Q. (page 8, report entitled Upgrade Transmission Line Corridor – Bay d'Espoir to Western Avalon) Section 3 lists Hydro's transmission planning criteria. Please summarize in a table all Hydro criteria that fall short of NPCC criteria, and explain how they come up short, what Hydro plans to do about it, and the cost if Hydro were to bring the criteria up to NPCC standards.

A. For comparison of the existing Hydro transmission planning criteria to that used in the bulk power system in North America, it is apparent to start with the North American Electric Reliability Corporation (NERC) transmission planning standards given that NERC is the international (i.e., U.S. and Canada) regulatory authority whose mission is to ensure the reliability of the bulk power system in North America. Following a comparison to the NERC transmission planning criteria it is reasonable to then compare the existing Hydro criteria to the Northeast Power Coordination Council Inc. (NPCC) transmission planning criteria given that NPCC is the closest regional reliability entity to the province of Newfoundland and Labrador and is responsible for promoting and improving reliability in Ontario, Québec, New Brunswick, Nova Scotia, New York, and six New England states.

The comparison of Hydro transmission planning criteria to NERC transmission planning criteria includes NERC standards:

- TPL-001-0.1 System Performance Under Normal (No Contingency) Conditions (Category A);
- TPL-002-0b System Performance Following Loss of a Single Bulk Electric System Element (Category B);

- TPL-003-0b System Performance Following Loss of Two or More Bulk Electric System Elements (Category C); and
- TPL-004-0a System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

Each standard provides a description of the purpose of the standard, to what the standard applies, the requirements, the measures, compliance and regional differences.

The NERC transmission planning standards apply to power system elements defined as **Bulk Electric System (BES) Elements.** The following table provides the NERC definition of BES elements effective July 1, 2014, rules on inclusion and exclusion, and a high level determination of which Island Interconnected System elements would be considered BES and subsequently required to meet the NERC TPL standards.

NERC Definition of Bulk Electric System (BES) and Island Interconnected System Impact	
NERC	**Hydro**
Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.	Hydro considers the Island 230 kV system and underlying 138 kV loops as bulk power system. 138 kV equipment in the Stony Brook to Sunnyside and Western Avalon to Holyrood 138 kV Loops are predominantly owned and operated by Newfoundland Power. Hydro plans for transformer capacity and acceptable voltage levels in these loops.
NERC Inclusions	**Impact to Hydro**
I1 – Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.	Includes: 230/138 kV transformer Deer Lake T2 Excludes on secondary voltage: 230/66 kV transformers at Massey Drive, Stephenville, Buchans, Bay d'Espoir, Holyrood, Hardwoods, Oxen Pond Excludes (under E1 and E3) 230/138 kV transformers at Bottom Brook, Stony Brook, Sunnyside, Western Avalon, Holyrood,

I2 – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating greater than 20 MVA, Or, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.	Includes: Bay d'Espoir, Holyrood (until retired), Cat Arm, Upper Salmon, Hinds Lake, Grand Falls, Holyrood 120 MW CT Exclude - NLH Paradise River, Star Lake, Rattle Brook, Corner Brook Co-gen, Hawke's Bay, St. Anthony, Snook's Arm, Venom Bight, Roddickton mini-hydro, Buchans, Hardwoods, Stephenville, Fermuse Wind, St. Lawrence Wind Exclude – NP Rose Blanche Brook, Grand Bay, Lookout Brook, Rattling Brook, Sandy Brook NP generation Burin Peninsula, Bonavista Peninsula and Avalon Peninsula Exclude - Deer Lake Power 50 Hz and 60 Hz
I3 – Blackstart Resources identified in the Transmission Operator's restoration plan.	New Holyrood 120 MW combustion turbine and 8 x 2 MW diesel plant
I4 – Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.	Includes: Hinds Lake 83.3 MVA at 138 kV Exploits at Grand Falls TL235 Exclude – less than 75 MVA NP generation Burin Peninsula (1.63 MW plus 20 MW CT) and Bonavista Peninsula (3.511 MW) Exclude - connected 66 kV NP generation Avalon Peninsula (southern shore 45.11 MW, CBS 6.18 MW, CBN 8.175 MW) Fermuse Wind 25 MW St. Lawrence Wind 25 MW
I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.	Includes: Come By Chance 230 kV capacitor banks Soldiers Pond Synchronous Condensers Exclude: Hardwoods and Oxen Pond 66 kV capacitor banks
NERC Exclusions	**Resultant Hydro Exclusions**
E1 – Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load. Or, b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75	Radial system exclusions: TL214/TL215 – Doyles/Port-aux-Basques system including Grand Bay combustion turbine and Rose Blanche Brook TL250 Bottom Brook to Grandy Brook/Burgeo TL209 Stephenville including 63 MVA combustion turbine Corner Brook co-gen

MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not in deified in Inclusions I2, I3, or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating). Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion. Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.	GNP – Deer Lake to St. Anthony including Hawkes Bay (6.25 MVA) and St. Anthony (9.7 MW) Diesel Plants 69 kV White Bay system including Rattle Brook (4 MW) Baie Verte Peninsula 363L and TL260 TL280 and Star Lake Generating Station (18.4 MW) TL264 and Duck Pond TL263 and Granite Canal Generating Station (45 MVA) TL263 will be included with construction of new Granite Canal to Bottom Brook line TL220 Connaigre Peninsula TL254 Boyd's Cove to Farewell Head (Fogo – Change Islands) TL212 and TL219 Burin Peninsula including Paradise River (8.9 MVA), Greenhill combustion turbine (25 MW) and St. Lawrence wind farm (25 MW) TL208 and Vale
E2 – A generating unit or multiple generating units on a customer's side of the retail meter that serve all or part of the retail Load with electric energy if (i) the net capacity provided by to the BES does not exceed 75 MVA, and (II) standby, back-up, and maintenance services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.	None present in Island Interconnected System
E3 – Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not accommodate bulk power transfer across the interconnected system. The LN characterized by all of the following: a) Limits of connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);	Exclude: 138 kV Loop Stony Brook to Sunnyside (flow into both sides of loop) 138 kV Loop Western Avalon to Holyrood (flow into both sides of loop) NP 66 kV local transmission networks Stephenville, Corner Brook – Bay of Islands, St. John's-CBS

b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).	
E4 – Reactive Power devices installed for the sole benefit of retail customer(s).	
Note – Elements may be included or exclude on a case-by-case basis through the rules of Procedure exemption process.	
Source: NERC Glossary of Terms used in NERC Reliability Standards July 7, 2014	

Based upon the NERC definition of Bulk Electric System (BES) Elements, one notes that the NERC transmission planning standards would only apply to the 230 kV transmission and larger generating stations on the Island Interconnected System. The radial transmission systems, generating stations below 75 MVA combined, the 138 kV loops Stony Brook to Sunnyside and Western Avalon to Holyrood, and load serving 230/138 kV and 230/66 kV stations would be excluded.

Each of the NERC TPL standards contains Table 1 Transmission System Standards – Normal and Emergency Conditions. The table lists, by Category, the contingencies and the system impacts or limits. The table is presented below with the comparison to existing Hydro transmission planning criteria.

Comparison of NERC and Hydro Transmission Planning Criteria					
Category	**Contingencies**	**System Limits or Impacts**			**Hydro Criteria**
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating	Loss of Demand or Curtailed Firm Transfers	Cascading Outages	
A No Contingencies	All Facilities in Service	Yes	No	No	Same
B Event resulting in the loss of a single element	Single line to Ground (SLG) or 3-Phase (3Φ) fault, with Normal Clearing:				
	1. Generator	Yes	No	No	Loss of generator results in under frequency load shedding (controlled load loss) prior to Labrador – Island HVdc Link
	2. Transmission Circuit	Yes	No	No	Same except TL247/248 or TL234/263 loss of generation resulting in under frequency load shedding (controlled load loss) prior to Labrador – Island HVdc Link
	3. Transformer	Yes	No	No	Failure of Deer Lake 230/138 kV T2 requires trip of TL247 and TL248 causing trip of Cat Arm Plant resulting in under frequency load shedding (controlled load loss) prior to Labrador – Island HVdc Link. For generator step up transformer under frequency load loss (controlled load loss) prior to Labrador – Island HVdc Link
	Loss of Element without fault	Yes	No	No	Same, except tripping a generator without fault will result in under frequency load shedding (controlled load loss) prior to Labrador – Island HVdc Link

