Agreement.

Required construction outages to build the new 345 kV switching station will be reviewed further in the Interconnection Facilities Study, along with outages required for the other identified Network Upgrades. Any requested outage must be cleared through an ATC screening process and be formally submitted (outage is logistically supported with a work order and associated construction resources) to the Midwest ISO for approval. The Midwest studies outages based on the submitted queue position within their outage scheduling database.

This study identifies steady state system thermal and voltage impacts, system angular stability impact and the circuit breaker fault duty impacts associated with the interconnection of G833 and G834. These interconnection system impacts are based on Linear Transfer and AC power flow analyses, transient stability analysis and short circuit analysis. This study also identifies the Network Upgrades and Interconnection Facilities required to eliminate any unacceptable system impacts and to allow the generator to interconnect to the system. Preliminary, good faith estimates of cost and schedule are also provided for the identified Network Upgrades.

In order for G833 and G834 to interconnect as an Energy Resource (ER), the required Network Upgrades and Interconnection Facilities must be completed. In order for G833 and G834 to qualify as a Network Resource (NR), any additional Network Upgrades that are identified based on the MISO deliverability analysis must also be completed.

1.1 Injection Limits[1]

The injection limits are identified in Tables A.1 and A.2 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 seasonal models studied.

The study identified three steady-state thermal violations for NERC Category B (N-1) events that meet the criteria for injection limits:

1. Cypress-Conceptual West Switching Station 345-kV Line (L-CYP31 north)
2. Point Beach-Sheboygan Energy 345 kV Line (L111)
3. Elkhart Lake-G611 Tap 138 kV Line (4035 southern section)

The Network Upgrades for these injection limits are described in Section 1.4 and are required for either ERIS or NRIS for the full 106 MW of requested interconnection service of G833 and G834.

1.2 Generating Facility Operation Restrictions

Two distinct NERC Category C.3 events (double contingencies) resulted in seven (7) distinct thermal constraints where the worst case overloading occurred for summer 2010 100% of system

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

peak load conditions (Table A.7, Appendix A). No violations were found for Category C.5 events, which is the outage of two circuits on a multi-circuit tower.

Thermal constraints will be mitigated in the day-ahead and real-time market through the MISO binding constraint procedures. Therefore, no operating restrictions are listed for these thermal constraints.

The existing limitations on Kewaunee generation for the outage of either Q-303 or R-304 followed by a fault on the remaining Kewaunee 345-kV outlet are unchanged with the addition of the proposed switching station. A new operating restriction will be created for Point Beach for the prior outage of the Point Beach 345 kV bus tie breaker 2-3. See Section 3.2.6 for more information.

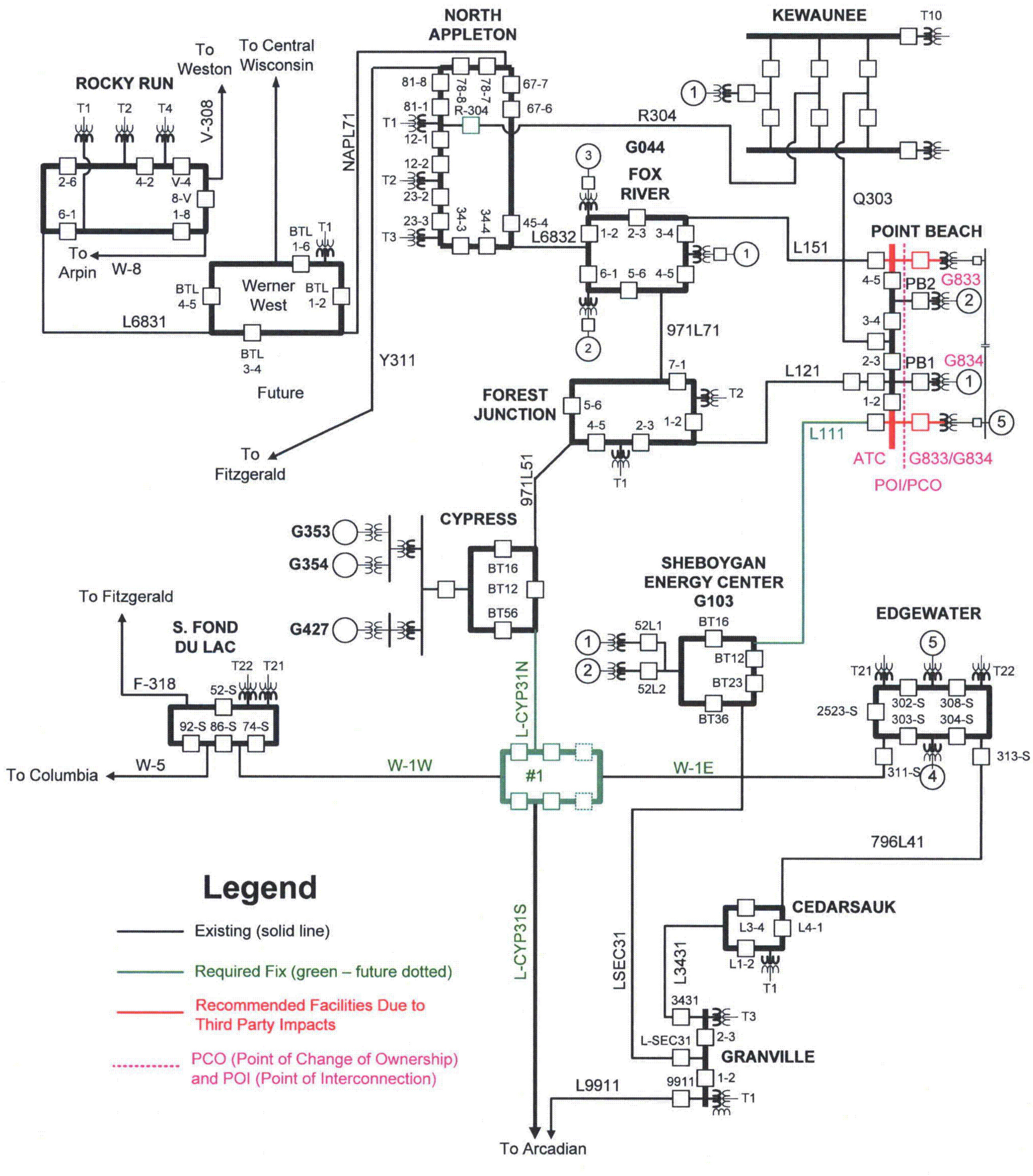

Figure 1.1 – Conceptual One Line Diagram of the 2011 System with G833 and G834 Shown With Kewaunee Bus Reconfiguration Project

1.3 Generating Facility Requirements

Point Beach Power System Stabilizers

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

Auxiliary Transformers T1X03 and T2X03 High-Side Breakers

ATC recommends that new 2 cycle 345 kV circuit breakers and adequate relaying be installed on the high-side of Point Beach auxiliary transformers T1X03 and T2X03 to avoid a trip of the Point Beach units for a breaker failure event (Table 1.4).

The current configuration of the Point Beach substation is shown in Figure 1.2. Due to the current design where the Bulk Electric System equipment is providing the primary fault protection for the T1X03 and T2X03, the follow events would occur for a fault on the T1X03 or T2X03 equipment, including a fault at the 13.8 kV level:

1. For a fault on T1X03,
    a. With normal clearing, 345 kV bus #1 will be removed from service and result in the loss of the network connection to Sheboygan Falls Energy Center substation via 345 kV line L111.
    b. With delayed clearing on 345 kV bus tie 1-2, 345 kV bus #1 and 345 kV bus #2 will be removed from service and result in the loss of the following elements:
        i. 345 kV line L111 to Sheboygan Falls Energy Center substation,
        ii. 345 kV line L121 to Forest Junction substation and
        iii. Point Beach generating unit #1.
2. For a fault on T2X03,
    a. With normal clearing, 345 kV bus #5 will be removed from service and result in the loss of the network connection to Fox River substation via 345 kV line L151.
    b. With delayed clearing on 345 kV bus tie 4-5, 345 kV bus #4 and 345 kV bus #5 will be removed from service and result in the loss of the following elements:
        i. 345 kV line L151 to Fox River substation and
        ii. Point Beach generating unit #2.

The addition of new 2 cycle 345 kV circuit breakers will eliminate the loss of 345 kV (i.e. Bulk Electric System) elements for the more probable normal fault clearing events and will substantially reduce the impact of certain delayed clearing events by eliminating a trip of a Point Beach generating unit and, for faults involving T1X03, a second 345 kV transmission line. ATC recommends these circuit breaker additions to improve the reliability of the transmission network and power plant interconnection, bringing the substation configuration closer to current ATC design standards.

Reduction of Auxiliary Transformers T1X03 and T2X03 Primary Clearing Times
ATC also recommends, regardless of whether or not the recommended T1X03 and T2X03 2 cycle 345 kV circuit breakers are installed, that the existing 5.1 cycle auxiliary transformer 345 kV fault primary clearing time should be reduced. Without the recommended circuit breakers, but with the proposed Kewaunee bus reconfiguration and the West switching station, fault clearing times will have to be reduced to 4.75 cycles for T1X03 and 4.25 cycles for T2X03. The existing primary clearing time is acceptable with the present system configuration and generation levels. With the addition of G833 and G834, failure to reduce these fault clearing times to the recommended times would result in loss of synchronism on the Point Beach and Kewaunee generators for high side faults on these auxiliary transformers cleared in primary time.

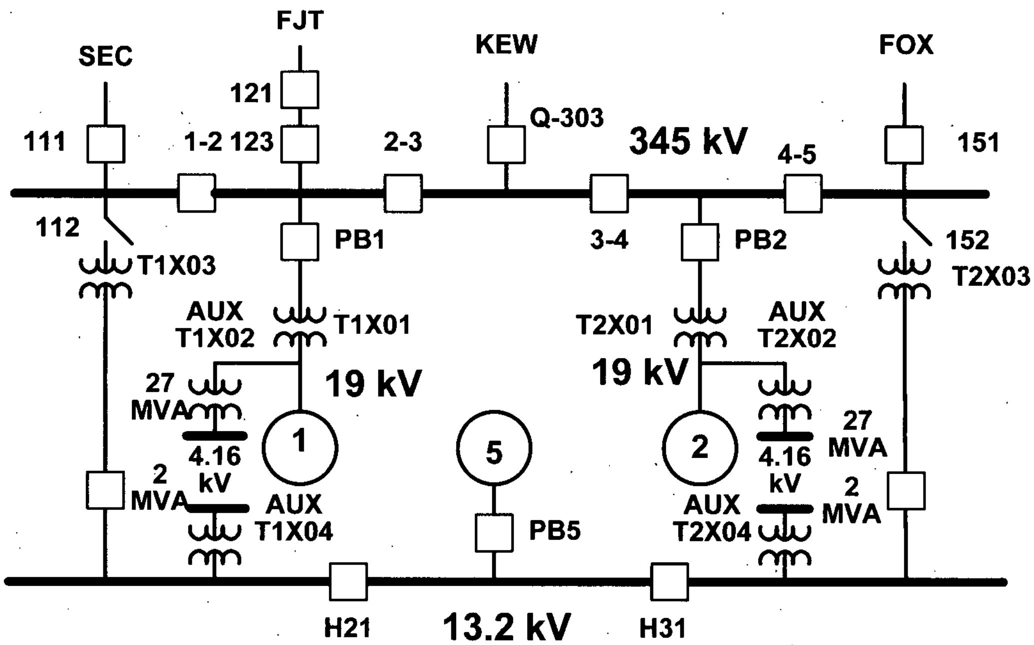

Figure 1.2 – Existing Point Beach Substation Configuration

Power Factor Capability
The G833 and G834 customer has submitted a generating facility design capable of maintaining power delivery at continuous rated power output at the POI (Point of Interconnection) at all power factors over 1.00 leading (when a facility is consuming reactive power from the transmission system) to 0.95 lagging (when a facility is supplying reactive power to the transmission system). For the scenarios examined, study results indicate that satisfactory system performance is achieved by supplying a range of 0 to 200 Mvars to the system, based on its maximum net generation, as measured at the low-side of the generator step-up transformer, of 612.6 MW.

Plant Specific Voltage Requirements
The Point Beach Nuclear has specific 345 kV voltage range requirements. The preferred range is 352 kV (1.020 pu) to 354 kV (1.026 pu), the normal range is 351 kV (1.017 pu) to 358 kV (1.037

pu) and the maximum permissible is 348.5 kV (1.010 pu) to 362 kV (1.049 pu). Any voltage outside the maximum permissible range is a voltage limitation as described in the plant technical specifications.

1.4 Network Upgrades

Existing Network Upgrades Required Before G833 and G834 Operation (See Table 1.1)

Injection Upgrades
Analysis prior to G833 and G834 found no required network 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.

Network Upgrades Required Due to G833 and G834 Addition (See Table 1.2)
The preliminary, good faith estimate of schedule indicates that all of the Network Upgrades can be in-service within 5 years of an executed Interconnection Agreement.

Stability Upgrades (see Table 1.2)
To achieve adequate system stability with G833 and G834 in service, one 345 kV switching station with complete Independent Pole Operation (IPO) for each 2 cycle 345-kV breaker is required as follows:

1) A four position ring bus at the intersection of lines L-CYP31 (Cypress-Arcadian) and W-1 (Edgewater-South Fond du Lac) with future expansion to a six position ring bus.

For Existing Kewaunee Bus Configuration
The following protection improvements included in Table 1.2 are required to achieve adequate system stability if the Planned Kewaunee bus reconfiguration is not constructed:

1) L111 (Point Beach-Sheboygan Energy Center 345 kV) at Point Beach fault clearing time should be reduced:
    a. **From** the existing 3.5 cycle local primary, 9.0 cycles local delayed, and 4.5 cycles remote primary,
    b. **To** either 3.5 cycle local primary, 8.25 cycles local delayed and 4.5 cycles remote primary.
2) L151 (Point Beach-Fox 345 kV) at Point Beach fault clearing time should be reduced:
    a. **From** the existing 3.5 cycle local primary, 9.0 cycles local delayed, and 5.5 cycles remote primary,
    b. **To** 3.5 cycle local primary, 8.5 cycles local delayed and 4.5 cycles remote primary.
3) Q-303 (Point Beach-Kewaunee 345 kV) at Point Beach fault clearing time should be reduced:
    a. **From** the existing 3.5 cycle local primary, 9.0 cycles local delayed, and 5.5 cycles remote primary,

   b. **To** 3.5 cycle local primary, 8.5 cycles local delayed, and 4.5 cycles remote primary.
4) R-304 (Kewaunee-North Appleton 345 kV) at Kewaunee fault clearing time should be reduced:
   a. **From** the existing 5.5 cycle local primary and 6.5 cycles remote primary,
   b. **To** 3.5 cycle local primary and 6.5 cycles remote.
5) Kewaunee T-10 (Kewaunee 345/138 kV) at Kewaunee fault clearing time should be reduced:
   a. **From** the existing 6.5 cycle 345 kV primary and 8.5 cycles 138 kV primary,
   b. **To** 4.5 cycle 345 kV primary and 5.5 cycles 138 kV primary.

For Planned Kewaunee Bus Reconfiguration
If the Planned Kewaunee bus reconfiguration is constructed, the following protection improvements are required:

1) L111 (Point Beach-Sheboygan Energy Center 345 kV) at Point Beach fault clearing time should be reduced:
   a. **From** the existing 3.5 cycle local primary, 9.0 cycles local delayed, and 4.5 cycles remote primary,
   b. **To** either 3.5 cycle local primary, 8.5 cycles local delayed and 4.5 cycles remote primary.
2) L151 (Point Beach-Fox River 345 kV) at Point Beach fault clearing time should be reduced:
   a. **From** the existing 3.5 cycle local primary, 9.0 cycles local delayed, and 4.5 cycles remote primary,
   b. **To** either 3.5 cycle local primary, 8.5 cycles local delayed and 4.5 cycles remote primary.
3) R-304 (Kewaunee-North Appleton 345 kV) at North Appleton fault clearing time should be reduced:
   a. **From** the existing 3.5 cycle local primary, 8.5 cycles local delayed, and 5.5 cycles remote primary,
   b. **To** 3.5 cycle local primary, 8.5 cycles local delayed and 4.5 cycles remote primary.

