Out-Year Interconnection System Impact Study of MPC01200

MPC01200*
Queue Request Date: April 17, 2008
In-Service Date: December 31, 2010
Point of Interconnection: Maple River 230 kV bus
Size and Fuel Type: 200 MW Wind Generation

*MPC01200 interconnection request has been adjusted from 200 MW to 100 MW per a Settlement Agreement in FERC Docket EL08-086-000

December 26, 2014

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Executive Summary

An Interconnection System Impact Study (SIS) has been completed for the MPC01200 generator interconnection request, a wind farm project interconnecting at the Maple River 230 kV bus. This study has been completed to address requirements for granting of interconnection service. It does not meet the requirements for granting of transmission service.

MPC01200 is a 200 MW wind generation request. The request date for this project was April 17, 2008. The maximum size of the MPC01200 interconnection request has been limited to 99.2 MW[1] per a Settlement Agreement in FERC Docket EL08-086-000.

MPC01200 is being developed in two stages. The first stage of 49.6 MW was completed in 2010 and was developed using GE XLE 1.6 MW wind turbines. It was built along with the final 12.8 MW of the MPC0500 interconnection request. This 62.4 MW wind farm is collectively known as Ashtabula 3.

The second stage of the development is being built under a Right of First Refusal provision of the aforementioned Settlement Agreement, and is thus referred to as the ROFR portion of the farm. The second stage of MPC01200 will be developed using 29 GE XLE 1.7 MW wind turbines for a total nameplate output of 49.3 MW. The expected in service date for the second stage is December 2016.

The nameplate capacity of the existing and ROFR portions of MPC01200 is 98.9 MW. This study evaluates the collective impact of both stages. Delineation of interconnection impacts between the existing and ROFR portions of the farm was made for identified interconnection constraints.

There are three wind farms presently in service and interconnected to the Maple River substation, Ashtabula 1, 2, and 3. Ashtabula 1 and 2 were originally queued as MPC0500, which was a 358 MW interconnection request at the Maple River 230 kV bus. For 358 MW delivered at Maple River, approximately 379 MW of nameplate generation is required at the wind farm location. There is a total of 366 MW of nameplate generation at the Ashtabula 1 and 2 locations. As noted above, the remaining 13 MW of generation for the MPC0500 interconnection request was included in the Ashtabula 3 wind farm. Ashtabula 3 is 62.4 MW in size, with 12.8 MW

[1] The difference in nameplate capacity of the turbines selected for the phases of MPC01200 results in a slightly smaller installed capacity of 98.9 MW. At times, the phases and collective project are respectively referred to as 50 MW and 100 MW capacities for simplicity.

developed under the MPC0500 request and 49.6 MW developed under the MPC01200 request. Therefore the total nameplate generation that is presently in service is 428 MW. The combined total of wind generation in place and still under study is as shown in Table E1. A simplified one line diagram of the 230 kV network which ties the MPC0500 and MPC01200 wind farms to Maple River is shown in Figure E1.

The 61 mile Pillsbury-Maple River 230 kV line provides a radial connection from each of the existing wind farms to the Maple River 230 kV substation. Wind-adjusted ratings will be used to allow a summer continuous conductor rating of 666 MVA when wind generation output is at maximum. During low wind conditions, the summer continuous conductor rating is 478 MVA. Substation equipment limits the line to a lower rating.

Table E1. Status of Interconnection Requests at Maple River 230 kV Substation

Interconnection Request	Size	Cumulative Size	Wind Farm	Status
MPC0500	196.5 MW	196.5 MW	Ashtabula 1	In service 2008
MPC0500	169.5 MW	366.0 MW	Ashtabula 2	In service 2009
MPC0500	12.8 MW	378.8 MW	Ashtabula 3	In service 2010
MPC01200	49.6 MW	428.4 MW	Ashtabula 3	In service 2010
MPC01200	49.3 MW	477.7 MW	N/A (ROFR)	Not developed
MPC01900	-	-	-	Withdrawn

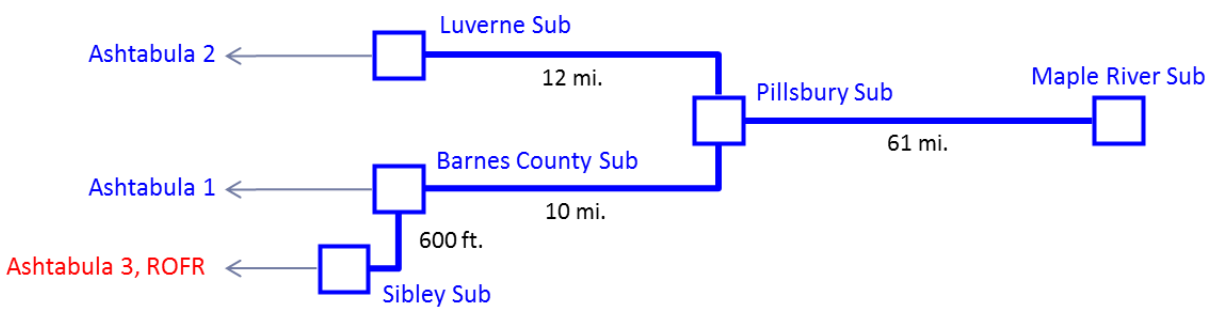

Figure E1. Simplified One Line Diagram of Interconnection Requests at the Maple River 230 kV Substation

Prior Interconnection SISs have been completed to allow interconnection of the MPC01200 wind farm in the near-term and mid-year timeframes. See references [1] and [2]. The MPC01900 interconnection request, which had obtained equal status with MPC01200 through the previously mentioned Settlement Agreement, is now withdrawn from the Minnkota interconnection queue. This out-year study will complete the full requirements for study timeframes for MPC01200. This study is

considered in-queue with respect to Minnkota's and all neighboring parties' generator interconnection queues.

This study was performed for the 2017 time frame and the following major transmission assumptions in the vicinity of the MPC01200 POI were modeled.

- CapX Fargo – St. Cloud 345 kV project
- CapX Bemidji – Grand Rapids 230 kV project
- MPC Center – Grand Forks 345 kV project.
    - Young 2 was dispatched 100 percent on the AC network
- Buffalo – Casselton 115 kV line in-service

Even though this study report specifically shows the impacts of the 50 MW and 100 MW stages of development for MPC01200, they will only become effective when the major transmission system additions described above occur[2]. The mitigation requirements established in the October 21, 2011 report [2] will be effective until that time. In some cases, the mitigation requirements for the out-year timeframe are lower than those observed in the October 21, 2011 report. In those cases, interim mitigations may be sufficient until the new facilities are in service.

For the purposes of this study, the MPC01200 wind farm was modeled at a fixed power factor under system intact conditions i.e., the reactive power output of the MPC01200 wind farm was adjusted to obtain unity power factor at the high-sides of the 34.5/230 kV substation transformers. System performance was evaluated based on this assumption unless otherwise noted.

Voltage stability, steady-state, transient stability and short-circuit analyses were performed to identify out-year impacts of the project. Steady state analysis included contingency analysis, constrained interface analysis, and no-load analysis. The following is a summary of study results.

Voltage stability analysis indicates that operating the MPC01200 wind farm at a fixed power factor results in a violation of MPC's voltage stability criteria. The voltage stability performance does not meet the required 10% margin from the nose of the curve. Further investigations showed that the voltage stability criteria can be met by operating the wind farm in voltage control mode. Study results indicate that it is possible to meet the margin requirements by allowing the wind farm to regulate the voltages at the Sibley 230 kV bus to 1.05 pu.

Steady-state contingency analysis identified two interconnection constraints.

- The Pillsbury – Maple River 230 kV line summer continuous rating must be increased to 470 MVA if and only if the ROFR portion of MPC01200 is built.

[2] Only the Bison – Alexandria 345 kV line remains to be completed before this out-year study will be applicable. This line is expected to be completed in the spring of 2015.

The line is limited by current transformers (CTs) at Maple River. The CTs have additional taps available to increase the rating.

- The Maple River 230/115 kV transformer '6' was overloaded in both the summer peak and winter peak cases following a breaker failure contingency. The maximum loadings observed were 256 MW in the winter peak case and 219 MW in the summer peak case. This upgrade will be required for both the existing and ROFR portions of MPC01200. The mitigation measures are unaffected by whether the ROFR portion of MPC01200 proceeds. Transformer replacement, additional transformer cooling, and installation of a Remedial Action Scheme[3] (RAS) were identified as potential mitigation options during preliminary review of the impacts.

The mitigation information provided above is based on preliminary research and should not be considered binding in any way. Actual mitigation options and costs must be further reviewed through Interconnection Facility Studies with the appropriate Transmission Owner(s) and Planning Coordinator(s).

No load analysis identified the need for reactive power absorption capabilities at the farm to maintain acceptable voltages when the turbines are not producing active power. Acceptable mitigation options could consist of 1) enabling WindFree® on all of the MPC01200 turbines or 2) adding a breakered shunt reactor on the MPC01200 34.5 kV bus.

Dynamic stability analysis showed acceptable system performance with no mitigation required.

Short circuit analysis indicates that fault currents at Maple River and the adjacent buses are not approaching any breaker limitations.

Low Short Circuit Ratio (SCR) has been identified as an issue affecting the performance of the wind farms at the Pillsbury site. Studies must be completed in conjunction with the turbine manufacturer to identify appropriate control modifications to accommodate the MPC01200 wind farm.

The following table summarizes the required mitigations with preliminary good faith cost estimates.

[3] Upon further review, MISO does not permit SPS/RAS mitigation of constraints on MISO transmission facilities caused by generator interconnection projects. RAS were formerly referred to as Special Protection Systems, or SPS.

Table E2. Mitigation Summary for MPC01200

Performance Criteria	Mitigation*	Existing MPC01200 Only	Full MPC01200 Project
Voltage Stability	WTG/WFMS must be placed in voltage control mode	Required	Required
No Load Voltage Control	Enable WindFree® option Alternative: Breakered 34.5 kV shunt reactor addition	All 31 turbines ~5 MVAr	All 60 turbines ~10 MVAr
Pillsbury - Maple River 230 kV	Maple River 230 kV terminal uprate (CT tap change) to 470 MVA	Not required	$10K
Maple River 230/115 kV Tfmr 6	Transformer replacement with 336 MVA unit Alternatives: Remedial Action Scheme** or Addition of fans	$5M Feasibility/Benefit of fans not known	No additional mitigation required Feasibility/Benefit of fans not known
Low SCR Mitigation	Implement control modifications identified by turbine manufacturer study	Required	Required

***The mitigation information provided above is based on preliminary research and should not be considered binding in any way. Actual mitigation options and costs must be further reviewed through Interconnection Facility Studies with the appropriate Transmission Owner(s).

**Preliminary review showed that SPS/RAS mitigation may be acceptable. Upon ad hoc review, MISO does not permit SPS/RAS mitigation of constraints on MISO transmission facilities caused by generator interconnection projects.

REPORT REVISION HISTORY

Rev No.	Revision Description	Date
Draft	Original DRS submittal	12/02/2014
1	Minor updates to transmission line loadings reported in Section 6. Loadings are now reported on an MVA basis instead of a current-adjusted basis. Added faults mg3 through mks in Table 7-2.	12/26/2014

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Main Report

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1. INTRODUCTION

1.1 Project Overview

Minnkota Power Cooperative, Inc. (MPC) commissioned ABB Power Systems Consulting (ESC) to perform a technical Interconnection System Impact Study to evaluate the MPC01200 generation interconnection request (GIR). The Point of Interconnection (POI) of this project is the Maple River 230 kV substation, which is also the POI of the existing Maple River wind farm, MPC0500. MPC0500 consists of a 358 MW interconnection request at the Maple River bus, which is approximately 379 MW of nameplate generation at the wind farm location. The Pillsbury – Maple River 230 kV line provides a radial connection from the wind farms to the Maple River 230 kV substation.

The MPC01200 GIR is a 200 MW wind generation request. The request date for this project was April 17, 2008. The total size of the MPC01200 interconnection request has been limited to 99.2 MW per a Settlement Agreement in FERC Docket EL08-086-000.

MPC01200 is being developed in two stages. The first stage of 49.6 MW was completed in 2010 and was developed using GE XLE 1.6 MW wind turbines. It was built along with the final 12.8 MW of the MPC0500 interconnection request. This 62.4 MW wind farm is collectively known as Ashtabula 3.

The second stage of the development is being built under a Right of First Refusal provision of the aforementioned Settlement Agreement, and is thus referred to as the ROFR portion of the farm. The second stage of MPC01200 will be developed using 29 GE XLE 1.7 MW wind turbines for a total nameplate output of 49.3 MW. The expected in service date for the second stage is December 2016. This study evaluates the impact of both stages.

The customer for MPC01200 had expressed interest in putting a 50 MW portion of the wind farm in service by December, 2010. Due to the requirement for equal priority of the MPC01200 and MPC01900 GIRs in the Settlement Agreement, a study was completed showing a 50 MW generation addition for each of the two requests with the transmission system modeled as it existed at that time. The study report [1] is dated December 10, 2010. Including MPC0500, 479 MW of wind was approved for interconnection.

A second study was completed evaluating an interim transmission topology scenario. The study report [2] is dated October 21, 2011. Including MPC0500, 641 MW of wind was approved for interconnection. The goals of the study were as follows:

- Determine the maximum size of MPC01200 and MPC01900 in order to make use of available thermal capacity of the Pillsbury – Maple River 230 kV line
- Determine the impact and mitigation requirements for different stages of wind capacity build out at Maple River in the 2013 time frame. The various build out stages are

- 50 MW of MPC01200
- 100 MW of MPC01200 and MPC01900
- Size of MPC01200 and MPC01900 to utilize available thermal capacity on Pillsbury – Maple River 230 kV line.

The MPC01900 GIR is now withdrawn from the Minnkota interconnection queue, and the MPC01200 GIR is limited to 100 MW of nameplate capacity per the Settlement Agreement.

As of the date of this report, 428 MW of nameplate wind generation capacity has been installed at Maple River, including the existing portion of MPC01200. See Table E1 for details.

1.2 Study Scope

The study evaluated the impact of proposed wind farms on transmission system performance and comprises voltage stability, steady-state, dynamic stability, constrained interface, short-circuit, and no-load analyses.

The scope of this study is limited to identifying and resolving possible criteria violations that may limit the ability of the proposed generation to interconnect. Any results related to delivery of power from the projects are for informational purposes only.

Even though this study report specifically shows the impacts of the 50 MW and 100 MW stages of development for MPC01200, they will only become effective when the major transmission system additions described in the Modeling section are completed[4]. The mitigation requirements established in the October 21, 2011 report [2] will be effective until that time. In some cases the mitigation requirements for the out-year timeframe are lower than those observed in the October 21, 2011 report. In those cases, interim mitigations may be sufficient until the new facilities are in service.

This Interconnection System Impact Study is being submitted to the Mid-Continent Area Power Pool (MAPP) Design Review Subcommittee (DRS) to obtain approval for the proposed generation interconnection. The study considers effects of prior-queued generation interconnection requests in the MPC, MISO, IS, MH, and Square Butte interconnection queues.

The study was performed with guidance from a study ad hoc group and the interconnection customer. The ad hoc study group included representation from neighboring Transmission Owners and Planning Coordinators, including BEPC, GRE, MDU, MH, MISO, MP, MRES, OTP, SPP, WAPA, and Xcel. Ad hoc calls were held to review the study scope and the study results. Feedback was received and incorporated as part of these calls and through ad hoc model review.

The Interconnection Customer provided all requested modeling information to facilitate accurate completion of the study.

[4] Only the Bison – Alexandria 345 kV line remains to be completed before this out-year study will be applicable.

2. DESCRIPTION AND MODELING OF THE PROPOSED PROJECTS

The following sections provide a brief description of the main characteristics of the wind farms relevant to this study.

2.1 Description of GE 1.6 MW and 1.7 MW Wind Turbine Generators

The existing portion of the MPC01200 wind farm comprises a total of 31 GE 1.6 MW DFIG wind turbine-generator. The ROFR portion will comprise a total of 29 GE 1.7 MW wind turbine-generators.

Each of GE wind turbines described in the preceding paragraph is a variable speed turbine and employs a three-phase doubly-fed induction generator with a power converter interfacing the rotor to the grid. The voltage at the wind turbine generator terminals is 690 V which is stepped up to feed a 34.5 kV collector network.

The GE wind turbine is capable of supplying/drawing reactive power to/from the grid. It can operate at a constant power factor (power factor control) or regulate grid voltages (voltage control mode). Power factor control or voltage control is achieved through a closed-loop control system. This system is typically structured to measure the power factor (voltage) at a particular bus, often the POI, and regulate this power factor (voltage) by sending a reactive power command to all the wind turbine-generators within the wind farm.

Additionally, the generation developer has indicated that the MPC01200 wind farm is not equipped with WindFree® controls. WindFree is an optional feature that allows wind turbine generators to generate or absorb a limited amount of reactive power even when they are not generating real power.

Specific details pertaining to the modeling of the MPC01200 wind farm are presented in Chapter 2.2.

2.2 Project Modeling Details

The MPC01200 project was modeled in two portions (existing and ROFR) to represent anticipated construction design and to uniquely identify the impacts of the existing MPC01200 generation compared to the full MPC01200 request. Each portion is connected to the Sibley 230 kV bus through a 34.5/230 kV transformer. The Sibley bus connects to Maple River via the Barnes County and Pillsbury 230 kV substations. See Figure E1 in the Executive Summary. Steady-state modeling data for this project is shown in Figure 2-1. All impedances are shown in per unit on system base (100 MVA). Collector data for new MPC01200 ROFR capacity was sized using collector data from the existing MPC01200 wind farm.

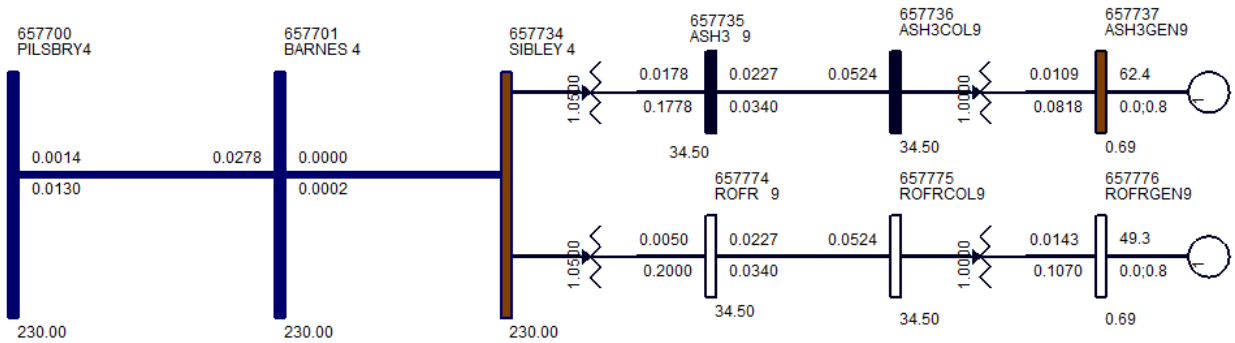

Figure 2-1: Impedance data for MPC01200[5]

Precise nameplate capacities and machine sizes are shown for MPC0500 and MPC01200 in Table 2-1 below. Elsewhere in the report, the numbers are rounded to whole numbers for convenience. Table 2-1 also lists the reactive capability and control settings of the Maple River wind farms. Both full-load and no-load capabilities are provided. No-load capabilities are used for the no- load analysis section, in which system voltages are monitored under zero wind conditions. The full-load capabilities are assumed for all other portions of the study unless otherwise noted.

The MPC01200 generation developer has indicated that the reactive power capability of the generators correspond to a power factor range from 0.90 lagging to 0.90 leading at the wind turbine-generator terminals. The reactive power capability varies as a function of generator terminal voltage as described in [7]. This variation cannot be represented in PSS/E and was therefore ignored for the purposes of this study. This however is not significant because the existing MPC01200 wind farm is presently operated in power factor control mode. Based on information provided by the generation developer, the wind farm WTGs regulate the power factor on the high side of the wind farm 230/34.5 kV transformer to unity (this is achieved using a plant level controller that commands each WTG in the wind farm to generate sufficient reactive power so that the desired power factor can be met at the 230 kV side of the transformer). For study purposes, the reactive power outputs of the MPC01200 WTGs[6] were iteratively adjusted such that the power factor on the high-sides of their respective 230/34.5 kV WTGs are at unity power factor when the WTGs are at full nameplate output. Power flow simulations show that the reactive power outputs of the MPC01200 WTGs are well within the reactive power capabilities stipulated in [7].

[5] For a line, R values are shown at the left on top, X values are shown at the left below the R value. The B value is shown to the right. For a transformer, R value is shown on the top and X value is shown below the R value. For a generator, Pgen is shown on the top and R source and X source values are shown below Pgen. For a shunt, the MVAr output at 1 p.u. is shown. Buses have their nominal voltages shown.

[6] For study purposes, the ROFR portion of the MPC01200 wind farm was also modeled assuming unity power factor on the high side of its 230/34.5 kV transformer.

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2.2.1 System Losses

It can be seen in Figure 2-1 that the proposed project is connected to Pillsbury 230 kV through the collector system, transformers, and 230 kV lines. This section discusses losses in the wind farms.

Pre- and post-project one-line diagrams for the 2017 summer peak load conditions are shown in **Figure 2-2** and Figure 2-3 respectively. The total nameplate Maple River wind is 477.7 MW. Figure 2-3 shows that the Net injection at Pillsbury 230 kV is 462.5 MW and it is 442.6 MW at Maple River 230 kV. A comparison of Figures 2-2 and 2-3 shows that the incremental injection at Maple River 230 kV due to MPC01200 is 87.7 MW.

Table 2-1: Maple River Wind Active and Reactive Power Capacity and Control Settings

Interconnection Request	Wind Farm	Turbine Active Power	Reactive Control Mode and Setpoint	Turbine Power Factor Capability	Control Point	No-Load Parameters		
						Turbines with WindFree	Reactive Capability	Backfeed Power
MPC0500	Ashtabula 1	131 WTG x 1.5 MW 196.5 MW	Voltage (1.05 pu)	+/- 0.90	Barnes Co. 230 kV bus	55	+/- 9.2 MVAr	2.3 MW
MPC0500	Ashtabula 2	80 WTG x 1.5 MW 120.0 MW	Voltage (1.05 pu)	+/- 0.90	Luverne 230 kV bus	48*	+/- 8.0 MVAr	2.0 MW
		33 WTG x 1.5 MW 49.5 MW	Power Factor (unity)	+/- 0.90	Flow into Luverne 34.5 kV			
MPC0500	Ashtabula 3	8 WTG x 1.6 MW 12.8 MW	Power Factor (unity)	+/- 0.90	Flow into Sibley 230 kV	0	0	0.5 MW
MPC01200		31 WTG x 1.6 MW 49.6 MW						
MPC01200	ROFR	29 WTG x 1.7 MW 49.3 MW	Power Factor (unity)	+/- 0.90	Flow into Sibley 230 kV	0	0	0.4 MW

*The number of Ashtabula 2 turbines with WindFree enabled was split pro rata in the models.

