

Engineering Support Services for:

Erikson 120 MW Wind Farm

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Interconnection Evaluation Study Report

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Revisions

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1. Summary

An Interconnection Evaluation Study (IES) has been performed to determine the Manitoba Hydro Interconnection Facilities necessary to connect a 120 MW wind farm near Erikson, Manitoba.

The Generator has requested the proposed generation facility be considered an Energy Resource Interconnection Service (ERIS). As stated in the Manitoba Hydro Open Access Interconnection Tariff (OAIT), “ERIS allows the Generator to connect the Facility to the System and be eligible to deliver the Facility’s output using the existing firm or non-firm capacity of the Transmission System on an “as available” basis. ERIS does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery.” ERIS requires Interconnection Facilities and Interconnection System Upgrades, but not Network Upgrades. As an energy resource, the wind farm power was scheduled to the nearest generation. The Dorsey HVDC generation was identified as the nearest sink. This IES determined the impact of interconnecting the wind generation on the existing MH transmission system by means of steady-state ac power flow analysis and stability analysis.

One option was studied for connecting the wind farm, which involved a direct connection to the Minnedosa 110 kV station bus via a 40 km 110 kV transmission line. Analysis was performed at a wind generation level of 120 MW using doubly-fed induction wind energy turbines.

AC contingency analysis was performed for N-1 and N-2 contingencies during system intact conditions. All analysis assumed the base cases included the St. Leon wind farm. Several thermal overloads were identified on Minnedosa to Victoria 110 kV line MR11, Minnedosa to Neepawa 110 kV line NM10 and Neepawa to Brandon 110 kV line BN5. These overloads are present in powerflow cases with the Erikson wind generation but are not present in the base powerflow cases before Erikson wind generation is connected. Interconnection System Upgrades required to overcome these line overloads include re-sagging line BN5, re-conductoring lines MR11 and NM10, replacing one current transformer at the Victoria end of line NM10 and replacing five 110 kV risers.

The Manitoba Hydro Transmission System Interconnection Requirements (TSIR) [1] state that the Generator must provide reactive supply that is able to control the voltage level at the Minnedosa 110 kV bus by adjusting the machine’s power factor between a minimum of 0.95 overexcited and 0.95 underexcited at the generator intermediate bus with a minimum response time of 15 seconds.

The doubly fed induction generator models used in this study have a reactive supply range from 0.9 lagging to 0.95 leading and hence does not require any additional reactive supply equipment.

In order for the wind turbines to remain connected during transient undervoltages, the wind turbines must have adequate fault ride-through capability. The doubly fed induction generator (DFIG) with low voltage ride-through has been designed with this capability. Stability investigations involving worst case contingencies reveal that these DFIG turbines successfully ride through the worst-case transient undervoltages and over-voltages without any extra equipment. Dynamic investigation also reveals that the over-frequency and under-frequency capabilities of these wind turbines meet the Manitoba Hydro connection standards.

A planning level cost estimate of the Manitoba Hydro Interconnection Facilities and Interconnection System Upgrades necessary to connect a 120 MW wind farm at Erikson to the Minnedosa 110 kV station bus was calculated. These total costs were estimated to be \$16,900,000 (\pm 50%).

An important note to make however is that the Minnedosa 110 kV station is not equipped with SCADA/communication. The Manitoba Hydro Generator Interconnection Operating Requirements lists

the requirements from an operational perspective; in order for Manitoba Hydro to provide functional control over the facility, the Generator must provide SCADA monitoring, minimum control (isolation if not curtailment) at the Minnedosa station and communication for coordinated protection with the wind farm. Developing a cost estimate for these communication requirements is beyond the scope of this IES. Detailed communication cost estimates are determined during the Interconnection Facilities Study (IFS) phase and are not included in the cost estimate provided in this IES report. It should be noted that there are potential large cost risks associated with these communication requirements given that the Minnedosa station does not have existing SCADA/communication, which will significantly impact the Interconnection Facilities cost estimate as calculated in this IES report.

2. Introduction

2.1. Background Information

This report documents the results of an Interconnection Evaluation Study for a 120 MW wind farm near the town of Erikson, Manitoba. The proposed in-service date is year 2009.

The Generator has indicated that the wind turbines could be installed in Section 6, Township-Range 16-18W. For the purposes of this study, the Generator's distribution station is assumed to be 40 km away from the Minnedosa 110 kV station.

The distribution station voltage level was assumed to be 34.5 kV. One 34.5 -110 kV transformer was modeled between the collector system and the high voltage grid to step up the voltage to 110 kV. A 40 km 110 kV line from the Manitoba Hydro system at the Minnedosa 110 kV station is connected to the high side of the step up transformer. This connection point is identified as the Point of Interconnection (POI).

A 110 kV switching station is located at Minnedosa. Two 110 kV lines terminate in this station. A 30.42 km line extends to Neepawa (NM10), and an 8.85 km line terminates at MR11-TAP (MR11). Figure 1 is a single line diagram showing the existing facilities connected to the Minnedosa 110 kV station.

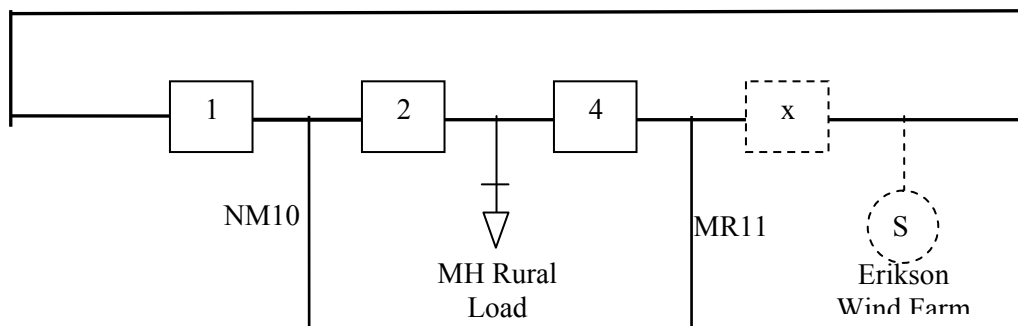


Fig. 1: Existing Minnedosa station single line diagram.

The major Interconnection Facilities required to connect the wind farm into the 110 kV station bus include one 110 kV circuit breaker within the Minnedosa station (and associated equipment) plus a 40 km 110 kV line. The line is assumed to have a 795 MCM ACSR 26/7 conductor, 100 deg C design temperature (188.2 MVA summer thermal rating). A minimum of one motor-operating disconnect is required at the Point of Interconnection (i.e. high side of Generator's 34.5-110 kV step-up transformer). MH requires visual isolation as well as the ability to automatically isolate the Generation Facility. The Generator must provide a circuit breaker near the point of interconnection. It is not MH's practice to provide primary protection for Generator's equipment due to liability concerns.

2.2. Objectives

The Interconnection Evaluation Study objectives are to determine:

- the voltage level at point of interconnection,
- facilities required to electrically connect the generator to the MH electrical system,
- adequacy of reactive power facilities,
- system reliability limitations (i.e. equipment overloads, voltage violations)
- planning level cost estimates of transmission facilities

If the Generator chooses to proceed, the Interconnection Facilities Study phase will:

- address the system reliability limitations
- determine short circuit impacts (e.g. circuit breaker replacement)
- determine a good faith cost estimate of all the interconnection facilities
- determine a good faith construction schedule estimate
- determine special protection requirements (e.g. breaker fail, generator cross trip)
- determine communication requirements including SCADA monitoring
- satisfy any requirements of the Regional Reliability Organization
- perform analysis on breaker fail scenarios at Brandon and Victoria 110 kV stations

3. Interconnection System and Network Upgrades

There are two types of Interconnection Services available:

1. Energy Resource Interconnection Service (ERIS)
As stated in the Manitoba Hydro Open Access Interconnection Tariff (OAIT), “ERIS allows the Generator to connect the Facility to the System and be eligible to deliver the Facility’s output using the existing firm or non-firm capacity of the Transmission System on an “as available” basis. ERIS does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery.” ERIS requires Interconnection Facilities and Interconnection System Upgrades, but not Network Upgrades.
2. Network Resource Interconnection Service (NRIS)
As stated in the Manitoba Hydro Open Access Interconnection Tariff (OAIT), “NRIS allows the Generator’s Facility to be designated as a Network Resource, up to the Facility’s full output, on the same basis as existing Network Resources interconnected to Manitoba Hydro’s System. NRIS in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery.” NRIS requires Interconnection Facilities, Interconnection System Upgrades and Network Upgrades.