Injection Upgrades (see Table 1.2)
In summary, the study identified the following line segment will need to be upgraded to achieve the necessary rating.

- Cypress-West Switching Station 345-kV line CYP31 (north) (11.7 miles) must be uprated to obtain a minimum summer emergency rating of 675 MVA (1130 A) or higher.
- Point Beach-Sheboygan Energy 345 kV line L111 (51.1 miles) must be uprated to obtain a minimum summer emergency rating of 555 MVA (929 A) or higher.
- Elkhart Lake-G611 Tap 138-kV line 4035 (18.7 miles) must be uprated to obtain a minimum summer emergency rating of 131 MVA (549 A) or higher.

Voltage Related
None

Breaker Duty Related
None

Network Resource Interconnection Service (NRIS) Related
MISO performed the generator deliverability analysis needed for G833 and G834 to qualify for NRIS. For nuclear generators full plant capacity (100%) is evaluated. No upgrades were identified to qualify for NRIS.

Typical planning level cost estimates for new and rebuilt facilities in the American Transmission Company (ATC) footprint are listed in Appendix G for the Interconnection Customer's reference.

1.5 Interconnection Facilities

Interconnection Facilities include all facilities and equipment that are located between the interconnecting generator's Generating Facility and the POI. Note that the POI is the terminal in the Point Beach 345-kV Substation where each unit will inject its power output, while the Point of Change of Ownership (PCO) may be a different element within the same 345-kV substation. The G833 and G834 Interconnection Facilities already exist. Table 1.3 describes the new facilities owned by the Interconnection Customer and the Transmission Owner respectively.

1.6 Further Study

In order for G833 and G834 to interconnect under Energy Resource Interconnection Service (ERIS), the required Network Upgrades and Interconnection Facilities must be completed. In order for G833 and G834 to qualify as a Network Resource (NR), any additional network upgrades that are identified based on the MISO deliverability analysis (none were found for G833 and G834) must also be completed.

The next step in the Generator Interconnection Request process is for the customer to decide whether or not to proceed to an Interconnection Facilities Study. An Interconnection Facilities Study will specify in more detail the time and cost of the equipment, engineering, procurement and construction of the system upgrades identified in this ISIS report.

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

Location	Facilities	Reason
None		

Table 1.2 – Required Network Upgrades due to the Addition of G833 and G834

Location	Facilities	Reason	Good Faith Cost Estimate (Y2008)
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
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
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
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
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
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
	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.

Table 1.3 – Required Interconnection Facilities for G833 and G834

Entity	Facilities	Cost Estimate (Y2008)
Transmission Owner	None.	NA
G833 and G834 Interconnection Customer	None. **Note:** These facilities are to be provided by the generator interconnection customer. Hence, cost estimate is not applicable.	NA

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

Entity	Facilities	Cost Estimate (Y2008)
G833 and G834 Interconnection Customer	Recommended improvements to the Point Beach substation design. Add 345 kV, 3000A, 50 kA, 2 cycle gas Circuit Breakers on the high side of Point Beach auxiliary transformers T1X03 and T2X03 with adequate primary and breaker failure relaying. Reduce Auxiliary Transformer T1X03 primary fault clearing time from 5.1 cycles to 4.75 cycles and Auxiliary Transformer T2X03 from 5.1 cycles to 4.25 cycles. **Note:** These facilities are to be provided by the generator interconnection customer. Hence, cost estimate is not applicable.	NA

2. Criteria, Methodology and Assumptions

2.1 Study Criteria

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

2.2 Study Methodology

The results of this study are subject to change. The results of the study are based on data provided by the 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	2009
G427	WEC	98	2006 (In Suspension)
G590	WEC	98	2007
G611	WEC	99	2008
G773	WPS	150	2009

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

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

0% TRM) along with real and reactive power flows. A 5% TRM was factored in the computation of required MVA rating for the limiting elements.

The linear transfer analysis was performed using the Linear Transfer Analysis modules of the Managing and Utilizing System Transmission-8.3.2 (MUST, Version 8.3.2) program from Siemens Power Technologies, Inc (PTI). All AC power flow solutions were performed using the Power Flow module of the Power System Simulation/Engineering-29.5.1 (PSS/E, Version 29.5.1) program from Siemens Power Technologies, Inc (PTI). These programs are 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 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 competing generators G384, G427, G590, G611 and G773 was delivered to the WAPA and TVA control areas in an equal distribution.

The output of G833 and G834 was delivered to all MISO generation for the linear analysis portion of the study. For the AC analysis portion of the study, half of the output of G833 and 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).

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.

Two stability scenarios were studied for G833 and G834. Specifically, high local generation and low local generation models were created. For the high generation scenario, in addition to Point Beach and competing generation (except G773), all local generation (Kewaunee, Fox River, Sheboygan Energy, 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 locally except that the gas plants at Fox Energy and Sheboygan Energy were modeled as off-line.

When the proposed switching station was modeled, the Edgewater unit outputs were increased slightly to their maximum capabilities and the South Fond du Lac units were put into service at their maximum capabilities.

2.3.3 Deliverability Analysis

Deliverability analysis, required for G833 and G834 to attain Network Resource Interconnection Service (NRIS), has been performed by MISO. No upgrades were identified to qualify for NRIS. Details on the MISO deliverability study methodology can be found in the whitepaper posted at the following link: **MISO Deliverability Whitepaper** (see Appendix E for complete URL).

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.

The generator has informed ATC that some of the dynamic models associated with the Point Beach units will change after the units are rewound as part of the G833 and G834 project. Dynamic model changes that have been reported to ATC have been incorporated into the Point Beach generator stability models. In addition, the generator step up transformers will be replaced as part of the G833 and G834 projects and these modifications were incorporated into the model.

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

The assumed high-side clearing times for faults on the Point Beach generator step up (GSU) and 345/13.2 kV auxiliary transformers used in the initial stability analysis were as follows:

1. For faults on T1X01 and T2X01 GSUs, total breaker failure clearing time was assumed to be 14 cycles.
2. For faults on T1X03 and T2X03 transformers, total breaker failure clearing time was assumed to be 12 cycles with the recommended 2 cycle high-side circuit breakers.

The actual clearing times determined using information from the Interconnection Customer and used for the analysis contained in Revision 3 of this report are:

1. For GSU transformers T1X01 and T2X01, the primary clearing time is 4.5 cycles and the breaker failure clearing time is 12.5 cycles for bus breakers and 13.0 cycles for line breakers.
2. For auxiliary transformers T1X03 and T2X03, the primary clearing time is 5.1 cycles and the breaker failure clearing time is 12.3 cycles for bus breakers and 23.5 cycles for line breakers.

It should be noted that both the assumed and actual clearing times listed above do not contain any ATC planning margins. Also, the actual clearing times assume the recommended high side auxiliary transformers breakers are not installed.

2.4.2 Synchronizing and Energization of Substation/Generator Step-Up Transformers

ATC's standard design is for synchronization of the generator to occur at the interconnection customer's high-side (i.e. transmission voltage) circuit breaker. Exceptions to this standard must be requested for examination during the interconnection study.

The Point Beach nuclear units are presently undergoing design development to support the inclusion of generator breakers in their Iso-phase Bus connections. The generator breaker(s) will be positioned so as to enable a generating unit trip at the generator output voltage level/position without the need to de-energize the main transformers. Since the high voltage side breakers will remained closed, the power plant auxiliary buses are intended to be powered via the backfeed Main Transformers and the Iso-phase bus direct-connected Unit Auxiliary Transformers. This arrangement eliminates the presently needed high speed transfer of auxiliary busses to the grid-connected Startup Transformer upon a generating unit trip, and will also serve to resolve present marginal bus voltage issues. For purposes of the grid studies, the generator breakers are considered to be in place and operable at the time of startup of the generating units at their increased levels of output.

A generator step-up transformer will require the initial energization to occur from the transmission grid. Prior to initial energization, the Interconnection Customer must permanently install mitigation equipment (e.g., pre-insertion resistors on the high-side transformer circuit breaker) or commission a technical study of the initial energization event to ensure that the initial energization of the transformer will not result in any unacceptable impact to ATC or interconnected customers.

2.4.3 Unit Black Start and ATC Black Start Plan Participation

Generating units interconnecting with the ATCLLC transmission system must report black start requirements to ATCLLC. Additionally, the customer and ATCLLC must discuss the unit's participation in the ATCLLC system black start plan.

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 Analysis power flow analysis used DC analysis techniques under 100% load conditions only.

3.1.1 Power Factor Capability and Voltage Requirements

Power Factor Capability
The G833 and G834 customer has submitted a generating facility design capable of maintaining power delivery at continuous rated power output at the POI (Point of Interconnection) at all power factors over 1.00 leading (when a facility is consuming reactive power from the transmission system) to 0.95 lagging (when a facility is supplying reactive power to the transmission system). For the scenarios examined, study results indicate that satisfactory system performance is achieved by supplying a range of 0 to 200 Mvars to the system, based on its maximum net generation, as measured at the low-side of the generator step-up transformer, of 612.6 MW. Tables A.3 through A.6 in Appendix A tabulate the results of the system voltage analysis under single contingencies and the analysis of the plant specific voltage requirements noted below.

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

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

3.1.2.1 Base Case Analyses

This analysis was conducted with all Fox Valley generation on line under 100% and 50% of system peak loading conditions with the proposed switching station modeled. The 50% of system peak loading model included expected generation levels in the Fox Valley. For this model, the Sheboygan Energy Center and Fox Energy Units were out of service and the wind farms were studied at both full output and at two-thirds of their maximum output (compare Table A.2 and Table A.11 in Appendix A).

This study identified one transmission element steady-state thermal violation due to G833 and G834 for NERC Category B (N-1) events for the summer 2010 100% of system peak load model. Three additional transmission element steady-state thermal violations due to G833 and G834 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.1, A.2 and A.11 in Appendix A.

The one Injection Upgrade found with 100% system peak load modeled was Line LCYP31 (north end), Cypress to the new West Switching Station 345 kV. Approximately 25% of the increased generation will flow on this line, with Line 6832 North Appleton-Fox River 345 kV out of service. In addition to a slightly increased loading found on LCYP31 (north end), two additional lines were found with 50% of system peak loading conditions and maximum generation modeled. These were L111 (Point Beach to Sheboygan Energy 345 kV), with approximately 23% of the increased generation flowing on this line with LCYP31 (north end) out of service, and Line 4035 (Elkhart Lake-G611 Tap), with approximately 3% 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.

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.10 in Appendix A. As shown in this table, the maximum real power output for injection limits without any system upgrades is 0 MW for all conditions studied.

Voltage analysis shows that no Transmission System voltage limits will be violated as a result of the interconnection of G833 and G834 (see Tables A.3 and A.4 in Appendix A).

3.1.2.2 Sensitivity Analyses

Sensitivity analyses are performed on the G833 and G834 interconnections to determine what effect the planned Kewaunee substation reconfiguration project will have on the study results. The project, which is in the "planned" stage, will reconfigure the Kewaunee substation from the existing configuration, shown in Figure 3.1, to the ultimate design shown in Figure 3.2. Included in the reconfiguration is the addition of a new 345/138-kV transformer parallel to the existing 345/138-kV transformer.

Inclusion of the second 345/138-kV transformer was not found to cause any significant changes in study thermal results. In most cases, the thermal results presented include worst case loading with and without the Kewaunee bus reconfiguration modeled. The loading differences are usually less than 1 MW. Past studies have shown that the Kewaunee 138 kV outlets overload as a result of adding the second 345/138 kV transformer for certain contingencies if G384 is constructed. This result was not seen in these studies, but if it does occur in the future, it will not be associated with G833-4 and overloads will be addressed by reducing Kewaunee generation or improving the transmission network.

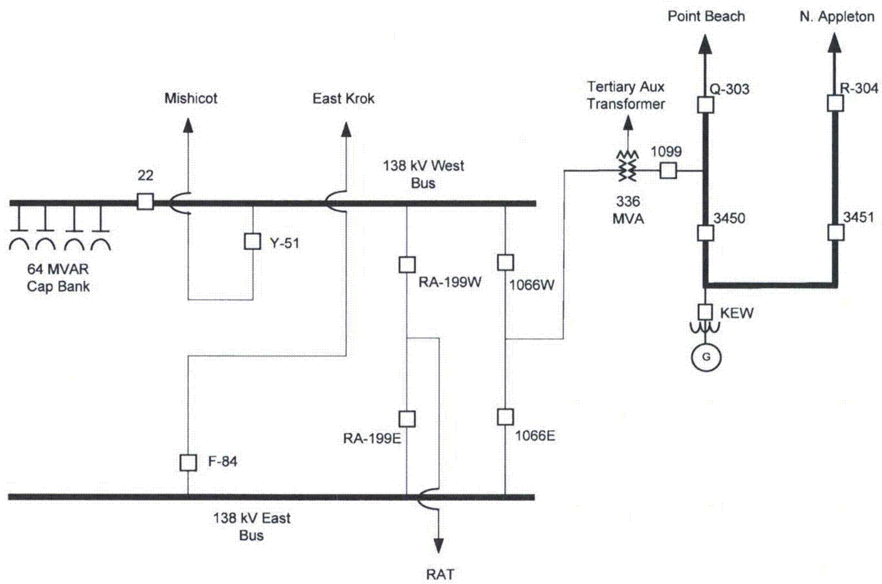

Figure 3.1 – Existing Kewaunee 345 kV and 138 kV Bus Configurations

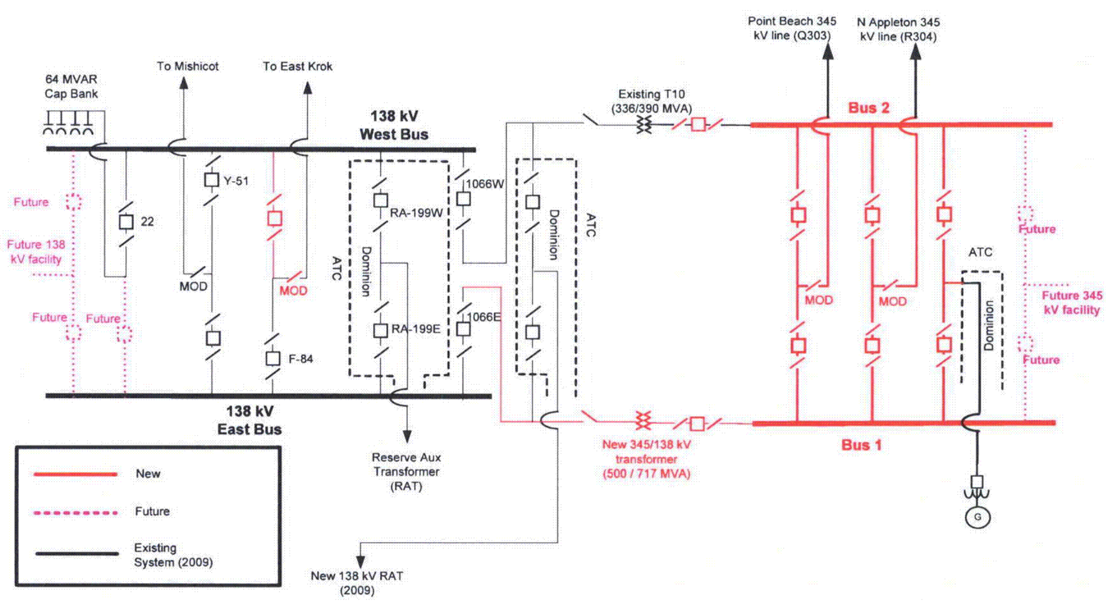

Figure 3.2 – Proposed Two Transformer Kewaunee Bus Configuration

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

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

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% of system peak load model with the West Switching Station in service, as well as the second Kewaunee 345/138 kV transformer. 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 linear transfer analysis. The distinct thermal violations identified from the summer 2010 100% of system peak load condition model used in the study are listed in Table A.7 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.