	Single Pole Block, Normal Clearing: 4. Single pole (dc) line	Yes	No	No	Same
C Event(s) resulting in loss of two or more (multiple) elements	SLG Fault, with Normal Clearing:				Loss of multiple elements not part of documented Hydro Criteria, but considered on station configuration basis
	1. Bus Section	Yes	Planned/ Controlled[1]	No	Fault on bus sections connecting generation will result in loss of generation and under frequency load shedding prior to Labrador – Island HVdc Link (controlled load loss). 230 kV faults on 230/66 kV load bus arrangements such as Massey Drive, Hardwoods and Oxen Pond will result in loss of non BES elements. 230 kV faults on common bus connecting multiple 230/138 kV transformers (Bottom Brook, Stony Brook, Sunnyside, Western Avalon and Holyrood) result in loss of non BES elements. 230 kV faults on bus sections in ring bus configurations (Bottom Brook, Buchans, Bay d'Espoir, Stony Brook, Sunnyside, Western Avalon) result in loss of lines but no load loss except TL234 bus section at Bay d'Espoir results in loss of generation and under frequency load shedding (controlled load loss) prior to Labrador – Island HVdc Link. 230 kV faults on Holyrood bus

					sections not connecting generation result in line loss with no loss of load.
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled[1]	No	From C1 above 230 kV breaker failure for generator connections result in loss of generation with under frequency load shedding prior to Labrador – Island HVdc Link (controlled load loss). From C1 above, 230 kV breaker failure on load bus arrangements (230/66 kV and 230/138 kV) result in loss of non BES elements. For 230 kV ring bus arrangements in C1 above 230 kV breaker failure will result in loss of one line east and west out of station. Transmission path maintained. For 230 kV breaker failure at Holyrood (breaker and one half arrangement) breaker failure will result in loss of generation with under frequency load shedding prior to Labrador – Island HVdc Link (controlled load loss).
	SLG or 3Φ Fault, with Normal Clearing. Manual System Adjustments, followed by another SLG or 3Φ Fault, with Normal Clearing:				Fault followed by system adjustment and subsequent fault not part of documented Hydro Criteria, but assessed at the operations level at time of event for system reconfiguration to minimize impact of subsequent event.
	3. Category B (B1, B2, B3 or B4) contingency,	Yes	Planned/ Controlled[1]	No	Same As in B1, B2, B3, B4

	manual system adjustments followed by another Category B (B1, B2, B3 or B4) contingency				above controlled load loss for each event.
	Bipolar Block, with Normal Clearing: 4. Bipolar (dc) line Fault (non 3Φ), with Normal Clearing: 5. Any two circuits on a multiple circuit towerline	 Yes Yes	 Planned/ Controlled[1] Planned/ Controlled[1]	 No No	 Same No multiple circuit 230 kV transmission towerlines
	SLG Fault, with Delayed Clearing (stuck breaker or protection system failure):				Not part of documented Hydro Criteria, but considered on station basis to limit impact
	6. Generator	Yes	Planned/ Controlled[1]	No	Same See B1 above
	7. Transformer	Yes	Planned/ Controlled[1]	No	Same See B3 above
	8. Transmission Circuit	Yes	Planned/ Controlled[1]	No	Same See B2 and C2 above
	9. Bus Section	Yes	Planned/ Controlled[1]	No	Same see C1 and C2 above
D Extreme event resulting in two or more (multiple) elements removed or cascading out of service.	3Φ Fault, with Delayed Clearing (stuck breaker or protection system Failure): 1. Generator 2. Transmission circuit 3. Transformer 4. Bus Section 3Φ Fault, with Normal Clearing 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines in a common right-of-way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of 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 Scheme (or 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.		Evaluate for risks and consequences. • May involve substantial loss of customer Demand and generation in a widespread are 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.		Not part of documented Hydro Criteria, but considered on station configuration basis D1, D2, D3, D4 as per C6, C7, C8, C9 above result in controlled load loss. D5 as per C2 above result in controlled loss of load. D6 Hydro has no towerline with three or more circuits. D7 – D13 result in potential for loss of customer load and generation in a wide geographic area (such as Avalon Peninsula) D14 New HVdc interconnections to limit exposure to disturbances from other regions.

Source: NERC TPL-001-0.1 Table 1 May 13, 2009 Note 1: 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.	

