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BY COURIER

June 2, 2008

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2008-0023 – Hydro One Networks' Section 92 Vanessa to Norfolk Transmission Reinforcement – Interrogatory Responses

I have attached two paper copies of Hydro One Networks' responses to the interrogatory questions from Ontario Energy Board staff. A text-searchable Acrobat version of these responses has been filed using the Board's Regulatory Electronic Submission System (RESS) and a copy of the confirmation note is attached in accordance with the Board's RESS filing guideline.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

OEB - INTERROGATORY #1 List 1

Interrogatory

1.0 Project Need

References: (1) Exh. B, Tab 1, Sch. 4, Sections 2.1 and 2.2
(2) Exh. B, Tab 6, Sch. 3, Page 5

Preamble

Table 1 in Ref. 1 shows that the summer peak load on the two stations supplied from the existing 115 kV circuit between Vanessa Junction and Norfolk TS. The table shows that the total load exceeds the rating of the existing 115 kV line (86 MW) starting in 2010. Hydro One concludes that additional transmission capacity is needed to avoid this overload condition on the existing 115 kV circuit.

In addition to the capacity requirement mentioned above, Hydro One also states that a second circuit is proposed as a means to “mitigate reliability concerns”. For justification of this proposal Hydro One refers to the IESO’s statement in Ref (2) that according to “proposed IESO load supply guidelines”, load levels between 76 MW and 150 MW should be restorable by switching and that this can be achieved by installing a second 115 kV circuit.

Board Staff seeks clarification regarding the need for the second circuit and specifically, the criteria applied to establish the need.

Questions / Requests

i. Please provide a copy of the “proposed IESO load supply guidelines” referenced in the preamble.

ii. Since these “guidelines” are referred to as “proposed” in a report dated November 12, 2002, have the guidelines since been finalized and approved?

iii. If the answer to (ii) is “no”, please provide the rationale for relying on the guidelines.

iv. If the answer to (ii) is “yes”, please provide the rationale for recommending the addition of the second circuit based on “guidelines”, since the term “guidelines” seems to suggest that they are not mandatory.

Response

i. Hydro One’s understanding is that the IESO load supply guidelines have been superseded by the Ontario Resource and Transmission Assessment Criteria (“ORAT”) finalized and issued by the IESO in 2007. The ORAT incorporated the standards of the load supply guidelines, with modifications. A copy of the ORAT document is attached as Attachment A, as is a copy of the latest (2005) version of the load supply guidelines (IESO Supply Deliverability Guidelines or "SDG") as Attachment B.

ii. Hydro One's understanding is that the Sept. 14, 2005 version of the SDG is the latest approved version. As noted in part (i), these Guidelines have been incorporated into and superseded by the ORAT.

iii. Not applicable

iv. The 2002 SIA relied on the IESO's SDG in planning the Vanessa to Norfolk project. Today, the ORAT criteria for load supply have been modified (details in IR #3). Hydro One has assessed the criteria and believes the Vanessa to Norfolk project is consistent with these criteria.

Hydro One's rationale for following the ORAT direction is provided in IR #3. Section 7.2 of the ORAT, states that the transmission system must be planned such that affected loads can be restored within the given restoration times.

Filed: June 2, 2008
EB-2008-0023
Exhibit C
Tab 1
Schedule 1
Attachment A
Page 1 of 61

IMO_REQ_0041

REQUIREMENTS

Ontario Resource and Transmission Assessment Criteria

Issue 5.0

This document is to be used to evaluate long-term system *adequacy* and *connection assessments*

Disclaimer

Document ID	IMO_REQ_0041
Document Name	Ontario Resource and Transmission Assessment Criteria
Issue	Issue 5.0
Reason for Issue	Released for Baseline 17.1
Effective Date	August 22, 2007

Document Change History

Issue	Reason for Issue	Date
1.0	First release	June 4, 2003
2.0	Issue released for Baseline 10.0	September 10, 2003
3.0	Name and logo changed to IESO	September 14, 2005
4.0	Released for Baseline 15.0	March 8, 2006
5.0	Revised for Baseline 17.1	August 22, 2007

