APPENDIX 3A
System Planning Criteria

SYSTEM PLANNING CRITERIA AND STANDARDS

BACKGROUND

Manitoba Hydro adheres to a variety of criteria and standards in the planning, design, construction and operation of its transmission system. Compliance with certain standards is a legislative requirement, or a contractual requirement in interconnection agreements with other transmission owners. In other cases, industry-wide guidelines or recommendations have been adopted as corporate policy. In many cases, Manitoba Hydro staff members participate in the national and international review committees charged with the development and revision of the criteria and standards.

In Canada, many such criteria and standards have been developed by the Canadian Standards Association (CSA) or derive from the National Building Code (NBC). As described on its website, www.csa.ca, "the Canadian Standards Association is a not-for-profit membership-based association serving business, industry, government and consumers in Canada and the global marketplace. CSA works in Canada and around the world to develop standards that address real needs, such as enhancing public safety and health".

Development of Canada's National Building, Fire and Plumbing Codes is the responsibility of the National Research Council of Canada (NRC) as is detailed on the NRC website www.nrc-cnrc.gc.ca. At the time of writing, the 2005 national codes were about to be supplanted (29 November 2010) by the 2010 national model codes. Although subject to some specific additions and adjustments, the National Building Code has historically been adopted as The Manitoba Building Code in the regulations under The Building and Mobile Homes Act (Chapter B93 of the Continuing Consolidated of the Statutes of Manitoba [CCSM], http://web2.gov.mb.ca/laws/statutes.

In North America, standards aimed at ensuring the reliable delivery of electricity to customers ("reliability standards") are largely developed through the North American Electric Reliability Corporation (NERC). Once guidelines, the various NERC reliability standards have been made mandatory in most North American jurisdictions, partly in response to the blackout that cascaded through eastern Canada and the United States in August 2003 (Manitoba Hydro, 2007/2008 Annual Report, page 42). NERC develops reliability standards through an industry stakeholder process. NERC also assesses the adequacy of the transmission system annually via a 10-year forecast and winter and summer forecasts; and educates, trains, and certifies industry personnel. In certain North American jurisdictions, NERC also monitors and/or enforces compliance with reliability standards.

Although NERC is an industry organization, it is subject to oversight by governmental authorities in Canada and the United States. In Canada, the construction and operation of international and designated interprovincial transmission lines are subject to federal jurisdiction and are regulated by the National Energy Board (NEB). However, the construction and operation of intraprovincial transmission lines falls under the jurisdiction of the Provinces. Accordingly, the NEB has entered into an MOU with NERC adopting reliability standards for NEB-regulated transmission lines which is intended to be implemented through a federal regulation or Order. Most Provinces have also either enacted legislation or entered into an MOU with NERC and/or a regional organization of NERC regarding the adoption of reliability standards for intraprovincial lines. In the United States, FERC enforces compliance with NERC standards pursuant to the Energy Policy Act of 2005 (see www.ferc.gov).

NERC has eight regional organizations under its umbrella that assist in carrying out its responsibilities. The members of the regional organizations come from all segments of the electricity industry: investor-owned utilities; U.S. federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and retail customers. These membership categories allow for the participation of all electricity industry stakeholders in the United States, Canada, and a portion of Baja California Norte, Mexico.

NERC and Manitoba Hydro

Manitoba Hydro became contractually obligated to adhere to NERC reliability standards in 1996 through its membership agreement in the Mid-Continent Area Power Pool ("MAPP"), which was formerly a regional organization of NERC. When NERC re-organized in 2005, Manitoba Hydro joined its successor organization, the Midwest Reliability Organization ("MRO")—adopting MRO and NERC standards, unless suspended, disallowed or remanded by the Lieutenant Governor in Council, through Manitoba Order-in-Council 206/2004.

The MRO region spans roughly one million square miles, including the provinces of Saskatchewan and Manitoba, the states of North Dakota, Minnesota, Nebraska and the majority of the territory in the states of South Dakota, Iowa and Wisconsin. The MRO includes more than 100 stakeholder organizations that are involved in the production and delivery of power to more than 20 million people.

Recent legislative amendments will create a more comprehensive statutory scheme for the adoption and enforcement of reliability standards applicable to all owners, operators and users of the bulk power system in Manitoba. Amendments to The Manitoba Hydro Act and The Public Utilities Board Act, passed by the Manitoba legislature 11 June 2009[1] provide, among other things, that the Lieutenant Governor in Council may make regulations adopting electricity reliability standards that have been made or recommended by a standards body, such as NERC or MRO. The legislation also includes a provision authorizing the Public Utilities Board to impose financial penalties for non-compliance.