Interconnection System Upgrades are the minimum necessary upgrades required to interconnect to the MH system and meet reliability criteria. A redispatch to the nearest existing Manitoba Hydro network resource is used as a test for Interconnection System Upgrades. For Erikson, this MH network resource is Dorsey. Where a facility is overloaded, dynamic line rating equipment could be installed to allow the operators to send a timely MW curtailment level to the plant, or equipment upgrades could be implemented.

Network Upgrades are the upgrades required when the Manitoba Hydro Transmission System is studied at peak load, and other load levels deemed appropriate by Manitoba Hydro, under a variety of severely stressed conditions, to determine whether, with the Facility at full output, the aggregate of generation in Manitoba can be delivered to the aggregate load on the transmission system, consistent with Manitoba Hydro’s reliability criteria and procedures. In other words, it is necessary to be able to redispatch to all generators and load without requiring pre-contingency curtailment or violating post-contingency voltage and loading criteria. A generation crosstrip scheme may be considered as an alternative to new lines or reconductoring if the special protection system (SPS) is made fully redundant and the crosstrip amount is less than Manitoba Hydro’s operating reserves.

Interconnection System Upgrades and Network Upgrades are separately identified.

The Generator has requested ERIS, therefore only Interconnection System Upgrades are identified.

3.1. Steady State AC Power Flow Analysis (ACCC)

The Generator has requested the proposed generation facility be considered an Energy Resource Interconnection Service (ERIS). As an energy resource, the impacts of scheduling to the Dorsey HVDC generation were evaluated.

3.1.1. Study Power Flow Models

Steady state post-disturbance analysis was performed using the following 2004 series MAPP base case powerflows:

- A. 2009 summer peak – Existing firm generation plus queued generation at Pine Falls (5 MW), Great Falls (4 MW), Kelsey (15 MW), and Point du Bois (120 MW).
- B. 2009 winter peak – Existing firm generation plus queued generation noted above.
- C. 2014 summer peak – Existing firm generation plus queued generation noted above plus Wuskwatim (200 MW) and associated transmission (Birchtree-Wuskwatim, Wuskwatim-Herblet Lake, Herblet Lake-Ralls Island), the Dorsey-Portage 230 kV line and the Neepawa 230-66 station.

All powerflow models included the Arrowhead-Weston line and Langdon wind generation with Langdon-Hensel 115 kV line. Dorsey was used as the sink for the proposed Erikson wind generation. St. Leon wind was set to its maximum output of 99 MW.

Sensitivity analysis to Manitoba Hydro Export (MHEX) and North Dakota Export (NDEX) was performed for both 2009 summer and winter peak cases. In addition to MHEX and NDEX exports, sensitivity analysis to Ontario Export (MH-OH) was performed on the 2014 summer peak cases. The Manitoba Hydro generation was adjusted to typical generation levels to achieve the transfer levels listed in Table 1.

Case	MHEX (MW)	NDEX (MW)	MH-OH (MW)	MH-SP Net (MW)	B10T(south) (MW)	F3M (south) (MW)
2009 Summer Peak						
1	2100	1950	200	0	165	150
2	2100	300	200	0	165	150
2009 Winter Peak						
3	-700	1950	0	0	-165	-100
4	-700	300	0	0	-165	-100
2014 Summer Peak						
5	2100	1950	200	0	165	150
6	2100	300	200	0	165	150
7	-700	1950	0	0	-165	-100
8	-700	0	0	0	-165	-100

Table 1: Tie line transfers

Table 2 summarizes the output from each generator in the maximum generation cases at maximum Manitoba-US export of 2175 MW, and also at the maximum firm Manitoba-US import of 700 MW. The associated transmission upgrades for the queued generation, identified earlier, are included in the analysis.

Plant	2009 Summer Peak	2009 Winter Peak	2014 Summer Peak	
	MHEX=2100	MHEX=-700	MHEX=2100	MHEX=-700
Limestone	1362.1	1095.4	1362.1	655.8
Long Spruce	1003.7	807.1	1003.7	483.2
Kettle	1194.3	923.1	1117.8	503.4
Jenpeg	168.0	139.8	168.0	168.0
Kelsey	252.6	150.0	252.6	252.6
Grand Rapids	479.9	236.4	479.9	160.0

Plant	2009 Summer Peak	2009 Winter Peak	2014 Summer Peak	
	MHEX=2100	MHEX=-700	MHEX=2100	MHEX=-700
Pine Falls	94.6	28.0	94.0	19.0
McArthur Falls	56.5	20.5	56.5	12.0
Great Falls	139.2	44.1	139.2	23.3
Seven Sisters	165.4	57.5	165.4	32.6
Slave Falls	68.0	33.0	68.0	14.0
Pointe du Bois	78.8	37.0	78.8	24.0
Brandon	386.5	0.0	386.5	0.0
Selkirk	145.0	0.0	145.0	0.0
St. Leon Wind	99.0	99.0	99.0	99.0
Wuskwatim	-	-	200.1	200.1
Total	5693.6	3670.9	5816.6	2647.0

Table 2: MH Generation.

3.1.2. Contingencies

The following contingencies were studied using PSS/E activity ACCC (AC contingency analysis):

- System intact
- N-1 contingencies for all transmission lines and transformers 110 kV and above within Manitoba including tie lines.
- N-2 contingencies for all 110 kV and above double-circuit outages in Manitoba and breaker fail outages approximately two buses¹ back from the Minnedosa station (i.e. at Neepawa, Cornwallis)

Steady state analysis was assessed with Erikson wind generation scheduled to Dorsey DC generation (AGC plant).

Facilities identified in the post-disturbance analysis were flagged if loading exceeded 100% and if the system intact power flow or contingency power flow resulted in a power transfer distribution factor (PTDF) or an outage transfer distribution factor (OTDF) greater than 2%, respectively. Branch loadings were monitored using Rate A for system intact conditions and Rate C following a contingency. Bus voltages lower than 0.90 pu were flagged. Mitigation is required for overloads in which the wind generation has a PTDF greater than or equal to 5% or an OTDF greater than or equal to 2% [2]-[6].

3.1.3. Planning Criteria – Transmission Line Overloads

Manitoba Hydro thermal loading criteria does not allow short-term overload for single contingency (category B) events. A short-term overload of up to 115% may be allowed for multiple contingency events (Category C such as double circuit common tower outages) on a case-by-case basis. If a short-term overload rating is applied, it is necessary to be able to reduce the loading to the steady state thermal rating within 30 minutes of the overload occurrence.

If the overloaded segment of a transmission line is station equipment rather than the line conductor, the overload capability for that piece of equipment will be individually assessed. Transformers are considered to have a 30-minute 119% Rate A summer overload rating.

¹ The IES study did not look at breaker fail scenarios at Brandon or Victoria 110 kV stations. This analysis will be part of the IFS scope.

3.2. Reliability Limitations

Several thermal overloads were identified through AC contingency analysis that required detailed investigation. N-1 and N-2 contingencies were studied for system intact conditions.

The following sections provide details on the worst-case overloads for which the powerflows with wind generation result in either of following two situations.