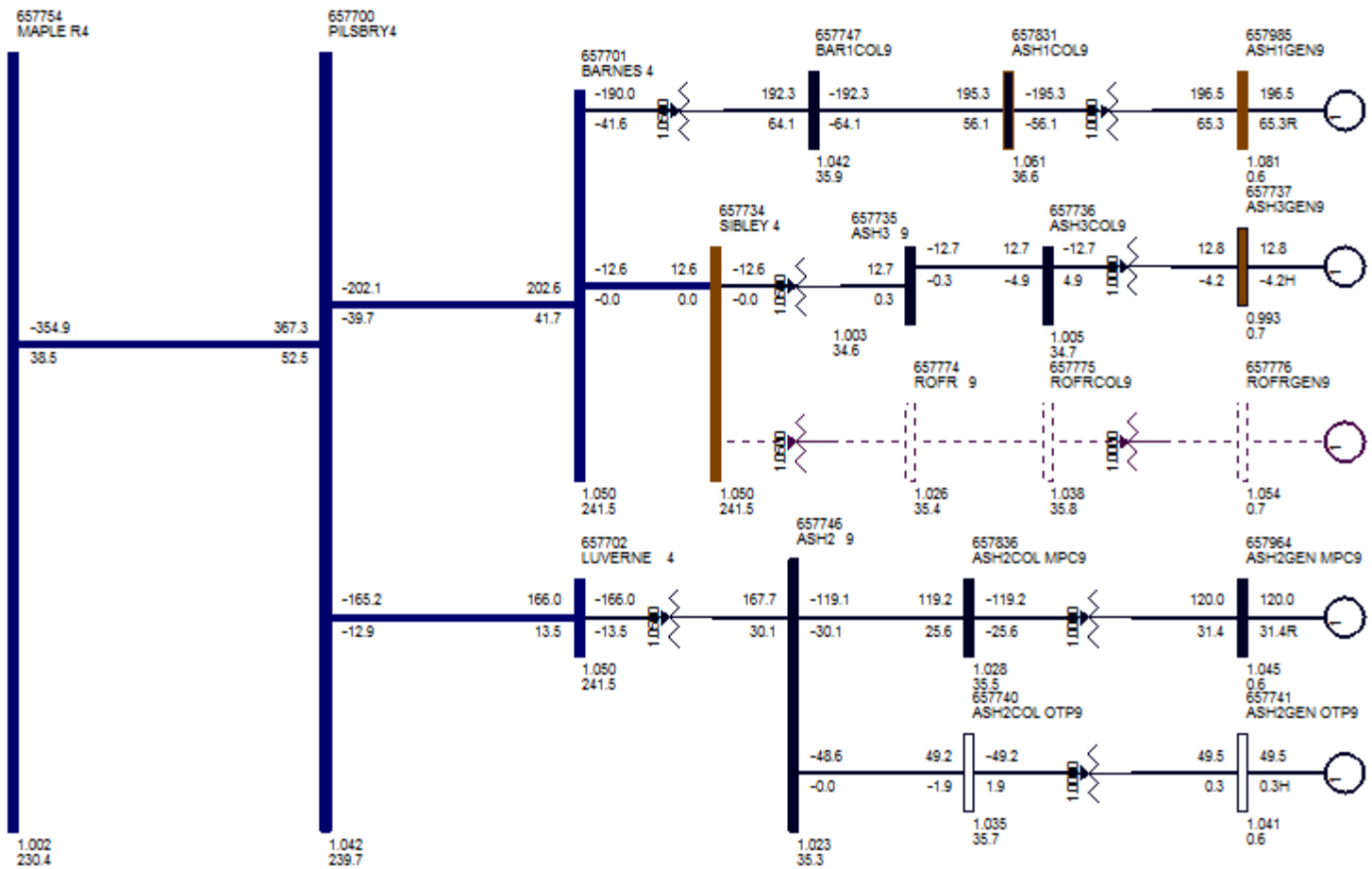

Figure 2-2: One-line Diagram for Case b02-sp17aa (Pre-project 2017 Summer Peak Case)

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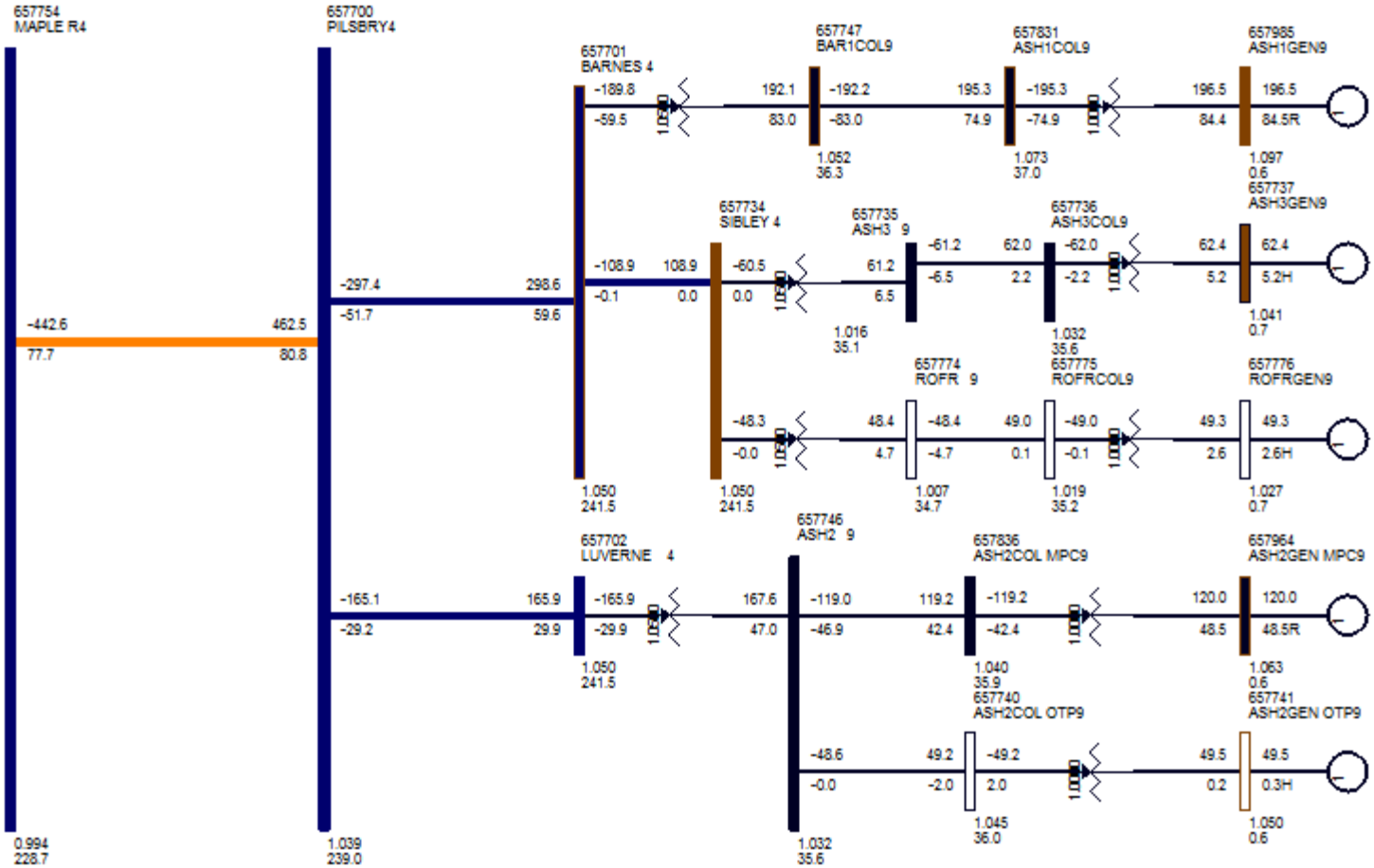

Figure 2-3: One-line Diagram for Case b03-sp17aa (Post-project 2017 Summer Peak Case)

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3. MODEL DEVELOPMENT

3.1 Summary of Models Developed

The steady-state models were developed using the September 2011 release of NMORWG 6-digit study package ('2012-6-dig-pack-09-22-2011'). The models were developed using PTI PSS/E version 32.

The models for stability analysis were developed using the January 2010 release of NMORWG 5-digit study package ('pkg2010-1-05-2010'). The models were developed using PTI PSS/E version 29.4.

Models were developed from the out-year models for the MPC0500 out-year study[7] [3]. The study considers effects of prior-queued generation interconnection requests in the MPC, MISO, IS, MH, and Square Butte interconnection queues. Projects which were queued between MPC0500 and MPC01200 were turned on and dispatched to their respective regions[8]. Although only slight changes were necessary in the models, descriptions of the prior-queued assumptions that are laid into the models are included below.

The study models were submitted to the ad hoc group, which included neighboring transmission owners and planning coordinators, for review and all feedback received was addressed.

3.2 Major Modeling Assumptions

The following major transmission projects near the MPC01200 POI are expected to have been built by the 2017 time frame and were included in the models:

- ISD 2012: Bemidji – Grand Rapids 230 kV
- ISD 2013: Buffalo – Casselton 115 kV
- ISD 2014: Center – Grand Forks 345 kV
- ISD 2015: Fargo – St. Cloud 345 kV

Other transmission upgrades are anticipated in the Fargo, ND area that may impact the transmission outlets for MPC01200. These projects are being developed in the interest of improving service to Fargo area loads. Xcel Energy substation modifications at the Cass County substation and Red River substation have been included, as well as a second 115 kV circuit from Maple River to Red River. Minnkota's proposed conversion of a 69 kV circuit to 115

[7] Steady state models started from models with the prefix e03. Dynamic models started from models with the prefix g03. Some of the modeling changes described in this report were completed as part of previous studies. Report language has been carried forward for documentation purposes.

[8] The models for the MPC0500 out-year study had previously been used for a preliminary study of the MPC01200/MPC01900 interconnection requests. Therefore, all necessary prior queued generation already existed in the models.

kV was not included due to uncertainty of the final project configuration and the development of the project well after the MPC01200 request was submitted. The Fargo SVC was modeled out of service as it is in disrepair and the owner has indicated there are no plans to fix it at this time.

Base load generation inside of the NDEX interface was increased to URGE levels in the summer off-peak case and CRUISE in the peak cases. Changes to MPC and MISO generators were dispatched to the MISO market, while changes to IS generation were dispatched to swing. ND base load generators were later reduced as part of a dispatch from wind generation in the MPC queue. ND base load generation is shown in Table 3-4.

The NDEX definition included the traditional lines plus the Cass Lake – Boswell 230 kV line and the Alexandria – Quarry 345 kV line. NDEX flow was dictated by North Dakota (ND) load level and ND base load and wind generation dispatch.

Line ratings and impedances were imported from the 2014 MRO series cases for two terminal branches with common topology. Local equipment was reviewed manually for accuracy. Updates submitted by the ad hoc group were implemented.

Interface flows, load levels, and generation assumptions are shown in Table 3-2.

3.3 Prior Queued Projects

Generation levels for prior-queued wind projects were determined based on impact on MPC01200 outlets. These dispatches were carried forward from previous wind interconnection studies at Maple River. A Distribution Factor (DF) analysis was performed using PSS-MUST to identify projects which have a significant impact on these outlets. Results of the DF analysis are shown in Table 3-3.

Generally, projects which had a 5% PTDF or 10% OTDF on the Maple River outlets were modeled at 100% of nameplate. Projects with lower DF's were generally modeled at 20% or turned off. In addition, engineering judgment was used to allow for factors such as proximity to the study area.

Prior-queued wind generation in the MPC GIR queue did not meet the DF threshold, but was assumed to be local to the study area and was, therefore, set at 100% and dispatched to the MISO market and ND baseload generation in the ratio 80:20, respectively.

MH wind generation was dispatched at 100% to the Dorsey DC bipoles in the summer cases and turned off in winter peak north flow case.

Changes made to MISO, IS and Square Butte prior-queued projects are described in the following sections.

3.3.1 MISO Generation Interconnection Queue

Output from MISO projects was dispatched to the remote MISO market. Queue coordination was assumed to be based on the date of the MPC project approval at the MAPP DRS and the date of the MISO DPP study report. For MPC01200, this translated to including MISO studies through DPP Cycle 5. MISO GIRs which were queued and studied prior to MISO's original queue reform were coordinated with the MPC queue based on traditional queue dates.

Projects in Group 5 and MN DPP Cycles 1 – 3 are mostly distant and downstream and provide backpressure to the Maple River outlet lines. Therefore, these projects were generally not modeled. One exception was G619, which was modeled per the dispatch shown in Table 3-5. Projects in ND DPP Cycles 1 – 5 were modeled with the exception of G752, which is remote from the project under study.

3.3.2 IS Generation Interconnection Queue

According to discussion with transmission owners from the ad hoc committee, IS wind generation was left as found in the MRO models. This approximated to a 35% dispatch of the IS wind farms which were in the models, while projects not in the MRO models were not added. GI-0918 (Day County wind) was turned off because it is post-queued to MPC01200.

IS peakers were turned off in the summer off-peak case. In summer peak, IS peakers were dispatched in a manner that stresses flow from north to south. The dispatch order was as follows: Culbertson, Groton, Deer Creek and Spirit Mound. In winter peak, IS peakers were set at 100%, except Spirit Mound which was turned off.

3.3.3 Square Butte Generation Interconnection Queue

Young 2, with a generation level of 455 MW net, was dispatched 100% on the AC network. It was reduced as necessary by other wind dispatches to ND base load generation.

Square Butte DC was set at 550 MW to accommodate the Oliver County 1-3 and Bison 1-6 wind farms. Wind generation dispatched over the Square Butte DC was dispatched to MP base load generators. The remaining wind generation was dispatched on the AC network to the MISO market. The dispatch assumptions were based on the system impact study for projects GS662 – GS666 [6].

The DF analysis summarized in Table 3-3 indicates that these generation projects are below the selection threshold used for other generation, but they were nevertheless deemed to have significant impact due to their electrical proximity to the project under study.

3.4 Development of Steady-State Cases

The steady state powerflow cases were developed for three load levels – summer peak, winter peak, and summer off-peak. Pre- and post-project cases were developed and are listed in Table 3-1.

The cases were developed starting from the post-project 2017 cases used in the MPC0500 out-year study[9]. These cases are based on the September 2011 series of MRO cases, with minor modifications for compatibility with the NMORWG package tools.

Pre-project cases were developed with the changes discussed in Chapters 3.2 through 3.3. Additionally, the Ashtabula 2 portion of MPC0500 (169.5 MW) was represented as 120 MW and 49.5 MW wind farms based on reactive control modes. The slider diagrams of pre-project cases are shown in Appendix B.

Post-project cases were developed from the corresponding pre-project cases by adding generators and interconnection facilities for MPC01200. The project was added at a capacity of 98.9 MW. As described in Chapter 2.2, the reactive power outputs of the project WTGs were iteratively adjusted such that the power factor on the high-sides of their respective 230/34.5 kV WTGs are at unity power factor. The powerflow data for MPC01200 is given in Appendix A.

MPC01200 was dispatched to the MISO market and ND baseload generation in the ratio of 80:20. The slider diagrams of the post-project cases are shown in Appendix B.

3.5 Development of No-Load Case

No-load analysis focuses on the ability of generators and reactive control devices to manage charging caused by light loading within the wind farm's collector system and on the grid. While individual loads and generators outside of the immediate area of the project under study tend to have little impact on no-load analysis results, regional transfer does affect the balance between local system charging and reactive losses caused by power transfer. Therefore, regional level adjustments were made to achieve a low transfer, light load scenario. The following steps were taken:

- Model MPC0500 and MPC01200 wind farms at no-load conditions (see section 2.2)

[9] Cases e03-sp17aa, e03-wp17aa and e03-so17aa described in reference [3].

- Reduce Manitoba – US exports to 0 MW and adjust Manitoba reactive controls per [5]
- Scale down regional load within the NDEX boundary by 20% (from 70% of peak to approximately 55% of peak) to imitate a light load case
- Scale regional generation within the NDEX boundary to achieve a minimal export case

3.6 Development of Stability Case

A post-project stability case was developed. The starting point of development of the powerflow case for stability was the post-project case of the study performed for the out-year interconnection evaluation of project MPC0500 [3]. Prior-queued projects and other transmission changes were made as mentioned in Chapters 3.2 through 3.3. The only exception is Spiritwood. This project was turned off for stability because it has been known to help support transient voltages in the Jamestown area. Additionally, the Ashtabula 2 portion of MPC0500 (169.5 MW) was represented as 120 MW and 49.5 MW wind farms based on reactive control modes.

Generators and interconnection facilities for MPC01200 were added at a capacity of 98.9 MW. MPC01200 was dispatched to the MISO market and ND base load generation in the ratio of 80:20, respectively.

3.7 Development of Snapshot

The starting point for developing a snapshot for dynamic stability analysis was the snapshot used for the interconnection evaluation of project MPC0500 for the out-year time frame [3]. This snapshot already included the dynamic data for projects queued between MPC0500 and MPC01200 and hence no additional changes were made. Since Ashtabula 2 was represented as two separate generators as noted in Chapter 3.6, it was necessary to modify the dynamic data for Ashtabula 2 by adding dynamic data for the two generators.

Stability data was added for the MPC01200 generators. The library model used to represent these generators is ‘gewt_p29_v600.lib’ dated September 14, 2011. For further details, see reference [8]. It should be noted that this library model makes no specific mention of the GE 1.7 MW WTGs. It is our understanding however that the electrical performance of GE 1.7 MW WTGs is the same as GE 1.6 MW WTGs. With this said, the dynamic model for the ROFR portion of the wind farm was also represented using the same library model. Parameter PRATE in model GEWTG2 for the ROFR generator was changed to 1.70 MW and the number of equivalent WTGs was changed to 29.

The snapshot developed with the above changes was called ‘nmorwg08-h03.snp.’

Table 3-1: Case Names

Season	Pre-Project	Post-Project	Analysis Used For
Summer Peak	b02-sp17aa	b03-sp17aa	Voltage Stability, AC steady state, Constrained Interface
Winter Peak	b02-wp17aa	b03-wp17aa	Voltage Stability, AC steady state
Summer Off-Peak (Steady-State)	b02-so17aa	b03-so17aa	Voltage Stability, AC steady state
Summer Off-Peak (Stability)	h02-so17aa	h03-so17aa	Dynamic Stability
Summer Off-Peak (No-Load)	N/A	bn3-so17aa	No-Load

Table 3-2: Model Development Summary

	2017	2017	2017	2017
	Summer Off-Peak (Stability)	**Summer Off-Peak (Steady-state)**	**Summer Peak**	**Winter Peak (North Bias)**
Case Origin	urg-so10aa.sav	mro-so17aa.sav	mro-sp17aa.sav	mro-wp17aa.sav
MPC01200 dispatch	80% MISO, 20% ND base load gen	80% MISO, 20% ND base load gen	80% MISO, 20% ND base load gen	80% MISO, 20% ND base load gen
ND coal field base load generation	URGE	URGE	CRUISE	CRUISE
Young 2	455 MW on AC**	455 MW on AC**	455 MW on AC**	455 MW on AC**
Square Butte Wind / DC	Square Butte DC = 550 MW OC3 and Bison 5-6= 175 MW on AC	Square Butte DC = 550 MW OC3 and Bison 5-6= 175 MW on AC	Square Butte DC = 550 MW OC3 and Bison 5-6= 175 MW on AC	Square Butte DC = 550 MW OC3 and Bison 5-6= 175 MW on AC
SW MN wind	1650 MW	1436 MW	1436 MW	1436 MW
Peaking Generation: Groton, Solway, Jamestown, Culbertson	Off	Off	IS: North to South bias Jamestown: On	On
MH wind	100%	100%	100%	Off
ND Load	3053 MW, 70.0% of 4361 MW	3158 MW, 72.4% of 4361 MW	4369 MW, 100.2% of 4361 MW	4918 MW, 100.2% of 4910 MW
MH Load	2348 MW, 75.5% of 3111 MW	2222 MW, 71.4% of 3111 MW	3111 MW, 100% of 3111 MW	4656 MW, 100% of 4656 MW
TC Load	7426 MW, 63.4% of 11705 MW	Pre-project: 7757 MW, 66.3% of 11705 MW Post-project: 7858 MW, 67.1% of 11705 MW	11705 MW, 100% of 11705 MW	9227 MW, 100% of 9227 MW
NDEX (MW)	Pre-project: 2467 Post-project: 2533	Pre-project: 2438 Post-project: 2505	Pre-project: 1421 Post-project: 1489	Pre-project: 156 Post-project: 225
MWEX (MW)	Pre-project: 1665 Post-project: 1665	Pre-project: 1636 Post-project: 1629	Pre-project: 1064 Post-project: 1078	Pre-project: 598 Post-project: 612
MHEX (MW)	Pre-project: 2175 Post-project: 2175	Pre-project: 2171 Post-project: 2172	Pre-project: 1466 Post-project: 1465	Pre-project: 701 North Post-project: 703 North
SaskPower-US export (B10T) (MW)	Pre-project: 164 Post-project: 165	Pre-project: 165 Post-project: 165	Pre-project: 165 Post-project: 165	Pre-project: 164 North Post-project: 165 North
Miles City DC Tie (MW)	Pre-project: 149 East Post-project: 149 East	Pre-project: 150 East Post-project: 150 East	Pre-project: 150 East Post-project: 150 East	Pre-project: 175 West Post-project: 175 West
Rapid City DC Tie (MW)	Pre-project: 129 East Post-project: 129 East	Pre-project: 131 East Post-project: 131 East	Pre-project: 131 East Post-project: 131 East	Pre-project: 198 East Post-project: 198 East
D602M or D602F @ Dorsey* (MW)	Pre-project: 1813 Post-project: 1818	Pre-project: 1358 Post-project: 1362	Pre-project: 1080 Post-project: 1083	Pre-project: 75 Post-project: 77
M602F @ Riel* (MW)	Pre-project: N/A Post-project: N/A	Pre-project: 1815 Post-project: 1822	Pre-project: 1289 Post-project: 1294	Pre-project: -348 Post-project: -346
Roseau Series Caps	Pre-project: 1857 MVA (1967 Amps) Post-project: 1858 MVA (1978 Amps)	Pre-project: 1848 MVA (1983 Amps) Post-project: 1854 MVA (1992 Amps)	Pre-project: 1331 MVA (1410 Amps) Post-project:1336 MVA (1416 Amps)	Pre-project: 367 MVA (387 Amps) Post-project: 364 MVA (382 Amps)
Chisago Series Caps	Pre-project: 1276 MVA (1420 Amps) Post-project: 1288 MVA (1436 Amps)	Pre-project: 1106 MVA (1278 Amps) Post-project: 1120 MVA (1294 Amps)	Pre-project: 770 MVA (900 Amps) Post-project: 777 MVA (909 Amps)	Pre-project: 688 MVA (817 Amps) Post-project: 683 MVA (811 Amps)

* Riel is not modeled in the stability case

** Young 2 reduced as necessary by other wind dispatches to ND base load generation

Table 3-3: Distribution Factor Analysis Showing Impact of Regional Generation on MPC01200 Transmission Outlets

SqBut, MPC, MH				PTDF (+/-5%)			OTDF (Loss of Bison-Alex) (+10%/-5%)		
NBus	Name KV	Queue	Sink	MRV-SHY	SHY-AUD	MRV-FRN	MRV-SHY	SHY-AUD	MRV-FRN
657700	PILSBRY4 230	MPC	20/80*	32.7%	10.2%	15.0%	40.9%	14.1%	19.8%
657703	LANGWIN7 115	MPC	20/80*	-1.7%	1.8%	4.0%	1.5%	3.3%	5.9%
657756	SQBUTTE4 230	SQ BUT	MISO mkt	1.2%	4.9%	4.2%	6.7%	7.4%	7.3%
669830	STLEON1W .600	MH	Dorsey	-0.3%	0.9%	0.5%	0.5%	1.2%	1.0%
669831	STJOS1 W .690	MH	Dorsey	-0.3%	1.0%	0.9%	0.6%	1.5%	1.5%
MISO				PTDF (+/-5%)			OTDF (Loss of Bison-Alex) (+10%/-5%)		
NBus	Name KV	Queue	Sink	MRV-SHY	SHY-AUD	MRV-FRN	MRV-SHY	SHY-AUD	MRV-FRN
661999	TATANKAW .575	MISO	MISO mkt	1.2%	3.5%	-8.9%	5.1%	5.3%	-6.6%
661995	MERRICRT G W.575	MISO	MISO mkt	1.1%	3.5%	-8.6%	5.0%	5.4%	-6.3%
620112	EDGE GEN .575	MISO	MISO mkt	9.5%	5.6%	-0.5%	16.3%	8.8%	3.4%
620115	RGBYGEN .600	MISO	MISO mkt	-1.0%	3.0%	3.5%	2.9%	4.9%	5.7%
600059	VELVA W .600	MISO	MISO mkt	-1.9%	3.9%	3.1%	2.4%	5.9%	5.5%
615901	GRE-STANTON4 230	MISO	MISO mkt	0.0%	4.4%	3.7%	4.9%	6.7%	6.5%
615015	GRE-SPRITWDG13.2	MISO	MISO mkt	14.6%	7.4%	8.8%	23.5%	11.6%	14.0%
661005	BAKER 7 115	MISO	MISO mkt	-2.0%	3.7%	2.0%	1.7%	5.4%	4.1%
600132	GRANT CO W .600	MISO	MISO mkt	1.7%	-1.2%	-4.8%	-0.3%	-2.2%	-6.0%
618203	GRE-TAMARAC7 115	MISO	MISO mkt	-5.7%	-18.1%	-5.0%	-3.2%	-17.0%	-3.6%
IS				PTDF (+/-5%)			OTDF (Loss of Bison-Alex) (+10%/-5%)		
NBus	Name KV	Queue	Sink	MRV-SHY	SHY-AUD	MRV-FRN	MRV-SHY	SHY-AUD	MRV-FRN
659290	POMONA W.690	IS	Lel Olds	-7.2%	1.3%	-1.1%	-6.9%	1.4%	-0.9%
659290	POMONA W.690	IS	MISO mkt	-9.9%	5.2%	1.1%	-5.7%	7.2%	3.5%
659290	POMONA W.690	IS	Sp Mound	-9.2%	4.2%	1.4%	-5.8%	5.8%	3.4%
659291	HYDE W.690	IS	Lel Olds	1.4%	-2.1%	-2.2%	-0.8%	-3.1%	-3.5%
659291	HYDE W.690	IS	MISO mkt	-1.3%	1.8%	-0.1%	0.4%	2.6%	0.9%
659291	HYDE W.690	IS	Sp Mound	-0.6%	0.9%	0.3%	0.3%	1.3%	0.8%
659274	GROTON G13.8	IS	Lel Olds	0.9%	-1.5%	-3.8%	-0.9%	-2.4%	-4.8%
659274	GROTON G13.8	IS	MISO mkt	-1.8%	2.4%	-1.7%	0.4%	3.4%	-0.4%
659274	GROTON G13.8	IS	Sp Mound	-1.1%	1.4%	-1.3%	0.3%	2.1%	-0.5%
659194	NDPRAIRWND1W.690	IS	Lel Olds	0.5%	0.0%	0.8%	0.8%	0.2%	1.0%
659194	NDPRAIRWND1W.690	IS	MISO mkt	-2.2%	4.0%	2.9%	2.0%	6.0%	5.4%
659194	NDPRAIRWND1W.690	IS	Sp Mound	-1.5%	3.0%	3.3%	1.9%	4.6%	5.3%
659294	ECKLUND W.690	IS	Lel Olds	-2.0%	0.8%	0.7%	-1.4%	1.1%	1.1%
659294	ECKLUND W.690	IS	MISO mkt	-4.7%	4.8%	2.8%	-0.1%	6.9%	5.4%
659294	ECKLUND W.690	IS	Sp Mound	-4.0%	3.8%	3.2%	-0.2%	5.6%	5.4%
659160	GROTON 3 345	IS	Lel Olds	1.0%	-1.7%	-3.4%	-0.8%	-2.6%	-4.5%