This study identified seven transmission element steady-state thermal constraints for the summer 2010 100% load condition.

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. No violations 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.8 (100% loading) and A.9 (50% loading), 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

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

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

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

That analysis did find stability problems for three scenarios involving a three-phase fault cleared in primary clearing time with a prior outage of another transmission element. Two of these problems were eliminated if the Point Beach Unit 1 power system stabilizer (PSS) was in-service. For the G833 and G834 analysis, it is assumed that this PSS is in-service whenever any other system element is out of service. An operating guideline exists to reduce local generation when this PSS and certain system elements outages are out of service.

The third prior outage problem concerned thermal limits at Kewaunee when Q-303 (Kewaunee-Point Beach 345 kV) was out of service and R-304 (Kewaunee-North Appleton 345 kV) tripped. Although, under the existing system configuration, a fault on Q-303 will trip Kewaunee Transformer T-10 so that an overload will not occur with R-304 out of service, with the proposed Kewaunee bus configuration, any fault on Q-303 or R-304 with the other line out of service will require limiting Kewaunee generator output. This is an existing limitation that will not be made better or worse by the addition of G833 and G834 and their associated Network Upgrades. Simulations were run adding a second Kewaunee-Point Beach 345 kV line to see if this addition would eliminate this restriction. While this problem was eliminated, the second line resulted in worse performance for at least one other prior outage condition. Because this is an existing problem that is not significantly affected by G833 and G834, it will not be discussed further in this report, other than to note that the existing operating guide will not be significantly changed when G833 and G834 go into service.

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

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

A planning margin of 1.0 cycle is required between any studied clearing time and the maximum expected clearing time of the system protection equipment (i.e. relay and circuit breaker operation). This 1.0 cycle is added to the local primary clearing time for primary clearing simulations and the local breaker failure time for breaker failure simulations. If a fault is cleared using Independent Pole Operation (IPO) breakers, it is assumed that only one phase of the breaker will fail, so that after the primary clearing time, a three phase 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 C.

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

The 13 faults listed in Table 3-2-1 were simulated as 3-phase faults cleared in primary time under intact system conditions. The only stability problem under intact system conditions was for a fault on the high side of Kewaunee transformer T10 if the proposed Kewaunee bus reconfiguration is not completed. This problem can be eliminated by reducing fault clearing times at Kewaunee. If the Kewaunee Bus Reconfiguration is not constructed, the Kewaunee T10 transformer fault clearing time must be reduced to 5.5 cycles after the West switching station is in service (5.0 cycles prior to the West switching station). Even though neither Point Beach Power System Stabilizer (PSS) was modeled, no damping problems were found under any of the faults simulated. These results are summarized in Table C.1 in Appendix C.

Table 3-2-1 – Simulated Single Circuit 3-Phase Faults Cleared in Primary Time

Faulted Element	Fault Location	Description
L111	Point Beach 345 kV	Point Beach-Sheboygan Energy 345 kV Line
L121	Point Beach 345 kV	Point Beach-Forest Junction 345 kV Line
L151	Point Beach 345 kV	Point Beach-Fox River 345 kV Line
Q-303	Point Beach 345 kV	Point Beach-Kewaunee 345 kV Line
Q-303	Kewaunee 345 kV	Point Beach-Kewaunee 345 kV Line
R-304	Kewaunee 345 kV	Kewaunee-North Appleton 345 kV Line
L151	Fox River 345 kV	Point Beach-Fox River 345 kV Line
L6832	Fox River 345 kV	Fox River-North Appleton 345 kV Line
971L71	Fox River 345 kV	Fox River-Forest Junction 345 kV Line
L111	Sheboygan Energy 345 kV	Point Beach-Sheboygan Energy 345 kV Line
LSEC31	Sheboygan Energy 345 kV	Sheboygan Energy-Granville 345 kV Line
LCYP31	Cypress 345 kV	Cypress-Arcadian 345 kV Line
KEW T10 H*	Kewaunee 345 KV	Kewaunee 345/138 kV Transformer

3.2.2 Results of Primary Clearing SLG Faults on Two Circuits of a Multiple Circuit Lines

The transmission system near Point Beach contains eight double circuit lines of concern (Table 3-2-2). Single line-to-ground faults were simulated on both ends of the double circuit, for a total of sixteen simulated events. Although a conservative single line-to-ground fault level of 63 kA was used for both the 345 kV and 138 kV faults and the Point Beach PSSs were not modeled, no synchronous machines were observed to be unstable and there were no damping problems. These results are summarized in Table C.2 in Appendix C.

Table 3-2-2 – Simulated Intact System Double Circuit Single Line-to-Ground Faults

Fault 1		Fault 2	
Element	Location	Element	Location
111–Pt. Beach -Sheboygan Energy 345 kV	38.5% from POB	971K51-Forest Jct.-Howard's Grove 138 kV	33.9% from FJT
111-Pt. Beach -Sheboygan Energy 345 kV	16.3% from SEC	971K51-Forest Jct.-Howard's Grove 138 kV	6.3% from HOG
111-Pt. Beach -Sheboygan Energy 345 kV	SEC	HOGL21-Howard's Grove-Holland 138 kV	46.8% from HOL
111-Pt. Beach -Sheboygan Energy 345 kV	15.7% from SEC	HOGL21-Howard's Grove-Holland 138 kV	12.3% from HOG
121-Pt. Beach -Forest Junction 345 kV	FJT	971K51-Forest Jct.-Howard's Grove 138 kV	FJT
121-Pt. Beach -Forest Junction 345 kV	42.3% from FJT	971K51-Forest Jct.-Howard's Grove 138 kV	33.9% from FJT
SEC31-Sheboygan Energy-Granville 345 kV	GVL	3431-Granville-Saukville 345 kV	GVL
SEC31-Sheboygan Energy-Granville 345 kV	26.7% from GVL	3431-Granville-Saukville 345 kV	25.3% from SAU
SEC31-Sheboygan Energy-Granville 345 kV	43.5% from GVL	8231-Sukville-Barton 138 kV	36.4% from BRT
SEC31-Sheboygan Energy-Granville 345 kV	48.3% from GVL	8231-Sukville-Barton 138 kV	36.4% from SAU
CYP31-Cypress-Arcadian 345 kV	32.0% from ADN	2642-Saukville-Germantown 138 kV	34.2% from SAU
CYP31-Cypress-Arcadian 345 kV	16.6% from ADN	2642-Saukville-Germantown 138 kV	GER
CYP31-Cypress-Arcadian 345 kV	10.8% from ADN	2661-Germantown-Bark River 138 kV	31.5% from GER
CYP31-Cypress-Arcadian 345 kV	16.6% from ADN	2661-Germantown-Bark River 138 kV	GER
CYP31-Cypress-Arcadian 345 kV	10.8% from ADN	9911-Granville-Arcadian 345 kV	45.4% from GVL
CYP31-Cypress-Arcadian 345 kV	ADN	9911-Granville-Arcadian 345 kV	ADN

3.2.3 Results of Primary Fault Clearing During a Prior Outage

Primary fault clearing under prior outage conditions simulated all of the events listed in Table 3-2-1 under the outages listed in Table 3-2-3 with the Point Beach PSSs initially out of service. If a problem was found, the PSSs were put into service. Previous studies simulating hundreds of cases resulted in unacceptable damping in only a few cases, all when the Point Beach PSSs were out of service. These damping problems were eliminated when the Point Beach PSSs were modeled as being in service. If G833 and G834 are constructed, future studies will determine system operating restrictions with the Point Beach PSSs out of service.

Table 3-2-3 – Simulated Prior Outage Elements

Element	Description
L111	Point Beach-Sheboygan Energy 345 kV Line
L121	Point Beach-Forest Junction 345 kV Line
L151	Point Beach-Fox River 345 kV Line
Q-303	Point Beach-Kewaunee 345 kV Line
R-304	Kewaunee-North Appleton 345 kV Line
L6832	Fox River-North Appleton 345 kV Line
971L71	Fox River-Forest Junction 345 kV Line
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
FOX 1-2, 2-3, 3-4, 4-5, 5-6, 6-1	Fox River 345 kV Breakers 1-2, 2-3, 3-4, 4-5, 5-6, 6-1
SEC BT12, BT23, BT36, BT16	Sheboygan Energy 345 kV Breakers BT12, BT23, BT36, BT16
CYP BT16, BT12, BT56	Cypress 345 kV Breakers BT16, BT12, BT56
FJT 1-2, 2-3, 4-5, 5-6, 7-1	Forest Junction 345 kV Breakers 1-2, 2-3, 4-5, 5-6, 7-1

With the existing Kewaunee substation modeled, 30 cases with generator instability were found for prior outage scenarios (Table C.3 in Appendix C). This number was decreased to 5 when the planned Kewaunee Substation reconfiguration was modeled (Table C.4 in Appendix C).

For Existing Kewaunee Bus Configuration

With the existing Kewaunee substation modeled, all but 3 of the prior outage problems can be eliminated by reducing fault clearing times. In most cases this will require breaker replacement at the Kewaunee bus and, possibly, replacing relays and/or upgrading communication equipment. The proposed West switching station, in association with reducing breaker clearing times, eliminated the problem of a 345 kV R-304 fault at Kewaunee with 345 kV line 6832 out of service. The remaining two problems, an R-304 fault with Q-303 out of service and a fault on L121 with Point Beach breaker 2-3 out of service can be eliminated by reducing Kewaunee and Point Beach Unit 1 generation, respectively. The R-304/Q-303 problem is addressed by an existing operating guide and G833 and G834 will not make the situation worse. The L121/POB

2-3 problem can be eliminated by an operating guide that will require Point Beach unit #1 restrictions for the unlikely condition of POB 2-3 being out of service when POB Unit 1 is in service.

With Planned Kewaunee Bus Reconfiguration
None of the 5 prior outage problems found with the planned Kewaunee substation reconfiguration modeled can be eliminated by reducing fault clearing times. The proposed Kewaunee bus reconfiguration will replace all Kewaunee 345 kV breakers, eliminating the need to replace breakers to obtain the fault clearing times required under the existing Kewaunee bus configuration. The proposed West switching station once again eliminated the problem of a 345 kV R-304 fault at Kewaunee with 345 kV line 6832 out of service. The remaining problems, an R-304 fault with Q-303 out of service, Q-303 fault with R-304 out (either end faulted) and a fault on L121 with Point Beach breaker 2-3 out of service can be eliminated by reducing Kewaunee generation for the Q-303 and R-304 faults and Point Beach Unit 1 generation for the L121 fault. The R-304/Q-303 problem is addressed by an existing operating guide and G833 and G834 will not make the situation worse. The L121/POB 2-3 problem can be eliminated by an operating guide that will require Point Beach unit #1 restrictions for the unlikely condition of POB 2-3 being out of service when POB Unit 1 is in service.

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

Delayed 3-phase fault clearing under otherwise intact system was simulated for the events listed in Table 3-2-4 both with and without the proposed Kewaunee substation reconfiguration. This reconfiguration will remove double breakers from Kewaunee, making three additional scenarios where breaker failure could occur, two of which (Q-303 and R-304 faults at Kewaunee) were found to cause generator instability. Three of the simulated breaker failure events resulted in generator instability for the existing Kewaunee configuration (Table C.5 in Appendix C) and four with the proposed Kewaunee bus configuration (Table C.6 in Appendix C) with existing clearing times and the proposed West Switching Station modeled. All of these unstable events can be eliminated if the faster breaker clearing times specified in Tables C.5 and C.6 are modeled.

With the existing Kewaunee substation configuration and the West Switching Station modeled, faults on L111, L151 and Q-303 at Point Beach resulted in generator instability if existing breaker clearing times (3.5 cycle primary local, 9.0 cycles delayed local and 4.5 cycles primary remote) were modeled. For the L151 and Q-303 faults, reducing the local delayed clearing time to 8.5 cycles eliminated the generator instability. For the L111 fault the local delayed clearing time had to be reduced to 8.25 cycles, the fasted primary breaker failure time achievable. For faults occurring 10% or more down the line from Point Beach, the acceptable clearing time is 8.5 cycles. These results indicate that the SPSs for L111, L151 and Q-303 at Point Beach can be removed.

With the proposed Kewaunee substation configuration and the West Switching Station modeled, faults on L111 and L151 at Point Beach and Q-303 and R-304 at Kewaunee resulted in generator instability if existing breaker clearing times were modeled. For all of these faults, reducing the primary local clearing time to 3.5 cycles, delayed local clearing time to 8.5 cycles and primary remote clearing time to 4.5 cycles eliminated the generator instability. These results indicate that the SPSs for L111, L151 and Q-303 at Point Beach can be removed.

Table C.8 presents results for three phase faults with breaker failure at the proposed West switching station for an otherwise intact system. These simulations provide the required clearing times for the new switching station and did not identify any stability problems.

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

Faulted Element	Fault Location	Description
L111	Point Beach 345 kV	Point Beach-Sheboygan Energy 345 kV Line
L151	Point Beach 345 kV	Point Beach-Fox River 345 kV Line
Q-303	Point Beach 345 kV	Point Beach-Kewaunee 345 kV Line
R-304	North Appleton 345 kV	North Appleton-Kewaunee 345 kV Line
L121	Forest Junction 345 kV	Forest Junction-Point Beach 345 kV Line
971L51	Forest Junction 345 kV	Forest Junction-Cypress 345 kV Line
971L71	Forest Junction 345 kV	Forest Junction-Fox River 345 kV Line
L151	Fox River 345 kV	Point Beach-Fox River 345 kV Line
L6832	Fox River 345 kV	Fox River-North Appleton 345 kV Line
971L71	Fox River 345 kV	Fox River-Forest Junction 345 kV Line
L111	Sheboygan Energy 345 kV	Point Beach-Sheboygan Energy 345 kV Line
LSEC31	Sheboygan Energy 345 kV	Sheboygan Energy-Granville 345 kV Line
LCYP31	Cypress 345 kV	Cypress-Arcadian 345 kV Line
971L51	Cypress 345 kV	Cypress-Forest Junction 345 kV Line
Q-303*	Kewaunee 345 kV	Point Beach-Kewaunee 345 kV Line
R-304*	Kewaunee 345 kV	Kewaunee-North Appleton 345 kV Line
KEW T10 H*	Kewaunee 345 KV	Kewaunee 345/138 kV Transformer

*Breaker Failure Scenario Only Possible with New Kewaunee Bus Configuration

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

Point Beach 345 kV Bus Fault Clearing

Table C.7 presents results for single-line-to-ground bus faults with breaker failure at Point Beach using existing system clearing times. These simulations did not identify any Network Upgrades or other required changes for G833 and G834 for these faults.

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

Tables C.9 and C.11 present results for single-line-to-ground (intact system with delayed clearing) and three phase (primary clearing under N-1 conditions) GSU faults. Simulating these faults with existing clearing times did not result in any generators going unstable or in unacceptable system damping. Therefore, there are no upgrades necessary due to these faults.

Auxiliary Transformer Fault Clearing (T1X03 and T2X03)

Table C.10 presents results for single-line-to-ground (intact system with delayed clearing) auxiliary transformer faults. Simulating these faults with existing clearing times did not result in any generators going unstable or in unacceptable system damping. Therefore, there are no upgrades necessary due to these faults.