- i. New overload in wind system intact case, or existing overload with PTDF $\geq 5\%$,
- ii. New overload in wind contingency case, or existing overload with OTDF $\geq 2\%$.

These overloads require mitigation. It was found that there are no overloads in the system intact wind case. For information purposes, please refer to Appendix B for a list of all thermal overloads in the post-contingency wind cases that have OTDFs greater than or equal to 2%.

Voltage violation impacts of 1% or greater are also listed.

3.2.1. System Intact: N-1 Contingencies

Table 3 shows the worst overloads for 2009 summer peak (SP09), 2009 winter peak (WP09) and 2014 summer peak (SP14) cases for n-1 contingencies. All of these overloads require system upgrades and the overloads marked in **bold** text correspond to the worst overload for each of the four overloaded lines. All of these overloads appear only in powerflow cases with wind generation and are not present in the base cases before wind generation is connected.

Overloaded Element	Connection	Case	Rating C (MVA)	Contingency	Highest OL After wind (%)
BN5	BRANDON (67519) to NEEPWA (67521)	SP14	81.2	MR11	111.6
NM10	MINNEDOSA(67520) to NEEPWA (67521)	SP09	81.2	MR11	146.7
		SP14	81.2	MR11	145.1
MR11	MINNEDOSA(67520) to MR11-TAP(67717)	SP09	81.2	NM10	138.3
		SP14	81.2	NM10	137.8
MR11	MR11-TAP (67717) to RAPD CTY(67718)	SP09	81.2	NM10	138.2
		SP14	81.2	NM10	137.7
MR11	RAPDCTY(67718) to VICTORIA AVE(67720)	SP09	57.2	NM10	194.3
		WP09	70.3	NM10	143.6
		SP14	57.2	NM10	193.6

Table 3: Overloads requiring system upgrades

3.2.1.1. Brandon to Neepawa 110 kV line BN5

The thermal rating of line BN5 is 81.2 MVA in summer and 124.8 MVA in winter. The line rating is limited by the line conductor and risers at both Brandon and Neepawa ends.

The line conductor type is 336.4 MCM ACSR 26/7 and it is sagged to 75 deg C. Line BN5 will need to be re-sagged to 100 deg C, which will increase the line conductor thermal rating by 35.7% to 108.6 MVA in summer and by 13.7% to 141.9 MVA in winter.

Risers at both ends of line BN5 will also require replacement to match the new line rating. After these upgrades, the thermal rating of line BN5 will be 108.6 MVA and 124.8 MVA in summer and winter respectively.

3.2.1.2. Minnedosa to Neepawa 110 kV line NM10

The thermal rating of line NM10 is 81.2 MVA in summer and 124.8 MVA in winter. The line rating is limited by the line conductor and risers at both Minnedosa and Neepawa ends.

The line conductor type is 336.4 MCM ACSR 26/7 and it is sagged to 75 deg C. Re-sagging line NM10 to 100 deg C would increase the line conductor thermal rating by 35.7% to 108.6 MVA in summer but this increased rating would not be sufficient to cater to the 2009 summer peak overload of 146.7%. Therefore, line NM10 needs to be re-conducted with same size ACSS conductor sagged to 150 deg C. This will increase the line conductor thermal rating by 79.6% to 145.8 MVA in summer and by 31.0% to 163.5 MVA in winter.

Risers at both ends of line NM10 will also require replacement to match the new line rating. After these upgrades the thermal rating of line BN5 will be 123.3 MVA (151.8%) in summer, limited by disconnects at both ends.

3.2.1.3. Minnedosa to MR11-Tap 110 kV line MR11

The thermal rating of line MR11 between Minnedosa and MR11 Tap is 81.2 MVA in summer and 124.8 MVA in winter. The line rating is limited by the line conductor.

The line conductor type is 336.4 MCM ACSR 26/7 and it is sagged to 75 deg C. Re-sagging this line to 100 deg C would increase the line conductor thermal rating by 35.7% to 108.6 MVA in summer but this increased rating would not be sufficient to cater to the 2009 summer peak overload of 138.3%. Therefore, this line also needs to be re-conducted with same size ACSS conductor sagged to 150 deg C. This will increase the line conductor thermal rating by 79.6% to 145.8 MVA in summer and by 31.0% to 163.5 MVA in winter.

After this upgrade the thermal rating of line MR11 between Minnedosa and MR11 Tap will be 135.1 MVA (166.4%) in summer, limited by a disconnect at the Minnedosa end.

3.2.1.4. MR11-Tap to Rapidcity 110 kV line MR11

The thermal rating of line MR11 between MR11 Tap and Rapid City is 81.2 MVA in summer and 124.8 MVA in winter. The line rating is limited by the line conductor.

Similar to the MR11 line section between Minnedosa and MR11-Tap, this line section also needs to be re-conducted with same size ACSS conductor sagged to 150 deg C. This will increase the line conductor thermal rating by 79.6% to 145.8 MVA in summer and by 31.0% to 163.5 MVA in winter, hence catering to the 2009 summer peak overload of 138.2%.

After this upgrade the thermal rating of the MR11 line section will be 145.8 MVA and 163.5 MVA in summer and winter respectively.

3.2.1.5. Rapid City to Victoria 110 kV line MR11

The thermal rating of line MR11 between Rapid City and Victoria is 57.2 MVA in summer and 70.3 MVA in winter. The line rating is limited by the line conductor, risers and a CT at the Victoria end.

The line conductor type is 226.8 MCM ACSR 26/7 and it is sagged to 75 deg C. Re-sagging this line to 100 deg C would increase the line conductor thermal rating by 63.3% to 93.5 MVA in summer but this increased rating would not be sufficient to cater to the 2009 summer peak overload of 194.3%. Therefore, the line needs to be re-conducted with same size ACSS conductor sagged to 150 deg C. This will increase the line conductor thermal rating by 154.8% to 145.8 MVA in summer and by 142.2% to 170.3 MVA in winter. Risers and a CT at the Victoria end also require replacement to match the new line rating.

After these upgrades the thermal rating of line MR11 between Rapid City and Victoria will be 123.3 MVA (215.6%) in summer and 165.8 MVA (235.8%) in winter, limited by a disconnect at the Victoria end.

3.2.2. System Intact: N-2 Contingencies

There are several breaker fail N-2 contingencies that resulted in overloads; however, the impact of those overloads in the wind cases was either less severe than the N-1 contingencies listed in Table 3 or else do not require any upgrades. Please refer to Appendix B for a complete list of overloads.

3.3. Steady State Voltage Violations

There were no steady state voltage violation impacts greater than 1%.

3.4. Summary of Required Interconnection System Upgrades

Table 4 summarizes the Interconnection System Upgrades required to connect the Erikson wind farm to Manitoba Hydro system at the 110 kV Minnedosa bus.

Facility	Connection	Equipment Upgrade
BN5	Brandon to Neepawa	Re-sagging of line conductor to 100 deg C.
		Riser replacements at each end.
NM10	Minnedosa to Neepawa	Re- conducting of line with same size ACSS sagged to 150 deg C.
		Riser replacements at each end.
MR11	Minnedosa to MR1-Tap	Re- conducting of line with same size ACSS sagged to 150 deg C.
	MR11-Tap to Rapdcty	Re- conducting of line with same size ACSS sagged to 150 deg C.
	Rapdcty to Victoria	Re- conducting of line with same size ACSS sagged to 150 deg C.
		Riser replacements at Victoria end.
		CT replacements at Victoria end.

Table 4: Interconnection System Upgrades.

4. DFIG Wind Turbine Model

The wind turbines used in this study are the variable-speed type consisting of a doubly-fed wound rotor induction generator. They are capable of fast voltage control over a power factor operation range of 0.95 overexcited to 0.9 underexcited.