ABB

NBus	Name KV	Queue	Sink	MRV-SHY	SHY-AUD	MRV-FRN	MRV-SHY	SHY-AUD	MRV-FRN
659160	GROTON 3 345	IS	MISO mkt	-1.7%	2.3%	-1.3%	0.4%	3.2%	-0.1%
659160	GROTON 3 345	IS	Sp Mound	-1.0%	1.3%	-0.9%	0.3%	1.9%	-0.2%
659285	DEERCREEK 1G13.8	IS	Lel Olds	1.9%	-2.9%	-3.3%	-1.3%	-4.4%	-5.1%
659285	DEERCREEK 1G13.8	IS	MISO mkt	-0.8%	1.0%	-1.1%	-0.1%	1.3%	-0.7%
659285	DEERCREEK 1G13.8	IS	Sp Mound	-0.1%	0.0%	-0.8%	-0.2%	0.0%	-0.8%
659270	CULBERTSON1G13.8	IS	Lel Olds	0.5%	-0.1%	0.0%	0.5%	-0.1%	0.0%
659270	CULBERTSON1G13.8	IS	MISO mkt	-2.2%	3.8%	2.2%	1.7%	5.7%	4.4%
659270	CULBERTSON1G13.8	IS	Sp Mound	-1.5%	2.9%	2.5%	1.6%	4.3%	4.3%
652522	SUMMIT-7 115	IS	Lel Olds	1.9%	-1.7%	-6.7%	0.2%	-2.6%	-7.8%
652522	SUMMIT-7 115	IS	MISO mkt	-0.7%	2.2%	-4.6%	1.4%	3.2%	-3.4%
652522	SUMMIT-7 115	IS	Sp Mound	-0.1%	1.2%	-4.2%	1.3%	1.8%	-3.4%
652299	AGATE 7 115	IS	Lel Olds	0.3%	-0.5%	1.6%	0.7%	-0.3%	1.8%
652299	AGATE 7 115	IS	MISO mkt	-2.3%	3.5%	3.8%	1.9%	5.5%	6.2%
652299	AGATE 7 115	IS	Sp Mound	-1.7%	2.5%	4.1%	1.8%	4.1%	6.1%

* 20% to ND base load generation, 80% to MISO market

Highlighting in the tables was used only to aid the eye for an at-a-glance understanding of the most impacting generators.

PTDF columns were highlighted green for PTDF > 5% and red for PTDF < -5% (negative DF indicates off-loading of monitored facility)

OTDF columns were highlighted green for OTDF > 10% and red for OTDF < -5% (negative DF indicates off-loading of monitored facility)

Table 3-4: Base Load Generation Levels

Generator	ID	Bus # (5 digit)	Bus # (6 digit)	Cruise Net	URGE Net	Summer Off-peak Net**		Summer Peak Net		Winter Peak Net	
						Pre	Post	Pre	Post	Pre	Post
Young 1	1	66749	657749	230	250	243	242	223	222	223	222
Young 2	1	66748	657748	430	455	443	441	418	416	418	416
Coyote	1	67315	661015	408	427	416	414	397	395	397	395
Heskett 1	1	67344	661044	20	30	29	29	19	19	19	19
Heskett 2	2	67345	661045	70	74.6	73	72	68	68	68	68
Stanton	1	63002	615010	178	196	191	190	173	172	173	172
Coal Creek 1	1	63000	615001	As Is*	As Is*	572	572	571	571	572	572
Coal Creek 2	2	63001	615002	As Is*	As Is*	561	561	561	561	562	562
Lewis & Clark	1	67355	661055	44	44	43	43	43	43	43	43
Big Stone	1	63315	620315	475	475	462	460	462	460	462	460
Hoot Lake 2	2	63323	620323	51	51	50	49	50	49	50	49
Hoot Lake 3	3	63324	620324	73	73	71	71	71	71	71	71
AVS 1	1	67103	659103	450	460	448	446	438	435	438	435
AVS 2	2	67107	659107	450	461.2	449	447	438	435	438	435
Leland Olds 1	1	67110	659110	210	225	219	218	204	204	204	203
Leland Olds 2	2	67111	659111	440	452.2	440	438	428	426	428	426
Garrison 1	1	66457	652457	94	102	99	99	91	91	91	91
Garrison 2	2	66458	652458	94	102	99	99	91	91	91	91
Garrison 3	3	66459	652459	94	102	99	99	91	91	91	91
Garrison 4	4	66460	652460	94	102	99	99	91	91	91	91
Garrison 5	5	66461	652461	94	102	99	99	91	91	91	91
Ft Peck 3	3	66410	652410	42	42	41	41	41	41	41	41
Ft Peck 4	4	66414	652414	45	45	44	44	44	44	44	44
Ft Peck 5	5	66415	652415	45	45	44	44	44	44	44	44

* Left as is in the MRO 2011 series cases
** Net Base load generation was the same between Summer Off-Peak steady state and stability cases

Table 3-5: Prior Queued Projects

Queue	GI #	Queue Date/Group	POI	Other Name	MW	Bus # (6 digit)	Bus # (5 digit)	SO	SP	WP
MISO	G132	9/17/2001	Ellendale 230	Tatanka	180	661999	67399	36	36	36
	G291	2/5/2003	Jamestown-Oakes 41.6	Edgeley OTP	21	620112	63165	21	21	21
	G359	3/27/2004	Wishek-Ellendale 230	Merricourt	150	661995	67384	30	30	30
	G380	11/21/2003	Rugby 230	Rugby Wind	150	620115	68378	30	30	30
	G408	3/2/2004	McHenry-Souris 115	Velva Wind	12	600059	63087	2	2	2
	G474	10/1/2004	Elbow Lake 115	Grant Co Wind	21	600132	63226	4	4	4
	G531	7/1/2005	Stanton 230	Stanton 2	68	615904	63003	0	68	68
	G645	5/26/2006	Spiritwood 115	Spiritwood 1	50	615015	63645	50**	50	50
	G619	Group 5	Tamarac 41.6	Lakeswind	50	618209	62525	10	10	10
	G767	ND DPP 2	Baker 57 kV	Diamond Willow	30	661307	67393	6	6	6
	J003	ND DPP 2	Baker 57 kV	Cedar Hills	20	661317	67317	4	4	4
MPC	MPC0100	9/11/2006	Langdon 115	Langdon 1	100	657600	66810	99	99	99
	MPC0200	11/13/2006	Langdon 115	Langdon 1	60	620413 620412	66813 66812	60	60	60
	MPC0300	7/31/2007	Langdon 115	Langdon 2	40	657601	66801	41	41	41
	MPC0500	1/3/2008	Maple River 230	Ashtabula 1,2,3	358*	657985 657964 657741 657737	66985 66964 66941 66737	379	379	379
	MPC01200	4/17/2008	Maple River 230	Ashtabula 3 + ROFR	100	657737 657776	66737 66976	100	100	100
IS	GI-0316	8/4/2003	Groton 115	Groton 1 pkr	120	659274	67274	0	120	120
	GI-0608	7/14/2006	Groton 115	Groton 2 pkr	120	659274	67274	0	120	120
	GI-0704 GI-0716	3/16/2007 7/6/2007	White 345	Deer Creek	300	659285	N/A	0	260	300
	GI-0708	5/9/2007	Culbertson 115	Culbertson	120	659270	67300	0	120	120
			Spirit Mound 115	Spirit Mound	104	659116 659117	67116 67117	0	0	0
Square Butte	G502	3/14/2005	Square Butte 230	Oliver Co 1	50	608603	61603	51	51	51
	GS659	9/1/2006	Square Butte 230	Oliver Co 2	50	608606	61606	50	50	50
	GS660	10/8/2007	Square Butte 230	Bison 1	75	608891	61594	80	80	80
	GS661	12/4/2007	Square Butte 230	Oliver Co 3	48	608607	61585	48	48	48
	GS662-666	2/28/2008	Square Butte 230	Bison 2-6	515	608892-6	66872-6	515	515	515
MH	-	10/17/2002	St. Leon 230	St. Leon	99	669830	67816	99	99	0
	-	12/14/2007	Letellier 230	St. Joseph	138	669831	67825	138	138	0

* Ashtabula 1, 2 and 3 have approval for 358 MW of injection at Maple River 230 kV bus. The corresponding nameplate generation is 379 MW.

** Spiritwood was turned off for stability because it supports voltages at Jamestown.

4. CRITERIA, METHODOLOGY AND ASSUMPTIONS

4.1 Pillsbury – Maple River 230 kV Line Rating

The Pillsbury – Maple River 230 kV line is a radial generator lead line, so it is known that line loading will be directly proportional to wind generation output, and hence wind speed. Therefore, a dynamic (wind-adjusted) rating can be used on the conductor. The wind-adjusted summer continuous conductor rating of the line is 478 MVA when generation output is low and 666 MVA when generation output is at maximum. The wind-adjusted rating is based on the assumption that wind speed anywhere between Pillsbury and Maple River is at least 20% of the wind speed at the wind farms. Minnkota Power's rating methodology allows for this assumption when the furthest point of the line is no more than 60 miles from the wind farms. The wind generators are assumed to put out full power when the wind speed is 30 mph. Therefore, the wind speed is assumed to be at least 6 mph everywhere along the line. Substation equipment limits the line to a lower rating, however.

4.2 Voltage Stability Analysis

See Chapter 5.

4.3 Steady-State Analysis

Steady-state performance was examined by simulating NERC TPL standard contingencies, including system intact and category B and C contingency conditions. The aim of this analysis was to identify the impact of the MPC01200 project. The pre-project case was modeled with MPC01200 out of service and the post-project case was modeled with MPC01200 in service.

BES transmission facilities rated 115 kV and above were monitored for loading in the GRE, MDU, MH, MP, OTP, WAPA and Xcel control areas. Transmission facilities rated 69 kV and above were additionally monitored in the OTP control area. For voltage impacts, transmission facilities rated 110 kV and above were monitored in the same control areas. The voltage limits used for the analysis are shown in Table 4-1 .

For the purposes of this analysis, Rate A is the continuous facility rating and Rate B is the emergency facility rating as established by the transmission owner(s).

Table 4-1: Voltage Monitoring Criteria

Area	Base kV	System Intact Conditions		N-1 Contingency Conditions	
		Max (pu)	Min (pu)	Max (pu)	Min (pu)
Regional Default*	110-500 kV	1.05	0.95	1.10	0.90
Xcel (Area 600)	110-500 kV	1.05	0.95	1.10	0.92
MP (Area 608)	110-500 kV	1.05	1.00	1.10	0.95
OTP** (Area 620)	110-500 kV	1.05	0.97	1.10	0.92

*Includes areas 600, 608, 615, 620, 652, 661, 667 unless modified

**MPC is in the OTP area. MPC voltage criteria is the same as was used for the OTP area

Unique criteria applied to:	At the following buses:
GRE	Hubbard, Wing River, Ramsey
Xcel	Series, shunt capacitor buses
WAPA	Phillip

System Intact Analysis:

The impact of the proposed projects on thermal loading and bus voltages of transmission facilities under system intact conditions was evaluated by comparing transmission system power flow cases in the pre- and post-project cases. This was done using an AC power flow solution.

All thermal overloads above 100% of the continuous facility rating (Rate A) were recorded. Voltages outside the monitoring criteria were flagged if the difference in the pre- and post-contingency voltages was greater than or equal to 0.01 pu.

Contingency Analysis:

Category B generator and breaker-to-breaker contingencies in the GRE, MDU, MH, MP, OTP, WAPA and Xcel control areas were simulated. Contingencies of the Manitoba-US tie lines were studied with associated DC runbacks modeled to reflect actual SPS operation. Selected breaker failure and common tower contingencies were also simulated in the vicinity of the MPC01200 POI.

Contingency analysis was performed using full AC power flow solutions based on activity ACCC of PSS/E. For the purposes of this analysis, automatic control of transformer taps and phase angle regulators were enabled. Switched shunts that were in discrete control mode were modeled in continuous control mode (this is to prevent toggling during solutions).

For the purposes of this analysis, facilities loaded above 100% of the continuous facility rating (Rate A) were recorded. Post-contingent flows which changed from the corresponding pre-contingent flow by less than 1 MW were not reported.

Post-contingency voltage limits used for analysis are shown in Table 4-1. Voltages outside those limits were flagged if the difference in pre- and post-contingent voltages was greater than or equal to 0.01 pu.

Criteria for Identifying Impacts:

Significantly Affected Facilities (SAFs) were identified based on Attachment A[10] of MAPP Design Review Subcommittee Policies and Procedures document [4].

All overloaded facilities that meet the following criteria were considered significantly affected, based on the impact of adding the MPC01200 project:

- System Intact Conditions: Report all overloaded facilities (loaded above continuous rating) that exhibit an increase in real power loading greater than 5% of 98.9 MW.
- Contingency Conditions: Report all overloaded facilities (loaded above continuous rating) that exhibit an increase in real power loading greater than 3% of 98.9 MW.

Buses are considered significantly affected if they show a voltage change of more than 0.01 pu pre-project vs post-project and a post-project voltage outside the criteria range for the respective buses.

Interconnection-related impacts are identified based on the following criteria:

- Line loading greater than 100% of continuous rating for system intact cases or emergency rating for post-contingent cases AND
  - Transfer Distribution Factor (TDF) greater than 20% OR
  - TDF greater than 10% and impacted facility in the vicinity of the project under study, subject to engineering judgment

Buses identified as SAFs due to voltage impacts are considered interconnection-related impacts if they were in the vicinity of the project under study, subject to engineering judgment.

In addition to the criteria above, per ad hoc request, MISO facilities are identified in the report if they met the following criteria:

- Line loading greater than 100% of continuous rating for system intact cases or emergency rating for post-contingent cases AND
  - PTDF greater than 5% OR
  - Impact greater than 20% of facility rating OR

[10] Steady-State facility and Flowgate Impact Determination Requirements and Screening Guidelines for Study Submissions.

- The overloaded facility or the overload-causing contingency is at the generator's outlet

Those MISO facilities identified as potential interconnection constraints were reviewed with MHEX reduced to 1848 MW, per standard MISO study practice.

4.4 Constrained Interface Analysis

The purpose of this analysis was to determine if the proposed projects would adversely impact the regional constrained interfaces (PTDF and OTDF interfaces) of the MAPP and MISO systems. Constrained interface analysis does not focus on the actual flow through those flowgates, but instead on the incremental impact the proposed projects would have on those flowgates. The results are, thus, less dependent on the dispatch assumptions used in developing the pre-project cases and more a consequence of the network topology between the proposed projects and the assumed sink.

Impacted interfaces[11] are identified based on the MAPP DRS Criteria of 5% PTDF and 3% OTDF. Constrained interface impacts are for informational purposes only to identify potential flowgate issues for the requested delivery component of the transmission. Mitigation may be required if it is determined that there is insufficient or no available transfer capability (ATC) on the affected constrained interfaces. This is an issue that should be addressed in the delivery analysis.

4.5 No-Load Analysis

The purpose of the no-load analysis is to quantify the reactive power exchange of the wind farms with the grid and to determine the potential for overvoltage at or near the wind farm when there is no wind, and therefore, no active power generated by the wind farm. Charging from the cables in the wind farm collector system and on unloaded lead lines can be significant under no-load conditions. The results of this analysis will determine the need for voltage control under no-load conditions and evaluate potential reinforcement options.

4.6 Stability Analysis

The purpose of the stability analysis is to determine whether the bulk electric system would meet stability criteria following the addition of the MPC01200

[11] As per Attachment A of reference [5], the minimum PTDF threshold for MAPP PTDF Interfaces is 5% and the minimum MW impact threshold is 1 MW. PTDF Interfaces that have PTDFs >= 5% -and- a MW impact >= minimum MW impact threshold are considered significantly impacted.

For OTDF Interfaces, the minimum OTDF threshold is 3% and the minimum impact threshold is 1 MW. OTDF Interfaces that have OTDFs >= 3% -and- a MW impact >= minimum MW impact threshold are considered significantly impacted.

project. Regional and local disturbances were simulated to assess the impact of the proposed wind generation addition on transmission system stability performance.

4.7 Short-Circuit Analysis

The purpose of the short-circuit analysis is to determine the impact of the proposed projects on substation fault current levels in the electrical vicinity of the wind farm. Three-phase and single-line-to-ground faults were simulated and the impact of the proposed projects on the fault currents was determined. Criteria is based on the actual short-circuit current limits of substation equipment.

5. VOLTAGE STABILITY ANALYSIS

Voltage stability analysis was performed using PV and QV curve analysis methods. The objective of the analysis was to determine if the system has the required voltage stability margin following the addition of the MPC01200 wind farm.

5.1 Methodology

5.1.1 PV Curve Analysis

The goal of the PV curve analyses is determination of the maximum transfer levels on the Pillsbury – Maple River 230 kV line leading to a voltage stable solution (i.e., convergent) and within-criteria voltages for system intact and critical contingency case conditions. Although the maximum transfer level corresponds to the pre-contingency flow on the Pillsbury – Maple River 230 kV line at the nose[12] of the PV curve (this operating point occurs when the reactive capability supporting the power transfer is exhausted), operation at this point is not recommended because slight increases in the power transfers lead to large degradation in system voltages. Instead, the system is usually operated at an operating point such that there is sufficient margin from the collapse point. MPC requires that a voltage stability margin of at least 10% be maintained from the nose of the curve. This 10% PV margin is chosen to reflect uncertainties in modeling, as well as to provide a reasonable margin for safe operation of the system away from the nose point.

The analysis was performed on the pre-project cases with the existing MPC0500 wind farm modeled at 378.8 MW nameplate. The output of the MPC01200 wind farm was increased incrementally[13] beyond its 98.9 MW nameplate rating until the point of voltage instability is reached. The intent is to determine whether the required voltage stability margin of 10% exists between an operating point characterized by MPC01200 at its 98.9 MW nameplate rating and the nose of the PV curve.

The analysis focused on voltage performance at the Maple River 345 kV and 230 kV, Pillsbury 230 kV and Sibley 230 kV buses. Following the initial simulations, the 34.5 kV buses in the MPC01200 collector system were also monitored. Pre- and post-contingency voltages at these buses were plotted against the pre-contingent MW flow on the Pillsbury – Maple River 230 kV line (as measured at Pillsbury).

PV curves were developed for system intact conditions and the following critical contingencies. The previously completed out-year studies for the MPC0500 wind

[12] The nose is the point at which the slope of the PV curve becomes infinite (vertical) and reaches the point of voltage collapse.

[13] 80% of the total project output is dispatched against the remote MISO market and 20% to ND base load generation, including Big Stone and Hoot Lake.

farm showed these contingencies to be the most limiting from a voltage stability perspective.

- Maple River – Sheyenne 230 kV and Maple River – Frontier 230 kV double circuit (MRV-SHY-FRN)
- Alexandria – Bison 345 kV line (ALX-BSN-345)

The total injection nameplate capacity of the MPC0500 and MPC01200 wind farms is 477.7 MW. This translates to approximately 462.5 MW of injection at Pillsbury. This is the post-project operating point of the system. Including a 10% stability margin, therefore, the system should be voltage-stable up to an injection of approximately 514 MW at Pillsbury.

5.1.2 QV Curve Analysis

The goal of the QV curve analysis is to determine whether sufficient reactive power is available to maintain the Pillsbury and Maple River area voltages within criteria for system intact and contingency case conditions. Whereas PV curve analyses are typically conducted at constant reactive compensation and variable MW injection, QV curve analyses are conducted at constant MW injection levels and variable reactive compensation.

The analysis was performed on the post-project case with the MPC0500 and MPC01200 wind farms at their full nameplate output of 477.7 MW.

QV curves are drawn by placing a fictitious synchronous condenser at the bus under study. The synchronous condenser regulates the voltage at that bus and its voltage setpoint is varied in small steps. The case is then solved and the output of the synchronous condenser is noted and plotted against the voltage at that bus. A positive reactive power output implies the system requires reactive support to hold the desired scheduled voltage. A negative reactive power output, on the other hand, implies reactive power is available in the system to hold the desired scheduled voltage.

QV curves were developed for the Maple River 345 kV and 230 kV, Pillsbury 230 kV, and Sibley 230 kV buses. Curves for each bus were generated separately by placing a synchronous condenser at that bus. The synchronous condenser's scheduled voltage was changed from 0.7 pu to 1.2 pu. The curves were developed for system intact conditions and the MRV-SHY-FRN 230 kV double contingency (as will be shown below, the PV analysis results showed this to be the most limiting contingency).

5.1.3 Assumptions

The PV curves developed in this study were based on the following assumptions:

- The base assumptions for the reactive control modes of MPC0500 and MPC01200 are described in the modeling section of this report. See Table 2-1.

- Constant MVA load representation was used for all loads in the power flow cases. It is generally accepted that such a representation results in more pessimistic voltage stability results. Loads may be voltage-sensitive in the short-term, but they all become constant MVA in the long-term, via distribution transformer tap action, thermostatic effects of load, load simultaneity effects (such as customers taking longer to heat pots of water), increased slip on motor loads, etc.

- Initial analysis was performed by allowing transformer taps, phase shifters, and switched shunts to regulate both under system intact and contingency case conditions (subject to equipment limits). Due to the mostly discrete nature of these devices, the resulting PV curves were found to be coarse thus making it difficult to identify the nose point. The analysis was repeated by modeling transformer taps, phase shifters, and switched shunts as regulating pre-contingency and non-regulating post-contingency. This resulted in smooth curves and facilitated identification of the nose point.

The above assumptions are also applicable for the QV curve analysis with the exception that transformer taps, phase shifters and switched shunts are assumed non-regulating under pre- and post-contingency conditions. This assumption was made primarily to obtain smooth QV curves without the discreteness inherent in transformer tap, phase shifter and/or switched shunt adjustments.

5.2 PV Curve Analysis Results

PV curves were developed for the 2017 summer peak load (SP), summer off-peak load (SO) and winter peak load (WP) cases. Only the summer peak cases are included in the report body as it was the most limiting. summer off-peak and winter peak results are included in the appendices. As noted above, the initial curves were developed by allowing transformer taps, phase shifters and switched shunts to regulate under pre- and post-contingency conditions.

Figure 5-1 shows the summer peak load PV curves for system intact and contingency case conditions. The top half of the figure shows the voltages at the Maple River 345 kV bus (MRV 345) as a function of MW flows on the Pillsbury – Maple River 230 kV line. The bottom half of the figure shows the voltages at the Maple River 230 kV and Pillsbury 230 kV buses (MRV 230 and PLB 230). Note from the curves that the voltages are well above the lower bounds of the respective voltage criteria[14].

Corresponding PV curves for summer off-peak and winter peak load conditions are shown in Appendix A. As above, the MRV and PLB voltages are well above the lower bounds of the applicable voltage criteria.

[14] System intact voltage criteria: 0.97 to 1.05 pu at MRV 345, MRV 230 and PLB 230.
Contingency case voltage criteria: 0.92 to 1.10 pu at MRV 345, MRV 230 and PLB 230.

Figure 5-1 shows that the MRV-SHY-FRN double contingency is the most-limiting because this contingency yielded the lowest power transfer on the PLB – MRV 230 kV line.

As a result of the curves being developed assuming a wind farm output step size of 10 MW, it is not possible to determine the nose point. This is because of two reasons: i) the discrete nature of the curves, and ii) the voltages do not dip low enough to allow determination of the nose point. The use of smaller step sizes (1 MW) resulted in excessive toggling of transformer taps and switched shunts, making it difficult to identify the nose point.