Table C.12 presents results for three phase (primary clearing under N-1 conditions) T1X03 and T2X03 faults. Simulating these faults with existing clearing times (i.e. 5.1 cycles) resulted in generators going unstable for 7 different outages for T1X03 faults and 6 different outages for T2X03 faults. As shown in Table C.13, generator stability can be maintained for all N-1 conditions if T1X03 clearing time is reduced to 4.75 cycles and T2X03 clearing time is reduced to 4.25 cycles.

Most, but not all, of the T1X03 and T2X03 auxiliary transformer fault issues could be eliminated with the existing fault clearing times by the addition of high side breakers to the auxiliary transformers. While not required, it is recommended that 345-kV 2 cycle circuit breakers be installed on the T1X03 and T2X03 auxiliary transformers to avoid tripping Point Beach units for a breaker failure event (see Section 1.3).

3.2.6 Stability Results Summary

The improvements in system stability required for G833 and G834 are provided by reductions in fault clearing times and the conceptual West switching station described in this report. Although these upgrades eliminate all of the stability problems created by G833 and G834, they do not fix the existing stability problems at Kewaunee when one of the Kewaunee 345 kV lines is out of service and the other is faulted. This problem is presently addressed by an operating guide that requires a Kewaunee generation reduction for a Q-303 line outage or trips the Kewaunee generator for a R-304 line outage followed by a fault on Q-303. This problem is not made worse by G833 and G834, so its solution is beyond the scope of this report. Although the stability problem found when L121 is faulted when Point Beach breaker 2-3 out of service does not presently exist due to Point Beach unit #1 net output never exceeding 550 MW, it can be dealt with by reducing Point Beach Unit 1 generation to 550 MW (net) in the unlikely event that POB Breaker 2-3 is out of service when Point Beach Unit #1 is in service. Alternatives to the Network Upgrades specified are discussed in Appendix H of this report.

3.3 Short-Circuit & Breaker Duty Analysis Results

Although this project is to increase generation at an existing generator, the effect of the proposed switching station, changes in Point Beach generator impedance and GSU impedance will affect system short circuit currents.

Fault currents with and without contribution from G383 and G384 for three-phase and single line-to-ground faults are given in Table D.1 in Appendix D. The corresponding Thevenin equivalent impedances are given in Table D.2.

The minimum short circuit current at the G833 and G834 POI bus occurs when Q-303 (Point Beach-Kewanee) is not in service. The three-phase and single line-to-ground fault currents for this weak source condition are also given in Table D.1.

Short circuit current analysis with the revised generator and GSU impedances as well as the conceptual West Switching Station showed that no over-dutied breakers had their fault levels increase by more than 1% due to the addition of G833-4 and associated upgrades. In addition, for circuit breakers impacted by more than 1% (Table D.3), none of these breakers were over-dutied. Therefore, no circuit breaker replacements due to increased fault currents are needed for G833 and G834 generator interconnection requests.

3.4 Deliverability Analysis Results

Nuclear generation interconnections are tested for deliverability to a maximum of 100% of the net MW capacity of the Generating Facility. The deliverability analysis for G833 and G834 did not identify any constraints at 100% output, as noted in Table E.1 in Appendix E.

All deliverability constraints must be resolved to achieve Network Resource Interconnection Service (NRIS). However, G833 and G834 may choose Energy Resource Interconnection Service (ERIS) without resolving the deliverability constraints, as long as all other identified Network Upgrades are constructed. NRIS certification does not guarantee a resource to serve a specific load or to operate during any particular set of operating circumstances. Additionally, certification of deliverability makes no guarantee as to price of available resources. Congestion charges may, in fact, be extremely high.

Appendix A: Power Flow Analysis Results

Table A.1 – Identified Thermal Violations Due to G833 and G834
Summer 2010 (100% Load) Delivery to MISO for NERC Category A and B events (TDF>3%)
West Switching Station in Service

Limiting Element	Existing Rating (MVA)	Required Rating (MVA)[1,2]	Worst Contingency[3]	TDF (%)	Injection Limit	Potential Solution Identified
Cypress – West Switching Station 345-kV Line L-CYP31 (North)	488 SE	659 SE	N. Appleton – Fox River345-kV Line 6832	25.6	Yes	No[4]
Elkhart Lake-G611 Tap 138-kV Line 4035 (South)	96 SE	98 SE	Granville-Sheboygan Energy 345-kV Line L-SEC31	3.2	No	No[5]

1. Includes provision for 5% TRM. The required ratings are calculated using AC transfer analysis in ACCC dispatching 100% of power from G833 and G834 to MISO. Because of the minimal difference in results with and without a second 345/138 kV Kewaunee Transformer, only worst case results are reported.
2. SN = Summer Normal, SE = Summer Emergency
3. Local Special Protection Systems are included if designed to operate for NERC Category A or B events, including:
   a. SPS to trip Kewaunee – N. Appleton 345-kV Line R-304 for a fault on the N. Appleton 345/138-kV Transformer T1
4. Required Rating Should be able to be met by increasing line clearance
5. Line Rating is being increased to 112 MVA due to requirements of G611 and G927 generation interconnection studies

Table A.2 – Identified Thermal Violations Due to G833 and G834
Summer 2010 (50% Load) Delivery to MISO for NERC Category A and B events (TDF>3%)
West Switching Station in Service, Wind Farms at Full Output

Limiting Element	Existing Rating (MVA)	Required Rating (MVA)[1,2]	Worst Contingency	TDF (%)	Injection Limit	Potential Solution Identified
Cypress – West Switching Station 345-kV Line L-CYP31 (North)	488 SE	675 SE	Point Beach-Sheboygan Energy Center 345-kV Line 111	27.2	Yes	No[3]
Point Beach-Sheboygan Energy Center 345-kV Line 111	488 SE	555 SE	Cypress – West Switching Station 345-kV Line L-CYP31 (North)	22.7	Yes	No
Arcadian – West Switching Station 345-kV Line L-CYP31 (South)	488 SE	554 SE	Edgewater-Saukville 345 kV Line 796L41	14.0	No	No
Elkhart Lake-G611 Tap 138-kV Line 4035 (South)	96 SE	131 SE	Point Beach-Sheboygan Energy Center 345-kV Line 111	3.2	Yes[5]	No[4]

1. Includes provision for 5% TRM. The required ratings are calculated using AC transfer analysis in ACCC dispatching 100% of power from G833 and G834 to MISO. Because of the minimal difference in results with and without a second 345/138 kV Kewaunee Transformer, only worst case results are reported. WN = Winter Normal, WE = Winter Emergency
2. SN = Summer Normal, SE = Summer Emergency
3. Required Rating Should be able to be met by increasing line clearance
4. Line Rating is being increased to 112 MVA due to requirements of G611 and G927 generation interconnection studies
5. This line is an Injection Limit because the contingency causing the overload is an outlet of the proposed generation.

Table A.3 – Identified Voltage Violations Due to G833 and G834
Summer 2010 Delivery (100% Load) to MISO for NERC Category A & B events (ΔV > 0.1 p.u.)

Limiting Element	Worst Contingency	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833-4	Post G833-4		
None Identified	-	-	-	-	-

Table A.4 – Identified Voltage Violations Due to G833 and G834
Summer 2010 Delivery (50% Load) to MISO for NERC Category A & B events (ΔV > 0.1 p.u.)

Limiting Element	Worst Contingency	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833-4	Post G833-4		
None Identified	-	-	-	-	-

Table A.5 – Voltage Measurements at the Point Beach 345-kV Substation with West Switching Station Summer 2010 100% Load with Selected Contingencies[1]

Contingency	Voltage[2] (p.u.)				
	Point Beach Bus #1	Point Beach Bus #2	Point Beach Bus #3	Point Beach Bus #4	Point Beach Bus #5
Intact System	1.02026	1.02020	1.02020	1.02020	1.02024
Point Beach BS 2-3	1.02026	1.02020	1.02020	1.02020	1.02023
Point Beach BS 2 – Forest Junction 345-kV Line 121	1.02026	1.02020	1.02020	1.02020	1.02014
Point Beach BS 1-2	1.02505	1.02020	1.02020	1.02020	1.02021
Point Beach BS 4-5[3]	1.020263	1.02020	1.02020	1.02020	1.02237
Point Beach BS 3-4	1.02026	1.02020	1.02020	1.02020	1.02019
Point Beach BS 5 – Fox River 345-kV Line 151	1.02026	1.02020	1.02020	1.02020	1.02019
Forest Junction – Fox River 345-kV Line 971L71	1.02026	1.02020	1.02020	1.02020	1.02025
Point Beach BS 1 – Sheboygan Energy 345-kV Line 111	1.02019	1.02020	1.02020	1.02020	1.02021
Point Beach BS 3 – Kewaunee 345-kV Line Q-303	1.02026	1.02020	1.02020	1.02020	1.02023
Forest Junction – Cypress 345-kV Line 971L51	1.02026	1.02020	1.02020	1.02020	1.02024
Forest Junction 345/138-kV Transformer T1	1.02026	1.02020	1.02020	1.02020	1.02025
Forest Junction 345/138-kV Transformer T2	1.02026	1.02020	1.02020	1.02020	1.02025
Fox River – N. Appleton 345-kV Line 6832	1.02026	1.02020	1.02020	1.02020	1.02024
Fox Energy Center Unit CT 1	1.02026	1.02020	1.02020	1.02020	1.02018
Fox Energy Center Unit CT 2	1.02026	1.02020	1.02020	1.02020	1.02018
Fox Energy Center Unit ST	1.02026	1.02020	1.02020	1.02020	1.02018
Sheboygan Energy – Granville 345-kV Line L-SEC31	1.02015	1.02020	1.02020	1.02020	1.02016
Sheboygan Energy Center Unit #1	1.02021	1.02020	1.02020	1.02020	1.02025
Sheboygan Energy Center Unit #2	1.020213	1.02020	1.02020	1.02020	1.02025
Point Beach Unit #1[4]	1.02025	1.02020	1.02020	1.02020	1.02025
Point Beach Unit #2[5]	1.02025	1.02020	1.02020	1.02020	1.02025
Point Beach Units #1 & #2[6]	1.01917	1.01912	1.01912	1.01912	1.01918

1. Included for Interconnection Customer's defined voltage levels:
   a. Preferred: 352-kV to 354-kV
   b. Normal: 351-kV to 358-kV
   c. Maximum Permissible: 348.5-kV to 362-kV, any voltage outside of the Maximum Permissible range would be identified in Table A.3 as a Voltage Violation
2. The planning case used models both Point Beach units as regulating the respective POI bus voltage at the Point Beach substation to 1.0202 p.u.
3. Point Beach Bus Section #5 is isolated from both Point Beach generating units for this contingency. The planning case used models the T2X03 345/13.2-kV transformer isolated at this bus with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus.
4. This contingency is intended to model the emergency trip of Point Beach Unit #1. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. As explained in Section 2.4.2 the Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA and WAPA.
5. This contingency is intended to model the emergency trip of Point Beach Unit #2. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. As explained in Section 2.4.2 the Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA and WAPA.
6. This contingency is intended to model an emergency dual unit trip modeled by the outage of each Point Beach generating unit, but maintaining the auxiliary load connection to the transmission system. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. As explained in Section 2.4.2 both generator Auxiliary loads are fed from their generator GSUs (23.4 MW and 13.9 MVAR each) and do not trip and are not moved. The Control Area replacement power was imported from TVA and WAPA.

Table A.6 – Voltage Measurements at the Point Beach 345-kV Substation After West Switching Station Winter 2010 (50% Load) with Selected Contingencies[1]

Contingency	Voltage[2] (p.u.)				
	Point Beach Bus #1	Point Beach Bus #2	Point Beach Bus #3	Point Beach Bus #4	Point Beach Bus #5
Intact System	1.02009	1.02020	1.02020	1.02020	1.02017
Point Beach BS 2-3	1.02013	1.02020	1.02020	1.02020	1.02014
Point Beach BS 2 – Forest Junction 345-kV Line 121	1.02004	1.02020	1.02020	1.02020	1.02008
Point Beach BS 1-2	1.02136	1.02020	1.02020	1.02020	1.02010
Point Beach BS 4-5[3]	1.02005	1.02020	1.02020	1.02020	1.01491
Point Beach BS 3-4	1.02011	1.02020	1.02020	1.02020	1.02012
Point Beach BS 5 – Fox River 345-kV Line 151	1.02005	1.02020	1.02020	1.02020	1.02019
Forest Junction – Fox River 345-kV Line 971L71	1.02009	1.02020	1.02020	1.02020	1.02022
Point Beach BS 1 – Sheboygan Energy 345-kV Line 111	1.02019	1.02020	1.02020	1.02020	1.02009
Point Beach BS 3 – Kewaunee 345-kV Line Q-303	1.02009	1.02020	1.02020	1.02020	1.02017
Forest Junction – Cypress 345-kV Line 971L51	1.02005	1.02020	1.02020	1.02020	1.02016
Forest Junction 345/138-kV Transformer T1	1.02009	1.02020	1.02020	1.02020	1.02018
Forest Junction 345/138-kV Transformer T2	1.02009	1.02020	1.02020	1.02020	1.02018
Fox River – N. Appleton 345-kV Line 6832	1.02007	1.02020	1.02020	1.02020	1.02015
Fox Energy Center Unit CT 1	N/A	N/A	N/A	N/A	N/A
Fox Energy Center Unit CT 2	N/A	N/A	N/A	N/A	N/A
Fox Energy Center Unit ST	N/A	N/A	N/A	N/A	N/A
Sheboygan Energy – Granville 345-kV Line L-SEC31	1.02030	1.02020	1.02020	1.02020	1.02009
Sheboygan Energy Center Unit #1	N/A	N/A	N/A	N/A	N/A
Sheboygan Energy Center Unit #2	N/A	N/A	N/A	N/A	N/A
Point Beach Unit #1[4]	1.02020	1.02020	1.02020	1.02020	1.02022
Point Beach Unit #2[5]	1.02020	1.02020	1.02020	1.02020	1.02022
Point Beach Units #1 & #2[6]	1.01894	1.01888	1.01888	1.01888	1.01891

1. Included for <u>Interconnection Customer's defined</u> voltage levels:
    a. Preferred: 352-kV to 354-kV
    b. Normal: 351-kV to 358-kV
    c. Maximum Permissible: 348.5-kV to 362-kV, any voltage outside of the Maximum Permissible range would be identified in Table A.3 as a Voltage Violation
2. The planning case used models both Point Beach units as regulating the respective POI bus voltage at the Point Beach substation to 1.0202 p.u.
3. Point Beach Bus Section #5 is isolated from both Point Beach generating units for this contingency. The planning case used models the T2X03 345/13.2-kV transformer isolated at this bus with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus.
4. This contingency is intended to model the emergency trip of Point Beach Unit #1. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. As explained in Section 2.4.2 the Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA and WAPA.
5. This contingency is intended to model the emergency trip of Point Beach Unit #2. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. As explained in Section 2.4.2 the Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA and WAPA.
6. This contingency is intended to model an emergency dual unit trip modeled by the outage of each Point Beach generating unit, but maintaining the auxiliary load connection to the transmission system. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. As explained in Section 2.4.2 both generator Auxiliary loads are fed from their generator GSUs (23.4 MW and 13.9 MVAR each) and do not trip and are not moved. The Control Area replacement power was imported from TVA and WAPA.