In PSS/E the wind farm is represented as one aggregate generator operating at 575 V. The aggregate generator is stepped up to 34.5 kV via a 140 MVA transformer of 5.0% impedance. The 34.5 kV collector system is stepped up to the 110 kV connection voltage level via a 140 MVA transformer of 8.5% impedance. A 40 km 110 kV transmission line connects the Erikson wind farm to the 110 kV Minnedosa station.

An IPLAN is used to add the wind farm to the PSS/E large system model. Detailed PSS/E user models representing the DFIG turbine are used to perform the stability analysis.

5. Frequency, Voltage and Reactive Power Requirements

This section describes the turbine capabilities in comparison with the MH interconnection requirements. The next section will demonstrate these capabilities through transient stability simulations.

5.1. Turbine Overfrequency / Underfrequency Ride-Through Capability

A typical generator connected to the MH network should stay connected if the frequency remains within the limits given in Table 5.

Time	Underfrequency	Overfrequency
Continuous	60.0-59.0 Hz	60.0-61.5 Hz
10 minutes	59.0-58.7 Hz	61.5-62.0 Hz
30 seconds	58.7-57.5 Hz	62.0-63.5 Hz

Table 5. MH Frequency Ride-Through Requirements.

The DFIG turbine frequency ride-through capability is summarized in Table 6.

Time	Underfrequency	Overfrequency
Continuous	60.0-57.5 Hz	60.0-61.5 Hz
30 seconds		61.5-62.5 Hz
10 seconds	56.5-57.5 Hz	

Table 6. DFIG Turbine Frequency Ride-Through Capability.

The wind turbine has adequate underfrequency ride-through capability. The MH Transmission System Interconnection Requirements document [1] states that the Generation Facility is to remain connected if the frequency is in the range of 62.0-63.5 Hz for 30 seconds. MH has agreed that the overfrequency capability of up to 62.5 Hz for 30 seconds will be adequate for connecting to the MH transmission grid.

5.2. Turbine Overvoltage / Undervoltage Ride-Through Capability

Table 7 summarizes the overvoltage and undervoltage requirements at the Minnedosa 110 kV bus during local and remote disturbances. The worst undervoltage cases occur during 110 kV faults near the Minnedosa station. The worst system overvoltage cases typically occur when large amounts of power from the HVdc system are lost (e.g. trip of Manitoba-USA 500 kV line followed by an HVdc reduction, or a permanent or temporary block of a bipole).

Overvoltage (pu)			Undervoltage (pu)
Continuous	1.10	Continuous	0.90
267 ms	1.15-1.10	2 sec	0.70-0.90
200 ms	1.20-1.15	0.5 sec	0.70
100 ms	1.20	267 ms	0.0-0.50
		100 ms	0.0

Table 7. MH Over- and Under-voltage Requirements at the Point of Interconnection.

Figure 2 below graphically represents the MH voltage criteria.

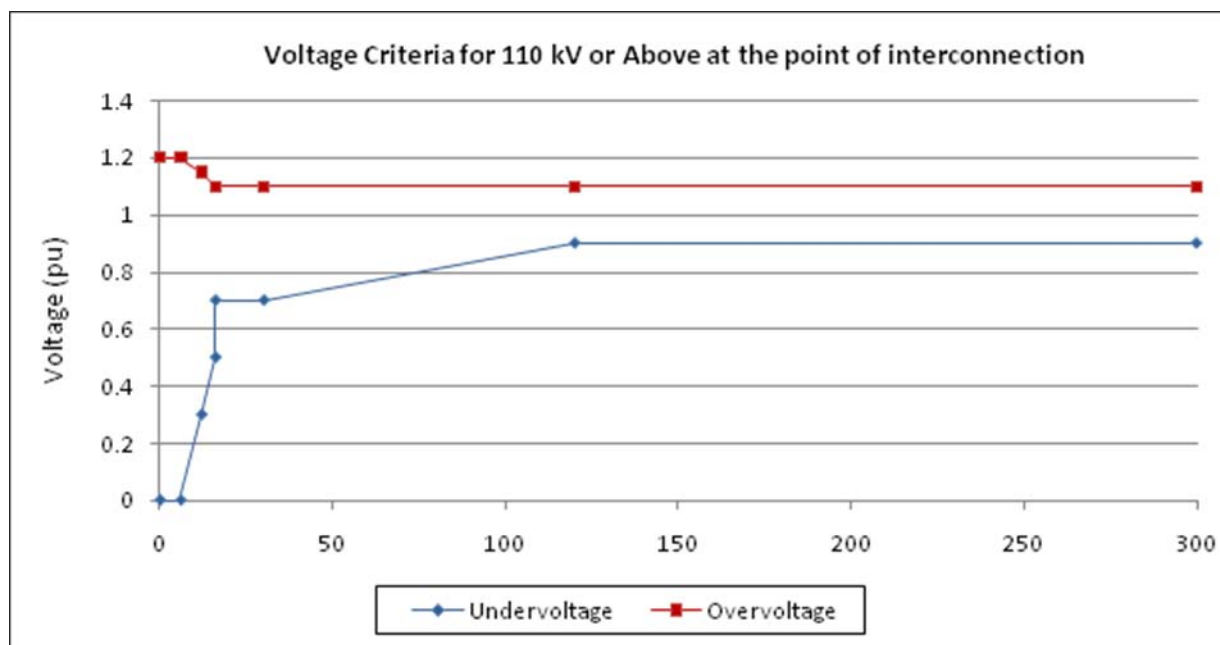


Fig. 2. Voltage Requirements for Interconnection to the Minnedosa 110 kV bus.

The DFIG wind turbine used in this study can operate continuously between 90% and 110% voltage. It has the capability to operate up to 115% for 1.0 second, and between 115% and 130% for 100 ms. With the Low Voltage Ride Through (LVRT) option II, for line-to-ground or three-phase-to-ground faults, the wind turbine will remain connected as long as the voltage does not drop below 70% for more than 1.0 second or 15% for more than 0.625 seconds. Within 3 seconds the voltage should recover to a minimum of 90%. For line-to-line faults, the wind turbine will remain connected as long as the voltage does not drop below 70% for more than 1.0 second or 15% for more than 0.2 seconds. Within 0.2 seconds the voltage should recover to a minimum of 70%, and within 3 seconds to a minimum of 90%.

The overvoltage ride-through capability of the wind turbine does not appear to meet Manitoba Hydro’s overvoltage criteria. However, due to the fast voltage control capability of the doubly-fed induction generator, the wind turbine controls actually aid in reducing the worst-case overvoltage at Minnedosa 110 kV bus and at the turbine 600 V generator bus, thus the wind turbine is able to ride through the worst-case overvoltage. This voltage control capability will be demonstrated in section 6 of the report.

For line-to-ground and three-phase-to-ground faults, the undervoltage ride-through capability of the turbine (LVRT option II) meets Manitoba Hydro’s undervoltage criteria. For line-to-line faults, the undervoltage ride-through capability is acceptable when considering normal clearing times. Stability investigation reveals that the DFIG wind turbine can successfully ride through a delayed slow-clearing stuck breaker (NERC Category C) faults. Please refer to Appendix A for stability plots.

5.3. Reactive Power Requirements

The Manitoba Hydro Transmission System Interconnection Requirements document [1] states that any Generation Facility greater than 10 MW comprised of induction type generators (such as may be connected to wind turbines) must provide reactive supply that is able to control the voltage level by adjusting the machine’s power factor between a minimum of 0.95 overexcited and 0.95 underexcited as measured at the Generator intermediate bus. The power factor requirements could be larger depending on transient stability analysis.

The DFIG wind turbines used in this study have inherent fast reactive power control capability ranging from 0.95 overexcited to 0.9 underexcited. Therefore, the turbines meet the Manitoba Hydro reactive power requirements.

6. Stability Investigation

Relevant stability plots are included in Appendix A.