The analysis was repeated by modeling transformer taps, phase shifters and switched shunts as regulating pre-contingency and non-regulating post-contingency. The step size was assumed to be 10 MW initially and then reduced to 0.1 MW near the nose of the PV curves. The analysis was performed for system intact conditions and for the most-limiting contingency (MRV-SHY-FRN double contingency).

Figure 5-2 and Figure 5-3 show the resulting PV curves for the summer peak case. Figure 5-2 shows the PV curves for system intact conditions. Corresponding curves for the MRV-SHY-FRN double contingency are shown in Figure 5-3. As illustrated in these figures, the curves are smooth for the most part, with some discreteness near the point of voltage collapse (this is because transformer taps, phase shifters and switched shunts as regulating pre-contingency that introduces some discreteness in the curves). The pre- and post-contingency voltages dip low enough to allow determination of the nose points of the curves.

Figure 5-2 shows that the nose point for system intact conditions occurs at a transfer level of approximately 513 MW on the PLB – MRV 230 kV line (as measured at Pillsbury). Voltages at MRV 345 kV dip below 0.97 pu at a transfer level of 511 MW. Voltages at the PLB 230 kV bus dip below 0.97 pu at a transfer level of 508 MW. For the double contingency, the nose point occurs at a transfer level of 485 MW as shown in Figure 5-3. Although post-contingent voltages at MRV 345 kV remain above 0.92 pu at the nose point, the voltages at the PLB 230 kV bus dip below 0.92 pu at this point. The nose points of 513 MW (system intact) and 485 MW (double contingency) show that the voltage stability margin is below 10% (as noted in Chapter 5.1.1, the system must be voltage-stable up to an injection of approximately 514 MW at Pillsbury 230 kV).

The results of Figure 5-2 and Figure 5-3 show unacceptable performance because the voltage stability margins are below 10%. Further investigation showed that this is a consequence of modeling the MPC01200 wind farm in power factor control mode (as described in Chapter 3 of this report, the reactive power outputs of the WTGs in these wind farms are fixed such that the power factor on the high-side of the wind farm 34.5/230 kV transformers is unity when the WTGs are dispatched at their rated nameplate output).

Note: The "+" sign in Figure 5-2 represents the minimum system intact voltage threshold of 0.97 pu at a transfer level of 462.5 MW on the PLB – MRV 230 kV line (as measured at PLB 230 kV). Similarly, the "+" sign in Figure 5-3 represents the minimum post-contingent voltage threshold of 0.92 pu at the same transfer level. As long as voltages on the PV curves are above these voltage thresholds at the 462.5 MW transfer level, there is no voltage violation.

A sensitivity was performed by modeling the MPC01200 wind farm in voltage control mode. The WTGs in the MPC01200 wind farms were allowed to regulate voltages at Sibley 230 kV to 1.05 pu, subject to WTG reactive power limits (this corresponds to a power factor capability of +/- 0.90 at the WTG terminals at rated output). Figure 5-4 and Figure 5-5 show the resulting PV curves. Figure 5-4 shows that the nose point for system intact conditions occurs at a transfer level of approximately 550 MW. For the double contingency, the nose point occurs at a transfer level of 520 MW as shown in Figure 5-5. These results show that the nose point is well above 514 MW which corresponds to the voltage stability margin of 10%. These results demonstrate that it is necessary to operate the proposed wind farms in voltage control mode in order to meet voltage stability criteria.

PV curves for summer off-peak and winter peak load conditions are shown in Appendix A. These results also show that it is necessary to operate the proposed wind farms in voltage control mode (i.e., regulate voltages at Sibley 230 kV to 1.05 pu) in order to meet the voltage stability margin of 10%.

Table 5-1 summarizes the results of the PV curve analysis.

Table 5-1: Summary of PV Curve Results

Case	MPC01200 Control Mode	Contingency	Nose† MW
b3a-sp17aa	Fixed Power Factor	MRV-SHY-FRN	**485**
b3a-so17aa	Fixed Power Factor	MRV-SHY-FRN	**485**
b3a-wp17aa	Fixed Power Factor	MRV-SHY-FRN	**489**
b3c-sp17aa	Voltage Control	MRV-SHY-FRN	520
b3c-so17aa	Voltage Control	MRV-SHY-FRN	520
b3c-wp17aa	Voltage Control	MRV-SHY-FRN	525

† Cases that do not meet the voltage stability margin requirement of 10% are marked in red. These cases exhibit nose points below 514 MW.

Case b3a-sp17aa

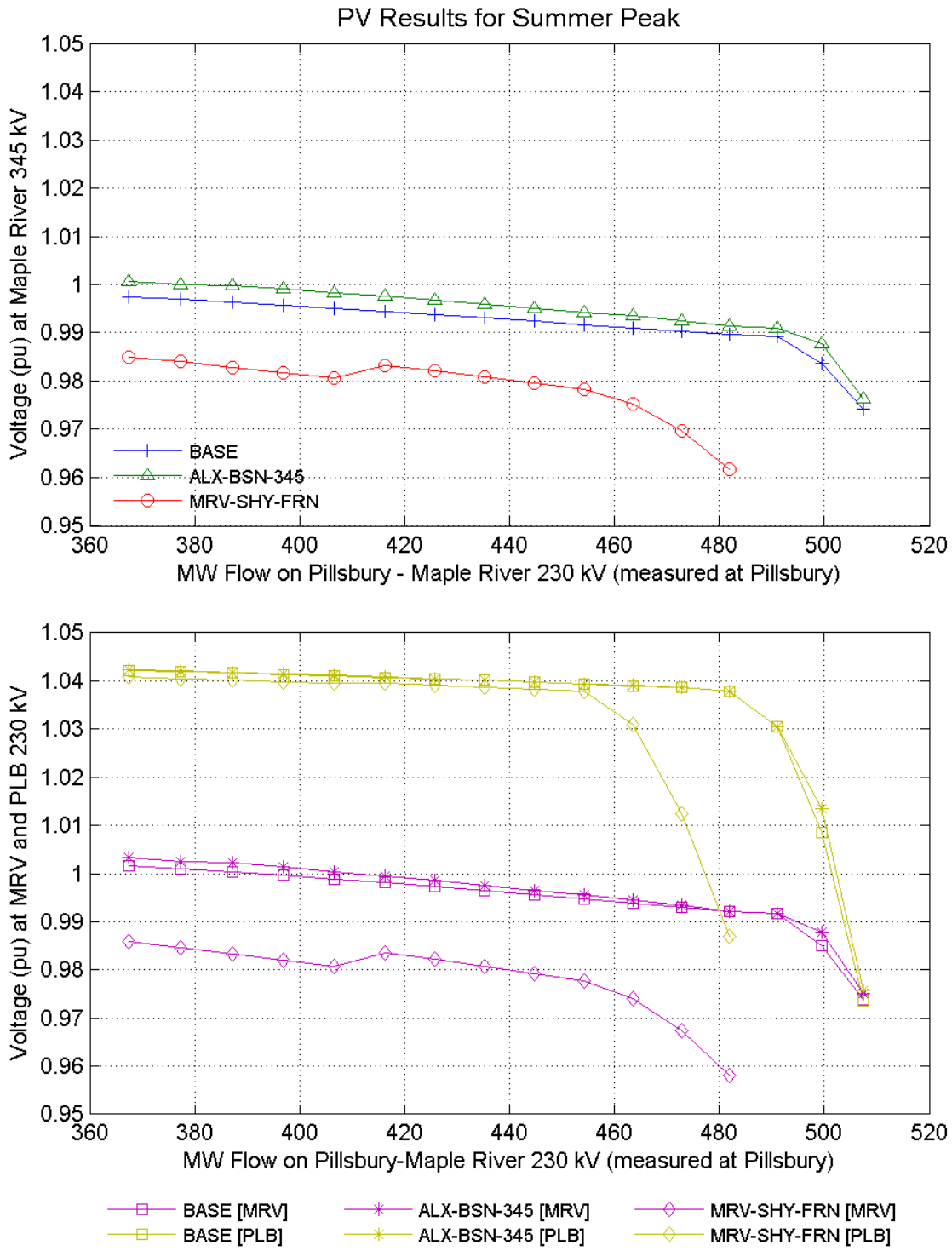


Figure 5-1: Case b3a-sp17aa: Initial PV Curves

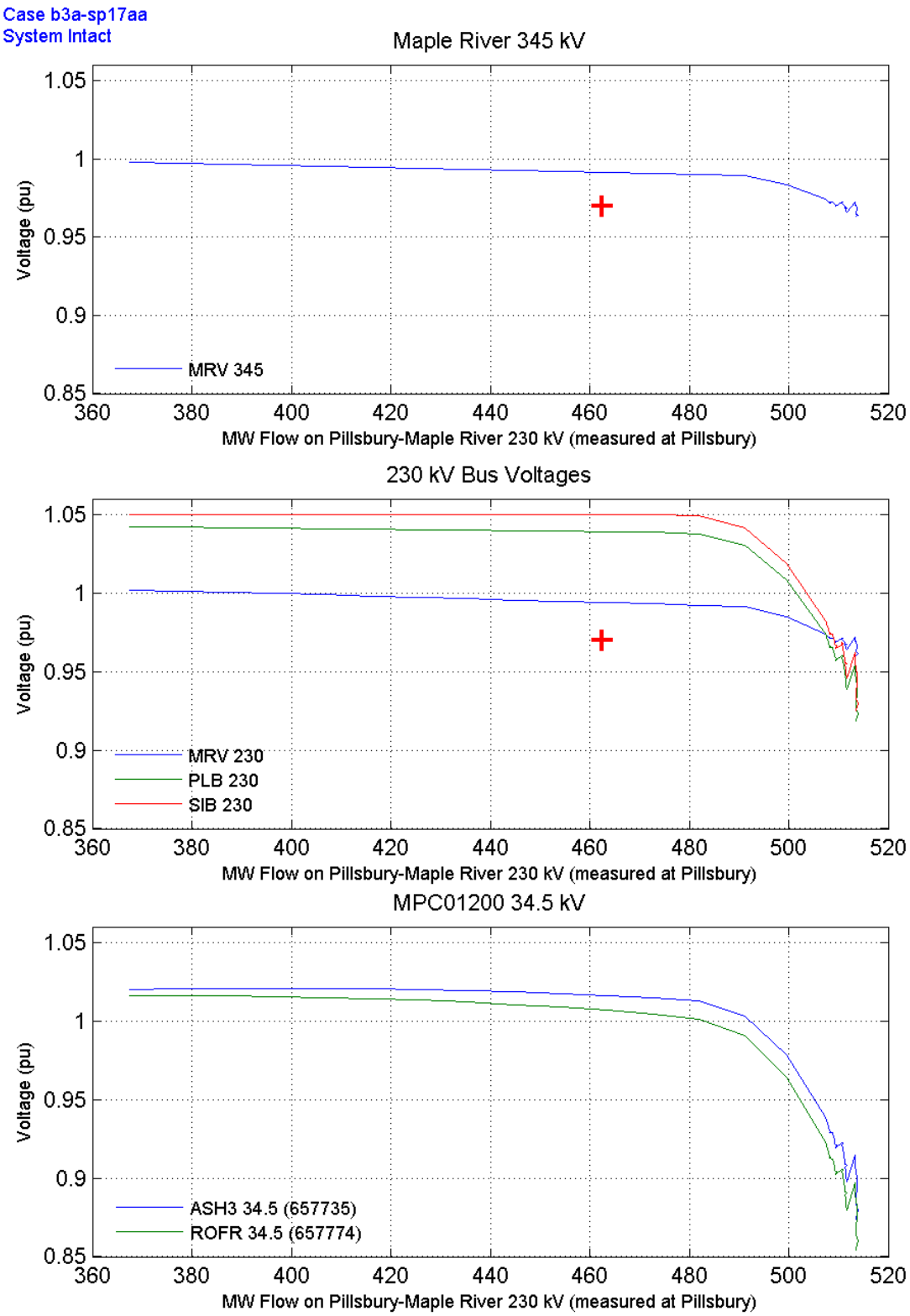


Figure 5-2: Case b3a-sp17aa – PV Curves for System Intact Conditions

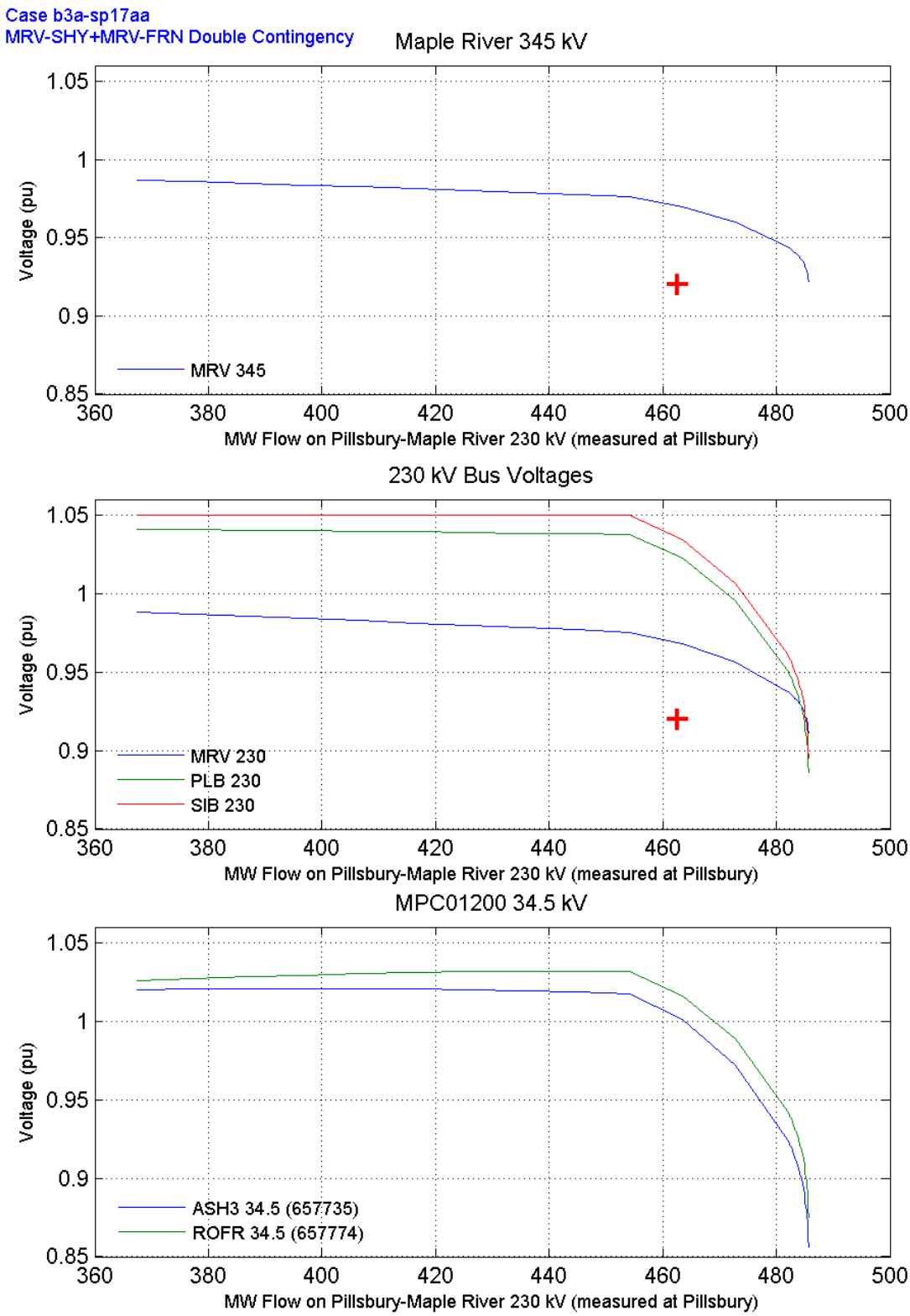


Figure 5-3: Case b3a-sp17aa – PV Curves for MRV-SHY-FRN Double Contingency

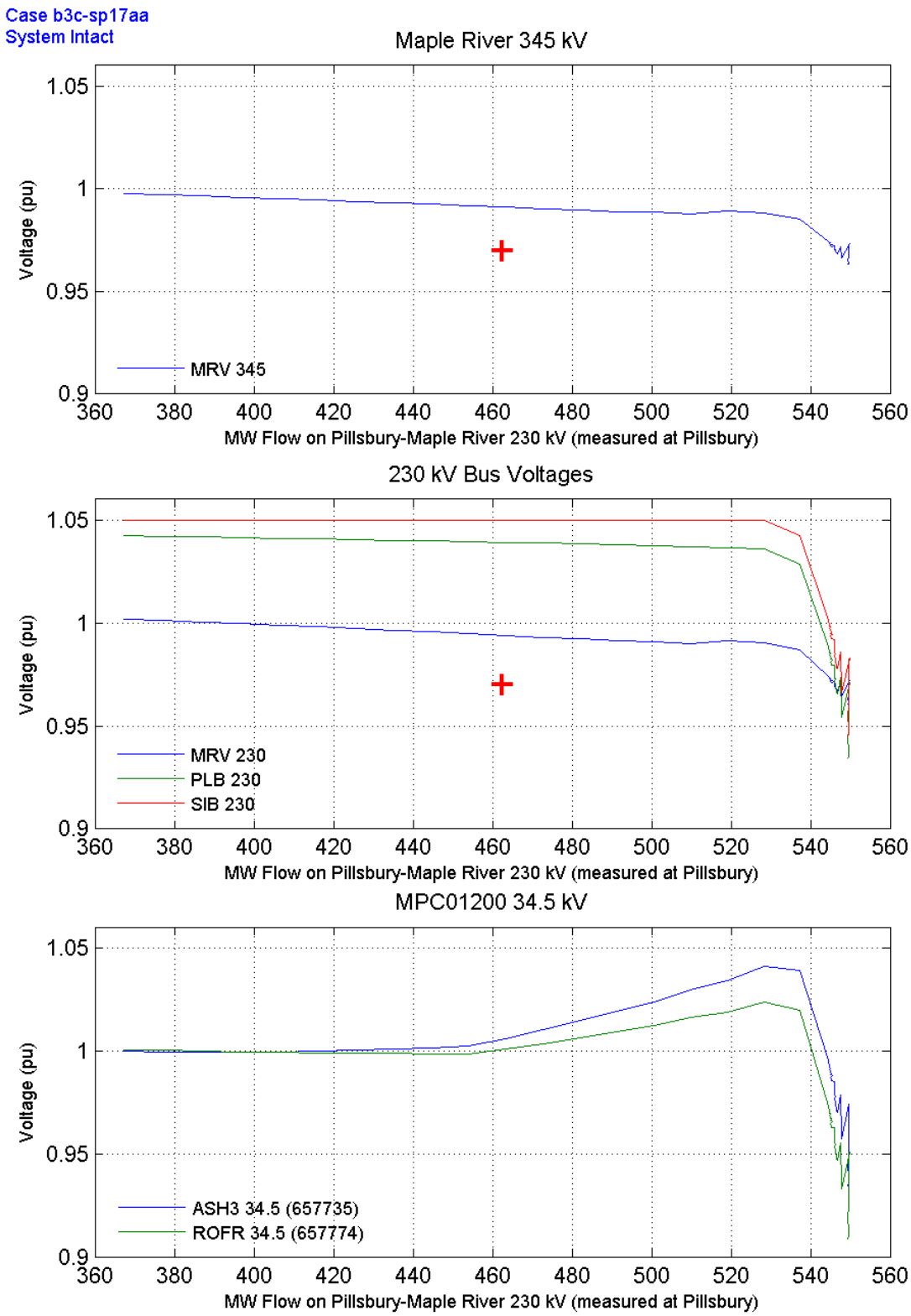


Figure 5-4: Case b3c-sp17aa – PV Curves for System Intact Conditions

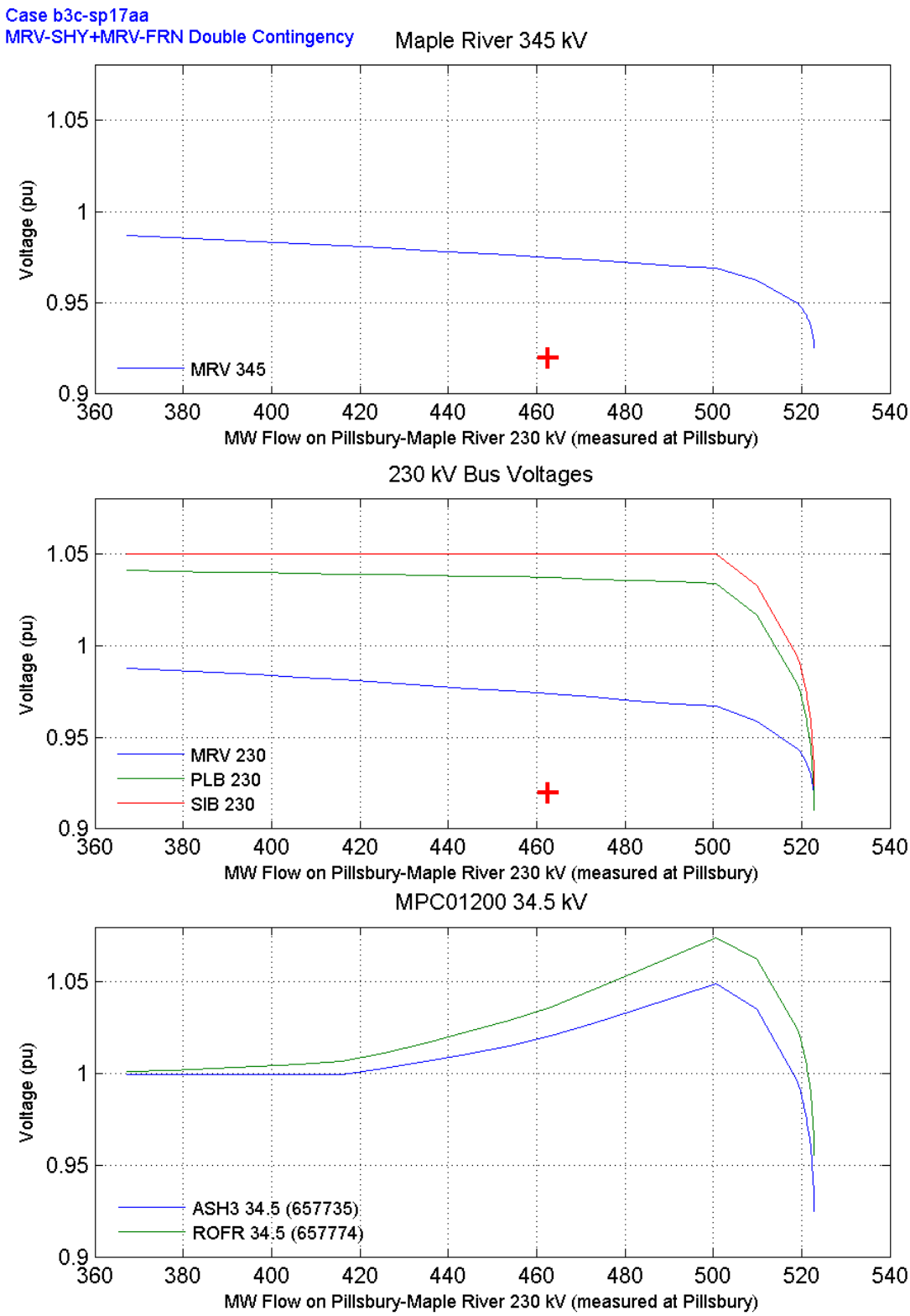


Figure 5-5: Case b3c-sp17aa – PV Curves for MRV-SHY-FRN Double Contingency

5.3 QV Curve Analysis Results

QV curve analysis was performed on the 2017 summer peak post-project case (case b03-sp17aa) with the MPC0500 and MPC01200 wind farms at their full nameplate output of 477.7 MW. Only the summer peak cases are included in the report body as it was the most limiting. Summer off-peak and winter peak results are included in the appendices.

QV curves were developed for system intact conditions and the MRV-SHY-FRN 230 kV double contingency. Curves were plotted at the Maple River 345 kV and 230 kV, Pillsbury 230 kV and Sibley 230 kV buses. Chapter 5.3.1 describes the general philosophy used to evaluate the resulting curves. A case list is given in Chapter 5.3.2. Results are described in Chapters 5.3.3 and 5.3.4.