Related Documents

Document ID	Document Title

Table of Contents

Table of Changes

Reference (Section and Paragraph)	Description of Change
Entire document	Name changed to Ontario Resource and Transmission Assessment Criteria. Defined terms were italicized. Document titles were reformatted as per section 1.4. Quotations were removed from words that are not documents.
Section 1	Clarified the purpose, scope and users of the document. Added conventions section.
Section 2	Clarified load modelling (sec 2.4) and contingency criteria (sec 2.7.1). Aligned section 2.7.1 with the criteria with NPCC document A-02 (section 5.0). Clarified study time periods, load forecasts and modelling, local area requirements, bulk power system and local area contingency studies.
Section 3	Clarified special protection systems (sec 3.4.1). Clarified how system conditions were to be modelled including generation dispatch, stability conditions, permissible control actions and special control systems. Changed to section 3.1.1 to 3.1 and corrected references to 3.1.1.
Section 4	Clarified P-V curves (sec 4.5.1). Clarified power transfer capability, pre-contingency voltage limits and voltage change limits, steady state voltage stability, lines and equipment loading and short circuit levels.
Section 5	Updated section heading and all references to be "Transmission Connection Criteria".
Section 6	Updated section heading and all references to be "Generation Connection Criteria". Clarified how transmission line ratings are calculated in the vicinity of wind farms.
Section 7	Created a new section titled " 7. Load Security and Restoration Criteria ". Clarified the effect of local generation when one element is out of service and when two elements are out of service. References to E-2 were deleted in section 7.2. Clarified control action criteria and application of restoration criteria.
Section 8	Created a new section titled "Resource Adequacy Assessment Criterion". Changed title of document to "Ontario Resource and Transmission Assessment Criteria"
Appendix E	Deleted
References	Added documents referred to within this document

1. Introduction

1.1 Purpose

The purpose of this document is to identify the technical criteria for use in the assessments of the *adequacy* and *security* of the *IESO-controlled grid* and to clarify how the *IESO* will apply the relevant *NPCC* and *NERC* standards and implement them within Ontario.

1.2 Scope

This document is to be used for assessing the current and future *adequacy* of the *IESO-controlled grid*, for conducting the *IESO's* 18-month outlooks, for identifying the need for system enhancements and for evaluating the effectiveness of planned generation and transmission enhancements. It does not identify operating or safety criteria.

1.3 Who Should Use This Document

This document is used by the *IESO* and may also be referred to by stakeholders and *market participants* to help them understand *IESO* criteria and further their *connection assessment* work.

1.4 Conventions

The standard conventions followed for market manuals are as follows:

- The word 'shall' denotes a mandatory requirement;
- Terms and acronyms used in this market manual including all Parts thereto that are italicized have the meanings ascribed thereto in Chapter 11 of the "Market Rules";
- Double quotation marks are used to indicate titles of legislation, publications, forms and other documents.

Any procedure-specific convention(s) shall be identified within the procedure document itself.

– End of Section –

2. Study Parameters and Contingency Criteria

This section is intended to provide guidance in carrying out the technical studies to assess the *adequacy* of the *IESO-controlled grid* in order to meet general load growth and *connection assessment* requirements, and to ensure that *reliability* is within standards. It also includes contingency criteria consistent with *NERC* and *NPCC* standards.

These study parameters must be applied on the basis of good utility practice and judgment, taking into account the particular circumstances and characteristics of the part of the *IESO-controlled grid* that is being studied.

This section includes study guidelines for: study period, base case, load levels, power transfer capability, area flow requirements, contingency based assessment and study conditions.

2.1 Study Purpose

The purpose of conducting studies is to identify system deficiencies and to establish the requirements for a connection proposal to ensure it satisfies *reliability standards*.

A comparison of the results of power flow studies under normal and *outage* conditions (with normal and *outage* power flows) will determine:

- the need date for new transmission investment in the *IESO-controlled grid* to maintain the *reliability* of supply within standards; or,
- the acceptability of a connection proposal for a *connection assessment*.

The sensitivity of the need date to load growth rate, resource variations (e.g. approved *connection assessments*) and related system developments should be investigated. The results of this investigation should normally be given in terms of a range of dates within which there is a high confidence level that the connection proposal is acceptable or that additional *facilities* or enhancements will be required.