Table A.7 – Identified Thermal Violations under select NERC Category C.3 events[1]
Summer 2010 100% Load Delivery to MISO
West Switching Station and Proposed 2nd KEW 345/138 kV Transformer in Service

Limiting Element	Existing Rating (MVA)	Required Rating[2,3] (MVA)	Worst Double Contingency	TDF (%)	Potential Solution Identified
Point Beach – Forest Junction 345-kV Line 121	883 SE	1099 SE	N. Appleton – Fox River 345-kV Line 6832 N. Appleton – Kewaunee 345-kV Line R-304	57.6	No[4]
Cypress-Forest Junction 345 kV Line 971L51	488 SE	612 SE		29.9	No[5]
Cypress-West Switching Station 345 kV Line CYP31 (North)	488 SE	878 SE		29.6	No[6]
Kewaunee – East Krok 138-kV Line F-84	287 SE	347 SE		8.4	No[7]
Forest Junction – Kaukauna Central Tap 138-kV Line 971K11	293 SE	325 SE		5.2	No[8]
Forest Junction – Darboy 138-kV Darboy – Lake Park 138-kV Line 728K21	293 SE 293 SE	504 SE 476 SE		4.8 4.8	No[9] No[9]
Neevin-Woodenshoe138-kV Line 80952	293 SE	369 SE	Cypress-West Switching Station 345-kV Line CYP31 (North) N. Appleton – Fitzgerald 345-kV Line Y-311	11.8	No[10]

1. NERC Category C.3 events studied are limited to the concurrent outage of two elements without manual system adjustments between outages. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.
2. Includes provision for 5% TRM. The required ratings are calculations using DC analysis in PSS/E dispatching G833 and G834 to all MISO generation.
3. SE = Summer Emergency
4. Rating limited by 12.6 miles of 2156.0 kcmil ACSR 84/19 Bluebird line conductor at an emergency temperature rating of 146° F.
5. Rating limited by 30.43 miles of 2156.0 kcmil ACSR 84/19 Bluebird line conductor at an emergency temperature rating of 120° F.
6. Rating limited by 11.7 miles of 2156.0 kcmil ACSR 84/19 Bluebird line conductor at an emergency temperature rating of 120° F.
7. Rating limited by line conductor, station conductors, meters, traps, switches, CTs and the East Krok breaker.
8. Rating limited by 9.3 miles of 795.0 kcmil ACSR 26/7 Drake line conductor at an emergency temperature rating of 200° F.
9. Rating limited by 11.7 miles of 795.0 kcmil ACSR 26/7 Drake line conductor at an emergency temperature rating of 200° F.
10. Rating limited by 4.04 miles of 795.0 kcmil ACSR 26/7 Drake line conductor at an emergency temperature rating of 230° F.

Table A.8 – Identified Voltage Violations under select NERC Category C.5 events[1]
Summer 2010 100% Loading Mode, Delivery to MISO, West Switching Station In

Limiting Element	Worst Contingency[1]	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833-4	Post G833-4		
None Identified	-	-	-	-	-

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit towerline. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment. See Table 3.1 for a list of all NERC Category C.5 events studied.

Table A.9 – Identified Voltage Violations under select NERC Category C.5 events[1]
Summer 2010 50% Loading Mode, Delivery to MISO, West Switching Station In

Limiting Element	Worst Contingency[1]	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833-4	Post G833-4		
None Identified	-	-	-	-	-

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit towerline. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment. See Table 3.1 for a list of all NERC Category C.5 events studied.

Table A.10 – Maximum Allowable Generation for G833 and G834 without Network Upgrades for Injection Limits

Limiting Element	Worst Contingency	Model Description[1]	G833-4 Max Output with Planned and Proposed Projects[1] (MW)
Cypress-West Switching Station (L-CYP31 north) 345 kV	Point Beach-Sheboygan Energy (L111) 345 kV	2010, 50% Load, Existing Kewaunee Sub[2]	0 MW
Arcadian-West Switching Station (L-CYP31 south) 345 kV	Edgewater-Saukville (796L41) 345 kV	2010, 50% Load, Existing Kewaunee Sub[3]	0 MW
Elkhart Lake-G611 Tap (4035 South) 138 kV	Granville-Sheboygan Energy (L-SEC31) 345 kV	2010, 50% Load, Proposed Kewaunee Sub[4]	0 MW
Point Beach-Sheboygan Energy (L111) 345 kV	Edgewater-Saukville (796L41) 345 kV	2010, 50% Load, Existing Kewaunee Sub[3]	0 MW

1. Planned and Proposed projects from the ATC 2006 Ten Year Assessment report (http://www.atc10yearplan.com/). The 345 kV West Switching Station described in this report is also modeled.
2. The Maximum Output is the same with 100% of system peak load and/or the new Kewaunee Substation configuration modeled. Maximum generator out put is 89 MW for Intact System conditions with 50% of system peak load modeled. There is no intact system generation limit under 100% of system peak load conditions.
3. The Maximum Output is the same with the new Kewaunee Substation configuration modeled. The overload does not exist for 100% of system peak load models.
4. The maximum output for the 50% of system peak load case (0 MW) is the same after the Line 4035 upgrade to 112 MVA for G611 and G927 is completed. For the 100% of system peak load case, there is no restriction after the 4035 line upgrade due to G611 and G927, but there would be a 125 MW (proposed Kewaunee substation configuration) or 141 MW (existing Kewaunee substation configuration) restriction at the existing line rating (96 MVA).

Table A.11 – Identified Thermal Violations Due to G833 and G834 Summer 2010 (50% Load) Delivery to MISO for NERC Category A and B events (TDF>3%) West Switching Station in Service, Wind Farms at Two-Thirds Output

Limiting Element	Existing Rating (MVA)	Required Rating (MVA)[1,2]	Worst Contingency
Cypress – West Switching Station 345-kV Line L-CYP31 (North)	488 SE	579 SE	Point Beach-Sheboygan Energy Center 345-kV Line 111
Point Beach-Sheboygan Energy Center 345-kV Line 111	488 SE	516 SE	Cypress – West Switching Station 345-kV Line L-CYP31 (North)
Arcadian – West Switching Station 345-kV Line L-CYP31 (South)	488 SE	513 SE	Edgewater-Saukville 345 kV Line 796L41
Elkhart Lake-G611 Tap 138-kV Line 4035 (South)	96 SE[3]	117 SE	Point Beach-Sheboygan Energy Center 345-kV Line 111

1. Includes provision for 5% TRM. The required ratings are calculated using AC transfer analysis in ACCC dispatching 100% of power from G833 and G834 to MISO. Because of the minimal difference in results with and without a second 345/138 kV Kewaunee Transformer, only worst case results are reported. WN = Winter Normal, WE = Winter Emergency
2. SN = Summer Normal, SE = Summer Emergency
3. Line Rating is being increased to 112 MVA due to requirements of other generation interconnection studies.

Appendix B: Operation Restrictions

Table B.1 – Summary of Identified Generation Restrictions due to Stability Constraints (West Switching Station in service and Kewaunee Substation Reconfigured)

Prior Outage	Worst Next Contingency	Generation Restriction
Q-303 Point Beach-Kewaunee 345 kV	R-304 Kewaunee-North Appleton 345 kV	Kewaunee Net Generation ≤ 500 MW[1]
R-304 Kewaunee-North Appleton 345 kV	Q-303 Point Beach-Kewaunee 345 kV	Kewaunee Net Generation ≤ 475 MW[2]
Point Beach 345 kV Breaker 2-3	L121 Point Beach-Forest Junction 345 kV	Point Beach Unit #1 Net Generation ≤ 550 MW[3]

1. The same restriction exists with or without the West Switching Station and with both existing and minimum North Appleton breaker clearing times. Prior to Kewaunee substation reconfiguration Kewaunee Generation must be ≤ 382 MW (T10 thermal limit).
2. The same restriction exists with or without the West Switching Station. Prior to Kewaunee substation reconfiguration there is no restriction on Kewaunee Generation because T10 is tripped with R-304.
3. The same restriction exists with or without the West Switching Station and before and after the Kewaunee Substation Reconfiguration.

Appendix C: Stability Analysis Results

Table C.1 – G833 and G834 Stability Results for Faults Clearing in Primary Time under Intact System Conditions (Kewaunee SPS Implemented for Existing Kewaunee Substation Configuration, Point Beach PSS out-of-service)

Item Number	Element Faulted	Fault Location	Remote Location	Kewaunee Substation	Clearing Cycles Local/Remote	High Gen Model Units Tripped	Low Gen Model Units Tripped
1	L111 - Point Beach-Sheboygan 345 kV	POB	SEC	Existing	4.5/4.5	none	none
2	L111 - Point Beach-Sheboygan 345 kV	POB	SEC	Proposed	4.5/4.5	none	none
3	L121 - Point Beach-Forest Junction 345 kV	POB	FJT	Existing	4.5/4.5	none	none
4	L121 - Point Beach-Forest Junction 345 kV	POB	FJT	Proposed	4.5/4.5	none	none
5	L151 - Point Beach-Fox Energy 345 kV	POB	FOX	Existing	4.5/4.5	none	none
6	L151 - Point Beach-Fox Energy 345 kV	POB	FOX	Proposed	4.5/4.5	none	none
7	Q-303 - Point Beach-Kewaunee 345 kV	POB	KEW	Existing	4.5/6.5	none	none
8	Q-303 - Point Beach-Kewaunee 345 kV	POB	KEW	Proposed	4.5/4.5	none	none
9	Q-303 - Point Beach-Kewaunee 345 kV	KEW	POB	Existing	6.5/4.5	none	none
10	Q-303 - Point Beach-Kewaunee 345 kV	KEW	POB	Proposed	4.5/4.5	none	none
11	R-304 - Kewaunee-North Appleton 345 kV	KEW	NAP	Existing	6.5/6.5	none	none
12	R-304 - Kewaunee-North Appleton 345 kV	KEW	NAP	Proposed	4.5/6.5	none	none
13	L151 - Point Beach-Fox Energy 345 kV	FOX	POB	Existing	4.5/4.5	none	none
14	L151 - Point Beach-Fox Energy 345 kV	FOX	POB	Proposed	4.5/4.5	none	none
15	L6832 Fox Energy-North Appleton 345 kV	FOX	NAP	Existing	4.5/4.5	none	none
16	L6832 Fox Energy-North Appleton 345 kV	FOX	NAP	Proposed	4.5/4.5	none	none
17	971L71 - Fox Energy-Forest Junction 345 kV	FOX	FJT	Existing	4.5/4.5	none	none
18	971L71 - Fox Energy-Forest Junction 345 kV	FOX	FJT	Proposed	4.5/4.5	none	none
19	L111 - Point Beach-Sheboygan 345 kV	SEC	POB	Existing	4.5/4.5	none	none
20	L111 - Point Beach-Sheboygan 345 kV	SEC	POB	Proposed	4.5/4.5	none	none
21	LSEC31 - Sheboygan-Granville 345 kV	SEC	GVL	Existing	4.5/6.5	none	none
22	LSEC31 - Sheboygan-Granville 345 kV	SEC	GVL	Proposed	4.5/6.5	none	none
23	L9932 - Cypress-Arcadian 345 kV	CYP	ADN	Existing	4.5/4.5	none	none
24	L9932 - Cypress-Arcadian 345 kV	CYP	ADN	Proposed	4.5/4.5	none	none
25	T10 - Kewaunee 345/138 kV Transformer	KWH	KWL	Existing	7.5/8.5	P, K*	P, K**
26	T10 - Kewaunee 345/138 kV Transformer	KWH	KWL	Proposed	5.5/5.5	none	none

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 Include 1.0 Cycle Margin on Faulted End Clearing Time

* Stable at 6.5/6.5 (KEW Trips at 7.0/7.0), Also Stable at 6.5/6.5 (KEW Trips at 7.0/7.0) with West Switching Station Modeled.

**Stable at 6.0/6.0 (KEW Trips at 6.5/6.5). Stable at 6.5/6.5 (KEW Trips at 7.0/7.0) with West Switching Station Modeled.

Table C.2 – G833 and G834 Stability Results for Double Circuit Single Line-to-Ground Faults Cleared in Primary Time under Intact System Conditions, Point Beach PSS in-service

Item	Faulted Element	Fault #1	#1	Faulted Element	Fault #2	#2	Existing KEW Sub		Future KEW Sub	
#	#1	Location	Cycles	#2	Location	Cycles	High Gen	Low Gen	High Gen	Low Gen
1	L111 - Point Beach-Sheboygan 345 kV	38.5% from POB	5.5	971K51 - Forest Junction-Howard's Grove 138 kV	33.9% from FJT	6.5	none	none	none	none
2	L111 - Point Beach-Sheboygan 345 kV	16.3% from SEC	5.5	971K51 - Forest Junction-Howard's Grove 138 kV	6.3% from HOG	6.5	none	none	none	none
3	L111 - Point Beach-Sheboygan 345 kV	SEC	5.5	HOGL21 - Howard's Grove-Holland 138 kV	76.9% from HOL	6.5	none	none	none	none
4	L111 - Point Beach-Sheboygan 345 kV	15.7% from SEC	5.5	HOGL21 - Howard's Grove-Holland 138 kV	31.4% from HOG	6.5	none	none	none	none
5	L121 – Pt. Beach-Forest Junction 345 kV	FJT	5.5	971K51 - Forest Junction-Howard's Grove 138 kV	FJT	6.5	none	none	none	none
6	L121 – Pt. Beach-Forest Junction 345 kV	42.3% from FJT	5.5	971K51 - Forest Junction-Howard's Grove 138 kV	33.9% from FJT	6.5	none	none	none	none
7	SEC31 - Sheboygan-Granville 345 kV	GVL	7.5	3431 - Granville-Saukville 345 kV	GVL	7.5	none	none	none	none
8	SEC31 - Sheboygan-Granville 345 kV	26.7% from GVL	7.5	3431 - Granville-Saukville 345 kV	25.3% from SAU	7.5	none	none	none	none
9	SEC31 - Sheboygan-Granville 345 kV	43.5% from GVL	7.5	8231 - Saukville-Barton 138 kV	36.4% from BRT	7.5	none	none	none	none
10	SEC31 - Sheboygan-Granville 345 kV	48.3% from GVL	7.5	8231 - Saukville-Barton 138 kV	36.4% from SAU	7.5	none	none	none	none
11	CYP31 - Cypress-Arcadian 345 kV	32.0% from ADN	5.5	2642 - Saukville-Germantown 138 kV	34.2% from SAU	7.5	none	none	none	none
12	CYP31 - Cypress-Arcadian 345 kV	16.6% from ADN	5.5	2642 - Saukville-Germantown 138 kV	GER	7.5	none	none	none	none
13	CYP31 - Cypress-Arcadian 345 kV	10.8% from ADN	5.5	2661 - Germantown-Bark River 138 kV	31.5% from GER	8.5	none	none	none	none
14	CYP31 - Cypress-Arcadian 345 kV	16.6% from ADN	5.5	2661 - Germantown-Bark River 138 kV	GER	8.5	none	none	none	none
15	CYP31 - Cypress-Arcadian 345 kV	10.8% from ADN	5.5	9911 - Granville-Arcadian 345 kV	45.4% from GVL	7.5	none	none	none	none
16	CYP31 - Cypress-Arcadian 345 kV	ADN	5.5	9911 - Granville-Arcadian 345 kV	ADN	7.5	none	none	none	none

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

Table C.3 – G833 and G834 Stability Results for 3-Phase Faults Cleared in Primary Time under Prior Outage Condition Units Tripping, Existing Kewaunee Substation Configuration, Point Beach PSS in-service