6.1. Study Stability Models

Ten base case system models used in the transient stability analysis were based on updated 2004 series MAPP stability models, and included:

- A. 2009 summer off-peak system intact with maximum MH-US exports:
MHEX=2175 MW, NDEX=1950 MW
MHEX=2175 MW, NDEX=300 MW
- B. 2009 summer peak system intact with maximum MH-US imports:
MHEX=-700 MW, NDEX=1950 MW
MHEX=-700 MW, NDEX=0 MW
- C. 2009 winter peak system intact with maximum MH-US imports:
MHEX=-700 MW, NDEX=1950 MW
MHEX=-700 MW, NDEX=300 MW
- D. 2014 summer peak system intact with maximum MH-US exports and maximum MH-US imports:
MHEX=2100 MW, NDEX=1950 MW
MHEX=2100 MW, NDEX=300 MW
MHEX=-700 MW, NDEX=1950 MW
MHEX=-700 MW, NDEX=0 MW

The 120 MW Erikson wind generation was scheduled to Dorsey HVDC generation.

6.2. Disturbances

The following NERC category B (single component) and C (multiple components) disturbances were tested to determine the impact of the Erikson generator on the Manitoba-US transfer capability, using the 2009 summer off-peak stability model:

1. ag1 fault – 4-cycle SLF 345 kV fault at Leland Olds on Ft. Thompson line. Stuck breaker. Clear faulted line at 11 cycles.
2. ei2 fault – permanent bipole fault on the CU DC line. Both Coal Creek units tripped at 0.28 seconds.
3. mqs fault – SLG fault at Sherco unit #3 with breaker fail 8N28. Trip Sherco unit #3.
4. nbz fault – 4-cycle 3-phase 500 kV fault on at Chisago on Forbes line 601. Cross-trip D602F. **This is the Overvoltage Ride-Through test discussed in section 6.3.**
5. mat fault – Loss of D602F with DC reduction.

The following NERC category B (single component) and C (multiple components) disturbances were tested to determine the impact of the Erikson generator on the transfer capability within Manitoba, using the 2009 summer peak, 2009 winter peak and 2014 summer peak stability models:

1. System intact, 3-phase normal clearing faults at Letellier on L20D, St. Leon on S60L, Letellier on Y51L, St. Leon on D14S, St. Leon on S53G, Glenboro on G37C, Laverendyre on D55Y, Glenboro on G82R, Dorsey on D12C, Dorsey on D54C, Cornwallis on D54C, Cornwallis on C28R, Reston on R7B, Boundary Dam on B10T, Reston on R29H, Virden on B70H, Birtle South on B69R, Vermilion on V38R, Minnedosa on MR11, Minnedosa on NM10.
2. System intact, single line-to-ground stuck breaker (slow clearing) faults (determined from ACCC analysis as candidate for stability analysis). See section 6.6.
3. mbs fault – Loss of Manitoba HVDC bipole 2 at Dorsey. No cross-trip of Manitoba-Ontario tie lines. **This is the underfrequency ride-through test discussed in section 6.7.

6.3. Overvoltage Ride-Through Test

The 'nbz' fault (4-cycle 3-phase 500 kV fault at Chisago on Forbes line 601, cross-trip D602F) is the disturbance used to test the overvoltage ride-through capability of the wind turbines. Please refer to figures in Appendix A-1.

Worst overvoltages are expected for lightly loaded summer off peak cases and it was found that wind turbines remained connected throughout the disturbance. The fast voltage controls of the doubly-fed induction generator aided in reducing the overvoltage seen at the Minnedosa 110 kV bus when compared to the case without the wind farm. Therefore, the DFIG turbine meets MH transient overvoltage criteria.

6.4. Under voltage Ride-Through Test

All of the close-in three-phase and single line-to-ground faults can be regarded as undervoltage ride-through tests. The Erikson wind farm was observed to ride through all close-in three-phase and single line-to-ground faults satisfying MH transient under voltage criteria. Please refer to figures in Appendix A-2.

6.5. System Intact with Local N-1 Contingencies

The MH transient under voltage criteria require that all system transient voltages remain above 0.7 pu after fault clearing.

The doubly-fed induction generators do not violate the transient undervoltage criteria for any local three-phase fault (N-1). The wind turbines remained connected throughout the disturbance. The fast voltage controls of the doubly-fed induction provided sufficient VAR support such that the Minnedosa 110 kV transient voltage remained above 0.7 pu immediately following fault clearing. Therefore, the DFIG turbines meet MH transient undervoltage criteria.

6.6. System Intact with Local N-2 Contingencies

The following two breaker fail scenarios were studied to observe the impact of slow clearing single line to ground faults (SLGF) on the Erikson wind farm:

- a. Single line to ground fault at Cornwallis on Cornwallis to Glenboro 230 kV line G37C. After 5 cycles, Glenboro end of line G37C is tripped but breaker R4 at Cornwallis fails to operate. After 16 cycles, fault is cleared by opening 230 kV line D54C from Cornwallis and Dorsey ends.
- b. Single line to ground fault at Neepawa on Neepawa to Minnedosa 110 kV line NM10. After 5 cycles, Minnedosa end of line NM10 is tripped but breaker R18 at Neepawa fails to operate. After 16 cycles, fault is cleared by opening 110 kV line BN5 from Neepawa and Brandon ends.

It was found that the doubly fed wind induction generator does not trip for these faults. For stuck breaker fault 'a' the wind farm just meets the 0.7 pu transient undervoltage criteria. For stuck breaker fault 'b' the transient undervoltage response is well within the 0.7 pu criteria, immediately jumping up to 0.9 pu upon fault clearing. The worst case transient undervoltage (0.7 pu during stuck breaker fault 'a') was observed during the 2009 winter peak cases.

Please note that a stuck breaker fault at Minnedosa would open both lines NM10 and MR11 which connect the 110 kV Minnedosa bus to the rest of MH system, leading to tripping of the Erikson wind farm.

6.7. Under-frequency Ride-Through Test

The ‘mbs’ fault (loss of Manitoba HVDC bipole, no cross-trip of Manitoba-Ontario tie lines) is the disturbance used to test the under frequency ride-through capability of the wind turbines, as well as to observe the impact of the wind farm on system frequency. The transient frequency is to remain above 59.3 Hz, without any reduction in wind output. The wind farm meets the under-frequency ride-through test. Please refer to figures in Appendix A-3.

6.8. Summary of Stability Results

Addition of generation in southwest Manitoba at the proposed wind site changes the powerflow in line NM10 from Minnedosa to Neepawa and in line MR11 from Minnedosa to Rapid City and Raven Lake. Stability investigations involving numerous worst case system faults revealed that the DFIG wind turbines proposed to be used in the Erikson wind farm do not require any additional equipment or special protection schemes. They must be equipped with the Low Voltage Ride through (LVRT) option II in order to meet fault ride-through requirements.

7. Planning Level Cost Estimate

The following planning level (+/-50%) unit cost estimates are used to determine the cost estimate for new Interconnection Facilities and Interconnection System Upgrades required to connect the Erikson wind farm to the Manitoba Hydro system.

1. 110 kV transmission line more than 10 km long: \$175,000/km
2. 110 kV breaker: \$1.5 million
3. Re-sagging line conductor to 100 deg C –\$15,000/km
4. Re- conductoring of line (with 336.4 MCM ACSS 26/7) – 50,000/km if more than 10 km and add 35% more if less than 10 km.
5. Riser replacement -\$100,000/site
6. Current Transformer(CT) replacement-\$200,000/site

The connection of the Erikson wind farm from the 110 kV collector bus to the 110 kV Minnedosa bus requires a new 40 km 110 kV transmission line and one 110 kV breaker at the Minnedosa bus, which is estimated to cost \$7.0 million and \$1.5 million respectively.