2.2 Study Period

The study period depends on the purpose of the assessment. When checking the reliability of long term projects and plans the study period must go out beyond the in-service date and include various years between the start and end dates of the study.

- For *connection assessments* for proposed load developments, the study period shall run from the planned in service date of the proposed *facility* up to 10 years into the future depending on the availability of load forecasts. Where the evaluation depends on factors or system developments beyond the 10 year study period, the study period may need to be extended farther into the future.

- For *connection assessments* for generators, the study period shall run from the planned in service date of the proposed *facility* up to 10 years into the future depending on the availability of demand forecasts. Where the evaluation depends on factors or system developments beyond the 10 year study period, the study period may need to be extended farther into the future.

- For *connection assessments* for proposed *transmission* developments, the study period shall run from the planned in service date of the proposed *facility* up to 10 years into the future depending on the availability of load forecasts. Where the evaluation depends on factors or system developments beyond the 10 year study period, the study period may need to be extended farther into the future.

- For *NPCC* transmission reviews, the study period covers a 4 to 6 year look ahead period from the report date. These reviews are of three types: a comprehensive or full review, an intermediate or partial review and an interim review. Refer to *NPCC* document B-04, "Guidelines for *NPCC* AREA Transmission Reviews" for details.

- For *NPCC* resource adequacy reviews, the study period covers a 5 year look ahead period. These reviews are of two types: a comprehensive resource review and an annual interim review. Refer to *NPCC* document B-08, "Guidelines for Area Review of Resource Adequacy" for details.

Note that it is unnecessary to consider every year in the study period. The first and last years of the study period plus sufficient intermediate years to zero in on and bracket the critical year(s) is generally adequate.

2.3 Base Case

Master base cases are used as the starting point for all studies. The master base cases include all *connection assessment* projects that are approved, including those that did not require a formal *connection assessment* study. *Local area* details are added as appropriate. Information regarding base cases can be found on the *IESO's* Forecasts webpage.

The *IESO* Web site also provides firm and planned resource scenarios as described in each 18-Month Outlook.

Connection assessment studies are conducted using the master base cases. Long term assessment studies start with the master base cases and exclude less firm generation *connection assessment* projects per the planned resource scenario. The impact of adding approved *connection assessment* projects should be reviewed to identify if approved *connection assessments* improve or worsen any identified deficiency.

2.4 Load Forecasts and Load Modelling

The load levels used in the study shall be based on the latest forecast[1] consistent with the IESO's and the OPA's latest long-term forecast. Load forecast uncertainty should be taken into account by investigating the sensitivity of the need date to various items (e.g. higher and lower loads).

The summer or winter median growth forecast (based on normal weather) should be used depending on the peak loading conditions of the area being studied.

The sensitivity study should be done with high-growth extreme weather forecasts and low-growth normal weather forecasts, and with light load scenarios as required in order to stress the system. Under light load conditions, worst case ambient conditions should be assumed.

If a *connection assessment applicant* provides a detailed local forecast, that forecast should be used.

For *local area* assessments, the 18 month master base case should be modified to ensure the forecast is representative of the most recent peak load and power factors based on billing data. Local load should be modeled as accurately as possible and any local *embedded generator(s)* or large motor(s) should be included.

For assessment purposes the power factor is assumed to be 0.90 at the *defined meter point*. If an *embedded generator* is connected to a load bus, the 0.90 power factor is assumed with the generator out-of-service. In certain circumstances detailed load models may be required if they are expected to impact the *local area* performance.

Dispatchable load will be assumed to be consuming as required in order to stress the system.

Studies should be done with a load model representative of the actual load. For powerflow planning studies assessing the voltage stability of the bulk system, loads normally should be modelled as constant megavolt-amperes (MVA). In assessing voltage change limits and transient performance, a voltage dependent load model should be used. If specific information is not available, the load model in Ontario should be as indicated in the following table:

<u>Static Load Models for Simulation</u>

REAL POWER		REACTIVE POWER	
Constant Current	**Constant Impedance**	**Constant Current**	**Constant Impedance**
(%)	**(%)**	**(%)**	**(%)**
50	50	0	100

Thus, in Ontario, a load model of P=50, 50, Q=0, 100 (e.g. $P \propto V^{1.5}$, and $Q \propto V^2$) should be used. The load models for neighboring areas should be consistent with load models used in Reliability First Corporation (RFC), Midwest Regional Organization (MRO), and *NPCC* studies.