Having made the comparison between existing Hydro transmission planning criteria and NERC TPL standards, one is in a position to complete the comparison between the Hydro criteria and the NPCC criteria. The NPCC transmission planning criteria are located in the NPCC Reliability Reference Directory #1 "Design and Operation of the Bulk Power System", dated December 1, 2009, revised April 20, 2012. The NPCC Directory #1 contains the requirements of the NERC TPL standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0, in addition to other NERC reliability standards. NPCC Directory #1 criteria are to be used in the design and operation of the **bulk power system**, and are applicable to entities which are part of, or make use of, the **bulk power system**. NPCC defines **bulk power system** (BPS) in its glossary of terms as:

*The interconnected electrical systems within northeastern North America comprised of system **elements** on which **faults** or **disturbances** can have a **significant adverse impact** outside of the **local area**.*[1]

NPCC defines **local area** as:

An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based upon system characteristics. A local area may be relatively large geographically with relatively few buses in a

[1] NPCC Glossary of Terms Used by Directories, January 18, 2012.

sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.[2]

Further, Appendix A of Directory #1 definition of **bulk power system** stipulates that in the context of Directory #1 local areas are determined by the Council members.

NPCC defines **significant adverse impact** as follows:

*With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**:*

a. instability;

- *any instability that cannot be demonstrably contained to a well-defined **local area**.*
- *any loss of synchronism of generators that cannot be demonstrably contained to a well-defined **local area***

b. unacceptable system dynamic response;

- *an oscillatory response to a **contingency** that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.*

c. unacceptable equipment tripping

- *tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system*

[2] NPCC Glossary of Terms Used by Directories, January 18, 2012.

configuration due to operation of a ***protection system*** *in response to a stable* ***power swing***

- *operation of a Type I or Type II* ***Special Protection System*** *in response to a condition for which its operation is not required*

d. *voltage levels in violation of applicable* ***emergency*** *limits;*

e. *loadings on transmission facilities in violation of applicable* ***emergency limits****.*[3]

Collectively, the NPCC defined terms **local area** and **significant adverse impact** determine the **bulk power system** elements that must meet the NPCC Directory #1. This is somewhat different than the NERC definition of the **bulk electric system** elements approach. The nuance from the Island Interconnected System perspective being that, if one defines the Island Interconnected System as an NPCC **local area**, and it is demonstrated that because of the HVdc connection between the island and the Maritime Provinces there is no **significant adverse impact** on the electrical system in the Maritimes (Nova Scotia being a member of NPCC will have to demonstrate that loss of the Maritime Link has no **significant adverse impact** on the system), then there are no **bulk power system elements** within the Island Interconnected System, and therefore the NPCC criteria contained in Directory #1 would not apply to the Island Interconnected System.

Notwithstanding the nuance between NERC and NPCC identification of system elements to be considered in application of transmission planning criteria, the

[3] NPCC Glossary of Terms Used by Directories, January 18, 2012.

following table provides a demonstrative comparison of the NPCC and existing Hydro transmission planning criteria.

Comparison of NPCC and Hydro Transmission Planning Criteria	
NPCC	**Hydro**
5.4 Transmission Design Criteria The portion of the **bulk power system** in each Planning Coordinator Area and in each Transmission Planning Area shall be designed with sufficient transmission capability to serve forecasted demand under the conditions noted in Sections 5.4.1 and 5.4.2. These criteria will also apply after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVdc pole has already been lost, assuming that the Planning Coordinator Area generation and **power** flows are adjusted between outages by the use of **ten-minute reserve** and where available, phase angle regulator control and HVdc control.	NPCC contemplates N-1-1 with system adjustment between contingencies. Hydro contemplates N-1 in documented transmission planning criteria and considers the N-1-1 potential configuration on an operational basis when the system is in the N-1 state.
5.4.1 Stability Assessment	
Stability of the **bulk power system** shall be maintained during and following the most severe of the **contingencies** stated below, with due regard to **reclosing**. For each of the **contingencies** below that involve a fault, **stability** shall be maintained when the simulation is based on **fault clearing** initiated by the **“system A” protection group**, and also shall be maintained when the simulation is based on **fault clearing** initiated by the **“system B” protection group**.	Hydro assumes reclosing on 230 kV transmission system. Hydro employs two different relay protections on each 230 kV transmission line each to give 6 cycle (100 msec) tripping. At present relay A and Relay B are supplied from the same dc source (battery bank) and utilize the same control wiring to the circuit breaker. NPCC requires protection system A and B to be supplied for separate battery banks.
a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with **normal fault clearing**.	Trip of generator results in under frequency load shedding until Labrador-Island HVdc Link is complete. Transformer trip will result in temporary loss of load until failed unit is isolated. Bus section trip may lead to load loss depending upon station (i.e. non ring or breaker-and-one-half arrangements)
b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion.	Hydro does not have multiple circuit transmission towers at the 230 kV or 138 kV voltage level. Hydro subscribes to the NPCC criteria that multiple circuit towers used only for station entrance and exit purposes should not exceed five towers from the station.
c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with **delayed fault clearing**.	Hydro assumes normal clearing time and accepts controlled loss of load within the system under delayed clearing. Note transformer and bus section faults may lead to temporary load loss.