A breakdown of planning level cost estimates for the Interconnection System Upgrades is provided in Table 8. The total Interconnection System Upgrades cost is estimated to be \$5.9 million. Therefore, the total cost estimate including Interconnection Facilities and Interconnection System Upgrades that are required to interconnect the Erikson wind farm to the Manitoba Hydro system is \$14.4 million*.

Facility	Equipment Upgrade	Line length (km)	Cost (1000'\$)
BN5	Re-sagging of line conductor to 100 deg C	57.5	862.5
	Two riser replacements	-	200.0
NM10	Re- conductoring of line ²	30.42	1521.0
	Two riser replacements	-	200.0
MR11	Re- conductoring of line ¹	8.85	597.4
	Re- conductoring of line ¹	11.97	598.5
	Re- conductoring of line ¹	32.6	1630.0
	One riser replacements	-	100.0
	One CT replacement	-	200.0
Total Cost (1000'\$)			5,909.4

Table 8: Breakdown of Cost Estimate for Interconnection System Upgrades.

***Important Note Regarding Communication Costs:**

The Minnedosa 110 kV station is not equipped with SCADA/communication. The Manitoba Hydro Generator Interconnection Operating Requirements lists the requirements from an operational perspective; in order for Manitoba Hydro to provide functional control over the facility, the Generator must provide SCADA monitoring, minimum control (isolation if not curtailment) at the Minnedosa station and communication for coordinated protection with the wind farm.

Developing a cost estimate for communication requirements is beyond the scope of the IES. Detailed communication cost estimates are determined during the Interconnection Facilities Study (IFS) phase. It should be noted that there are potential large cost risks associated with these communication requirements

² indicates all the re-conductorng requires same size ACSS conductors.

given that the Minnedosa station does not have existing SCADA/communication, which will significantly impact the Interconnection Facilities cost estimate as calculated for this IES report.

8. References

[1] Manitoba Hydro Transmission System Interconnection Requirements, Revision 0, December 2003, http://www.hydro.mb.ca/business_customer/tariffsummary.shtml.

[2] ABB Coordinated Group Study of Group 1 Generator Projects, submitted to MISO and WAPA on April 5, 2004.
http://www.midwestiso.org/plan_inter/documents/CGS-Group1%20Draft-R2.pdf

[3] Attachment A and B, MISO Generator Interconnection Manual, Volume 6.2, Version 2, May 5, 2004.
http://www.midwestiso.org/plan_inter/documents/generation_inter/Generator%20Interconnection%20Manual_day1_050504_cln.pdf

[4] MISO Generation Deliverability Study Method, “Deliverability Study White Paper”
http://www.midwestiso.org/plan_inter/documents/gen_deliver_test/MISO_Generator_Deliverability_Draft_2-10-05.pdf

[5] MAPP DRS document, “Steady-State Facility & Constrained Path Impact Determination Requirements & Screening Guidelines for Study Submissions” approved October 23, 2003. (on MAPP Member web site)

[6] MAPP Members Reliability Criteria and Study Procedures Manual, Nov. 9, 2004

Appendix A: Stability Plots

Overvoltage Ride-Through Test (Section 5.3): nbz fault

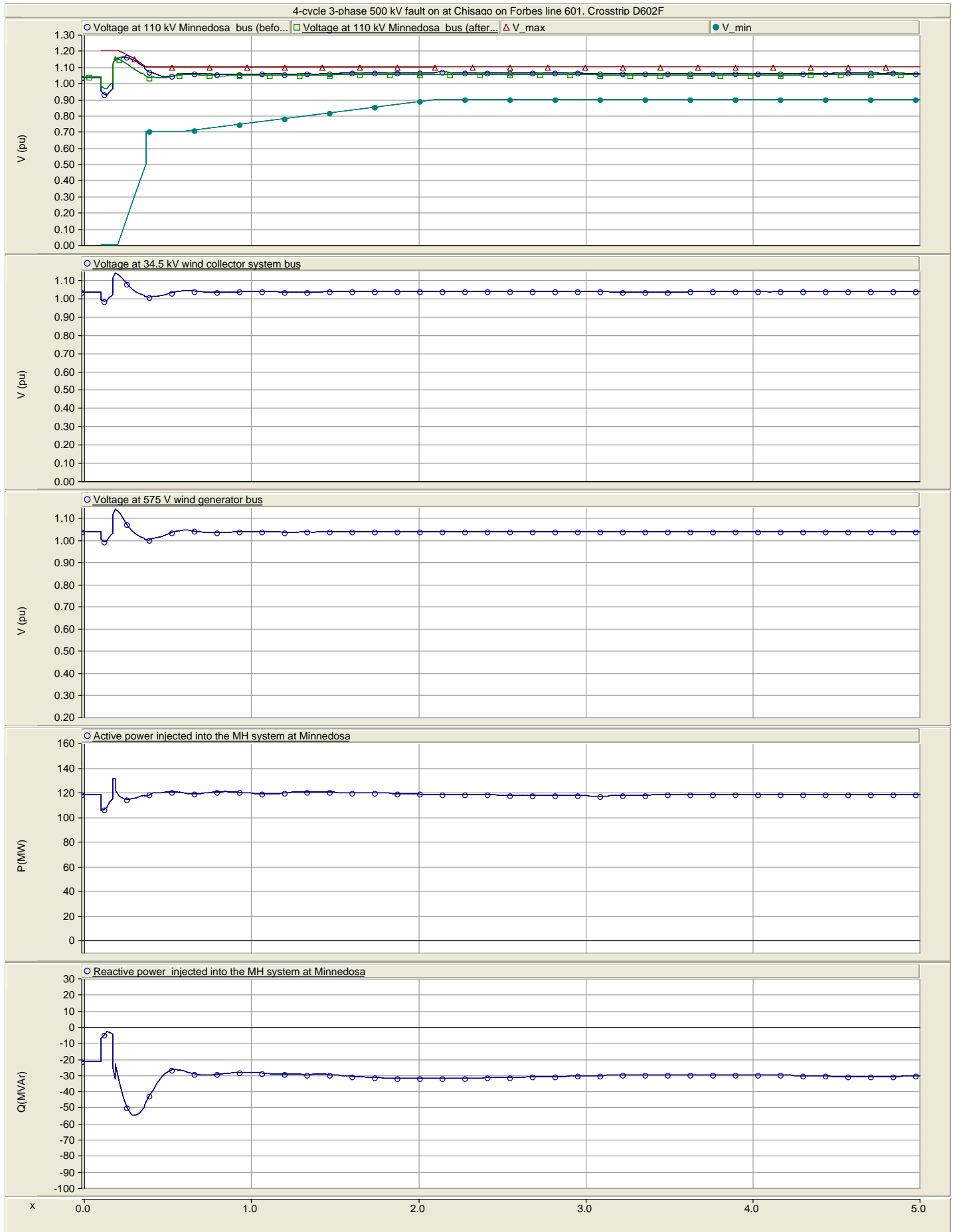
Figure A-1 Base case & 120 MW Wind (NDEX=1950 MW,MHEX=2175 MW)