5.3.1 Criteria for Evaluating QV Curves

It should be noted that each point on a QV curve represents a unique steady-state operating point. Points on the QV curve that intersect the x-axis denote operating points where there is no injection or absorption of MVAr by the synchronous condenser. Figure 5-6 shows the QV curves for post-project summer peak case b03-sp17aa developed in Chapter 3 of this report. Note from this figure that there are two such intersections for each QV curve. One is on the right-hand side of the QV curve, and to the right of the knee (the knee point is where the voltage “bottoms out”). Points to the right hand side of the knee denote voltage-stable operation (increasing voltages with increasing MVAr injections). The other intersection occurs on the left-hand side of the QV curve, and to the left of the knee point. Points on the QV curves to the left-hand side of their respective knee points denote voltage-unstable operation (reducing voltages with increasing MVAr injections). If this left-hand side intersection were to occur at voltages higher than 0.9 pu (at a minimum), the system could be operating at an unstable condition. The QV curves shown in Figure 5-6 show that there are no such concerns. The initial operating point is on the right-hand side intersection.

It is important to note that points on the QV curves that do not intersect the x-axis represent the reactive power injected or absorbed by the synchronous condenser to maintain a specific voltage. If the synchronous condenser injects MVAr in the system (i.e., positive Q), it implies that there is a “reactive power deficiency” at that bus. On the other hand, if the synchronous condenser absorbs MVAr (negative Q), there is a “reactive power surplus”. Points on the QV curve that are below the x-axis point to a reactive power surplus at a given voltage. Similarly, points on the QV curve that are above the x-axis point to a reactive power deficiency at a given voltage. It follows then that if the QV curve is above the x-axis (i.e., no intersection with the x-axis), the synchronous condenser needs to inject reactive power at that bus and therefore there is a reactive power deficiency at that bus.

In the absence of a synchronous condenser, steady-state operation is established only at points where the QV curves intersect the x-axis. Operation at other points is

not possible given that there is no physical shunt compensation at these buses (the synchronous condenser used to develop the QV curves is merely a fictitious device; it does not exist). These points merely indicate a reactive power deficiency or surplus at a given voltage. Steady-state operation can be established at these points only if there were actual shunt compensation, such as a synchronous condenser or capacitors, at these buses (or these buses are candidates for deploying shunt compensation). In the cases of capacitors, one would also plot "capacitor curves" (based on the $Q = YV^2$ relationship). Only points where the capacitor curves intersect the QV curves would be considered potential operating points. For example, switching in a capacitor would establish the operating point at the intersection of a QV curve and a capacitor curve. In this study however, none of the buses under study have physical shunt compensation and therefore steady-state operating points cannot be established at points where there is no intersection.

Considering that there are two intersections of each QV curve with the x-axis, the question is whether the operating point could suddenly transition from the right-hand side "voltage-stable" intersection to the left-hand side "voltage-unstable" intersection, say following a contingency. In such cases, the operating point could potentially swing from the right-hand intersection of the system intact QV curve to the left-hand side intersection of a different "post-contingent" QV curve such as that plotted in Figure 5-6(b). As will be explained below, an examination of the post-contingent voltages following the MRV-SHY-FRN 230 kV double contingency shows that the post-disturbance operating point is established at the right-hand side intersection of the post-contingent QV curve with the x-axis (0 MVAr injection). Thus, the post-disturbance system is voltage-stable. It is important to ensure that the right-hand side intersection and the left-hand side intersection are sufficiently apart. This is to prevent the possibility of transitioning from the right-hand side intersection to the left-hand side intersection for minor changes in system operating point.

Significance of Critical Voltage:
QV curve analyses typically involve examination of the "critical voltage" or voltage at the knee point. As discussed above, the knee denotes the point of separation between the voltage-stable and voltage-unstable parts of the QV curve. A general guideline is that critical voltages should be sufficiently low and well below the range of normal operating voltages. The rationale is this provides a safety margin and reduces the possibility of the system transitioning from the voltage-stable region to the voltage-unstable region by passing through the knee point for minor excursions in system operating point. Although this makes sense, high critical voltages within the range of normal operating voltages do not automatically imply that the QV curves are unacceptable. What is important is not the magnitude of the critical voltage but the location of the knee point relative to the intersection of the QV curve with the right-hand side of the x-axis. This is described in the next paragraph.

As long as the knee of the QV curve does not intersect the x-axis (or the capacitor curve), the knee point does not constitute a valid operating point. However, the location of the knee relative to the intersections of the QV curves with the x-axis is

important. In general, there would be a concern if the knee is located close to the right-hand side intersection of the QV curve with the x-axis. Modeling approximations or equipment tolerances could result in the knee intersecting with the x-axis, thereby establishing an operating point at this intersection. Another concern here is a small change in reactive power injection could move the operating point from the voltage-stable intersection to the voltage-unstable intersection. It is therefore important to ensure that the knee is far away from the intersection of the right-hand side of the QV curve with the x-axis.

Flat QV Curves:
When analyzing a QV curve, it is important ensure that it has a positive slope at the operating point in the voltage-stable region (increasing voltage with increasing reactive power injection). Flat or shallow QV curves at a bus are of particular concern especially in cases where actual shunt compensation already exists at that bus (or the bus is a candidate for deploying shunt compensation). The concern here is small changes in reactive supply could cause large voltage deviations. For example, switching in or out a capacitor may result in high or low voltages outside of applicable criteria. Another possibility is the operating point transitioning from the voltage-stable region to the voltage-unstable region if the curves are flat.

Summary of Criteria to Assess QV Curves:
Based on the above discussion, the following general guidelines are used to screen the QV curves developed in this study:

- Confirm that the right-hand side and left-hand side intersections of a QV curve with the x-axis are sufficiently apart (the voltages at these intersections should be separated by at least 0.10 pu as per ABB engineering judgment).This is to ensure that the operating point does not move from the voltage-stable intersection to the voltage-unstable intersection for minor excursions about the operating point.
- Ensure that the left-hand side intersection of the QV curve with the x-axis does not occur above a voltage of 0.90 pu.
- Check that the knee point is located away from the initial operating point (right-hand side intersection of the QV curve with the x-axis). Ideally, the knee should be located well below the x-axis (surplus MVAr) and the critical voltage should be separated from the initial operating voltage by at least 0.10 pu as per ABB engineering judgment. If the bus is a candidate for deploying shunt compensation, the critical voltages at that bus should be 0.85 pu or below (this is to ensure that the knee does not occur within the range of voltages over which the shunt device is expected to operate).
- Confirm that there is a finite positive slope at the right-hand side intersection of the QV curve with the x-axis. If the bus is a candidate for deploying shunt compensation, a positive slope is required to the right of the knee point. Again, this is to ensure that the slope is positive within the range of voltages over which the shunt device is expected to operate.
- Ensure that there is adequate reactive power surplus available to support the

voltages at the Sibley 230 kV, Pillsbury 230 kV and Maple River 230 kV and 345 kV buses above their minimum steady-state voltage criteria.

5.3.2 Case List

QV curves were developed for the post-project cases listed in Table 5-2.

Case b3d-sp17aa is the same as case b03-sp17aa described previously with the exception that the MPC01200 wind farm regulates voltages at the Sibley 230 kV bus to 1.05 pu (subject to WTG reactive power limits). For study purposes, it is assumed that the WTGs regulate their own terminal voltages instead of the regulating voltage at Sibley 230 kV bus – this is to prevent conflicts in reactive power sharing with the synchronous condenser used to develop QV curves at the Sibley 230 kV bus. In addition, it is assumed that Ash 1 and the MPC Ash 2 WTGs also regulate their own terminal voltages instead of regulating the Barnes and Luverne 230 kV bus voltages respectively. The terminal voltage setpoints are chosen such that the system intact voltages at the Barnes, Luverne and Sibley 230 kV buses are 1.05 pu. Terminal voltage control produces conservative results as the burden of controlling the voltages at the 230 kV buses is borne mainly by the synchronous condenser instead of the WTGs.

Table 5-2: Case List for QV Analysis

Case	PLB-MRV 230 MW Flow	MPC01200 Control Mode
b03-sp17aa	462.5	Fixed Power Factor
b3d-sp17aa	462.5	Voltage Control

Note: MW flow is measured at Pillsbury 230 kV end of the line.

5.3.3 QV Analysis Results for Case b03-sp17aa

The system intact and post-contingent QV curves for case b03-sp17aa are shown in Figure 5-6. These QV curves are acceptable and there are no concerns. Details are presented below.

System Intact QV Curve

The initial operating voltages are at the right-hand side of the QV curves where they intersect the x-axis (0 MVAr injection). The voltage at the Sibley 230 kV bus (solid curve) is 1.05 pu.

As the scheduled voltage at the Sibley 230 kV bus is increased above 1.05 pu by the synchronous condenser, the area WTGs start to absorb MVAr (this is at the expense of the synchronous condenser that is injecting MVAr into the Sibley 230 kV bus). The discontinuities in the QV curves correspond to the points where the WTGs (Ash 1 and the MPC portion of Ash 2) are unable to absorb MVAr i.e., they reach their Qmin limits.

As the scheduled voltage at the Sibley 230 kV bus is reduced below 1.05 pu, the synchronous condenser absorbs MVAr. The Ash 1 and MPC Ash 2 WTGs inject MVAr until their reactive power reserves are exhausted i.e., they reach their Qmax limits around 1.03 pu.

For voltages below 1.03 pu at Sibley 230 kV, the WTGs are all maxed out. Voltages are controlled by the synchronous condenser (in reality, voltages would be at the mercy of the system as the synchronous condenser does not exist).

Critical voltages occur at or below 0.86 pu which is well below the normal voltage range of 0.95 to 1.05 pu for system intact conditions. The knee points for the different QV curves are located sufficiently away from the right-hand side intersection. Also, the right-hand side and left-hand side intersections are sufficiently apart.

The slopes on the right-hand side of the QV curves are acceptable because they indicate increasing voltage with increasing reactive power injection. Although the slopes of the various QV curves are zero around the knee, this is not a concern because the knee occurs at low voltages (at or below 0.86 pu). A zero or near-zero slope (flat or near-flat QV curve) at a given bus would only be a cause for concern if shunt compensation was deployed at that bus. In this case however, none of the buses have shunt compensation.

Figure 5-6(a) shows that adequate reactive power reserves are available to support the Maple River 230 kV and 345 kV, Pillsbury 230 kV, and Sibley 230 kV bus voltages above their minimum steady-state voltage criteria (0.97 pu under system intact conditions).

Post-Contingent QV Curves

Figure 5-6(b) shows the post-contingent QV curves. Comparing these curves against those shown in Figure 5-6(a), it is seen that the post-contingent QV curves have moved upwards (lesser MVAr surplus) and to the right (higher critical voltages).

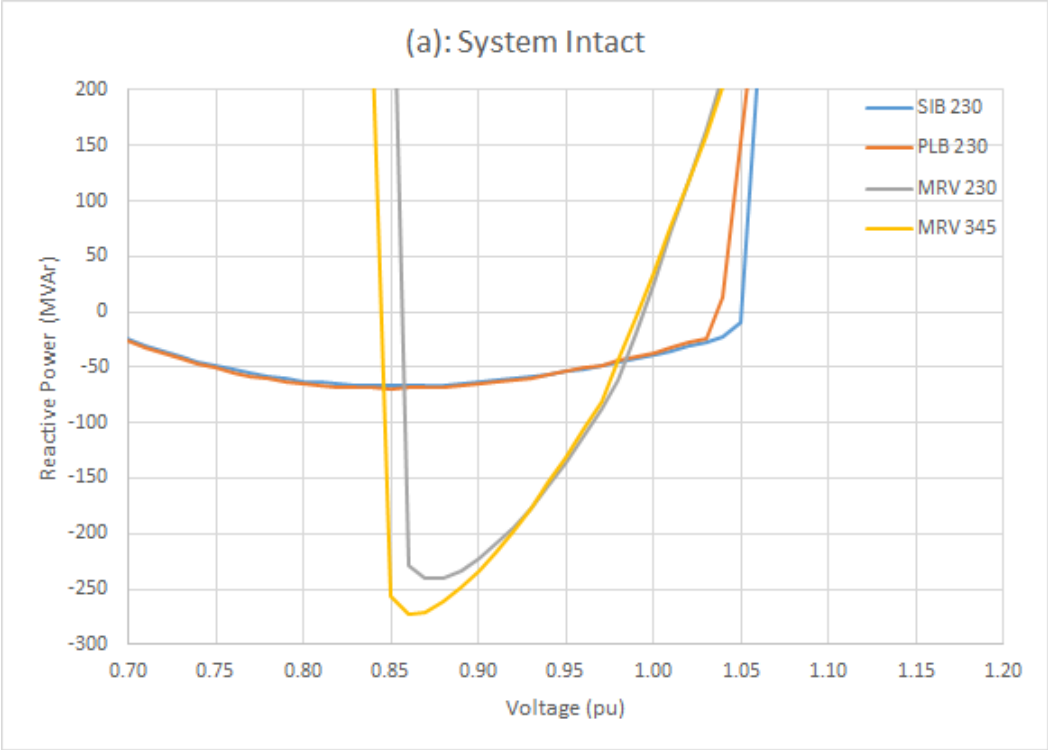
An examination of system conditions in the post-contingent power flow case (without the synchronous condenser) shows that the post-contingent operating point is established at the right-hand side intersection of the QV curves with the x-axis i.e., the post-contingent system is voltage-stable. Critical voltages occur at or below 0.88 pu which is below the acceptable voltage range for post-contingency conditions. There is adequate separation between the knee point and the right-hand side intersection of the QV curve with the x-axis.

Figure 5-6(b) shows that adequate reactive power reserves are available to support the Maple River 230 kV and 345 kV, Pillsbury 230 kV, and Sibley 230 kV bus voltages above their minimum post-contingent steady-state voltage criteria (0.92 pu under post-contingent conditions).

In general, there are no concerns with the post-contingent QV curves.

5.3.4 QV Analysis Results for Case b3d-sp17aa

Figure 5-7 shows the system intact and post-contingent QV curves for this case. Comparing these curves against the corresponding curves for case b03-sp17aa, it is seen that the Figure 5-7 curves are deeper (more MVAr surplus) than those shown in Figure 5-6. This is because the WTGs are in voltage control mode. The reactive power capabilities of the WTGs are reflected in the QV curves as a reactive power surplus. Figure 5-7 shows that adequate reactive power reserves are available to support the 230 kV and 345 kV bus voltages above their minimum steady-state voltage criteria. In general, there are no concerns with the QV curves for this case.



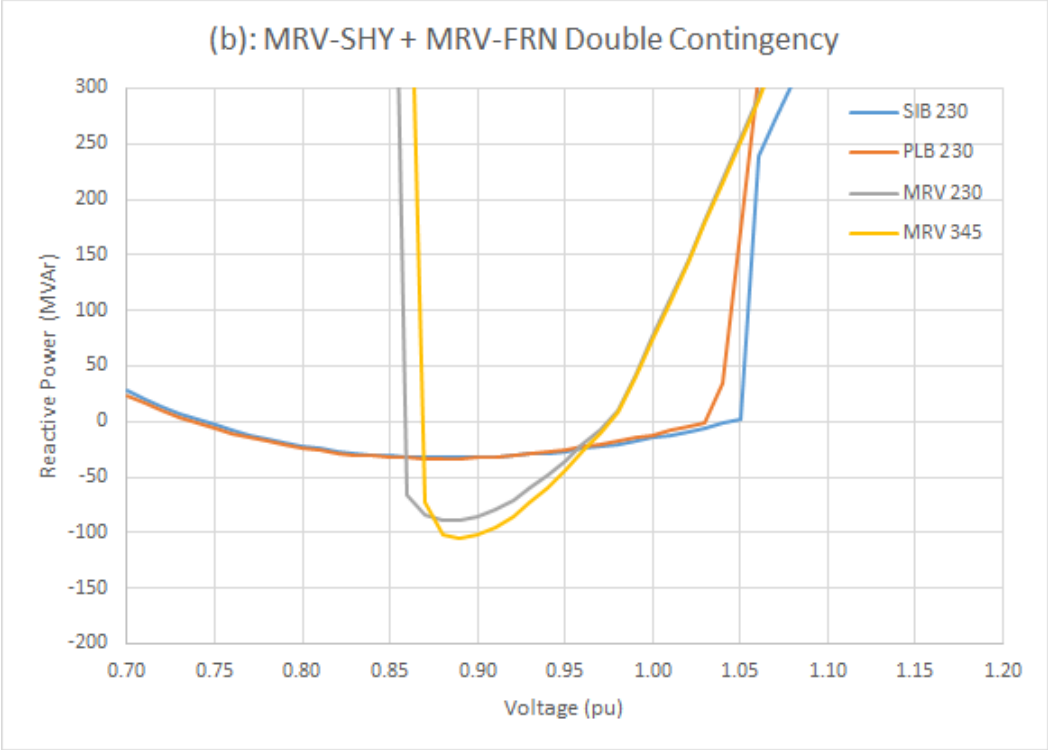
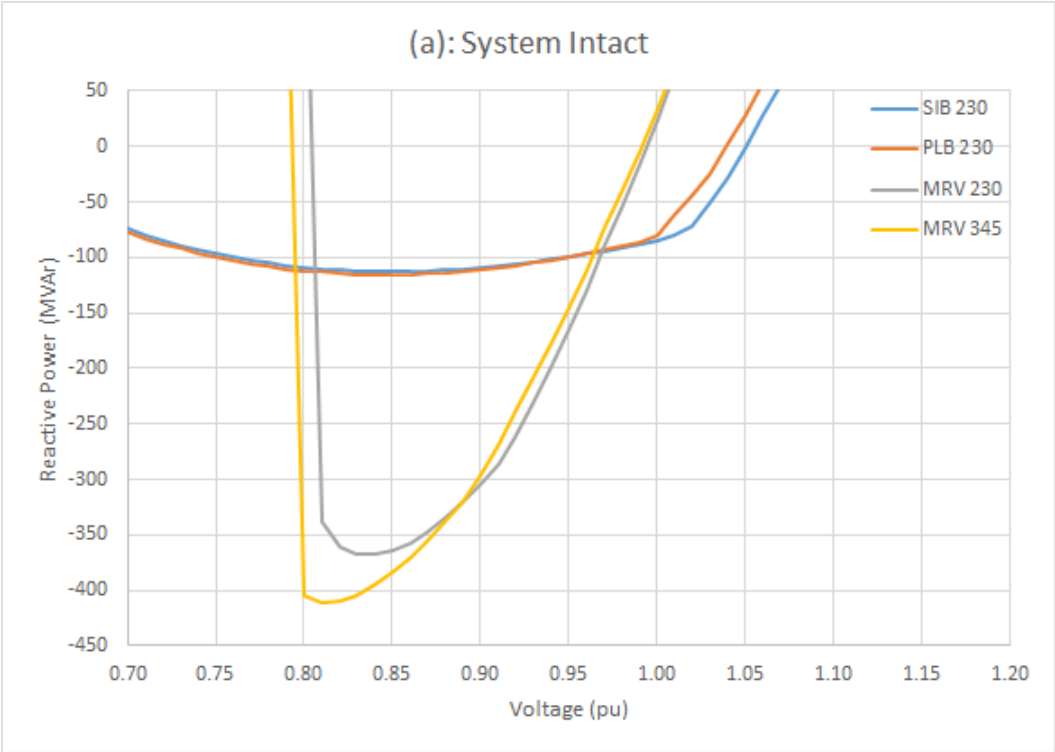


Figure 5-6: QV Curves for Case b03-sp17aa



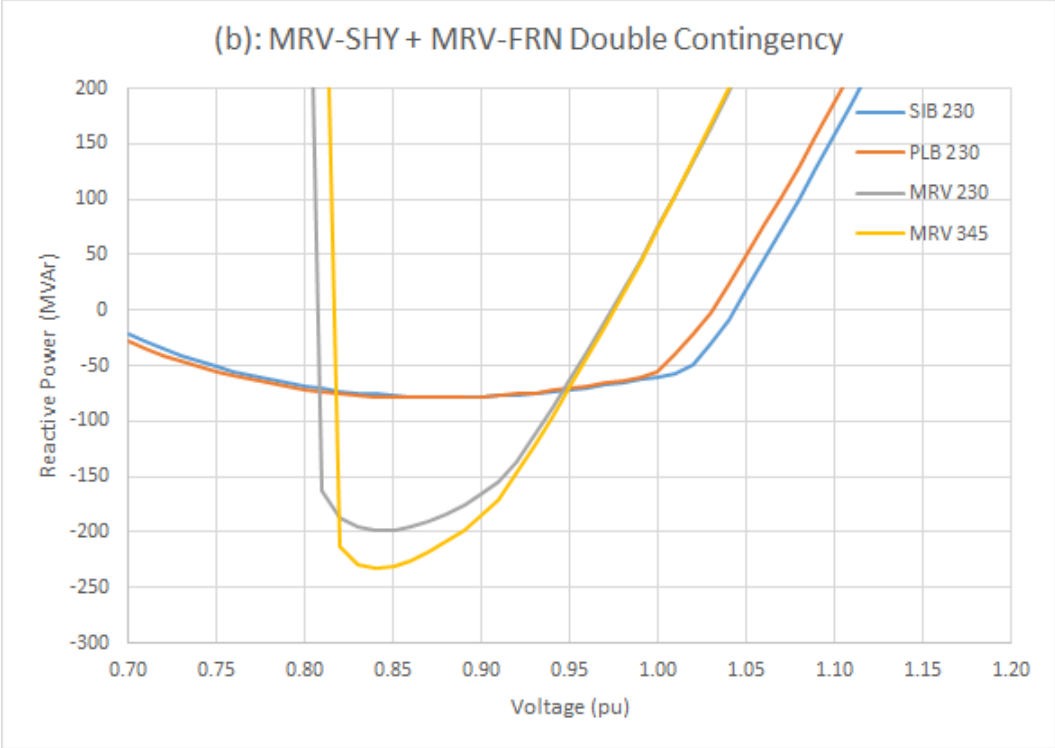


Figure 5-7: QV Curves for Case b3d-sp17aa

5.4 Delineation of Impacts between Existing and ROFR Portions of MPC01200

A sensitivity analysis was performed to delineate the voltage stability impacts of the existing portion of MPC01200 from the ROFR portion. The purpose is to verify whether the existing portion of the MPC01200 wind farm meets voltage stability criteria without considering the effects of the ROFR addition.

The analysis was performed for summer peak load conditions. Pre- and post-project sensitivity cases were developed by disconnecting the ROFR portion of the wind farm. The existing portion of MPC01200 was modeled in power factor control mode. The resulting injection at the Pillsbury 230 kV bus in the post-project case is 415 MW. Including a 10% stability margin, therefore, the system should be voltage-stable up to an injection of approximately 461 MW at Pillsbury.

5.4.1 PV Curve Analysis Results

PV curve analysis was performed on the pre-project case. The output of the MPC01200 wind farm was increased incrementally beyond its 49.6 MW nameplate rating until the point of voltage instability was reached. Results of the analysis are shown in Figure 5-8 for system intact conditions and in Figure 5-9 and for the MRV-SHY-FRN double contingency, respectively. Figure 5-9 shows that the nose of the post-contingent PV curve occurs at 460 MW. This is slightly below the required 10% stability margin (as noted above, the system should be voltage-stable up to an injection of 461 MW).

Further analysis showed that voltage stability criteria can be met by operating the existing portion of the MPC01200 wind farm in voltage control mode. For the purposes of this analysis, MPC01200 was set to regulate voltages at the Sibley 230 kV bus to 1.05 pu, subject to WTG reactive power limits. Figure 5-10 and Figure 5-11 show the resulting PV curves. Figure 5-11 shows that the nose point for the double contingency occurs at a transfer level of approximately 479 MW, which is above the required the 10% voltage stability margin. These results demonstrate that it is necessary to operate the existing portion of the MPC01200 wind farm in voltage control mode in order to meet voltage stability criteria.

Table 5-3 summarizes the results of the PV curve analysis.

Table 5-3: PV Curve Analysis Results for Existing Portion of MPC01200

Case	MPC01200 Control Mode	Contingency	Nose† MW
b4a-sp17aa	Fixed Power Factor	MRV-SHY-FRN	**460**
b4c-sp17aa	Voltage Control	MRV-SHY-FRN	479

† Cases that do not meet the voltage stability margin requirement of 10% are marked in red. These cases exhibit nose points below 461 MW.

5.4.2 QV Curve Analysis Results

QV curves were developed for the post-project cases listed in Table 5-4.

Table 5-4: QV Analysis Case List for Existing Portion of MPC01200

Case	PLB-MRV 230 MW Flow	MPC01200 Control Mode
b04-sp17aa	415	Fixed Power Factor
b4d-sp17aa	415	Voltage Control

Note: MW flow is measured at Pillsbury 230 kV end of the line.

Case b04-sp17aa is the post-project case with MPC01200 wind farm in power factor control mode. In case b4d-sp17aa, the MPC01200 wind farm regulates voltages at the Sibley 230 kV bus to 1.05 pu (subject to WTG reactive power limits). As noted previously, it is assumed that the WTG regulates its own terminal voltages instead of the regulating voltage at Sibley 230 kV bus – this is to prevent conflicts in reactive power sharing with the synchronous condenser used to develop QV curves at the Sibley 230 kV bus.