Event	Faulted	Fault	Prior	Existing Clearing	Existing Clearing High Gen		Existing Clearing Low Gen		Tested Clearing	Tested Clearing High Gen		Tested Clearing Low Gen	
#	Element	Location	Outage	Time	Existing	West SS	Existing	West SS	Time	Existing	West SS	Existing	West SS
1	**T-10**	KEW	**None**	7.5/8.5	P, K	P, K	P, K	P, K	5.5/5.5	none	none	none	none
2	**R-304**	KEW	**L-111**	6.5/6.5	P, K	P, K	P, K	P, K	4.5/6.5	none	none	none	none
3	**T-10**	KEW	**L-111**	7.5/8.5	P, K, F2s	P, K, Fs	P, K	P, K	5.5/5.5	none	none	none	none
4	**R-304**	KEW	**L-121**	6.5/6.5	P, K	P, K	P, K	P, K	4.5/6.5	none	none	none	none
5	**T-10**	KEW	**L-121**	7.5/8.5	P, K	P, K	P, K	P, K	5.5/5.5	none	none	none	none
6	**R-304**	KEW	**L-151**	6.5/6.5	P, K	P, K	P, K	P, K	4.5/6.5	none	none	none	none
7	**T-10**	KEW	**L-151**	7.5/8.5	P, K	P, K	P, K	P, K	5.5/5.5	none	none	none	none
8	**R-304**	KEW	**Q-303**	6.5/6.5	K*	K*	K*	K*	4.5/6.5	K*	K*	K*	K*
9	**T-10**	KEW	**Q-303**	7.5/8.5	K*	K*	K*	K*	5.5/5.5	none	none	none	none
10	**R-304**	KEW	**6832**	6.5/6.5	P, K, F, S	P, K, F, S	P, K	P, K	4.5/6.5	P, K, F, S*	none	none	none
11	**T-10**	KEW	**6832**	7.5/8.5	P, K, F, S	P, K, F	P, K	P, K	5.5/5.5	none	none	none	none
12	**T-10**	KEW	**971L71**	7.5/8.5	P, K	P, K	P, K	P, K	5.5/5.5	none	none	none	none
13	**R-304**	KEW	**SEC31**	6.5/6.5	P, K, F, S	P, K, F, S	P, K	P, K	4.5/6.5	none	none	none	none
14	**T-10**	KEW	**SEC31**	7.5/8.5	P, K, F2s, S	P, K, F, S	P, K	P, K	5.5/5.5	none	none	none	none
15	**R-304**	KEW	**CYP31**	6.5/6.5	P, K	none	P, K	none	4.5/6.5	none		none	
16	**T-10**	KEW	**CYP31**	7.5/8.5	P, K, F2s	P, K	P, K	P, K	5.5/5.5	none	none	none	none
17	**R-304**	KEW	**T10**	6.5/6.5	none		P, K	none	4.5/6.5	none		none	
18	**R-304**	KEW	**NAPL71**	6.5/6.5	P, K	none	P, K	none	4.5/6.5	none		none	
19	**T-10**	KEW	**NAPL71**	7.5/8.5	P, K, F	P, K, Fs	P, K	P, K	5.5/5.5	none	none	none	none
20	**R-304**	KEW	**971L51**	6.5/6.5	none		P, K	P, K	4.5/6.5	none		none	none
21	**T-10**	KEW	**971L51**	7.5/8.5	P, K	P, K	P, K	P, K	5.5/5.5	none	none	none	none
22	**R-304**	KEW	**L311**	6.5/6.5	none		P, K	none	4.5/6.5	none		none	
23	**T-10**	KEW	**L311**	7.5/8.5	P, K	P, K	P, K	P, K	5.5/5.5	none	none	none	none
24	**R-304**	KEW	**POB12**	6.5/6.5	P, K	P, K	P, K	P, K	4.5/6.5	none	none	none	none
25	**T-10**	KEW	**POB12**	7.5/8.5	P, K, F2S	P, K, Fs	P, K	P, K	5.5/5.5	none	none	none	none
26	**L121**	POB	**POB23**	4.5/4.5	P1*	P1*	P1*	P1*	n/a				
27	**R-304**	KEW	**POB23**	6.5/6.5	P2, K	P2, K	P2, K	P2, K	4.5/6.5	none	none	none	none
28	**T-10**	KEW	**POB23**	7.5/8.5	P2, K	P2, K	P2, K	P2, K	5.5/5.5	none	none	none	none
29	**T-10**	KEW	**POB34**	7.5/8.5	K	K	P2, K	K	5.5/5.5	none	none	none	none
30	**R-304**	KEW	**POB45**	6.5/6.5	P, K	P, K	P, K	P, K	4.5/6.5	none	none	none	none
31	**T-10**	KEW	**POB45**	7.5/8.5	P, K	P, K	P, K	P, K	5.5/5.5	none	none	none	none

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 Existing Kewaunee Generation 382 MW Limit for Kewaunee Transformer T10 Thermal Concerns
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.
P, K, F, S* - Unstable with even with 4.5/4.5 Cycle Clearing, None* - Stable at 6.5/6.5 Clearing Time, none** - Stable at 6.0/6.0 Clearing Time.

Table C.4 – G833 and G834 Stability Results for 3-Phase Faults Cleared in Primary Time under Prior Outage Condition Units Tripping, Proposed Kewaunee Substation Configuration, Point Beach PSS in-service

Event	Faulted	Fault	Prior	Existing Clearing	Existing Clearing High Gen		Existing Clearing Low Gen		Tested Clearing	Tested Clearing High Gen		Tested Clearing Low Gen	
#	Element	Location	Outage	Time	Existing	West SS	Existing	West SS	Time	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*
2	**Q-303**	POB	**R-304**	4.5/4.5	K	K**	K	K**	n/a				
3	**Q-303**	KEW	**R-304**	4.5/4.5	K	K**	K	K**	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
5	**L-121**	POB	**POB23**	4.5/4.5	P1*	P*1	P1*	P1*	n/a				

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 C.5 – G833 and G834 Stability Results for 3-Phase Faults Cleared in Delayed Time under Intact Conditions, Units Tripping, Existing Kewaunee Substation Configuration, Point Beach PSS in-service

Event	Element	Fault	Remote	Event	Existing	High Generation Base		High Generation – West SS		Low Generation Base		Low Generation – West SS	
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	P, K*	PK
2	L151	POB	FOX	T2X03 Tripped, Aux Moved	3.5/10.0/4.5		none		none	none	PK	none	PK
3	Q303	POB	KEW	Trip T10 Primary, Delay POB Split	3.5/10.0/6.5	none	P2, K	none	P2, K	P2*	P K	none	P K
4	R-304	NAP	KEW	Split NAP Primary, T10 Trips in BF	5.5/14.25/5.5		none		none		none		none
5	L121	FJT	POB	Trips Transformer	3.5/10.5/4.5		none		none		none		none
6	971L51	FJT	CYP	Trips Line 971L71	3.5/10.5/4.5		none		none		none		none
7	971l71	FJT	FOX	Trips Line 971L51	3.5/10.5/4.5		none		none		none		none
8	L151	FOX	POB	BF Trips Fox Unit 1	3.5/10.5/4.5		none		none		none		none
9	L6832	FOX	NAP	BF Trips Fox Unit 2	3.5/10.0/4.5		none		none		none		none
10	971L71	FOX	FJT	BF Trips Fox Unit 2	3.5/10.0/4.5		none		none		none		none
11	L111	SEC	POB	Do Not Trip Gen (worst case)	3.5/10.5/4.5		none		none		none		none
12	LSEC31	SEC	GVL	Do Not Trip Gen (worst case)	3.5/10.5/6.5		none		none		none		none
13	LCYP31	CYP	ADN	Trips CYP Units	3.5/10.5/4.5		none		none		none		none
14	971L51	CYP	FJT	Trips CYP Units	3.5/10.5/4.5		none		none		none		none

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

* - Stable at 9.25 cycles at bus and 9.5 cycles for a fault at 10% of the line length.

** - Stable at 9.0cycles at bus.

Table C.6 – G833 and G834 Stability Results for 3-Phase Faults Cleared in Delayed Time under Intact Conditions, Units Tripping, Proposed Kewaunee Substation Configuration, Point Beach PSS in-service

Event	Element	Fault	Remote	Event	Existing	High Generation Base		High Generation – West SS		Low Generation Base		Low Generation – West SS	
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
2	L151	POB	FOX	T2X03 Tripped, Aux Moved	3.5/10.0/4.5		none		none	none	PK	none	PK
3	Q303	POB	KEW	Delay POB Split	3.5/10.0/6.5		none		none	none	P2	none	none
4	Q303	KEW	POB	Trip T10 Primary, Delay POB Split	3.5/10.0/4.5		none		none	none	K	none	K
5	R-304	KEW	NAP	Split NAP Primary, T10 Trips in BF	5.5/14.25/5.5		none		none	none	PK	none	PK
6	KEW T10	KEWH	KEWL	Split NAP Primary, T10 Trips in BF	5.5/14.25/5.5		none		none		none		none
7	R-304	NAP	KEW	Split NAP Primary, T10 Trips in BF	5.5/14.25/5.5		none		none		none		none
8	L121	FJT	POB	Trips Transformer	3.5/10.5/4.5		none		none		none		none
9	971L51	FJT	CYP	Trips Line 971L71	3.5/10.5/4.5		none		none		none		none
10	971l71	FJT	FOX	Trips Line 971L51	3.5/10.5/4.5		none		none		none		none
11	L151	FOX	POB	BF Trips Fox Unit 1	3.5/10.5/4.5		none		none		none		none
12	L6832	FOX	NAP	BF Trips Fox Unit 2	3.5/10.0/4.5		none		none		none		none
13	971L71	FOX	FJT	BF Trips Fox Unit 2	3.5/10.0/4.5		none		none		none		none
14	L111	SEC	POB	Do Not Trip Gen (worst case)	3.5/10.5/4.5		none		none		none		none
15	LSEC31	SEC	GVL	Do Not Trip Gen (worst case)	3.5/10.5/6.5		none		none		none		none
16	LCYP31	CYP	ADN	Trips CYP Units	3.5/10.5/4.5		none		none		none		none
17	971L51	CYP	FJT	Trips CYP Units	3.5/10.5/4.5		none		none		none		none

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

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

** - Stable at 9.0cycles at bus.

Table C.7 – G833 and G834 Stability Results for Point Beach Bus Single Line-to-Ground Faults Cleared in Delayed Time under Intact Conditions All Cases with West Switching Station Modeled, Point Beach PSS in-service

Event	Fault	Breaker Failure	Existing	Existing Kewaunee Substation		Proposed Kewaunee Substation	
#	Location	Element Tripped	Clearing*	High Gen Model	Low Gen Model	High Gen Model	Low Gen Model
1	POB Bus 1	POB-SEC	4.75/24.5	none	none	none	none
2	POB Bus 1	POB Bus 1-2	4.75/12.5	none	none	none	none
3	POB Bus 2	POB Bus 2-1	4.75/12.5	none	none	none	none
4	POB Bus 2	POB Bus 2-3	4.75/12.5	none	none	none	none
5	POB Bus 3	POB Bus 3-2	4.75/12.5	none	none	none	none
6	POB Bus 3	POB-KEW	5.0/8.0	none	none	none	none
7	POB Bus 3	POB Bus 3-4	4.75/12.5	none	none	none	none
8	POB Bus 4	POB Bus 4-3	4.75/12.5	none	none	none	none
9	POB Bus 4	POB Bus 4-5	4.75/12.5	none	none	none	none
10	POB Bus 5	POB Bus 5-4	4.75/12.5	none	none	none	none
11	POB Bus 5	POB-FOX	4.75/24.5	none	none	none	none

Table C.8 – G833 and G834 Stability Results for 3-Phase Faults at Proposed West Switching Station Cleared in Delayed Time under Intact Conditions, Units Tripping Listed, Planned Kewaunee Substation Configuration with Network Upgrades, PSS in-service

Event	Faulted	Breaker Failure	Simulated	Existing Kewaunee Sub		Proposed Kewaunee Sub	
#	Line	Element Tripped	Clearing*	High Gen Model	Low Gen Model	High Gen Model	Low Gen Model
1	Arcadian	S. Fond du Lac	3.5/10.5/4.5	none	none	none	none
2	Arcadian	Edgewater	3.5/10.5/4.5	none	none	none	none
3	Cypress	S. Fond du Lac	3.5/10.5/4.5	none	none	none	none
4	Cypress	Edgewater	3.5/10.5/4.5	none	none	none	none
5	Edgewater	Arcadian	3.5/10.5/4.5	none	none	none	none
6	Edgewater	Cypress	3.5/10.5/4.5	none	none	none	none
7	S. Fond du Lac	Arcadian	3.5/10.5/4.5	none	none	none	none
8	S. Fond du Lac	Cypress	3.5/10.5/4.5	none	none	none	none

Table C.9 – G833 and G834 GSU Single Line-to-Ground Faults Cleared in Delayed Time under Intact Conditions, Units Tripping, Existing and Planned Kewaunee Substation Configuration with West Switching Station Modeled, Point Beach PSS in-service

Event	Faulted	Breaker Failure	Simulated	Existing Kewaunee Sub		Proposed Kewaunee Sub	
#	Element	Element Tripped	Clearing*	High Gen Model	Low Gen Model	High Gen Model	Low Gen Model
1	POB Unit 1 GSU	POB Bus 2	4.5/13.5/14.0	none	none	none	none
2	POB Unit 2 GSU	POB Bus 4	4.5/13.5	none	none	none	none

* - Primary Clearing Time/Bus Breaker Failure Time/Line Breaker Failure Time (GSU #1 Only)
Simulation Results (i.e. no stability problems) were the same without the West Switching Station Modeled.

Table C.10 – G833 and G834 Auxiliary Transformer High Side Single Line-to-Ground Faults Cleared in Delayed Time under Intact Conditions, Units Tripping, Existing and Planned Kewaunee Substation Configuration with West Switching Station Modeled, Point Beach PSS in-service

Event	Faulted	Breaker Failure	New AUX	Simulated	Existing Kewaunee Sub		Proposed Kewaunee Sub	
#	Element	Element Tripped	HS Breaker?	Clearing*	High Gen Model	Low Gen Model	High Gen Model	Low Gen Model
1	POB AUX1 HS	POB-SEC @ SEC	No	5.1/24.5	none	none	none	none
2	POB AUX2 HS	POB-FOX @ FOX	No	5.1/24.5	none	none	none	none
3	POB AUX1 HS	POB Bus 2**	No	5.1/13.03	none	none	none	none
4	POB AUX2 HS	POB Bus 4***	No	5.1/13.3	none	none	none	none

* - The Stability Model Time Step is 0.25 cycles, so a 13.3 cycle fault actually clears in 13.5 cycles.
** - POB-Forest Junction 345 kV line Trips, POB Generator 1 is Isolated.
*** - POB Generator 2 is isolated
Simulation Results (i.e. no stability problems) were the same without the West Switching Station Modeled.

Table C.11 – G833 and G834 GSU Three Phase 345 kV Faults Cleared in Primary (5.5 cycles, including 1 cycle margin) Time under N-1 Conditions, Units Tripping, Existing and Planned Kewaunee Substation Configuration with and without West Switching Station Modeled, Point Beach PSS in-service

		High Gen				Low Gen			
		No Fix		West SS		No Fix		West SS	
Fault	PO	As Is KEW	New KEW	As Is KEW	New KEW	As Is KEW	New KEW	As Is KEW	New KEW
FltPBGSU1	None	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	111	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	121	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	151	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	303	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	304	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	6832	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	971L71	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	SEC31	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	CYP31	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	T10	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	NAPL71	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	971L51	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	311	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	B12	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	B23	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	B34	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU1	B45	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	None	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	111	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	121	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	151	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	303	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	304	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	6832	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	971L71	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	SEC31	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	CYP31	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	T10	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	NAPL71	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	971L51	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	311	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	B12	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	B23	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	B34	OK	OK	OK	OK	OK	OK	OK	OK
FltPBGSU2	B45	OK	OK	OK	OK	OK	OK	OK	OK

Table C.12 – G833 and G834 Auxiliary Transformer High Side 3-Phase Faults Cleared in Primary Time (6.1 cycles, including 1 cycle margin) under N-1 Conditions, Existing and Planned Kewaunee Substation Configurations with and without West Switching Station Modeled, Point Beach PSS in-service (No Aux High Side Breaker (existing condition).