Undervoltage Ride-Through Test (Section 5.4): 3PF D54C, System intact

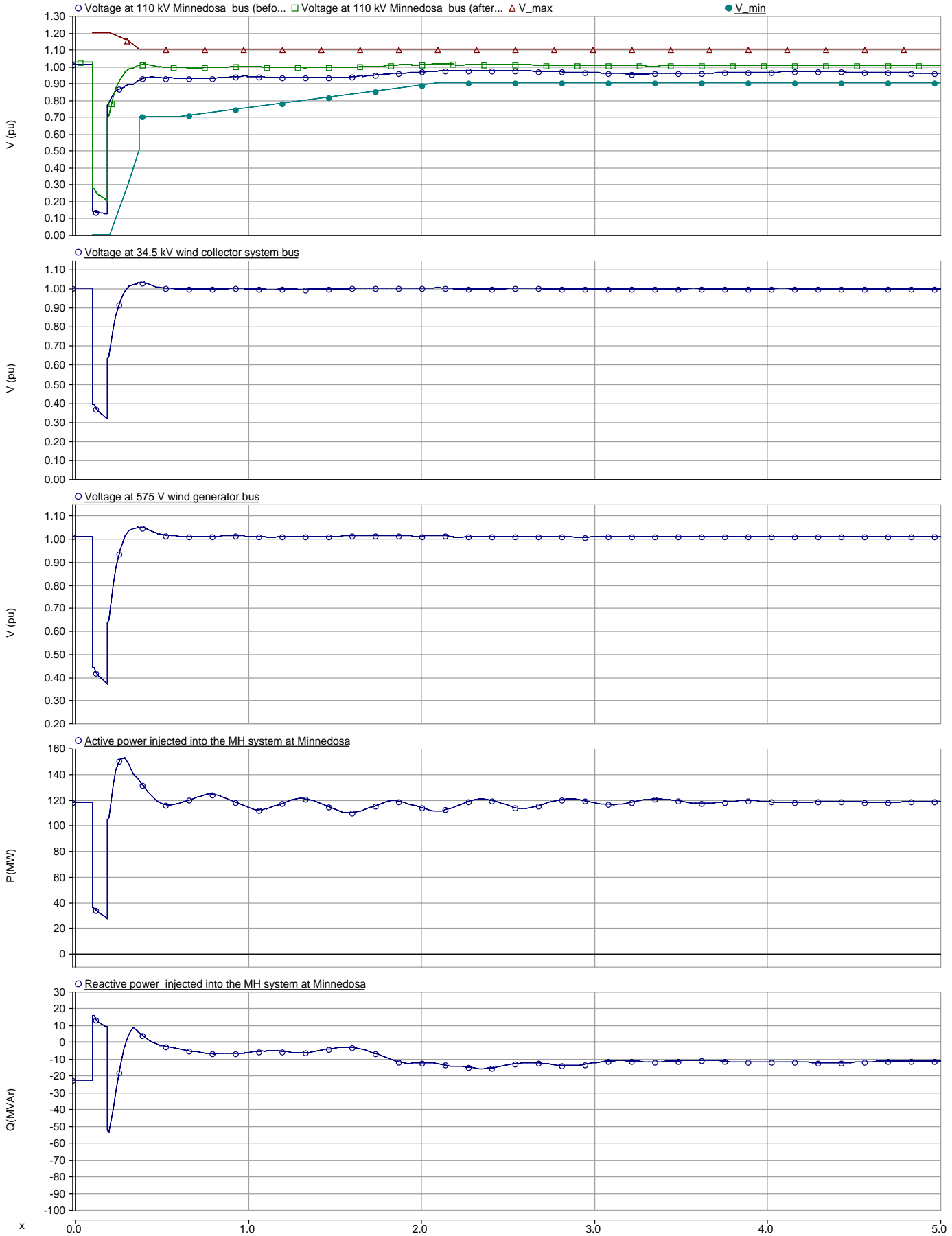
Figure A-2 Base case & 120 MW Wind (NDEX=1950 MW,MHEX=-700 MW)

Underfrequency Ride-Through Test (Section 5.7): mbs fault

Figure A-3 Base case & 120 MW Wind (NDEX=300 MW,MHEX=2100 MW)

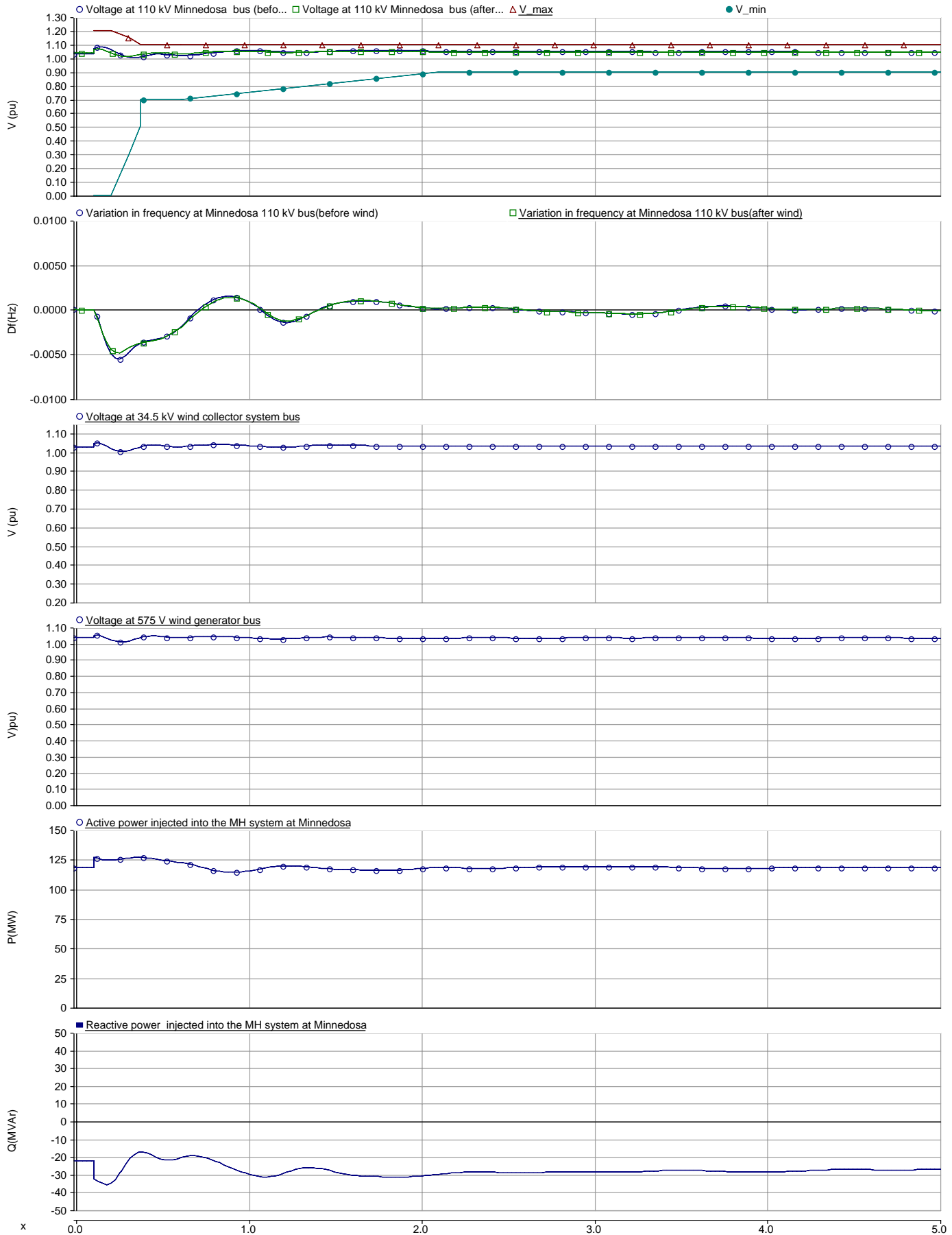


3Phase to ground fault at Dorsey on D54C



Appendix A3

Loss of Manitoba HVDC bipole 2 at Dorsey. No cross-trip of Manitoba-Ontario tie lines



Appendix B: ACCC Results - Thermal Overloads (NEW or OTDF > 2%)