NERC Reliability Standards

NERC reliability standards cover a broad range of issues affecting bulk power system planning and operation:

- Resource and Demand Balancing (BAL);
- Communications (COM);
- Critical Infrastructure Protection (CIP);
- Emergency Preparedness and Operations (EOP);
- Facilities Design, Connection and Maintenance (FAC);
- Interchange Scheduling and Coordination (INT);
- Interconnection Reliability Operations and Coordination (IRO);
- Modeling, Data, and Analysis (MOD);
- Nuclear (NUC);
- Personnel Performance, Training and Qualifications (PER);
- Protection and Control (PRC);
- Transmission Operations (TOP);

1 Bill 20, The Manitoba Hydro Amendment and Public Utilities Board Amendment Act (Electricity Reliability); Province of Manitoba; Royal assent June 11, 2009. The Bill's explanatory note was as follows: "Manitoba's electricity generation and transmission facilities are part of an integrated regional grid with other provinces and the United States. This Bill provides for the adoption and enforcement of mandatory reliability standards for planning and operating Manitoba facilities that form part of that grid".

- Transmission Planning (TPL); and
- Voltage and Reactive (VAR).

The NERC website, www.nerc.com, provides details respecting the content and status of individual standards under each of these headings. Pursuant to NERC's Interconnection Reliability Operations and Coordination Standards, Manitoba Hydro has retained the services of the Midwest ISO to act as Reliability Coordinator to continually assess transmission reliability and coordinate emergencies within Manitoba Hydro's larger interconnected region.

Transmission Planning Reliability Standards

In the Bipole III project context, the NERC Transmission Planning Standards are of particular relevance. While these standards do not obligate Manitoba Hydro to build Bipole III, they have directly influenced Manitoba Hydro's assessment of its system reliability, which in turn has led to the corporate decisions to proceed with the Riel Sectionalization and Bipole III projects.

Apart from standards dealing with the preparation of regional and interregional self-assessment reliability reports and the provision of data from the regional reliability organization needed to assess reliability, this group of standards includes several which seek to ensure system performance under a variety of operating conditions and contingencies. For each category, the standards stipulate a common purpose that "System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs". The categories range from Category A ("System Performance Under Normal [No Contingency] Conditions") to Category D ("System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements") and are elaborated in the table on the following page taken from the NERC website, www.nerc.com.

In order to achieve compliance with NERC Standards TPL001-0 through 003-0, a long term system assessment must be conducted annually to demonstrate that the performance of the Manitoba portion of the interconnected system meets Category A through Category D performance requirements over a ten year planning horizon. The models used for this assessment study include existing and all planned facilities like Bipole III. If the assessment indicates that the performance requirements cannot be met in a future year, a mitigation plan is developed, along with an implementation plan, to correct the performance deficiency.

NERC Standard TPL-004-0 requires Manitoba Hydro to assess the risks and consequences of extreme (Category D) disturbances like the loss of the Bipole I and II lines on a common corridor, or the loss of an entire station like the Dorsey Converter Station. However, TPL-004-0 does not require mitigation of such extreme disturbances. Pursuant to this NERC standard, Manitoba Hydro has evaluated the risk of the Bipole I and II corridor loss and the loss of Dorsey along with the consequences of these outages. A risk analysis of weather related events has indicated that the probability of the loss of Bipole I and II due to a tornado hitting the corridor is 0.06 per year (one chance in 16 years). Similarly, the probability of non-tornadic winds simultaneously damaging the Bipole I and II lines, or the Dorsey station is 0.002 to 0.02 per year (one chance in 50 to 500 years).

The Bipole I and II outages caused by extreme weather events can be of extended duration such as several weeks for a corridor loss and possibly over two years for a Dorsey station loss. Given that 70% of Manitoba Hydro's generation required to serve Manitoba load and firm exports is transmitted over Bipole I and II, Manitoba Hydro has determined that the consequences of such an event to Manitoba Hydro and the Province of Manitoba would be an unacceptable risk to the reliable supply of electricity. Manitoba Hydro examined the installation of gas turbines in southern Manitoba or the construction of import tie lines and purchase of generation in the United States as alternatives to Bipole III. These alternatives proved to be uneconomic compared to Bipole III. As a result, Bipole III was recommended to provide redundancy for the existing HVdc transmission system.

Table 3A-1: Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No[b] No[b] No[b] No[b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/Controlled[c] Planned/Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/Controlled	No

Category	Contingencies	System Limits or Impacts		
	Bipolar Block, with Normal Clearing[e]:	Yes	Planned/Controlled[c]	No
	4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]:	Yes	Planned/Controlled[c]	No
	5. Any two circuits of a multiple circuit towerline[f]			
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure):	Yes	Planned/Controlled[c]	No
	6. Generator	Yes	Planned/Controlled[c]	No
	7. Transformer	Yes	Planned/Controlled[c]	No
	8. Transmission Circuit	Yes	Planned/Controlled[c]	No
	9. Bus Section			
D[d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section			
	3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault)	Evaluate for risks and consequences. May involve substantial loss of customer Demand and generation in a widespread area or areas. Portions or all of the interconnected systems may or may not achieve a new, stable operating point. Evaluation of these events may require joint studies with neighboring systems.		
	6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or			

Category	Contingencies	System Limits or Impacts
	remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization	

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.