[1] The IESO continues to produce 10-year demand forecasts using an econometric model. These forecasts are coordinated with OPA's multi-year end use forecasts and adjusted for Conservation and Demand Management (CDM).

2.5 Power Transfer Capability

A power transfer capability analysis should be performed throughout the study period taking into account the effects of planned *facilities*, the growth in loads, and the effects (if any), of various system generation patterns. The transfer limits should be determined for one or both directions of flow (as necessary).

With all transmission *facilities* in service, the power transfer capability is determined for the worst applicable contingency. Also, it will generally be necessary to determine the effects of seasonal variations (e.g., summer and winter line ratings) on the limits.

Generally, the transmission interface limits will be determined by one or more of the following post-contingency considerations:

- line and equipment loading must not exceed ratings,
- voltage declines must not exceed certain limits,
- machine and voltage angles must remain in synchronism, and
- voltages are stable (V-Q sensitivity is positive).

2.6 Local Area Requirements

Inter-area transmission is any circuit or group of transmission circuits interconnecting two areas of the *IESO-controlled grid*. Flows across the interface may either always be in one direction or in different directions at different times, in which case it may be necessary to consider each of the areas as the receiving area. The impact of *local area facilities* on inter-area transmission must be evaluated.

The magnitude and direction of future power flow requirements on the area studied should be determined for normal and contingency conditions. Peak, off-peak, and light load flow requirements should be considered.

With all transmission *facilities* in service (normal conditions), the schedule for generation in the receiving area should be based on the historically typical conditions. That is, for pre-contingency conditions, nuclear and run of river hydro-electric generation should be assumed at a level that is available 98% of the time. For example, on-peak conditions should be assessed with peaking hydro-electric generation plants, fossil plants and wind farms running at maximum output. Where *reliability* depends on local generation, sensitivity studies should be done to assess the impact of *outages* of local generation.

Load diversity and transmission losses should be given due consideration to ensure *facility* requirements are not overestimated.

2.7 Contingency-Based Assessment

The principal purpose of a system *adequacy/connection assessment* is to identify any areas where supply *reliability* may be at unacceptable risk. This could be due to a combination of factors such as load growth, load reduction, generation, or non-deliverability within a certain area.

The *IESO-controlled grid* must be planned with sufficient capability to withstand the loss of specified, representative and reasonably foreseeable contingencies at projected customer *demand* and anticipated transfer levels. Application of these contingencies should not result in any criteria violations, or the loss of a major portion of the system, or unintentional separation of a major portion of the system. The *IESO-controlled grid* shall be designed with sufficient capability to keep voltages, line and equipment loading within applicable limits for these contingencies

The *IESO*, as a member of *NPCC*, uses a contingency-based assessment to evaluate the *adequacy* and *security* of the bulk power system. The contingencies considered are identified in *NPCC* criteria A-02, "Basic Criteria for Design and Operation of Interconnected Power Systems". The *IESO* conducts studies with these contingencies applied throughout the *IESO-controlled grid*, assuming that *facilities* have not been designed to bulk power system standards, to test for the consequences. The *IESO* evaluates the study results to determine if a *facility* should be designated a bulk power system *facility*. If the consequence of the contingency has a significant adverse impact outside the *local area*, the *facilities* are deemed to be bulk power system *facilities* and must comply with *NPCC* criteria A-02, A-04, "Maintenance Criteria for Bulk Power System Protection" and A-05, "Bulk Power System Protection Criteria". *NPCC* Criteria are not applied in *local areas* where the consequence of faults or disturbances is well understood and restricted to a clearly defined set of *facilities* on the *IESO-controlled grid*.

NPCC extreme contingencies shall be assessed periodically in accordance with *Reliability* Coordinating Council criteria A-02, and guideline B-04, "Guideline for *NPCC* AREA transmission Reviews".

NPCC is in the process of developing the classification methodology for identifying the elements that constitute the bulk power system (reference *NPCC* A-10, "Classification of Bulk Power System Elements". The *IESO's* definition of the bulk power system will be consistent with *NPCC's* definition.