6.1 cycle Clearing		High Generation Modeled				Low Generation Modeled			
Fault	PO	Existing	Kew 2T	Fix 1	K2T, Fx1	Existing	Kew 2T	Fix 1	K2T, Fx1
FltPOBAX1	None	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX1	111	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX1	121	PK	PK	PK	PK	PK	PK	PK	PK
FltPOBAX1	151	PK	PK	PK	OK	PK	PK	PK	PK
FltPOBAX1	303	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX1	304	PKFs	PKFs	PK	PK	PK	PK	PK	PK
FltPOBAX1	6832	PKF	PKF	PKF	PKF	PK	PK	OK	OK
FltPOBAX1	971L71	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX1	SEC31	OK*	OK*	OK*	OK*	OK	OK	OK	OK
FltPOBAX1	CYP31	PKF	PKF	OK	OK	PK	PK	OK	OK
FltPOBAX1	T10	PK	OK	OK	OK	PK	OK	OK	OK
FltPOBAX1	NAPL71	PKF	PKF	PKF	PKF	PK	PK	PK	PK
FltPOBAX1	971L51	PKF	PKF	PKF	PKF	PK	PK	PK	PK
FltPOBAX1	311	PKF	PKF	OK	OK	PK	PK	OK	OK
FltPOBAX1	B12	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX1	B23	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX1	B34	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX1	B45	PK	PK	PK	PK	PK	PK	PK	PK
FltPOBAX2	None	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX2	111	PK	PK	PK	PK	PK	PK	PK	PK
FltPOBAX2	121	PK	PK	PK	PK	PK	PK	PK	PK
FltPOBAX2	151	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX2	303	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX2	304	PK	PK	PK	PK	PK	PK	PK	PK
FltPOBAX2	6832	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX2	971L71	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX2	SEC31	PKS	PKS	PKS	PKS	PK	PK	PK	PK
FltPOBAX2	CYP31	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX2	T10	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX2	NAPL71	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX2	971L51	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX2	311	OK	OK	OK	OK	OK	OK	OK	OK
FltPOBAX2	B12	PK	PK	PK	PK	PK	PK	PK	PK
FltPOBAX2	B23	P2K	OK	P2K	OK	P2K	P2K	P2K	P2K
FltPOBAX2	B34	OK**	OK**	OK**	OK**	OK**	OK**	OK**	OK**
FltPOBAX2	B45	OK	OK	OK	OK	OK	OK	OK	OK

*SEC Gens Isolated **POB GEN 2 Isolated

Table C.13 – G833 and G834 Auxiliary Transformer High Side 3-Phase Faults Cleared in Primary Time (6.1 cycles, including 1 cycle margin) under N-1 Conditions, Planned Kewaunee Substation Configurations with West Switching Station Modeled, Point Beach PSS not in service (No Aux High Side Breaker, existing condition). Critical Clearing Time Simulations.

		High Generation Modeled					Low Generation Modeled				
Fault	PO	6.1/6.25	6.0 cycles	5.75 cycles	5.5 cycles	5.0 cycles	6.1/6.25	6.0 cycles	5.75 cycles	5.5 cycles	5.25 cycles
FltPOBAX1	121	PK	OK	OK	OK	OK	PK	PK	OK	OK	
FltPOBAX1	151	OK	OK	OK	OK	OK	PK	OK	OK	OK	
FltPOBAX1	304	PK	PK	OK	OK	OK	PK	PK	OK	OK	
FltPOBAX1	6832	PKF	OK	OK	OK	OK	OK	OK	OK	OK	
FltPOBAX1	NAPL71	PKF	PKFs	OK	OK	OK	PK	PK	OK	OK	
FltPOBAX1	971L51	PKF	OK	OK	OK	OK	PK	PK	OK	OK	
FltPOBAX1	B45	PK	OK	OK	OK	OK	PK	OK	OK	OK	
FltPOBAX2	111	PK	OK	OK	OK	OK	PK	PK	OK	OK	
FltPOBAX2	121	PK	PK	PK	OK	OK	PK	PK	PK	PK	OK
FltPOBAX2	304	PK	PK	OK	OK	OK	PK	PK	PK	OK	
FltPOBAX2	SEC31	PKS	PKS	PKS	OK	OK	PK	PK	OK	OK	
FltPOBAX2	B12	PK	OK	OK	OK	OK	PK	PK	OK	OK	
FltPOBAX2	B23	OK	OK	OK	OK	OK	P2K	OK	OK	OK	

Appendix D: Short Circuit / Breaker Duty Analysis Results

Table D.1 – Maximum and Minimum Fault Duties at the G833-4 Point of Interconnection

	Maximum Fault Duty		*Minimum Fault Duty*	
	Single-phase	*Three-Phase*	*Single-phase*	*Three-Phase*
Without G8433-4	23,023 A	20,820 A	17,795 A	16,075 A
With G833-4 and West Switching Station	24,575 A	21,813 A	19,374 A	17,109 A

Note: Minimum fault duty was calculated with the Q-303 (Point Beach-Kewaunee 345 kV) line out of service.

Table D.2 – Thevenin Equivalent Impedances in Ohms corresponding to Maximum Fault Duty

	Pos Seq.	*Neg. Seq.*	*Zero Seq.*
Without G8433-4	0.4989+ j9.5541 Ω	0.5744+j9.5596 Ω	0.5885+j6.7883 Ω
With G833-4 and West Switching Station	0.4785+j9.1192 Ω	0.7572+j9.1083 Ω	0.4817+j6.0275 Ω

Table D.3 – Breaker Fault Duty Analysis for Breakers with >1% Increase in Fault Current

			Three Phase Fault Analysis						Single Phase Fault Analysis					
			Derated Breaker Rating	Symmetrical Fault Current (amps)		Change in Fault Current	Breaker Margin (%)		Derated Breaker Rating	Symmetrical Fault Current (amps)		Change in Fault Current	Breaker Margin (%)	
BUS NAME	KV	BREAKER	(kA)	Before	After	(%)	Before	After	(kA)	Before	After	(%)	Before	After
ARCADIAN_5	138	LINE_9952	53.3	33492	33888	1.2%	31.9	31.0	55	37732	38229	1.3%	37.6	36.8
ARCADIAN_6	138	LINE_9962	53.3	36094	36494	1.1%	27.2	26.2	55	40226	40730	1.3%	33.5	32.7
ARCADIAN_4	138	LINE_9942	63	36043	36444	1.1%	38.4	37.6	63	40180	40684	1.3%	36.2	35.4
ARCADIAN_4	138	BUS 4-5	63	32096	32397	0.9%	47.1	46.6	63	35678	36060	1.1%	25.9	24.9
ARCADIAN_5	138	BUS 5-6	63	32171	32473	0.9%	48.5	48.0	63	35375	35750	1.1%	43.8	43.3
ARCADIAN2	345	LINE_LERG71	40	19534	20150	3.2%	51.2	49.6	40	17926	18531	3.4%	55.2	53.7
ARCADIAN3	345	LINE_971L51	40	21634	24023	11.0%	45.9	39.9	40	19640	21515	9.5%	50.9	46.2
ARCADIAN1	345	LINE_612	40	20300	20907	3.0%	49.2	47.7	40	18229	18833	3.3%	54.4	52.9
ARCADIAN1	345	LINE_9911	40	18056	18915	4.8%	54.9	52.7	40	16330	16978	4.0%	59.2	57.6
ARCADIAN1	345	BUS 12	40	15977	16794	5.1%	60.1	58.0	40	14315	14965	4.5%	64.2	62.6
ARCADIAN1	345	XFORMER_1	50	23213	23819	2.6%	53.6	52.4	50	20429	21036	3.0%	59.1	57.9
BUTTERNUT_B4	138	BUS 4 5	40	6754	6832	1.2%	83.1	82.9	40	4358	4386	0.6%	89.1	89.0
BUTTERNUT_B5	138	G-BTB52	40	6754	6832	1.2%	83.1	82.9	40	4358	4386	0.6%	89.1	89.0
CEDARSAUK_4	345	BUS L41	50	12304	12459	1.3%	73.8	73.6	50	9406	9429	0.2%	80.2	80.1
CEDARSAUK	345	BUS L12	50	12304	12459	1.3%	73.8	73.6	50	9439	8915	-5.6%	81.1	80.9
Cypress_B1	345	BT12	50	8549	14105	65.0%	82.9	71.8	50	6160	10379	68.5%	87.7	79.2
Cypress_B2	345	BUS 2-3	50	8549	14105	65.0%	82.9	71.8	50	6160	10379	68.5%	87.7	79.2
Cypress_B1	345	BT16	50	8549	14105	65.0%	82.9	71.8	50	6160	10379	68.5%	87.7	79.2
ForestJct_1	138	BSK-12	50	33501	34446	2.8%	28.3	26.0	50	37217	38155	2.5%	21.9	20.2
ForestJct_2	138	BSK-23	50	33501	34446	2.8%	28.3	26.0	50	37217	38155	2.5%	21.9	20.2
ForestJct_3	138	BSK-34	50	32813	33761	2.9%	29.7	27.3	50	36597	37541	2.6%	23.0	21.3

Table D-3 Continued			Three Phase Fault Analysis						Single Phase Fault Analysis					
			Derated Breaker Rating	Symmetrical Fault Current (amps)		Change in Fault Current	Breaker Margin (%)		Derated Breaker Rating	Symmetrical Fault Current (amps)		Change in Fault Current	Breaker Margin (%)	
BUS NAME	KV	BREAKER	(kA)	Before	After	(%)	Before	After	(kA)	Before	After	(%)	Before	After
ForestJct_10	138	BSK-1011	50	34085	35053	2.8%	27.0	24.6	50	37707	38661	2.5%	20.8	19.2
ForestJct_11	138	BSK-1112	50	32683	33656	3.0%	29.8	27.4	50	36442	37402	2.6%	23.2	21.5
ForestJct_4	138	BSK-45	50	34092	35058	2.8%	27.2	24.8	50	37722	38677	2.5%	21.0	19.3
ForestJct_5	138	BSK-56	50	34092	35058	2.8%	27.2	24.8	50	37722	38677	2.5%	21.0	19.3
ForestJct_6	138	BSK-67	50	33856	34790	2.8%	27.5	25.1	50	37254	38177	2.5%	21.8	20.1
ForestJct_8	138	BSK-89	50	34128	35092	2.8%	26.9	24.5	50	37707	38658	2.5%	20.9	19.2
ForestJct_9	138	BSK-910	50	34128	35092	2.8%	26.9	24.5	50	37707	38661	2.5%	20.8	19.2
ForestJct1	345	BS-L12	50	17188	18859	9.7%	63.0	59.6	50	16287	17662	8.4%	67.4	64.7
ForestJct2	345	BS-L23 (L121)	50	17185	18855	9.7%	63.0	59.6	50	16297	17673	8.4%	67.4	64.7
ForestJct3	345	BS-L45	50	17185	18855	9.7%	63.0	59.6	50	16297	17673	8.4%	67.4	64.7
ForestJct5	345	BS-L56	50	16168	16373	1.3%	65.5	65.3	50	16151	16311	1.0%	67.7	67.4
ForestJct7	345	BS-L71	50	17188	18859	9.7%	65.6	62.3	50	16287	17662	8.4%	67.4	64.7
FOX_Bus_3	345	BSL-34	50	19489	20163	3.5%	61.0	59.7	50	19488	20023	2.7%	61.0	60.0
FOX_Bus_5	345	BSL-56	50	19335	20009	3.5%	61.3	60.0	50	19141	19675	2.8%	61.7	60.7
FOX_Bus_1	345	BSL-12	50	19256	19917	3.4%	61.5	60.2	50	18938	19456	2.7%	62.1	61.1
FOX_GSU1_311	345	BSL-45	50	17265	17790	3.0%	65.5	64.4	50	17230	17642	2.4%	65.5	64.7
FOX_GSU2_311	345	BSL-61	50	19315	19988	3.5%	61.3	60.0	50	19121	19654	2.8%	61.8	60.7
FOX_Bus_2	345	BSL-23	50	19444	20117	3.5%	61.1	59.8	50	19234	19768	2.8%	61.5	60.5
Granville_3	345	LINE 3431	39.5	16549	16788	1.4%	48.5	47.8	39.5	14239	14315	0.5%	49.7	49.4
Granville_2	345	BUS 2-3	40	15013	15209	1.3%	59.3	58.8	40	12911	12959	0.4%	61.1	61.0
Granville_1	345	BUS 1-2	42	12567	12737	1.4%	61.7	61.2	42	11058	11100	0.4%	62.3	62.1
NAP_345B_L1	345	BUS 12-1	40	21493	21722	1.1%	46.3	45.7	40	20088	20235	0.7%	49.8	49.4
NAP_345B_L34	345	BS34-4	40	21493	21722	1.1%	46.3	45.7	40	20088	20235	0.7%	49.8	49.4
NAP_345B_L81	345	BS 81-8	39.8	21493	21722	1.1%	35.2	34.8	39.8	20088	20235	0.7%	38.8	39.0
NAP_345B_L12	345	BUS 12-2	40	21493	21722	1.1%	46.3	45.7	40	20088	20235	0.7%	49.8	49.4
NAP_345B_L1	345	BS 81-1	50	21493	21722	1.1%	57.0	56.6	50	20088	20235	0.7%	59.8	59.5
NAP_345B_L4	345	BS 45-4	50	21493	21722	1.1%	57.0	56.6	50	20088	20235	0.7%	59.8	59.5
NAP_345B_L6	345	BS 67-6	50	21493	21722	1.1%	57.0	56.6	50	20088	20235	0.7%	59.8	59.5
NAP_345B_L67	345	BS 67-7	50	21493	21722	1.1%	57.0	56.6	50	20088	20235	0.7%	59.8	59.5
NAP_345B_L3	345	BS 34-3	38	21493	21722	1.1%	41.9	41.5	40	20088	20235	0.7%	47.8	47.9
NAP_345B_L7	345	BS 78-7	50	21493	21722	1.1%	57.0	56.6	50	20088	20235	0.7%	59.8	59.5
NAP_345B_L78	345	BS 78-8	50	21493	21722	1.1%	57.0	56.6	50	20088	20235	0.7%	59.8	59.5
NAP_345B_L2	345	BUS 23-2	42	21493	21722	1.1%	38.6	38.2	42	20088	20235	0.7%	42.0	42.1
NAP_345B_L23	345	BUS 23-3	42	21493	21722	1.1%	38.6	38.2	42	20088	20235	0.7%	42.0	42.1
POINT_BCH_B1	345	BS 1-2	40	18278	19262	5.4%	49.6	49.4	40	20560	22098	7.5%	45.3	44.8
POINT_BCH_B2	345	BS 2-3	40	13943	14344	2.9%	62.7	63.1	40	14946	15681	4.9%	61.3	60.8
POINT_BCH_B3	345	BS 3-4	40	16483	17064	3.5%	56.6	56.6	40	17219	18145	5.4%	56.2	54.6
POINT_BCH_B4	345	BS 4-5	40	18746	19652	4.8%	48.5	48.6	40	20815	22279	7.0%	44.2	44.3
POINT_BCH_B1	345	LINE 111	40	18278	19262	5.4%	49.6	49.4	40	20713	22243	7.4%	44.9	44.4
POINT_BCH_B2	345	LINE 121	40	18729	19499	4.1%	48.5	48.8	40	20886	22218	6.4%	43.9	44.5
POINT_BCH_B2	345	LINE 123	40	18729	19499	4.1%	48.5	48.8	40	20886	22218	6.4%	43.9	44.5
POINT_BCH_B3	345	LINE Q303	40	16127	17109	6.1%	55.5	55.3	40	17838	19374	8.6%	51.4	51.6
POINT_BCH_B5	345	LINE 151	40	18843	19750	4.8%	48.2	48.3	40	21008	22464	6.9%	43.7	43.8

Appendix E: Deliverability Analysis Results

Table E.1 – Deliverability Analysis Restrictions

Limiting Element	Contingency	G833 and G834 MW Deliverable	Potential Solution
None identified.		106 MW (100%)	Not applicable.