The system intact and post-contingent QV curves for case b04-sp17aa are shown in Figure 5-12 . These QV curves are acceptable and there are no concerns.

Figure 5-13 shows the system intact and post-contingent QV curves for case b4d-sp17aa. Comparing these curves against the corresponding curves for case b04-sp17aa, it is seen that the Figure 5-13 curves are deeper (more MVAr surplus) than those shown in Figure 5-12. This is because the WTGs are in voltage control mode. In general, there are no concerns with the QV curves for this case.

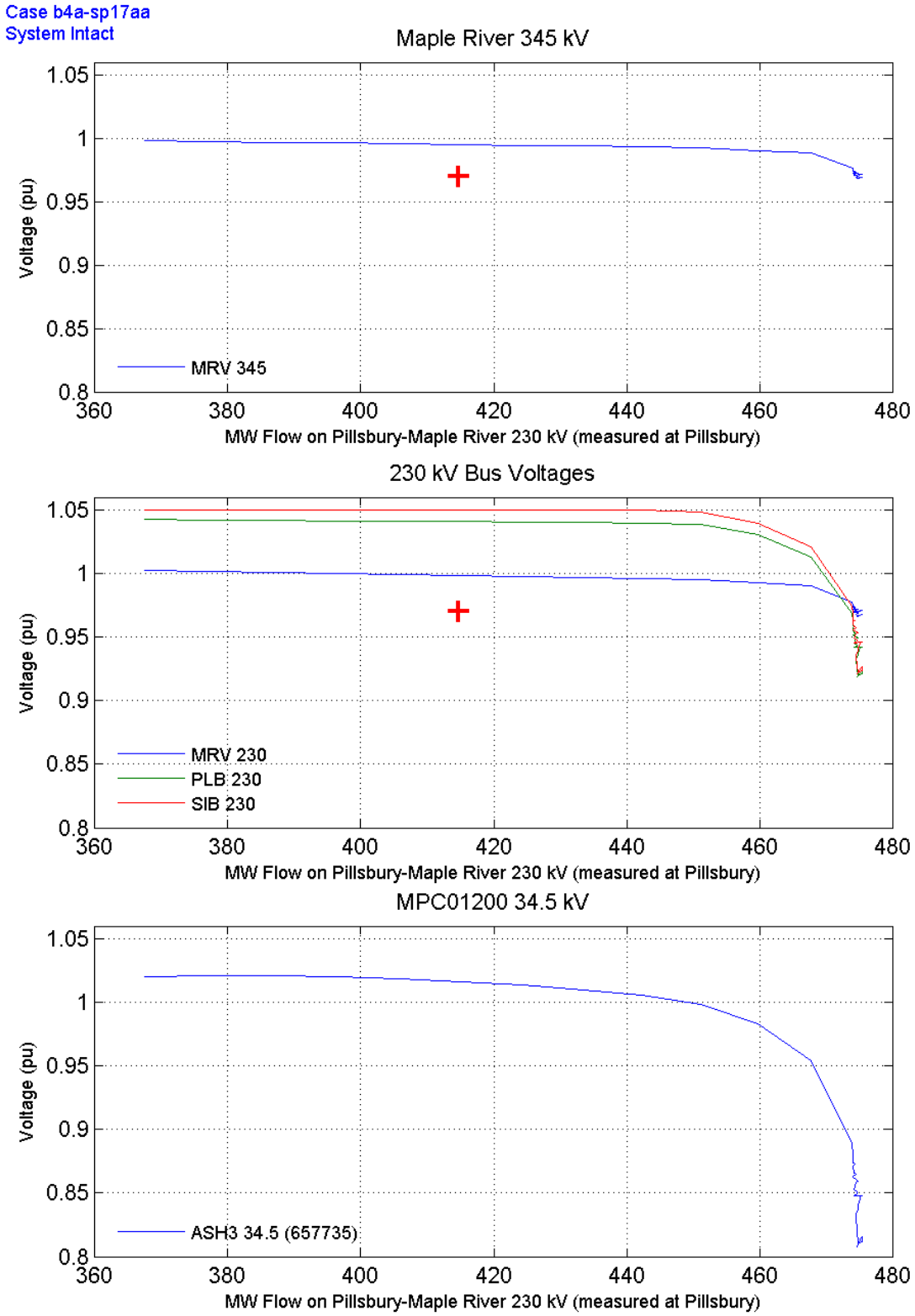


Figure 5-8: Case b4a-sp17aa – PV Curves for System Intact Conditions

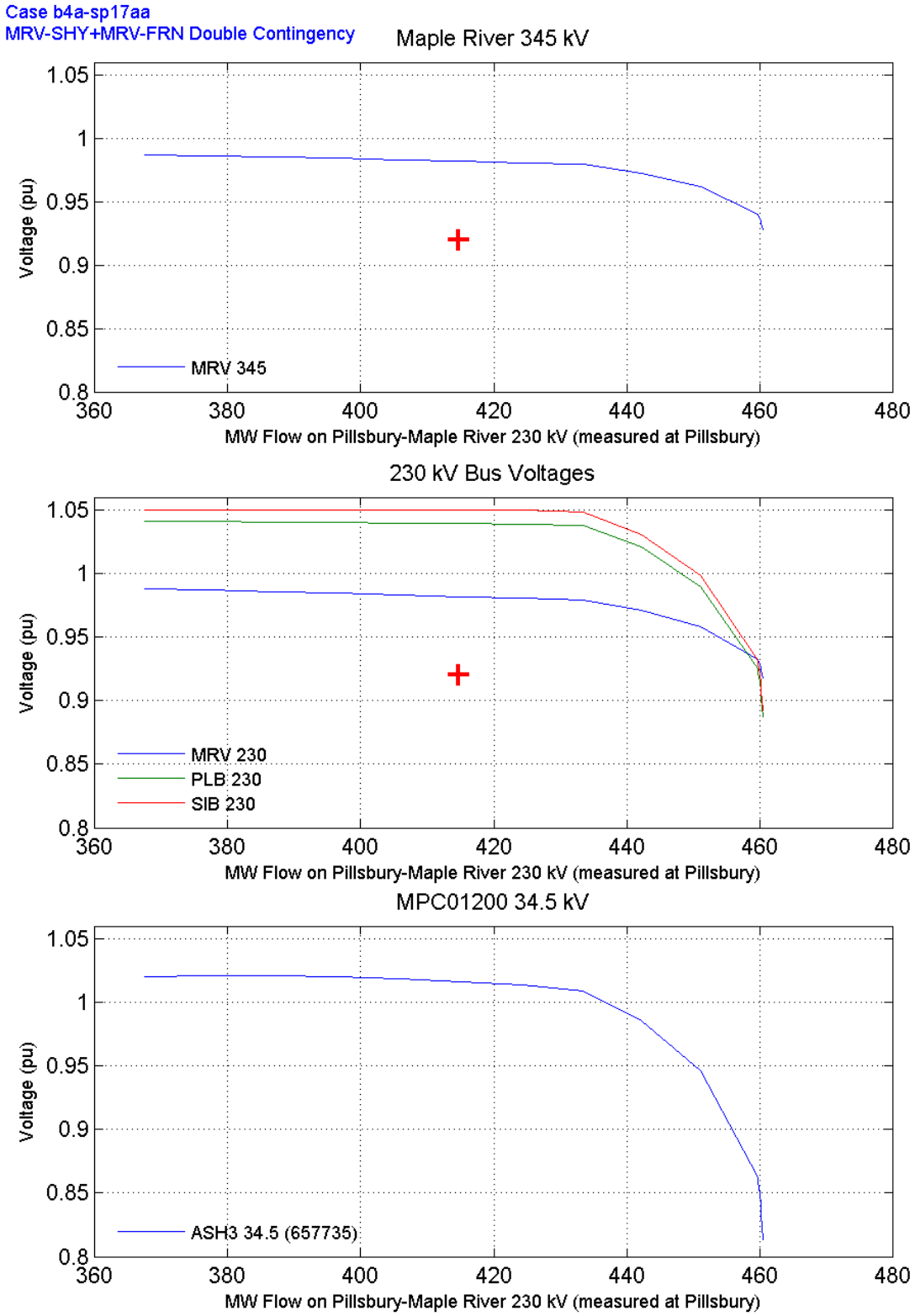


Figure 5-9: Case b4a-sp17aa – PV Curves for MRV-SHY-FRN Double Contingency

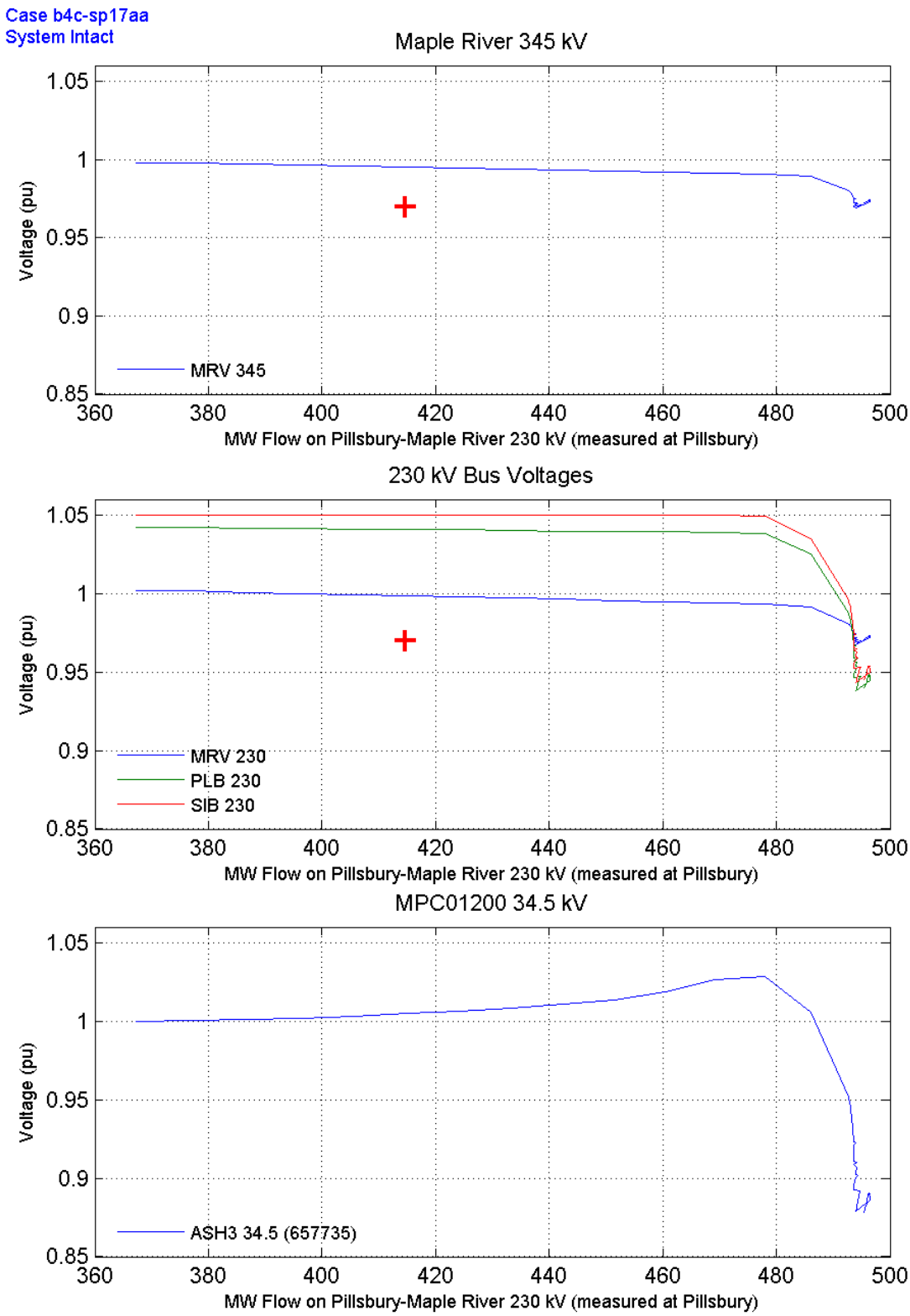


Figure 5-10: Case b4c-sp17aa – PV Curves for System Intact Conditions

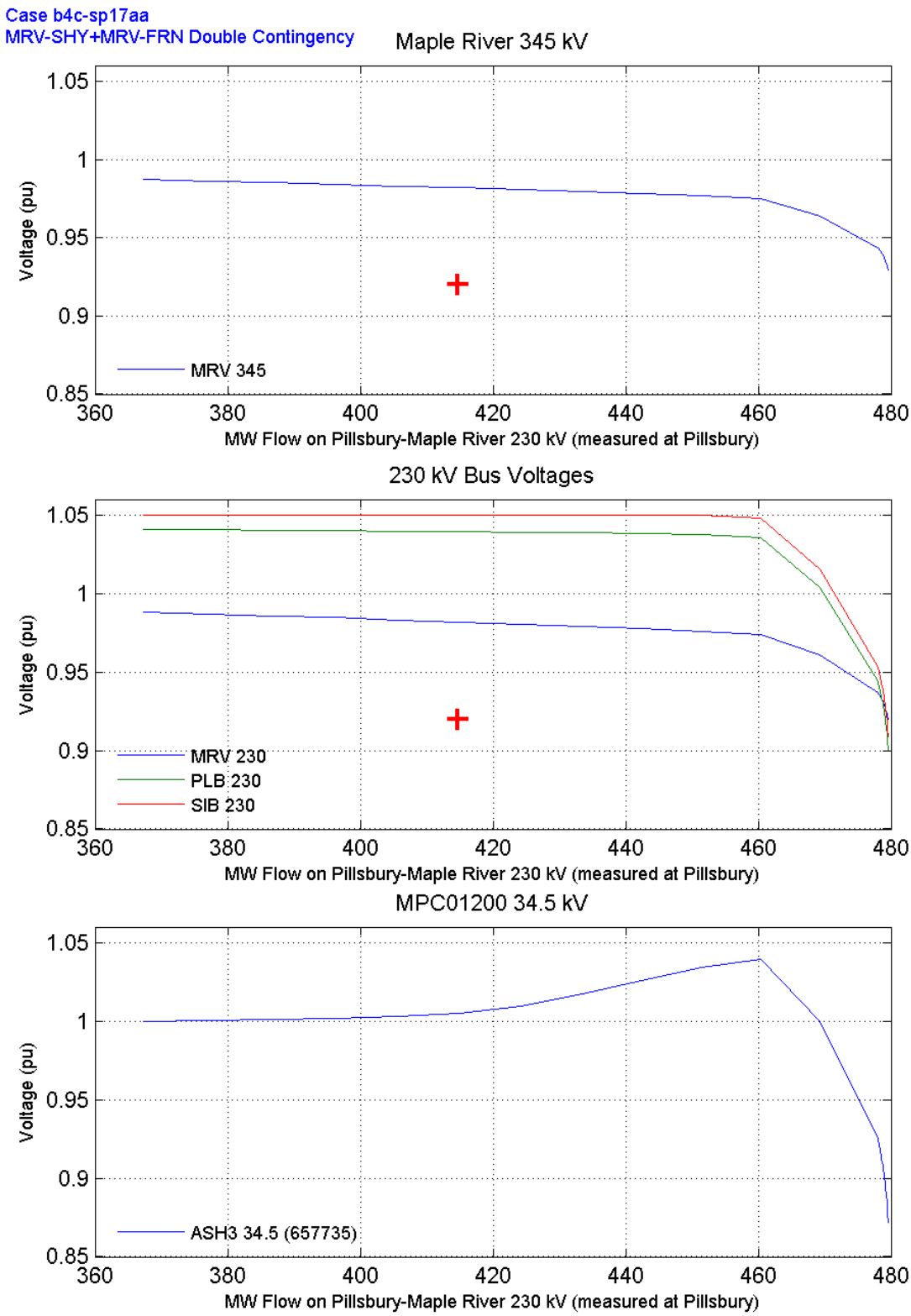
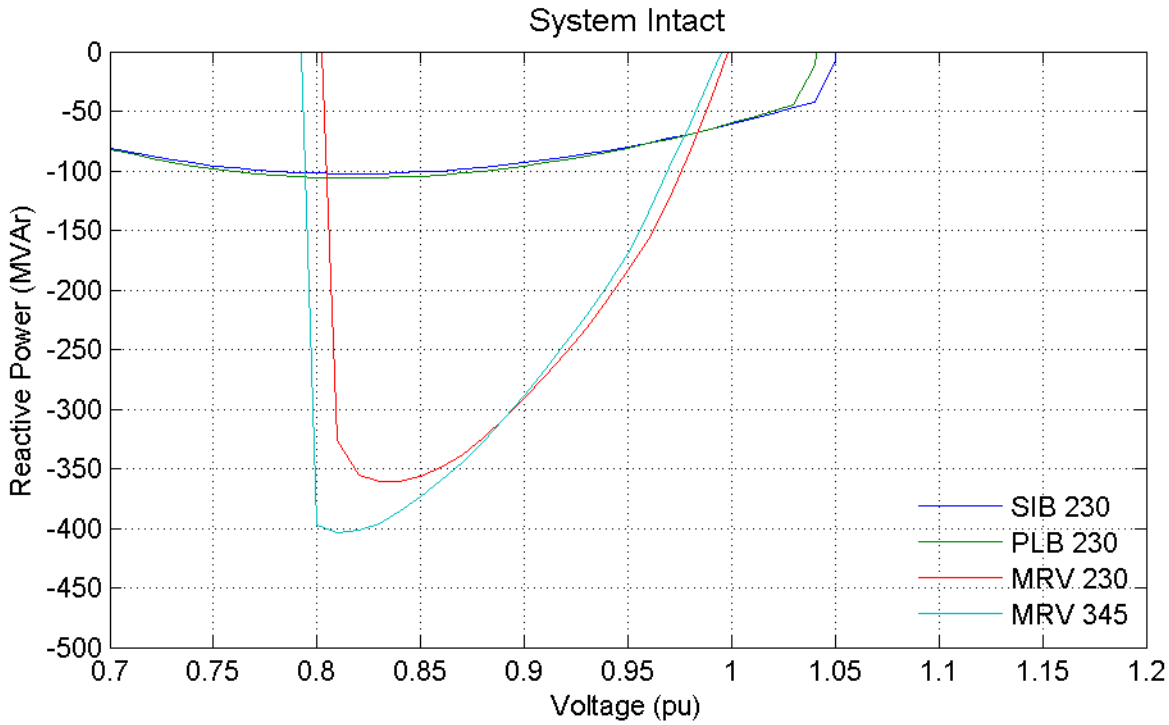


Figure 5-11: Case b4c-sp17aa – PV Curves for MRV-SHY-FRN Double Contingency

Case b04-sp17aa



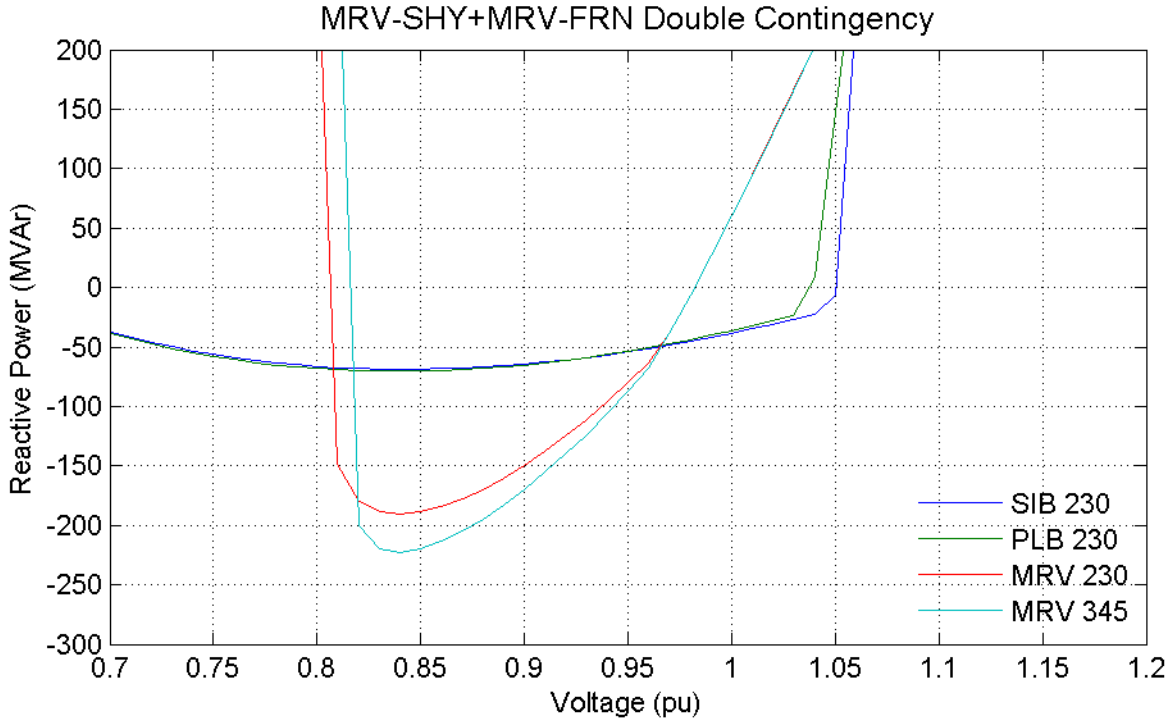


Figure 5-12: QV Curves for Case b04-sp17aa

Case b4d-sp17aa

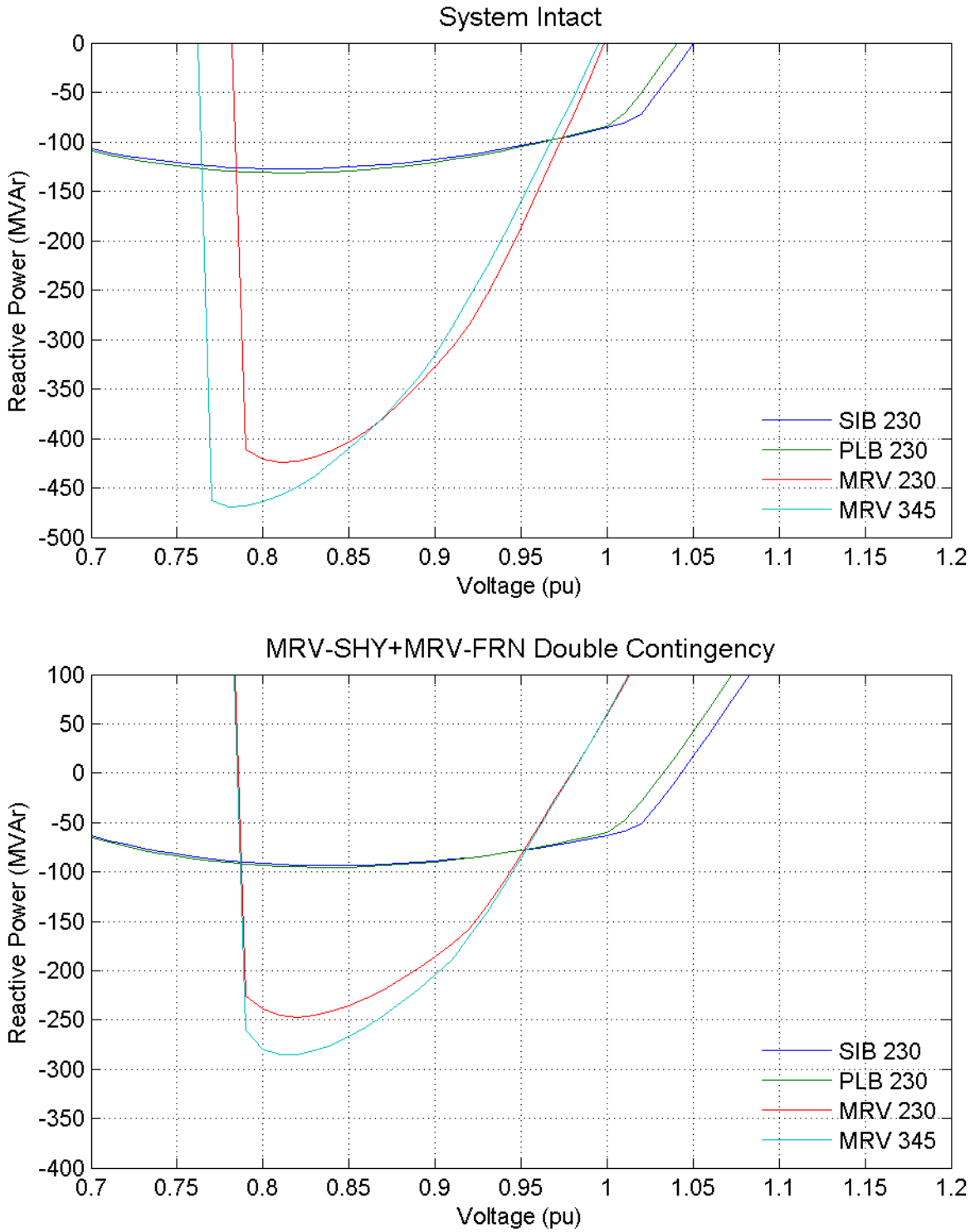


Figure 5-13: QV Curves for Case b4d-sp17aa

6. STEADY-STATE ANALYSIS

Steady-state analysis was performed to evaluate the thermal and voltage impacts of MPC01200. The criteria, methodology and assumptions described in Chapter 4.3 were used for steady-state analysis. The denominator for the Transfer Distribution Factors (TDFs or DFs) was calculated based on an injection of 87.7 MW at the Maple River 230 kV bus (98.9 MW nameplate) from the MPC01200 wind farm.