When conducting *connection assessments* or assessing system *adequacy*, various contingencies are applied to the *IESO-controlled grid* and their impact is evaluated. Different contingencies are evaluated for the bulk power system and *local areas*. For those parts of the *IESO-controlled grid* that are designated as bulk power system *facilities*, *NPCC* design criteria contingencies are applied, per Section 2.7.1. For those parts of the *IESO-controlled grid* that are designated as *local areas*, *local area* contingencies are applied, per Section 2.7.2.

In *local areas*, where the contingency propagates to a higher voltage level or causes a net load loss in excess of 1000MW, the *IESO* will apply the bulk power system contingencies described in section 2.7.1.

2.7.1 The Bulk Power System Contingency Criteria

In accordance with *NPCC* criteria A-02, the bulk power system portion of the *IESO-controlled grid* shall be designed with sufficient transmission capability to serve forecasted loads under the conditions noted in this section. 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 generation and power flows are adjusted between *outages* by the use of *ten-minute operating reserve* and where available, phase angle regulator control and HVdc control.

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. The following contingencies are evaluated for the bulk power system portion of the *IESO-controlled grid*:

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with normal fault clearing.

b. Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent circuits of 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, this condition is an acceptable risk and therefore can be excluded.

c. A permanent phase-to-ground fault on any transmission circuit, transformer or bus section with delayed fault clearing (This contingency covers a breaker failure).

d. Loss of any element without a fault.

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.) Note that this condition covers the blind spot on a breaker or on a bus section between a free standing current transformer (CT) and a breaker. It is included for completeness and is not intended to be more onerous than c) above (e.g. neither a stuck breaker nor a protection system failure need be considered for this type of contingency on account of the low probability of such an occurrence, therefore, there would normally be no reason to actually test for this condition).

f. Simultaneous permanent loss of both poles of a direct current bipolar *facility* without an ac fault.

g. The failure of a circuit breaker to operate when initiated by an *SPS* following: the 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.

The bulk power system portion of the *IESO-controlled grid* shall be designed in accordance with these criteria and the *IESO's* local voltage control procedures and criteria, which shall be coordinated with adjacent *control areas*[2]. Adequate reactive power resources and appropriate controls shall be installed in the *IESO-controlled grid* to maintain voltages within normal limits for predisturbance conditions, and within applicable *emergency* limits for the system conditions that exist following the contingencies specified above.

Line and equipment loadings shall be within normal limits for predisturbance conditions and within applicable *emergency* limits for the system conditions that exist following the contingencies specified above.

The *IESO-controlled grid* shall be designed to ensure that equipment capabilities are adequate for fault current levels with all transmission and *generation facilities* in service for all potential operating conditions. Procedures established to manage fault levels shall be coordinated with adjacent areas and regions[2].

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[2] Language and accountabilities used in NPCC A-2 is evolving. Terms such as control areas, areas, and regions should be interpreted broadly to include the meaning originally intended in A-2, until it is revised.

2.7.2 Local Area Contingencies

For *local areas* the *IESO-controlled grid* must exhibit acceptable performance following:

a. the loss of an element without a fault, and

b. a phase-to-phase-to-ground fault on any generator, transmission circuit, transformer, or bus section with normal fault clearing.

In the non bulk power system, the contingencies studied and the acceptability of involuntary load interruptions are dependent on the amount of load impacted. Typically only single-element contingencies are evaluated. The *IESO* defines a single-element as a single zone of protection. Double element contingencies are evaluated as per section 2.7.1.

2.7.3 Extreme Contingencies

NPCC criteria A-02 recognizes that the bulk power system can be subjected to extreme contingencies. Even though the probability of these situations is low, *NPCC* criteria states that analytical studies shall be conducted to determine the effect of certain extreme contingencies. In the case where an extreme contingency assessment concludes there are serious consequences, an evaluation of implementing a change to design or operating practices to address such contingencies must be conducted, and measures may be utilized where appropriate to reduce the likelihood of such contingencies or to mitigate the consequences indicated in the assessment of such contingencies.