d. Loss of any **element** without a fault.	Same
e. A permanent phase to ground fault on a circuit breaker with **normal fault clearing**. (**Normal fault clearing** time for this condition may not always be high speed.)	For circuit breaker fault, Hydro may experience controlled load loss.
f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault	Hydro accepts planned loss of load for permanent bipole loss.
g. The failure of a circuit breaker to operate when initiated by a **SPS** following: loss of any **element** without a fault; or a permanent phase to ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.	For circuit breaker failure, Hydro may experience controlled load loss.
5.4.2 Steady State Assessment	
a. Each Transmission Planner shall design its system in accordance with these criteria and its own voltage control procedures and criteria, and coordinate these with adjacent Transmission Planner Areas**.** Adequate **reactive power** resources and appropriate controls shall be installed in each Transmission Planner Area to maintain voltages within normal limits for pre-**disturbance** conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.4.1.	Hydro ensures adequate reactive power resources and voltage control to maintain voltages within normal and emergency limits for single element contingencies only. Hydro same for 5.4.1 contingencies a, c, d, e, f and g. Contingency 5.4.1.b not applicable to Island Interconnected System.
b. Line and equipment loadings shall be within normal limits for pre-**disturbance** conditions and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.4.1.	Same
5.6 Extreme Contingency Assessment a. Loss of the entire capability of a generating station. b. Loss of all transmission circuits emanating from a generating station, switching station, dc terminal or substation c. Loss of all transmission circuits on a common right-of-way. d. Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with **delayed fault clearing** and with due regard to **reclosing**. e. The sudden dropping of a large **load** or major **load** center. f. The effect of severe **power** swings arising from **disturbances** outside the Council's interconnected systems. g. Failure of a **special protection system**, to operate when required following the normal **contingencies** listed in Section 5.4.1. h. The operation or partial operation of a **special protection system** for an event or condition for which it was not intended to operate. i. Sudden loss of fuel delivery system to multiple plants, (i.e. gas pipeline **contingencies**, including both gas transmission lines and gas mains.) Note: The requirement of this section is to perform	Not part of documented Hydro Criteria, but considered on station configuration basis 5.6.a, b, c, d, e, g, and h result in potential for loss of customer load and generation in a wide geographic area (such as Avalon Peninsula) 5.6.f New HVdc interconnections to limit exposure to disturbances from other regions. 5.6.i existing thermal plants on Island not dependent upon a common fuel delivery system (i.e. no common natural gas pipeline). Holyrood fired on heavy oil, combustion turbines fired on light distillates.

extreme **contingency** assessments. In the case where extreme **contingency** assessment concludes there are serious consequences, an evaluation of implementing a change to design or operating practices to address such **contingencies** shall be conducted.	
Source: NPCC Directory #1	

Hydro has not completed its assessment on full NPCC membership post completion of the Labrador – Island HVdc Link and Maritime Link, or to what extent the NERC and NPCC criteria should be adopted for use within the provincial transmission system. Based upon the establishment of the **Bulk Electric System (BES)/Bulk Power System (BPS)** and interpretation of NPCC defined **local area** and **significant adverse impact**, there would be flexibility in how Hydro adopts and implements the various NREC/NPCC planning standards if full membership is undertaken. Hydro expects that any significant change to existing transmission planning criteria on the Island Interconnected System will require acceptance by the Board prior to implementation. Hydro continues to monitor the NERC and NPCC standards to ensure that the transmission planning processes are meeting the spirit of the standards, consistent with good utility practice.