Manual power flow simulations were performed to verify the maximum post-contingent loadings on potential interconnection constraints with switched shunts restored to discrete control in the power flow models (as noted in Chapter 4.3, switched shunts that were in discrete control mode were modeled in continuous control mode to prevent toggling during solutions). The corresponding final loadings are shown in separate tables. Results show that setting the switched shunts to discrete control does not impact the maximum loadings on these facilities.

Highlighted cells in the tables following this section indicate interconnection constraints.

6.1 System Intact Analysis Results

Table 6-1 shows SAFs for system intact conditions along with sensitivities as noted below.

The maximum observed loading on the Pillsbury – Maple River 230 kV line for system intact was 470 MVA. Interpolation of the results indicates that this upgrade is only necessary for the ROFR portion of the farm. The Pillsbury – Maple River 230 kV line is an interconnection constraint and must be mitigated for the ROFR portion of MPC01200.

With MHEX at 2175 MW, Table 6-1 also shows system intact overloads on the M602F (Riel – Forbes) 500 kV line in the pre- and post-project summer off-peak case. The TDF on this line meets the MISO interconnection constraint criteria. Therefore, a sensitivity was performed on these overloads by reducing MHEX flows to 1848 MW (firm) as per MISO practice. With the MHEX interface flows reduced, pre- and post-project flows on the M602F line were within the line's continuous rating. Therefore, the M602F line is not an interconnection constraint for MPC01200.

System intact voltage analysis did not show any SAFs.

6.2 Contingency Analysis Results

Appendix D includes the SAF list limited to a maximum of 10 entries for each SAF identified in the contingency analysis. A shorter list of the five most

limiting contingencies for each SAF is shown in Table 6-2, Table 6-3, and Table 6-4 for the summer peak, winter peak, and summer off-peak cases, respectively. Sensitivities are also included. The definitions of the contingencies shown in these tables are provided in Appendix D.

See Chapter 6.1 for a discussion of the impacts on the Pillsbury – Maple River 230 kV line.

Overloads in excess of the emergency rating were observed on the Maple River 230/115 kV transformer 6 for a breaker failure contingency of CB 64 at the Maple River 230 kV substation. The overload meets both MPC and MISO interconnection constraint criteria, as the TDF was greater than 10% and it is adjacent to the MPC01200 POI. The maximum loadings observed were 256 MW in the winter peak case and 219 MW in the summer peak case. The corresponding winter and summer emergency ratings are 243 MVA and 215 MVA, respectively. As the transformer loading was at its emergency rating in the pre-project winter peak case, this upgrade will be required for both the existing and ROFR portions of MPC01200. The Maple River 230/115 kV transformer 6 is an interconnection constraint and must be mitigated.

Post-contingent voltage analysis did not show any SAFs.

6.3 Mitigation of Interconnection Constraints

Preliminary, high level, non-binding review of the interconnection constraints has been performed and produced the following information.

The Pillsbury – Maple River 230 kV line is limited by current transformers (CTs) at Maple River. The CTs have additional taps available to increase the rating. The line conductor has adequate capacity to handle the observed loading. Mitigation is anticipated to cost $10,000.

The Maple River 230/115 kV transformer 6 is owned by Northern States Power (NSP/Xcel Energy). NSP indicated that a very high level cost estimate to replace the transformer with a 336 MVA unit would be $5 million. Preliminary research also indicated that it may be acceptable per both MPC and NSP policy to use a Remedial Action Scheme to mitigate the impacts. However, MISO does not permit SPS/RAS mitigation of constraints on MISO transmission facilities caused by generator interconnection projects. Additional cooling options may be available to increase the rating of the transformer. No research was done regarding cooling options such as additional fans.

This mitigation information is based on preliminary research and should not be considered binding in any way. Actual mitigation options and costs must be further reviewed through Interconnection Facility Studies with the appropriate Transmission Owner(s).

Table 6-1: Significantly Affected Facilities – System Intact Conditions

2017 Summer Peak

MONITORED ELEMENT							Rate A	Rate B	PRE-		POST-		TDF %
LFNUM	LFNAM	LFKV	LTNUM	LTNAM	LTKV	LCKT			MVA	% Normal	MVA	% Normal	
657700	PILSBRY4	230	657754	MAPLE R4	230	1	451.0	495.0	371.0	82.3	469.5	104.1	112.3

2017 Winter Peak

MONITORED ELEMENT							Rate A	Rate B	PRE-		POST-		TDF %
LFNUM	LFNAM	LFKV	LTNUM	LTNAM	LTKV	LCKT			MVA	% Normal	MVA	% Normal	
657700	PILSBRY4	230	657754	MAPLE R4	230	1	451.0	496.0	370.9	82.2	469.2	104.0	112.1

2017 Summer Off-Peak

MONITORED ELEMENT							Rate A	Rate B	PRE-		POST-		TDF %
LFNUM	LFNAM	LFKV	LTNUM	LTNAM	LTKV	LCKT			MVA	% Normal	MVA	% Normal	
657700	PILSBRY4	230	657754	MAPLE R4	230	1	451.0	495.0	370.6	82.2	467.9	103.7	110.9
601012	ROSEAUN2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	1848.3	106.7	1853.9	107.0	6.3
601013	ROSEAUS2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	1809.8	104.5	1817.9	105.0	9.2
601012	ROSEAUN2	500	667501	RIEL 2	500	1	1732.1	1905.3	1848.3	106.7	1853.9	107.0	6.3
601001	FORBES 2	500	601013	ROSEAUS2	500	1	1732.1	2165.1	1809.8	104.5	1817.9	105.0	9.2

2017 Summer Off-Peak Loadings with MHEX Flow Reduced to 1848 MW (Firm)

MONITORED ELEMENT							Rate A	Rate B	PRE-		POST-		TDF %
LFNUM	LFNAM	LFKV	LTNUM	LTNAM	LTKV	LCKT			MVA	% Normal	MVA	% Normal	
601012	ROSEAUN2	500	601038	ROSEAUM 2	500	1	1732.1	2165	1651.3	95.3	1658.5	95.8	8.3
601013	ROSEAUS2	500	601038	ROSEAUM 2	500	1	1732.1	2165	1584.1	91.5	1592.9	92.0	10.1
601012	ROSEAUN2	500	667501	RIEL 2	500	1	1732.1	1905	1651.3	95.3	1658.5	95.8	8.2
601001	FORBES 2	500	601013	ROSEAUS2	500	1	1732.1	2165	1593.7	92.0	1601.4	92.5	8.9

Table 6-2: Significantly Affected Facilities Identified in Contingency Case Conditions – 2017 Summer Peak

MONITORED ELEMENT							Rate A	Rate B	CONTINGENCY	PRE-		POST-			TDF	Impact as %
LFNUM	LFNAM	LFKV	LTNUM	LTNAM	LTKV	LCKT				MVA	% Normal	MVA	% Normal	% Emerg	%	of Rate A
601028	EAU CL 3	345	3WNDTR		WND 1	10	263.2	263.2	B3.EAU CLAIR	268.5	102.0	272.7	103.6	103.6	4.8	1.6
602021	EAU CLA5	161	3WNDTR		WND 2	10	263.2	263.2	B3.EAU CLAIR	261.1	99.2	265.3	100.8	100.8	4.7	1.6
602026	MAYFAIR5	161	601043	NLAX 5	161	1	197.0	216.0	B2.LAX-MRS	231.3	117.4	234.3	118.9	108.4	3.4	1.5
602026	MAYFAIR5	161	601043	NLAX 5	161	1	197.0	216.0	B2.MRS-LAX	224.7	114.1	227.7	115.6	105.4	3.4	1.5
603020	MAPLE R7	115	3WNDTR	MAPL RIV TR6	WND 2	6	187.0	215.1	C2.MPR-64F	204.8	109.5	218.9	117.0	101.7	16.0	7.5
603027	DGLASCO7	115	620222	ALEXAND7	115	1	120.0	132.0	BALEX QUARR3	117.9	98.3	122.9	102.4	93.1	5.7	4.2
620222	ALEXAND7	115	658050	ALEXSS 7	115	1	120.0	132.0	BALEX QUARR3	141.9	118.3	146.9	122.4	111.3	5.7	4.2
620238	WINGER 7	115	3WNDTR	230/115	WND 2	1	140.0	175.0	C2F.WLT4-20F	142.7	102.0	146.2	104.4	83.5	3.9	2.5
620238	WINGER 7	115	3WNDTR	230/115	WND 2	1	140.0	175.0	BWILTOWINGE4	138.6	99.0	141.9	101.3	81.0	3.7	2.3
657758	WINGER 4	230	3WNDTR	230/115	WND 1	1	140.0	175.0	C2F.WLT4-20F	145.3	103.8	148.4	106.0	84.8	3.5	2.2
657758	WINGER 4	230	3WNDTR	230/115	WND 1	1	140.0	175.0	BWILTOWINGE4	139.9	99.9	143.1	102.2	81.8	3.6	2.3

Maple River 230/115 kV transformer loadings with switched shunts restored to discrete control (Most-limiting Contingency)

MONITORED ELEMENT							Rate A	Rate B	CONTINGENCY	PRE-		POST-			TDF	Impact as %
LFNUM	LFNAM	LFKV	LTNUM	LTNAM	LTKV	LCKT				MVA	% Normal	MVA	% Normal	% Emerg	%	of Rate A
603020	MAPLE R7	115	3WNDTR	MAPL RIV TR6	WND 2	6	187.0	215.1	C2.MPR-64F	204.2	109.0	219.2	117.0	101.7	17.1	8.0

Table 6-3: Significantly Affected Facilities Identified in Contingency Case Conditions – 2017 Winter Peak

MONITORED ELEMENT							Rate A	Rate B	Contingency	PRE-		POST-			TDF	Impact as % of Rate A
LFNUM	LFNAM	LFKV	LTNUM	LTNAM	LTKV	LCKT				MVA	% Normal	MVA	% Normal	% Emerg	%	
657754	MAPLE R4	230	3WNDTR	MAPL RIV TR5	WND 1	5	187.0	243.1	C2.MPR-65F	178.3	95.4	187.7	100.4	77.2	10.7	5.0
657754	MAPLE R4	230	3WNDTR	MAPL RIV TR6	WND 1	6	187.0	243.1	C2.MPR-64F	243.3	130.1	255.9	136.8	105.2	14.3	6.7
657754	MAPLE R4	230	3WNDTR	MAPL RIV TR6	WND 1	6	187.0	243.1	C2.MPR-65F	179.8	96.1	189.2	101.2	77.8	10.8	5.0
620238	WINGER 7	115	3WNDTR	230/115	WND 2	1	166.0	208.0	C2F.WLT4-20F	178.0	107.2	180.9	109.0	87.0	3.4	1.8

Maple River 230/115 kV transformer loadings with switched shunts restored to discrete control (Most-limiting Contingency)

MONITORED ELEMENT							Rate A	Rate B	CONTINGENCY	PRE-		POST-			TDF	Impact as %
LFNUM	LFNAM	LFKV	LTNUM	LTNAM	LTKV	LCKT				MVA	% Normal	MVA	% Normal	% Emerg	%	of Rate A
657754	MAPLE R4	230	3WNDTR	MAPL RIV TR5	WND 1	5	187.0	243.1	C2.MPR-65F	178.1	95.0	187.6	100.0	76.9	10.8	5.1
657754	MAPLE R4	230	3WNDTR	MAPL RIV TR6	WND 1	6	187.0	243.1	C2.MPR-64F	243.3	130.0	255.9	137.0	105.4	14.4	6.7

Table 6-4: Significantly Affected Facilities Identified in Contingency Case Conditions – 2017 Summer Off-Peak

MONITORED ELEMENT							Rate A	Rate B	Contingency	PRE-		POST-			TDF	Impact as % of Rate A
LFNUM	LFNAM	LFKV	LTNUM	LTNAM	LTKV	LCKT				MVA	% Normal	MVA	% Normal	% Emerg	%	
601001	FORBES 2	500	601013	ROSEAUS2	500	1	1732.1	2165.1	BBK41-CANEX7	1921.6	110.9	1930.7	111.5	89.2	10.4	0.5
601001	FORBES 2	500	601013	ROSEAUS2	500	1	1732.1	2165.1	MHUS 907	1902.2	109.8	1911.5	110.4	88.3	10.7	0.5
601001	FORBES 2	500	601013	ROSEAUS2	500	1	1732.1	2165.1	BTIOGABDV 4	1884.5	108.8	1893.0	109.3	87.4	9.7	0.5
601001	FORBES 2	500	601013	ROSEAUS2	500	1	1732.1	2165.1	C2F.BKR1 JMS	1881.8	108.6	1892.8	109.3	87.4	12.6	0.6
601001	FORBES 2	500	601013	ROSEAUS2	500	1	1732.1	2165.1	C2F.BKR1 JMS	1881.8	108.6	1892.8	109.3	87.4	12.6	0.6
601012	ROSEAUN2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	BBK41-CANEX7	1955.9	112.9	1962.0	113.3	90.6	7.0	0.4
601012	ROSEAUN2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	MHUS 907	1935.8	111.8	1942.2	112.1	89.7	7.4	0.4
601012	ROSEAUN2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	BTIOGABDV 4	1920.6	110.9	1926.4	111.2	89.0	6.6	0.3
601012	ROSEAUN2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	C2F.BKR1 JMS	1917.6	110.7	1925.8	111.2	89.0	9.3	0.5
601012	ROSEAUN2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	C2F.BKR1 JMS	1917.6	110.7	1925.8	111.2	89.0	9.3	0.5
601012	ROSEAUN2	500	667501	RIEL 2	500	1	1732.1	1905.3	BBK41-CANEX7	1955.9	112.9	1962.0	113.3	103.0	7.0	0.4
601012	ROSEAUN2	500	667501	RIEL 2	500	1	1732.1	1905.3	MHUS 907	1935.8	111.8	1942.2	112.1	101.9	7.4	0.4
601012	ROSEAUN2	500	667501	RIEL 2	500	1	1732.1	1905.3	BTIOGABDV 4	1920.6	110.9	1926.4	111.2	101.1	6.6	0.3
601012	ROSEAUN2	500	667501	RIEL 2	500	1	1732.1	1905.3	C2F.BKR1 JMS	1917.6	110.7	1925.8	111.2	101.1	9.3	0.5
601012	ROSEAUN2	500	667501	RIEL 2	500	1	1732.1	1905.3	C2F.BKR1 JMS	1917.6	110.7	1925.8	111.2	101.1	9.3	0.5
601013	ROSEAUS2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	BBK41-CANEX7	1921.6	110.9	1930.7	111.5	89.2	10.4	0.5
601013	ROSEAUS2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	MHUS 907	1902.2	109.8	1911.5	110.4	88.3	10.7	0.5
601013	ROSEAUS2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	BTIOGABDV 4	1884.5	108.8	1893.0	109.3	87.4	9.7	0.5
601013	ROSEAUS2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	C2F.BKR1 JMS	1881.8	108.6	1892.8	109.3	87.4	12.6	0.6
601013	ROSEAUS2	500	601038	ROSEAUM 2	500	1	1732.1	2165.1	C2F.BKR1 JMS	1881.8	108.6	1892.8	109.3	87.4	12.6	0.6
603027	DGLASCO7	115	620222	ALEXAND7	115	1	120.0	132.0	BALEX QUARR3	127.5	106.3	133.7	111.4	101.3	7.0	5.1
620222	ALEXAND7	115	658050	ALEXSS 7	115	1	120.0	132.0	BALEX QUARR3	139.9	116.6	145.7	121.4	110.4	6.6	4.8
652436	FARGO 7	115	658080	MPSBROOK	115	1	119.0	130.9	WND4FA-SB-C1	121.7	102.3	124.5	104.6	95.1	3.2	2.4

6.4 Constrained Interface Analysis

The Constrained Interface Analysis was run on the pre- and post-project summer peak cases developed in this study (cases *b02-sp17aa* and *b03-sp17aa*) using the DFCALC program included in the September 2011 NMORWG package. Results are attached in Appendix D.3. The constrained interfaces and flowgates evaluated in this analysis are based on definition file "MRO-2007-ties-TSR-OutYear.txt". Flows on some of the remote flowgates could not be monitored due to topology differences between the case and the interface definitions. These flowgates are remote from the area of interest and no further effort was made to reconcile these differences. See Appendix D.3 for a list of errors.

Table 6-5 compares the interface flows with and without the proposed MPC01200 project. This table shows the interface impacts for an injection of 87.7 MW at Maple River 230 kV from the proposed project to the sink. For the PTDF interfaces, impacts > 5% and for OTDF interfaces, impacts > 3% from pre-project condition are shown in this table. These impacts are for informational purposes only to identify potential flowgate issues for the delivery component of the transmission.

Table 6-5: List of Impacted Interfaces

	Flow			TDF
Interface	b02_sp17aa	b03_sp17aa	Change	%
PTDF Interfaces				
EAUARP__PTDF	532.7	540.7	8.0	9.1
NDEX	1421.8	1490.4	68.6	78.3
MWEX	1064.1	1077.8	13.7	15.6
COOPER_S	418.4	426.8	8.3	9.5
PR_ISL_BYRON	283.6	291.3	7.7	8.8
FTCAL_S	406.5	412.7	6.2	7.1
D602F	1289.0	1294.2	5.1	5.8
LKFLKG__PTDF	768.8	777.1	8.3	9.4
OTDF Interfaces				
CDVNELQUA471	1158.5	1167.3	8.8	10.0
EAUARPWMPPAD	540.6	548.5	7.9	9.0
EAUARPPRIBYR	539.7	547.8	8.1	9.3
BYNCHEBYNCHE	1408.5	1411.1	2.7	3.0
BYRCHEBYRCHE	1474.6	1477.4	2.8	3.2
QUA471CDVNEL	1160.0	1168.8	8.8	10.1
QUACDVQUA471	1648.1	1660.8	12.7	14.5
CHESILNELELC	899.9	904.4	4.5	5.1
PLPZIOCHESIL	558.9	562.3	3.4	3.9
PLPZIOZIOARC	531.3	534.6	3.3	3.8
LACNEOLANWIC	324.1	326.9	2.8	3.2
IATSTRLRDNUA	463.2	466.1	3.0	3.4

6.5 No-Load Analysis

No-load analysis was performed using case bn3-so17aa listed in Table 3-1 as well as slight variations of that case to test mitigation options. A one-line diagram of system conditions in the vicinity of the Maple River wind farms for the system intact case is shown in Figure 6-1. Based on the assumptions for the MPC01200 equivalent collector system, the MPC01200 wind farm injects 10.8 MVAr into the Sibley 230 kV bus.

Voltages in the wind farm collector system and at Maple River were monitored for the following system conditions:

- System Intact
- Maple River – Sheyenne 230 kV and Maple River – Frontier 230 kV double circuit contingency (MRV-SHY-FRN)
- Alexandria – Bison 345 kV line contingency (ALX-BSN-345)

Results are summarized in Table 6-6 (system intact violations of 1.05 in red). For the full MPC01200 project (case bn3-so17aa), system voltages at Maple River remain within normal operating ranges following the addition of MPC01200. However, system intact and post-contingent voltages at the Sibley, Barnes, Luverne, and Pillsbury 230 kV buses are above 1.05 pu, which is the continuous operation overvoltage criteria for most transmission owners, including MPC and OTP. This voltage difference between the Pillsbury area 230 kV substations and the Maple River substation demonstrates that the overvoltages are isolated within the 230 kV portion of the wind farm interconnection facilities. As such, system mitigation options from the existing grid are of limited use for reducing voltage at the wind farm.

Potential mitigation options include installation of the WindFree option (see Chapter 2.1) on the MPC01200 turbines and/or the addition of a shunt reactor. According to the Interconnection Customer, for every six turbines with WindFree enabled, the turbines can absorb approximately 1 MVAr. The shunt reactor would need to be switchable to ensure that it would not exacerbate the voltage stability issues identified in this study for full load operation of the wind farm. Changing transformer taps is not a viable mitigation option for reducing voltage as it would negatively impact constraints identified in the voltage stability analysis.

Additional analysis was performed to investigate whether equipping the MPC01200 wind farms with WindFree capabilities would provide adequate mitigation for the overvoltages observed. For the purposes of this analysis, it was assumed that all 60 wind turbines in the MPC01200 wind farm were equipped with WindFree capability. The backfeed power and reactive power capabilities of MPC01200 were adjusted assuming WindFree operation. Both power factor and voltage control modes were evaluated (cases bn4-so17aa and bn5-so17aa, respectively). Figure 6-2 shows the resulting one-line

diagram assuming power factor control. Figure 6-3 shows the resulting one-line diagram assuming voltage control. With WindFree enabled on the entire MPC01200 farm, the MPC01200 wind farm injects 0.5 MVAr into the Barnes County 230 kV bus. Therefore, the use of WindFree is roughly able to compensate for the full charging added by the MPC01200 collector system. System intact and post-contingent voltages are summarized in Table 6-6. Additional analysis was performed to delineate the impacts of the existing portion of MPC01200 from the ROFR portion (cases bn6-so17aa through bn8-so17aa).

Regardless of whether power factor or voltage control mode is assumed, the results in Table 6-6 show that the MPC01200 WTGs are pegged at their Qmin limits (–5.17 MVAr assuming all 31 turbines in the existing portion of MPC01200 have WindFree capability, and –4.83 MVAr assuming all 29 ROFR turbines have this capability). It can be seen that the system intact voltages at the Pillsbury, Barnes, Luverne and Sibley 230 kV buses are exactly at 1.05 pu. Reducing the number of turbines with WindFree capability will drive the system intact voltages above 1.05 pu, thus violating criteria. Therefore, all WTGs in the existing and ROFR wind farms need to be equipped with WindFree capabilities to allow system intact voltages at the Pillsbury, Barnes, Luverne and Sibley 230 kV buses to be within the system intact voltage criteria of 1.05 pu.

A brief test was performed to determine the size of a shunt reactor needed to maintain the system intact 230 kV bus voltages at 1.05 pu. A switched reactor was added to the existing Ashtabula 3 34.5 kV bus in the bn3-so17aa case and set to control the Sibley 230 kV bus to 1.05 pu in continuous control. Simulations showed that approximately a 10 MVAr shunt reactor would be adequate to mitigate the no load voltage impacts of the MPC01200 collector system for both the existing and ROFR portions of the project. A similar test showed that approximately a 5 MVAr shunt reactor would be necessary for the existing MPC01200 wind farm if the ROFR portion is not built. It should be noted that MPC01200 reactive absorption requirements approximately equal the reactive power injection from its collector system as there is minimal margin on the system.

While 1.05 pu voltage is traditionally the system intact overvoltage criteria in a planning study, voltage must also be restored to this same 1.05 pu normal operating criteria within 30 minutes of a contingency. It is recommended that the chosen mitigation take into consideration the post-contingent voltage reduction requirements to restore the system to normal operating voltages. Post-contingent results are also included in Table 6-6 (post-contingent voltages in excess of 1.05 in orange).

Changes to the final collector system and equivalent model may alter the results of this analysis.