2.7.4 Extreme System Conditions

The bulk power system can be subjected to abnormal system conditions with a low probability of occurring such as peak load conditions resulting from extreme weather conditions with applicable ratings of electrical elements or fuel shortages. An assessment to determine the impact of these conditions on expected steady-state and dynamic system performance shall be done in order to obtain an indication of system robustness or to determine the extent of a widespread adverse system response. After due assessment of extreme system conditions, measures may be utilized, where appropriate, to mitigate the consequences that are indicated as a result of testing for such system conditions.

2.8 Study Conditions

The system load and generation conditions under which the contingencies are assumed to occur are chosen on a deterministic basis to represent the reasonable worst case scenario. For loadflow and transient stability studies, the system should be studied with various pre-contingency conditions that stress the system. Various contingencies should then be evaluated to identify the most limiting contingencies and conditions. Typical sets of system conditions to evaluate in the study of the bulk power system and *local areas* are shown below. Not all conditions need to be evaluated. Studies should start with the one or two most stressful system conditions. If no deficiency is identified then no additional study is required. If a deficiency is identified, sensitivity studies should be done to further define the timing and magnitude of the deficiency. These additional conditions for long term assessments may include modifying the master base case to include approved connection approvals.

Various interface transfer levels should be considered to stress the system as required to uncover deficiencies.

Sample System Conditions to Evaluate in Studies for the Bulk Power System

Weather/Load	Generation	Transmission	Contingencies per Section 2.7.1
Median growth extreme weather	All in service	All in service	All
Median growth normal weather	2 units out of service	All in service	All
Median growth normal weather	All in service	1 element out of service	All
Low growth normal weather	All in service	All in service	All
Light load normal weather	Reduced *dispatch* as required	All in service	All

The purpose of the analysis is to identify the consequence of various scenarios up to two single contingencies, but not necessarily the worse possible contingencies under the worst load and ambient conditions.

Sample System Conditions to Evaluate in Studies for Local Areas

Weather/Load	Local Generation	Local Transmission	Contingencies per Section 2.7.2
Median growth extreme weather	Up to 2 local units out of service	All in service	All
Median growth extreme weather	All in service	Any one element out of service	All
Light load normal weather	Various scenarios	Various scenarios	All
Low growth normal weather	All in service	All in service	All

– End of Section –

3. System Conditions

The specific load and generation conditions and assumptions, applicable stability conditions, and permissible use of control actions for the area being studied are identified in the following sections.

3.1 Generation Dispatch

Generation is to be *dispatched* as required in order to stress the system so as to identify limitations of the *transmission* transfer capability.

3.2 Exports and Imports

All exports and imports should be taken into account to achieve the conditions of section 3.1. The pre-contingency level of the transfer selected should be based on the existing and projected *interconnection* capability. Combinations of maximum transactions coincident with high internal power flows should be considered in order to stress the import interface and to ensure studies evaluate the full range of power flow scenarios. In addition, the effect of bilateral *interconnection* assistance up to the tie-tine capability should be studied with all transmission *facilities* in service. Post-contingency tie flows that are different from the scheduled flows on phase-shifted ties or greater than the pre-contingency interface flow on unregulated ties may be permitted before adjustment provided they are within applicable limits (generally the 15 minute rating).

3.3 Stability Conditions

3.3.1 Contingencies

The system shall remain stable during and after the most severe of the contingencies listed in 2.7.1 and 2.7.2, with due regard to reclosing as per *NPCC* criteria A-02.

3.3.2 General Guidelines

The *NPCC* A-02 criteria do not stipulate the use of margin on transient stability limits. However, the *IESO* criteria require that all stability limits should be shown to be stable if the most critical parameter is increased by 10%. This is to account for modeling errors, metering errors and variations in *dispatch*.

The 10% increase can be simulated by generation or load changes even beyond the forecast load or generation capabilities provided it does not lead to invalid results. Negative values of local load is preferable to increasing local generation beyond its maximum capability.

3.4 Permissible Control Actions

Following the occurrence of a contingency, the following control actions may be used to respect the loading, voltage decline, and stability limits referenced in this document:

- Generation Redispatch
- Automatic tripping of generation (generation rejection)
- Trip circuits open to change flow distributions
- Trip or redispatch *dispatchable loads*
- Switch reactors and/or capacitors out (switching in of capacitors in locations that are especially sensitive to voltage changes is to be done only in such a manner as to ensure minimal impact on customers, e.g., using independent pole operation (IPO) breakers)
- Operate phase shifters

In addition to the above control actions, automatic or manual tripping of *non-dispatchable load* may be considered for certain contingencies with one or more transmission elements out-of-service. Generally, *facilities* for the automatic tripping of load will only be acceptable as a stop gap measure to increase the power transfer capability across a bulk transmission interface to cope with temporary deficiencies.