Appendix B

Overload Summary-Summer Peak 2009									
Contingency	Overloaded Lines	Line Name	Line Rating C [MVA]	Overload [%] and OTDF					
				NDEX=300			NDEX=1950		
				MHEX=2100			MHEX=2100		
				Before Wind	After Wind	OTDF	Before Wind	After Wind	OTDF
109 MR11	67520*MINDOS 7 110 67521 NEPWA 7 110 1	NM10	81.2	none	146.1	NEW	none	146.7	NEW
BKF2	67520*MINDOS 7 110 67521 NEPWA 7 110 1	NM10	81.2	none	146.0	NEW	none	146.7	NEW
MH-019	67520*MINDOS 7 110 67521 NEPWA 7 110 1	NM10	81.2	none	144.3	NEW	none	144.8	NEW
110 NM10	67520*MINDOS 7 110 67717 MR11 T 7 110 1	MR11	81.2	none	138.2	NEW	none	138.3	NEW
BKF14	67520*MINDOS 7 110 67717 MR11 T 7 110 1	MR11	81.2	none	138.1	NEW	none	138.3	NEW
MH-028	67541 STVITAL7 110 67727*DAKOTB37 110 1	XV39	110.1	none	100.1	NEW*	100.7	none	IMPROVED
48 R49R	67557*LETELER4 230 66752 DRAYTON4 230 1	L20D	460.5	none	101.0	NEW	none	none	OK
166 DSY BK5	67557*LETELER4 230 66752 DRAYTON4 230 1	L20D	460.5	none	100.9	NEW	none	none	OK
MH-006	67557*LETELER4 230 66752 DRAYTON4 230 1	L20D	460.5	none	101.0	NEW	none	none	OK
110 NM10	67717*MR11 T 7 110 67718 RAPDCTY7 110 1	MR11	81.2	none	138.1	NEW	none	138.2	NEW
BKF14	67717*MR11 T 7 110 67718 RAPDCTY7 110 1	MR11	81.2	none	138.0	NEW	none	138.2	NEW
110 NM10	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	194.2	NEW	none	194.3	NEW
76 BN5	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	120.7	NEW	none	114.5	NEW
84 CN9	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	100.8	NEW	none	100.8	NEW
BKF14	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	194.1	NEW	none	194.3	NEW
MH-008	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	124.1	NEW	none	115.8	NEW
MH-014	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	100.8	NEW	none	100.8	NEW

*Base case OL is more than the wind case

Appendix B

Overload Summary-Winter Peak 2009									
Contingency	Overloaded Lines	Line Name	Line Rating C [MVA]	Overload [%] and OTDF					
				NDEX=300			NDEX=1950		
				MHEX=-700			MHEX=-700		
				Before Wind	After Wind	OTDF	Before Wind	After Wind	OTDF
110 NM10	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	70.3	none	143.6	NEW	none	143.6	NEW

Appendix B

Overload Summary-Summer Peak 2014																
Contingency	Overloaded Lines	Line Name	Line Rating C [MVA]	Overload [%] and OTDF												
				NDEX=0			NDEX=300			NDEX=1950			NDEX=1950			
				MHEX=-700			MHEX=2100			MHEX=-700			MHEX=2100			
				Before Wind	After Wind	OTDF	Before Wind	After Wind	OTDF	Before Wind	After Wind	OTDF	Before Wind	After Wind	OTDF	
20 F27P	67510*GR.RPDS4 230 67702 WILRIVR4 230 1	G8P	249.0	none	100.7	NEW*	none	none	OK	100.8	101.7	1.9	none	none	OK	
109 MR11	67519 BRANDON7 110 67521*NEPWA 7 110 1	BN5	81.2	none	111.6	NEW	none	none	OK	none	105.7	NEW	none	none	OK	
BKF2	67519 BRANDON7 110 67521*NEPWA 7 110 1	BN5	81.2	none	111.3	NEW	none	none	OK	none	105.4	NEW	none	none	OK	
MH-019	67519 BRANDON7 110 67521*NEPWA 7 110 1	BN5	81.2	none	110.2	NEW	none	none	OK	none	104.3	NEW	none	none	OK	
109 MR11	67520*MINDOS 7 110 67521 NEPWA 7 110 1	NM10	81.2	none	145.1	NEW	none	144.3	NEW	none	144.0	NEW	none	143.7	NEW	
BKF2	67520*MINDOS 7 110 67521 NEPWA 7 110 1	NM10	81.2	none	144.9	NEW	none	144.2	NEW	none	143.8	NEW	none	143.6	NEW	
MH-019	67520*MINDOS 7 110 67521 NEPWA 7 110 1	NM10	81.2	none	143.2	NEW	none	142.4	NEW	none	142.1	NEW	none	141.9	NEW	
110 NM10	67520*MINDOS 7 110 67717 MR11 T 7 110 1	MR11	81.2	none	137.7	NEW	none	137.8	NEW	none	137.5	NEW	none	137.7	NEW	
76 BN5	67520*MINDOS 7 110 67717 MR11 T 7 110 1	MR11	81.2	none	108.1	NEW	none	none	OK	none	103.5	NEW	none	none	OK	
BKF14	67520*MINDOS 7 110 67717 MR11 T 7 110 1	MR11	81.2	none	137.9	NEW	none	137.9	NEW	none	137.9	NEW	none	137.8	NEW	
MH-008	67520*MINDOS 7 110 67717 MR11 T 7 110 1	MR11	81.2	none	111.6	NEW	none	none	OK	none	105.2	NEW	none	none	OK	
110 NM10	67717*MR11 T 7 110 67718 RAPDCTY7 110 1	MR11	81.2	none	137.6	NEW	none	137.7	NEW	none	137.4	NEW	none	137.6	NEW	
76 BN5	67717*MR11 T 7 110 67718 RAPDCTY7 110 1	MR11	81.2	none	108.0	NEW	none	none	OK	none	103.4	NEW	none	none	OK	
BKF14	67717*MR11 T 7 110 67718 RAPDCTY7 110 1	MR11	81.2	none	137.7	NEW	none	137.7	NEW	none	137.8	NEW	none	137.7	NEW	
MH-008	67717*MR11 T 7 110 67718 RAPDCTY7 110 1	MR11	81.2	none	111.5	NEW	none	none	OK	none	105.2	NEW	none	none	OK	
110 NM10	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	193.4	NEW	none	193.6	NEW	none	193.1	NEW	none	193.4	NEW	
24 G37C	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	114.7	NEW	none	none	OK	none	114.5	NEW	none	none	OK	
25A G82R	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	none	OK	none	none	OK	none	109.6	NEW	none	none	OK	
55 Y51L	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	none	OK	none	104.3	NEW	none	none	OK	none	none	OK	
75 BK41	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	100.6	NEW	none	none	OK	none	none	OK	none	none	OK	
76 BN5	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	151.4	NEW	none	135.4	NEW	none	144.9	NEW	none	128.1	NEW	
84 CN9	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	112.3	NEW	none	112.6	NEW	none	112.6	NEW	none	112.3	NEW	
9 D12C	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	112.0	NEW	none	none	OK	none	none	OK	none	none	OK	
BASE CASE	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	108.2	NEW	none	100.6	NEW	none	105.2	NEW	none	none	OK	
BKF14	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	193.5	NEW	none	193.7	NEW	none	193.6	NEW	none	193.5	NEW	
BKF8	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	113.3	NEW	none	104.9	NEW	none	none	OK	none	none	OK	
BKF9	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	121.1	NEW	none	none	OK	none	121.2	NEW	none	none	OK	
G1	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	none	OK	none	105.9	NEW	none	none	OK	none	102.4	NEW	
G11	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	none	OK	none	104.3	NEW	none	none	OK	none	100.5	NEW	
G2	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	none	OK	none	105.9	NEW	none	none	OK	none	102.4	NEW	
MH-008	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	156.3	NEW	none	137.2	NEW	none	147.4	NEW	none	127.8	NEW	
MH-011	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	100.9	NEW	none	none	OK	none	none	OK	none	none	OK	
MH-014	67718*RAPDCTY7 110 67720 BRANE 7 110 1	MR11	57.2	none	112.3	NEW	none	112.6	NEW	none	112.6	NEW	none	112.3	NEW	

*Base case OL is more than the wind case