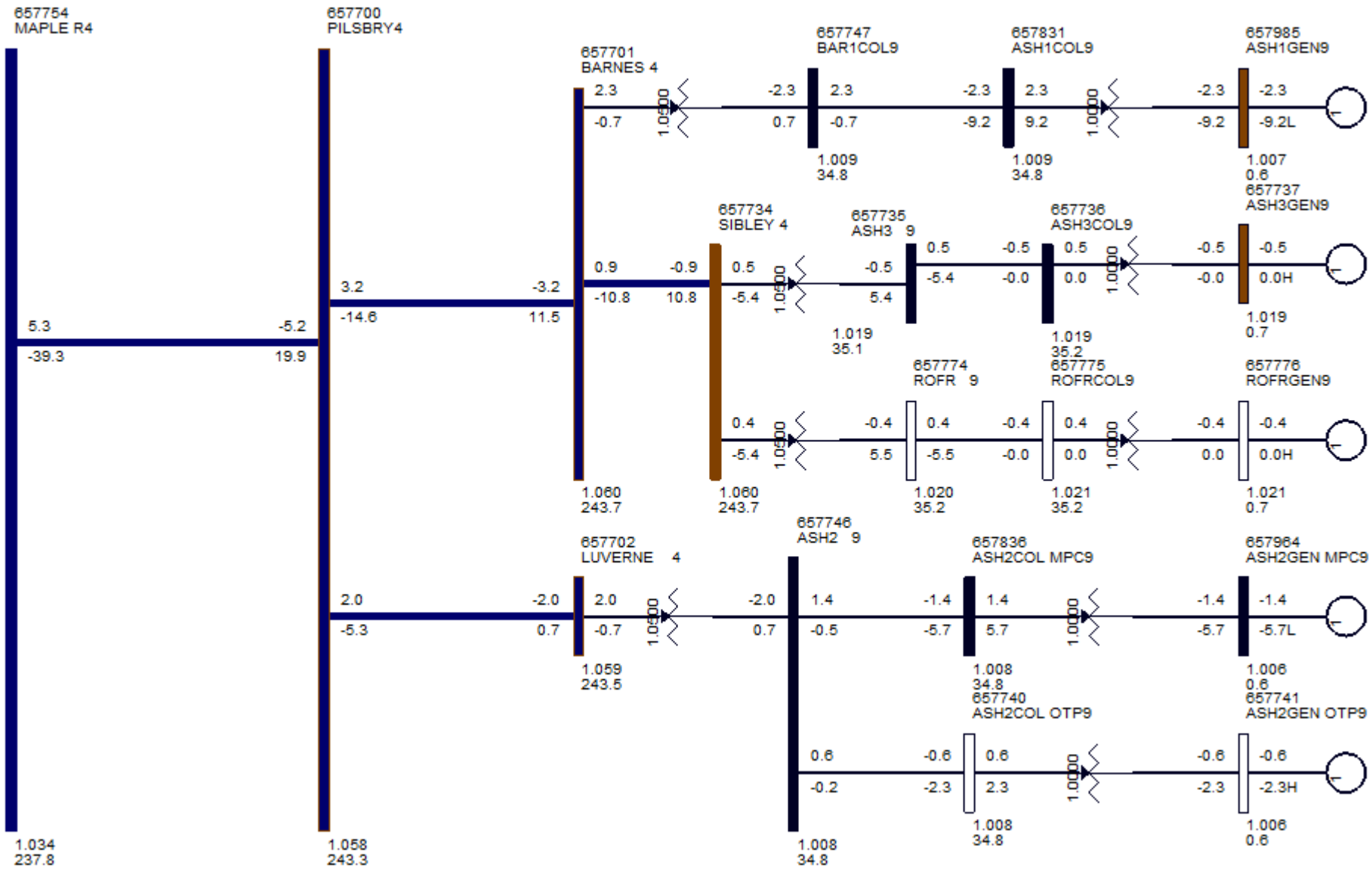


Figure 6-1: One-line Diagram for Case bn3-so17aa (2017 Summer Off-Peak Case for No-Load Analysis) – MPC01200 Wind Farms Not Equipped with WindFree Capability

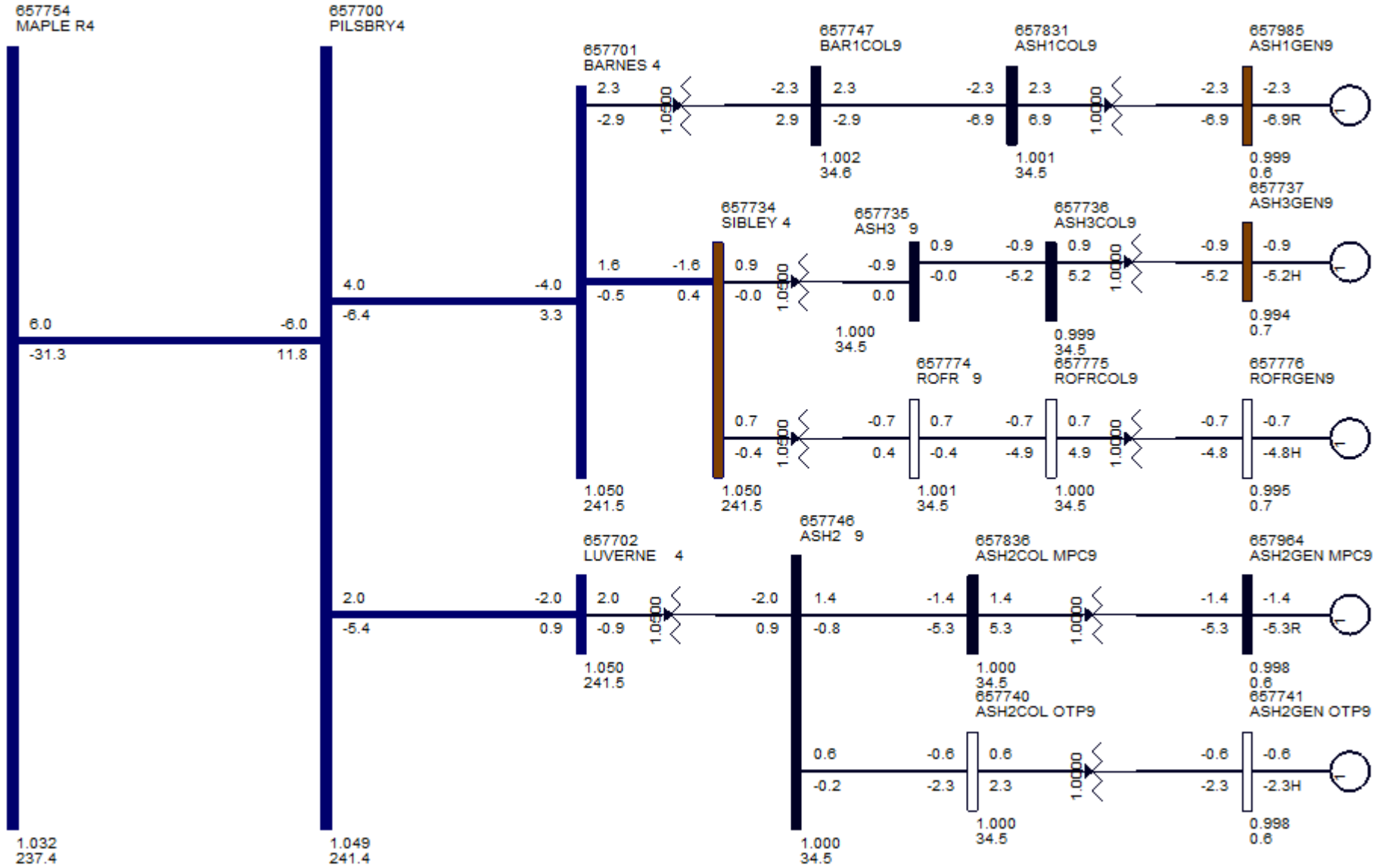


Figure 6-2: One-line Diagram for Case bn4-so17aa (2017 Summer Off-Peak Case for No-Load Analysis) – MPC01200 Wind Farms Equipped with WindFree Capability (Power Factor Control Mode Assumed)

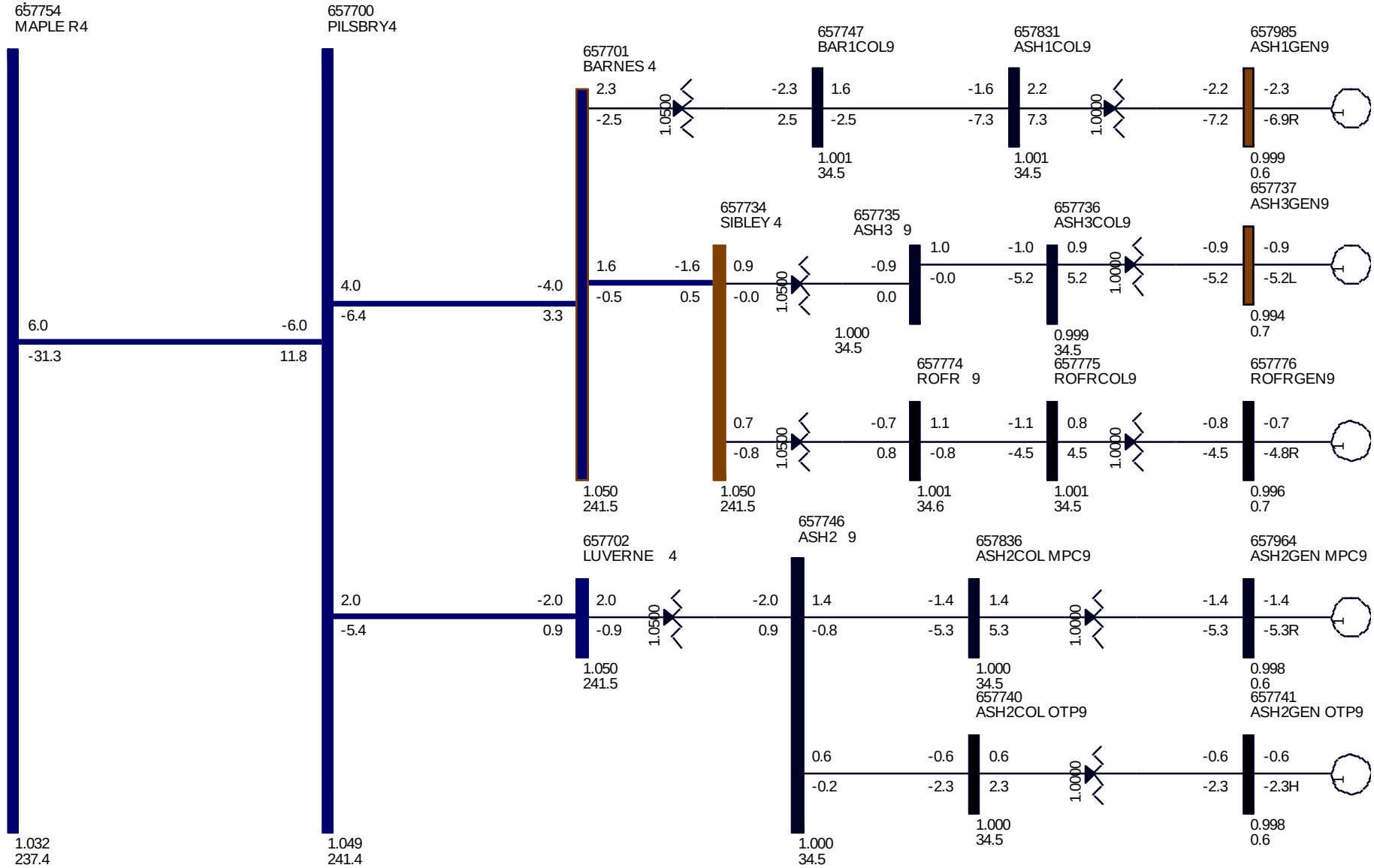


Figure 6-3: One-line Diagram for Case bn5-so17aa (2017 Summer Off-Peak Case for No-Load Analysis) – MPC01200 Wind Farms Equipped with WindFree Capability (Voltage Control Mode Assumed)

Table 6-6: No-Load Analysis Results

Case	Type of Control[1]	# Turbines with WindFree (Capacity)		Contingency	WTG MVAr Output[3]		Voltage by Bus (Owner)						
		Existing	ROFR		Existing	ROFR	MRV 345 OTP	MRV 230 MPC	MRV 115 Xcel	PLB 230 MPC	BRN 230 NextEra	LVN 230 OTP	SIB 230 NextEra
bn2-so17aa	MPC01200 Disconnected[5]	-	-	System Intact	-	-	1.0319	1.0320	1.0314	1.0495	1.0500	1.0500	1.0500
		-	-	MRV-SHY-FRN	-	-	1.0242	1.0222	1.0295	1.0486	1.0500	1.0500	1.0500
		-	-	ALX-BSN	-	-	1.0390	1.0367	1.0359	**1.0518**	**1.0521**	**1.0523**	**1.0521**
bn3-so17aa	None[2]	0	0	System Intact	0	0	1.0335	1.0339	1.0332	**1.0580**	**1.0596**	**1.0585**	**1.0596**
		0	0	MRV-SHY-FRN	0	0	1.0243	1.0223	1.0296	1.0489	**1.0504**	1.0500	**1.0504**
		0	0	ALX-BSN	0	0	1.0418	1.0398	1.0389	**1.0642**	**1.0658**	**1.0647**	**1.0658**
bn4-so17aa	Power Factor Control	31	29	System Intact	-5.17	-4.83	1.0319	1.0320	1.0315	1.0495	1.0500	1.0500	1.0500
		31	29	MRV-SHY-FRN	-5.17	-4.83	1.0242	1.0223	1.0295	1.0486	1.0500	1.0500	1.0500
		31	29	ALX-BSN	-5.17	-4.83	1.0391	1.0368	1.0360	**1.0522**	**1.0525**	**1.0527**	**1.0525**
bn5-so17aa	Voltage Control	31	29	System Intact	-5.17	-4.83	1.0319	1.0320	1.0315	1.0495	1.0500	1.0500	1.0500
		31	29	MRV-SHY-FRN	-5.17	-4.83	1.0242	1.0223	1.0295	1.0486	1.0500	1.0500	1.0500
		31	29	ALX-BSN	-5.17	-4.83	1.0391	1.0368	1.0360	**1.0522**	**1.0525**	**1.0527**	**1.0525**
bn6-so17aa	None[2]	0	-	System Intact	0	-	1.0324	1.0325	1.0320	**1.0521**	**1.0529**	**1.0525**	**1.0529**
		0	-	MRV-SHY-FRN	0	-	1.0242	1.0223	1.0295	1.0486	1.0500	1.0500	1.0500
		0	-	ALX-BSN	0	-	1.0404	1.0382	1.0374	**1.0580**	**1.0589**	**1.0585**	**1.0589**
bn7-so17aa	Power Factor Control	31	-	System Intact	-5.17	-	1.0319	1.0320	1.0314	1.0495	1.0500	1.0500	1.0500
		31	-	MRV-SHY-FRN	-5.17	-	1.0242	1.0223	1.0295	1.0486	1.0500	1.0500	1.0500
		31	-	ALX-BSN	-5.17	-	1.0390	1.0367	1.0359	**1.0518**	**1.0520**	**1.0523**	**1.0520**
bn8-so17aa	Voltage Control	31	-	System Intact	-5.17	-	1.0319	1.0320	1.0314	1.0495	1.0500	1.0500	1.0500
		31	-	MRV-SHY-FRN	-5.17	-	1.0242	1.0223	1.0295	1.0486	1.0500	1.0500	1.0500
		31	-	ALX-BSN	-5.17	-	1.0386	1.0362	1.0355	1.0500	1.0500	**1.0505**	1.0500

MRV: Maple River; PLB: Pillsbury; BRN: Barnes; LVN: Luverne; SIB: Sibley

1. Power factor control or voltage control is only possible with WindFree® option.
2. WTGs have no reactive capability and therefore do not have the ability to regulate power factor or voltage.
3. WTG MVAr needed to maintain unity power factor on high-sides of MPC 34.5/230 kV transformers -or- WTG MVAr needed to maintain 1.05 pu voltage at Sibley 230 kV.
   Positive sign indicates WTG produces MVAr; Negative sign indicates WTG absorbs MVAr.
4. MVAr at high-side of 230/34.5 kV transformers of MPC01200.
   Positive sign denotes MVAr injection into Sibley 230 kV bus. Negative sign indicates MVAr absorption from Sibley 230 kV bus.
5. The pre-project case was developed by disconnecting all collector system equipment downstream from the Sibley 230 kV bus.

7. STABILITY ANALYSIS

System stability was evaluated by studying system response to regional faults as well as faults local to the Maple River region. For the purposes of this analysis, it was assumed that MPC01200 is in power factor control mode (not voltage control mode).

7.1 Fault Definitions

The faults that were evaluated are the same as those used in the MPC0500 out-year study [3]. The regional faults which were run are shown in Table 7-1 and the local faults are shown in Table 7-2. Faults *mg3* through *mks* in Table 7-2 were tested to verify the ability of the Maple River wind farms to ride through faults without tripping.

In simulating single-phase faults, admittance values used were the same as those used in the MPC0500 out-year study [3]. These values are considered to be appropriate to simulate single-phase faults if the positive sequence voltage at the fault bus falls to around 0.6 pu during the fault. This was found to be the case and therefore, new values were not used.

7.2 Stability Results

All faults resulted in acceptable system performance without violations. The Maple River wind farms as well as prior-queued wind farms were able to ride through faults without tripping. Simulation summary tables for post-project performance are given in Appendix F. Plots for selected faults are given in Appendix G.

Table 7-1: Regional Fault List

Fault Name	Faulted Bus	Fault Type	Clearing Time (Cycles)	Initial Clearing	Backup Clearing (Cycles)	Backup Clearing
AG1	Leland Olds 345 kV	SLGBF	4	Leland Old - Ft Thompson line	11	FLTD line
AG3	Leland Olds 345 kV	3-phase	4	Leland Old - Ft Thompson line		
EF3	Staton 230 kV	3-phase	5	Staton – Coal Creek – McHenry line		
EI2	Coal Creek 230 kV	Fault	10	CU HVDC bipole	7	Coal Creek 1 & 2
EQ1	Coal Creek 230 kV	SLGBF	4.5	CU HVDC #1	11	Coal Creek #2
FDS	Square Butte 230 kV	3-phase	4	Square Butte - Stanton 230 kV line		
MAD	Dorsey 500 kV	3-phase	4	Dorsey - Forbes 500 kV line		
MQS	Sherco	SLGBF	4	Sherco #3	9	Sherco - Benton Co
MTS	Monticello 345 kV	SLGBF	5	Monticello - Elm Creek line	9	Monticello bus
NAD	Forbes 500 kV	3-phase	4	Forbes - Dorsey 500 kV line		100% DC reduction
NMZ	Chisago Co 500 kV	3-phase	4	Chisago Co - Forbes 500 kV line		100% DC reduction
PAS	Forbes 500 kV	SLGBF	4	Forbes - Dorsey 500 kV line	13	Forbes-Chisago Co
PCS	King 345 kV	SLGBF	4	King - Eau Claire 345 kV line	14	King-Chisago Co
PCT	King 345 kV	Trip		King - Eau Claire 345 kV line		
PYS	Prairie Island 345 kV	SLGBF	4	Prairie Island - Byron 345 kV line	14	PI 345/161 Tx
PYT	Prairie Island 345 kV	Trip		Prairie Island - Byron 345 kV line		

Table 7-2: Local Fault List

Fault Name	Faulted Bus	Fault Type	Clearing Time (Cycles)	Initial Clearing	Backup Clearing (Cycles)	Backup Clearing
ABZ	Bison 230	3-phase	4.5	Alex – Bison 345		
MF3	Maple River 230	3-phase	5.0	Maple River-Frontier 230		
MPZ	Maple River 230	3-phase	5.0	Maple River - Pillsbury 230		
MS3	Maple River 230	3-phase	5.0	Maple River-Sheyenne 230		
MW3	Maple River 230	3-phase	5.0	Maple River-Winger 230		
SA3	Maple River 230	3-phase	5.0	Sheyenne-Audubon 230		
SF3	Maple River 230	3-phase	5.0	Sheyenne-Fargo 230		
MJZ	Maple River 345	3-phase	4.5	Maple River-Bison 345 Maple River 345/230 xfrs		
MWZ	Maple River 230	3-phase	5.0	Maple River-Frontier 230 Maple River-Sheyenne 230		
AFS	Maple River 230	SLGBF	5.0	Maple River-Frontier 230	15.0	Maple River 230/115 xfr 5
APZ	Maple River 230	SLGBF	5.0	Maple River-Pillsbury 230	15.0	Maple River 230/115 xfr 6
ASZ	Maple River 230	SLGBF	5.0	Maple River-Sheyenne 230	15.0	Maple River 230/115 xfr 5
AWS	Maple River 230	SLGBF	5.0	Maple River-Winger 230	15.0	Maple River 230/115 xfr 6
AJS	Maple River 345	SLGBF	4.5	Maple River-Bison 345	13.5	Maple River 230/115 xfr 5
ARS	Maple River 230	SLGBF	5.0	Maple River-Winger 230	15.0	Maple River-Sheyenne 230
FSS	Fargo 230	SLGBF	5.0	Fargo-Sheyenne 230	15.0	Fargo 230/115 xfr Fargo-Jamestown 230 line #2 Fargo-Moorehead 230
FMS	Sheyenne 230	SLGBF	5.0	Sheyenne-Maple River 230	15.0	Sheyenne-Audubon 230 Sheyenne 230/115 xfr
AQS	Maple River 230	SLGBF	5.0	Sheyenne-Maple River 230	15.0	Maple River-Winger 230
MG3	Pillsbury 230	3-phase	5.0	Pillsbury-Barnes 230		
MH3	Pillsbury 230	3-phase	5.0	Pillsbury-Luverne 230		
MGS	Barnes 230	SLGBF	25.0	Barnes 230 kV bus		
MHS	Luverne 230	SLGBF	25.0	Luverne 230 kV bus		
MKS	Sibley 230	SLGBF	25.0	Sibley 230 kV bus		

8. SHORT-CIRCUIT ANALYSIS

Prior studies [1] and [2] show that short circuit currents are well within the limits of the breakers' ratings. A quick analysis was performed to confirm the prior study results. Short circuit calculations of fault currents were performed using the ASPEN program for the Maple River area. The analysis was done using the latest MPC short circuit models. Single line-to-ground and three-phase fault currents were determined at multiple substations in the vicinity of Maple River. Short circuit currents were determined for the following cases and are shown in Table 8-1.

- Total nameplate output from wind farm at Pillsbury 230 kV is 366 MW (Ashtabula I and II online).
- Total nameplate output from wind farm at Pillsbury 230 kV is 477.7 MW (Ashtabula III and ROFR portion of MPC01200 turned on).

Table 8-1: Short Circuit Currents near Maple River

BUS	Maximum Fault Current (Ash I & II) (366 MW Total Generation)		Maximum Fault Current (Ash I-III & ROFR) (478 MW Total Generation)		CB Rating
	1LG	3PH	1LG	3PH	
Pillsbury 230 kV	4504	3604	4971	3981	40 kA
Maple River 230 kV	13054	11305	13199	11465	67 & 69 = 31.5 kA; all others = 37.5 kA
Sheyenne 230 kV	10899	10202	10974	10301	7F4 = 40 kA; all others = 31.5 kA
Frontier 230 kV	6714	7620	6744	7679	40 kA
Fargo 230 kV	9781	9458	9834	9532	382 & 782 = 13 kA; 182 = 31.5 kA; all others = 40 kA

A comparison of the post-project fault currents to the capability of the existing breakers at the local substations indicates that there is adequate interrupting capability following the addition of the new generation.

9. CONCLUSIONS

Comprehensive details of mitigation requirements identified in this study have been provided throughout the report and are revisited in more detail in the Executive Summary. The following is a brief list of mitigation requirements for the MPC01200 interconnection request:

- Mitigation of overloads on the Maple River 230/115 kV transformer
- Mitigation of overloads on the Pillsbury – Maple River 230 kV line
- The WTGs/WFMS for MPC01200 must be set to control voltage rather than power factor in order to maintain adequate margin from the nose of the voltage stability curve
- Reactive power absorption is required at the wind farm site to prevent overvoltages under no load conditions.

Additionally, low Short Circuit Ratio (SCR) has been identified as an issue affecting the performance of the wind farms at the Pillsbury site. Studies must be completed in conjunction with the turbine manufacturer to identify appropriate control modifications to accommodate the MPC01200 wind farm.

10. REFERENCES

[1] “Evaluation of Near-Term Interconnection of MPC01200 at 50 MW and MPC01900 at 50 MW”, Prepared by ABB Inc., December 10, 2010.

[2] “Interconnection Evaluation of MPC01200 and MPC01900 for 2013 Time Frame”, Prepared by ABB Inc., October 21, 2011.

[3] “Out-Year Interconnection Evaluation of MPC0500”, Prepared by ABB Inc., July 24, 2012.

[4] “MAPP Design Review Subcommittee Policies and Procedures”, Prepared by MAPP Design Review Subcommittee Members, Version 2.3, September 2014.

[5] “MAPP Members Reliability Criteria and Study Procedures Manual”, Prepared by MAPP, Version 1.4, April 2009.

[6] "GS662-GS666 System Impact Study - Interconnection of 500 MW of Wind Generation at Square Butte”, Prepared by Minnesota Power and ABB Inc., December 2009.

[7] <Redacted> “Reactive curves rev 1.xlsx”. Spreadsheet provided by generation developer on 9/22/2014.

[8] "PSS®E Wind Modeling Package for GE 1.5/1.6/2.5/2.75/4.0 MW Wind Turbines – User Guide”, Issue 6.0.0, Prepared by Siemens Power Technologies, Inc., August 2011.