The control actions that are permissible are shown below:

Permissible Control Actions Following Contingency

System Condition Prior to Contingency	**Permissible Control Actions Following Contingency**
All elements in service	• Generation Redispatch • Load Redispatch • Generation Rejection • Capacitor Switching • Reactor Switching • Open circuits to change flow distributions
One or more transmission elements out of service	• Generation redispatch including transactions • Generation Rejection • Capacitor Switching • Reactor Switching • Open circuits to change flow distributions • Load Rejection

3.4.1 Special Protection System

A *special protection system* (*SPS*) is defined as a protection system designed to detect abnormal system conditions and take corrective action(s) other than the isolation of faulted elements. Such action(s) may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. The *NPCC* A-02 criteria provide for the use of a *SPS* under normal and *emergency* conditions.

A *SPS* shall be used judiciously and when employed, shall be installed consistent with good system design and operating policy. A *SPS* associated with the bulk power system may be planned to provide protection for infrequent contingencies, for temporary conditions such as project delays, for unusual combinations of system demand and outages, or to preserve system integrity in the event of severe outages or extreme contingencies. The reliance upon a *NPCC* type I *SPS* for *NPCC* A-2 design criteria contingencies with all transmission elements in service must be reserved only for transition periods while new transmission reinforcements are being brought into service. A *SPS* associated with the non-bulk portion of the power system may be planned to provide protection for a wider range of circumstances than a *SPS* associated with the bulk system.

The decision to employ a *SPS* shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits. The requirements of *SPSs* are defined in *NPCC* criteria A-05, and in NPCC criteria A-11, "Special Protection System Criteria". With all transmission elements in service, continued reliance on a *SPS* is a trigger for considering additional transmission.

A *SPS* proposed in a *connection assessment* must have full redundancy and separation of the communication channels, and must satisfy the requirements of the *NPCC* Type I *SPS* criteria to be considered by the *IESO*.

Automatic Tripping of Generation (Generation Rejection)

Automatic tripping of generation via Generation Rejection Schemes (G/R) is an acceptable post-contingency response in limited circumstances as specified below in section 7.3, Control Action Criteria. Arming of G/R may be acceptable for selected contingencies provided the G/R corrects a *security* violation and results in an acceptable operating state.

– End of Section –

4. Pre and Post Contingency System Conditions

This section identifies the acceptable pre-and post-contingency response on the *IESO-controlled grid*. Criteria include:

- Power Transfer Capability
- Pre Contingency Voltage Limits
- Voltage Change Limits
- Transient Voltage Criteria
- Steady State Voltage Stability
- Congestion
- Line and Equipment Loading
- Short Circuit Levels

If studies indicate that any criterion in this section is not met, the *IESO* will either notify the *IESO-administered market* of a system inadequacy or inform the *connection assessment* proponent that the submitted proposal is not acceptable (i.e. that the proposal must be re-designed).

4.1 Power Transfer Capability

To evaluate the impact of a *connection assessment* on power flow across an interface, it is important to consider:

- The impact on the power flow caused by the introduction of a new limiting contingency (new elements introduce new contingencies); and
- The impact on power flow distribution over the interface (transfer capability) caused by the introduction of new *facilities* which change power flow distribution.

New or modified connections to the *IESO-controlled grid,* for example a new generator, may increase congestion on transmission *facilities* but will not be permitted to lower power transfer capability or operating *security limits* by 5% or more. This will be assessed on a case by case basis. The following are examples of changes that could affect the transfer capability or operating *security* limits:

- an increase in load or generation greater than or equal to 20 MVA;
- where the connectivity of the transmission system is changed and a new contingency is created;

- where the electrical characteristics of generation facilities are changed by greater than or equal to 5%, or exceed accepted design standards and tolerances, or are not in conformance with Appendix 4.2 of the Market Rules;
- where the electrical characteristics of a transmission facility change by greater than or equal to 10%;
- where the transfer capability is reduced by more than 5%; or
- where a new or modified SPS is proposed

4.2 Pre-Contingency Voltage Limits

Under pre-contingency conditions with all *facilities* in service, or with a critical element(s) out of service after permissible control actions and with loads modeled as constant MVA, the *IESO-controlled grid* is to be capable of achieving acceptable system voltages. The table below indicates the maximum and minimum voltages generally applicable. These values are obtained from Chapter 4 of the "Market Rules", and CSA standards for distribution voltages below 50 kV.