For a full description of the Midwest ISO Generator deliverability process, follow the "Deliverability Study Whitepaper" link that can be found at:
http://www.midwestmarket.org/publish/Document/3e2d0_106c60936d4_-767f0a48324a?rev=4

(Navigate to: www.midwestmarket.org > Planning > Generator Interconnection > Generator Deliverability Tests)

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) $\geq$ 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: Typical Planning Level Cost Estimates

Typical Transmission Line and Substation Capital Costs – March 16, 2006

It should be noted that the costs listed are merely representative for projects within each category. Actual project costs can vary, in some cases dramatically, based on the scope, location and particular design of the project. Capital costs include material, labor, licensing, design, land acquisition, environmental mitigation fees if applicable and project close-out. While some projects require additional costs of generator redispatch during construction outages, such costs are very project specific and have not been included in the estimates below.

Cost estimates for 345kV, 138kV, 115kV, 69kV T-Lines and Substations:

- New transmission line cost estimates include new structures, foundations, insulators, hardware, conductor, and easements shown in dollars per mile. No distribution underbuild costs are included.

- Rebuilt transmission line cost estimates include 100% new structures, foundations, insulators, hardware, and conductor on existing ROW/easements shown in dollars per mile. No distribution underbuild costs are included.

- Reconductor transmission line cost estimates include 10 ~ 30% new structures & foundations, 100% new conductor, insulators, and hardware on existing ROW/easements shown in dollars per mile. No distribution underbuild costs are included.

- Uprate 69kV to 69kV or 138kV to 138kV transmission line cost estimates include 25% new structures, foundations to increase clearances, reuse existing conductor, insulators, and hardware on existing ROW/easements shown in dollars per mile. No distribution underbuild costs are included.

- Uprate 69kV to 138kV transmission line cost estimates include 25% new structures, foundations to increase clearances, 100% new insulators, and hardware, and reuse existing conductor on existing ROW/easements shown in dollars per mile. No distribution underbuild costs are included.

- Routing an existing transmission line into a new substation typically requires two terminals, particularly at 100 kV and above.

- New substation cost estimate includes purchase and prepare site, control house, switches, bus, structures, breakers, and protection shown in dollars per terminals, transformers, and breakers at each voltage.

- Installing a new transformer in a substation requires two terminals, one at the higher voltage and one at the lower voltage. Thus, a new 345-138 kV substation that incorporates an existing 345 kV line and two 138 kV transmission lines, all of which exist near the new substation site, would require three 345 kV terminals and five 138 kV terminals. Two spare terminals that include disconnect switches and bus, but no breaker, for each voltage, should be provided for future growth.

- Transformer costs are shown for typical transformer sizes in each class, 500 MVA, 345/138 kV, and 345/115 kV; 100 MVA, 138/69 kV and 115/69 kV.

Typical Transmission Line and Substation Project Capital Costs

TRANSMISSION FACILITY	TYPICAL CAPITAL COST UNIT IN 2006 $
New 345 kV single circuit line rural ~ urban	$1,600,000 ~ $2,200,000/Mile
New 345 kV double circuit line rural ~ urban	$3,000,000 ~ $3,600,000/Mile
New 345 kV HPFF single circuit UG line (w/o terminals)	$10,000,000/Mile
New 345 kV HPFF UG line 2 terminals with shunt reactors	$8,900,000
New 345 kV HPFF UG line 2 terminals without shunt reactors	$4,300,000
New 138 kV single circuit line rural ~ urban	$630,000 ~ $800,000/Mile
New 138 kV double circuit line rural ~ urban	$900,000 ~ $1,100,000/Mile
New 138 kV XLPE 1,200A single circuit UG line (w/ terminals)	$3,500,000/Mile
New 138 kV HPFF 1,200A single circuit UG line (w/ terminals)	$3,500,000/Mile
New 69 kV single circuit line rural ~ urban	$450,000 ~ $585,000/Mile
New 69 kV double circuit line rural ~ urban	$650,000 ~ $770,000/Mile
New 69 kV XLPE 550A single circuit UG line (w/ terminals)	$2,500,000/Mile
New 69 kV HPFF single circuit underground line (w/ terminals)	$2,800,000/Mile
Rebuild 138 kV to 138 kV single circuit	$530,000 ~ $700,000/Mile
Rebuild 138 kV to 138 kV double circuit	$800,000 ~ $1,000,000 /Mile
Rebuild 69 kV to 138 kV, single circuit	$530,000 ~ $670,000/Mile
Rebuild 69 kV to 69 kV, single circuit	$280,000 ~ $330,000/Mile
Reconductor 138 kV or 115 kV line, single circuit	$210,000/Mile
Reconductor 69 kV line, single circuit	$117,000/Mile
Uprate 138 kV to 138 kV single circuit	$125,000 ~ $200,000/Mile
Uprate 69 kV to 138 kV single circuit	$350,000 ~ $375,000/Mile
Uprate 69 kV to 69 kV single circuit	$125,000 ~ $150,000/Mile
345 kV substation terminal[1]	$550,000 each
345kV gas circuit breaker[2]	$754,000 each
138 kV or 115 kV substation terminal[1]	$450,000 each
138kV gas circuit breaker[2]	$390,000 each
69 kV substation terminal[1]	$375,000 each
69kV gas circuit breaker[2]	$310,000 each
345/138 kV transformer[4] (transformer only $2,700,000[3])	$5,000,000 each
138/69 kV transformer[6] (transformer only $1,405,000[5])	$2,500,000 each

Notes:
All substation costs are in year 2006 dollars.
[1] includes dead end structure, line switch and line terminal relays
[2] includes breaker, two maintenance switches, breaker failure relay, controls
[3] 300/400/500 MVA unit includes high and low side switches and transf. relays
[4] includes transformer[3], 2-345kV GCBs[2] and 2-138kV GCBs[2]
[5] 100 MVA unit, includes high side and low side switches and transf. relays
[6] includes transformer[5], 2-138kV GCBs[2], and 1-69kV GCB[2]

Appendix H: Alternatives Considered

The transmission system near Point Beach has five large generating stations (Point Beach, Kewaunee, Fox River, Sheboygan Energy Center, and Cypress) with a total generating capability of approximately 3000 MW and only four 345 kV lines connecting this generation to the rest of the system. Three additional wind generation projects with a total rated generation of approximately 350 MW and queue positions below G833 and G834 (G590, G611, and G773) are located on the Fox Valley 138 kV system near Forest Junction. These three projects were not modeled in the G833-4 study stability analysis because of their location on the 138 kV system, but they were modeled in the study's thermal analysis. This combination of high generation and relatively few transmission outlets produces stability issues with the existing system strength and fault clearing times, in particular at Kewaunee and North Appleton which have slower breakers and longer clearing times than other area busses. In addition to these general issues which can be addressed by breaker replacement, protection improvements, and a number of system configurations to strengthen the system, there are three specific issues that need to be addressed to make the Point Beach generation increase acceptable. These issues are (1) the isolation of Point Beach Generator 1 on L111 (Point Beach-Sheboygan) which occurs when Point Beach 345 kV breaker 2-3 is out of service and L121 (Point Beach-Forest Junction 345 kV) trips, (2) the outage of 6832 (Fox River-North Appleton) followed by a fault on R-304 (Kewaunee-North Appleton), and (3) the outage of R-304 followed by a fault on Q-303 (Kewaunee-Point Beach) and vice versa.

Issue (1) is addressed in this study by reducing Point Beach Unit #1 net generation to 550 MW. It could also have been addressed by strengthening L111. It could also be addressed changing the connectivity at the Point Beach bus so that Unit 1 could not be isolated on L111 or by strengthening L111 by creating a 345 kV switching station at the intersection of lines LSEC31 (Sheboygan Energy - Granville), W-1 (Edgewater - South Fond Du Lac) and 796L41 (Edgewater – Cedarsauk). Issue (2) is a problem because the two strongest connections to the rest of the system are taken out of service at the same time. This problem can not be solved by changing system connectivity near Point Beach, it must be addressed by either strengthening the remaining connections to the rest of the system, as is done by the proposed 345 kV switching station at the intersection of L-CYP31 (Cypress – Arcadian) and W-1, or adding a new connection. Issue (3) is a local issue at Kewaunee that is not made worse by the addition of G833 and G834, which can be addressed by reducing Kewaunee net generation. If a second transformer is not added at Kewaunee, Kewaunee generation is reduced below the stability limit to protect the Kewaunee 345/138 kV transformer. If a second transformer is added at Kewaunee, Kewaunee generation must be reduced to 500 MW with Q-303 out or 475 MW with R-304 out, although

Many of the alternatives considered to address these issues are shown in Figure H.1. Because these alternatives were not fully investigated, the substation configurations have not been optimized. A short description of several of the various alternatives considered and the advantages and disadvantages of each are discussed below in no particular order.

Create an East Switching Station by Connecting 345 kV Lines LSEC31, W-1, and 796L41. This switching station, could address the Point Beach connectivity issues related to Point Beach Generator 1 being isolated on L111 when POB breaker 2-3 is out of service and there is a fault on L121. There is approximately 1 mile between these lines. An alternative to this switching station is to reduce Point Beach #1 gross generation to 550 MW when POB breaker 2-3 is out of service. Coordinating breaker and generator outages would minimize the need to implement this generation restriction, making the time and expense necessary to build the proposed switching station unnecessary.

Forest Junction to West Switching Station 345 kV Line (Approximately 42 miles). One of the first alternatives evaluated was an approximately 42 mile 345 kV line from Forest Junction to the West Switching Station. This alternative, with some reductions in fault clearing time, addressed system strength issues, but did not address the Point Beach connectivity issues related to Point Beach Generator 1 being isolated on L111 under certain system conditions. Essentially, this is the same improvement achieved with the West Switching Station alone.

A Second Point Beach to Kewaunee 345 kV Line (Approximately 6 miles). Although eliminating the local Kewaunee stability issue (the loss of both Kewaunee 345 kV lines) is not required for G833 and G834 because they do not make the existing issues (which are addressed by an operating guide) worse, the addition of a second Point Beach-Kewaunee 345 kV line was investigated to see if it addressed any other issues. When connected to Point Beach Bus 4, as shown in Figure H.1, the line does not improve the Unit 1/L111 issue. If the line was added in connection with a Point Beach 345 kV bus reconfiguration it could possibly do so, but that was not investigated. Although the line did address the local Kewaunee generation issue, because it does not strengthen area outlets, it did not improve the outlet issues and in fact made at least one event (SEC31 out fault R-304) worse, it was not considered an acceptable alternative.

Forest Junction to North Switching Station 345 kV Line (Approximately 13 miles). A North Switching Station Connecting L111 and L121 when they are about a mile apart approximately 18 miles west of Point Beach solves all of the issues concerning Point Beach Unit 1 isolated on L111, except for when the western part of L121 is out of service and there is a fault on Q-303 with an SPS operation splitting the Point Beach bus. To handle this situation, an approximately 13 mile line from Forest Junction to the North Switching Station could be built on existing 345 kV towers that are presently being used by a 138 kV line. A 345/138 kV transformer would probably be necessary at the North Switching station to support the existing 138 kV line. Because these projects do not strengthen area outlets, however, they do not eliminate the 6832/R-304 prior outage/fault issue. This alternative, coupled with the West Switching Station may solve these problems, but because the economics of this alternative, it was not fully evaluated.

Forest Junction to East Switching Station 345 kV Line (Approximately 55 miles). Although not shown in Figure H.1, a 345 kV line from Forest Junction to the East Switching Station was considered. This line would address the system strength and Point Beach Unit 1/L111 isolation issue, but these issues could be addressed by the East Switching Station without the line. If the North Switching Station were also built and this line tied into it, all of the issues addressed by the East and West Switching Station solution might be addressed, but the additional cost of 55 miles of 345 kV line, is not justified.

In summary, several alternatives to the Conceptual East and West Switching Station project were evaluated. The projects that addressed all of the issues presented included at least 13 miles of 345 kV line, which would most make the alternatives more expensive and more difficult to implement.

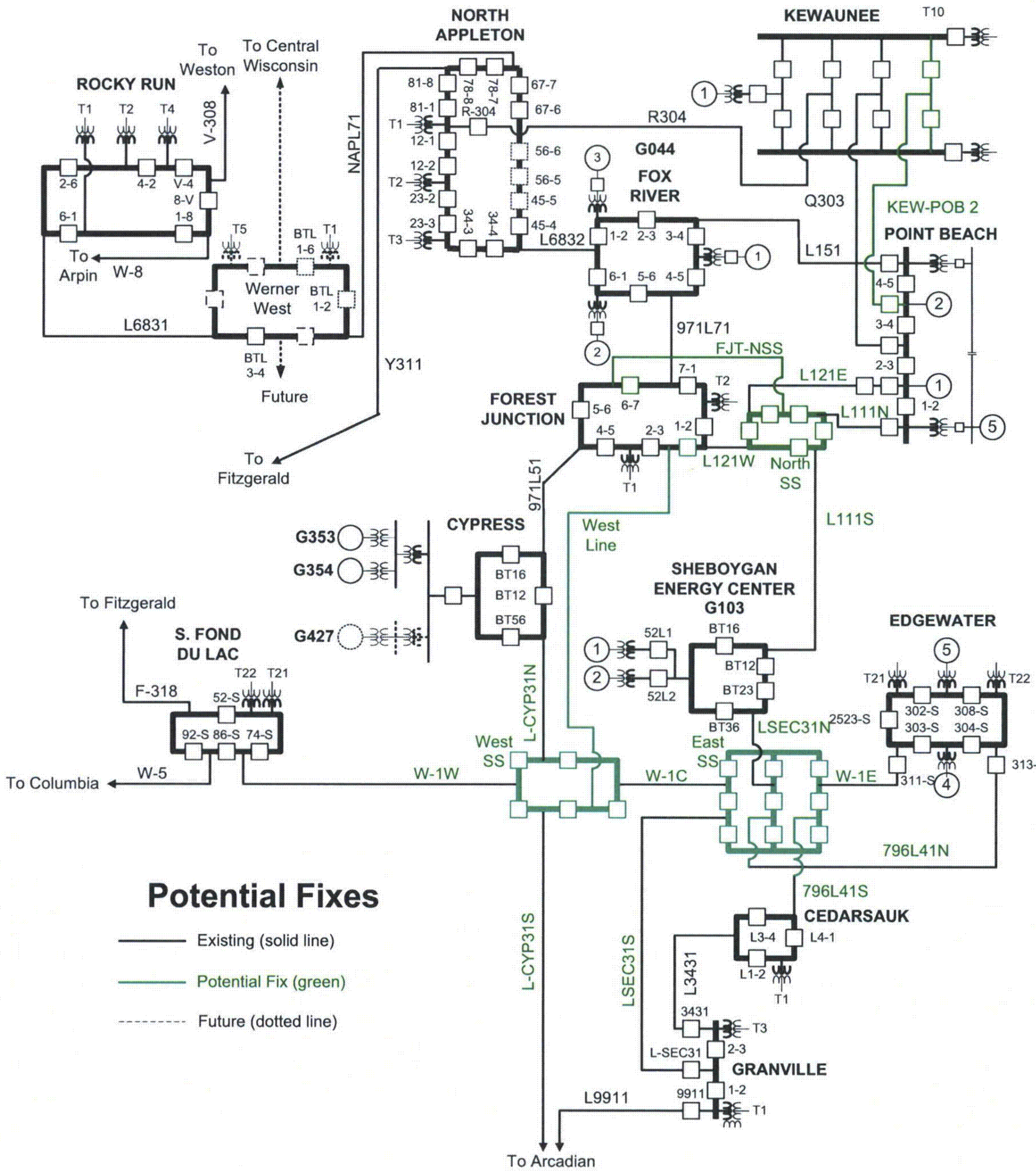

Figure H.1 – Alternative System Enhancements Considered (Kewaunee Reconfigured)