Nominal Bus Voltages

Nominal Bus Voltage (kV)	**500**	**230**	**115**	**Transformer Stations, e.g. 44, 27.6, 13.8 kV**
Maximum Continuous (kV)	550	250	127*	106%
Minimum Continuous (kV)	490	220	113	98%

* Certain buses can be assigned specific maximum and minimum voltages as required for operations. In northern Ontario, the maximum continuous voltage for the 115kV system can be as high as 132kV.

- Transmission equipment must be able to interrupt fault current for voltages up to the *maximum continuous rating*.
- Transmission equipment must remain in service, and not automatically trip, for voltages up to 5% above the maximum continuous rating, for up to 30 minutes, to allow the system to be re-*dispatched* to return voltages within their normal range.

Transformer stations must have adequate under-load tap-changer or other voltage regulating *facilities* to operate continuously within normal variations on the *transmission system* and to operate in *emergencies* in accordance with transmission voltage ranges as listed in the table in section 4.3.

In general, system pre-contingency voltages used in planning studies should approximate existing system voltage profiles under similar load and generation conditions.

Voltages below 50kV shall be maintained in accordance with CSA 235 by the *transmitter* and/or *distributor*.

4.3 Voltage Change Limits

With all planned *facilities* in service pre-contingency, system voltage changes in the period immediately following a contingency are to be limited as follows:

Nominal Bus Voltage (kV)	**500**	**230**	**115**	**Transformer Station Voltages**		
				44	**27.6**	**13.8**
% voltage change **before** tap changer action	10%	10%	10%	10%	10%	10%
% voltage change **after** tap changer action	10%	10%	10%	5%	5%	5%
AND within the range						
Maximum* (kV)	550	250	127	112% of nominal		
Minimum* (kV)	470	207	108	88% of nominal		

*The maximum and minimum voltage ranges are applicable following a contingency. After the system is redispatched and generation and power flows are adjusted the system must return to within the maximum and minimum continuous voltages identified in section 4.2.

Before tap-changer action (immediate post-contingency period) a constant MVA load model can be used. If the voltage change exceeds the limits identified above, a voltage dependent load model should be used (e.g. $P \propto V^{1.5}$, and $Q \propto V^2$). After tap-charger action a constant power load model should be assumed (e.g. the load will return to its pre-contingency level). In areas of the system where it is known that post-contingency voltages will remain depressed after tap-changer and other automatic corrective actions, or in situations where special control actions are proposed (e.g., blocking of under-load tap-changers), the use of variable loads in the longer term post-contingency period may be acceptable.

In cases where voltage rises are a possibility (e.g., islanded generators), transient stability tests should be carried out as a check to ensure that realistic reactive additions are appropriate and that customer equipment will not be exposed to excessive voltages after the transient post-contingency period. The occurrence of a voltage rise for loss of a system element is rare but voltage rises after reclosure operations, especially where capacitor or reactor switching are involved, are relatively common and should be checked. Voltage rises should not result in bus voltages higher than the maximum values indicated in the above table. Not only is equipment damage a concern at such high voltages but, in addition, it may not be safe to carry out breaker switching operations to reduce the voltages to acceptable levels. Capacitor breakers at locations where excessive voltages are possible should be designed for appropriately higher operating voltages.

4.3.1 Reactive Element Switching Change

Reactive devices should be sized to ensure that voltage declines or rises at *delivery point* buses on switching operations will not to exceed 4% of steady state rms voltage before tap changer action using a voltage dependent load model (e.g. $P \propto V^{1.5}$, and $Q \propto V^2$).

4.3.2 Capacitive Element Switching Change

Capacitive devices include HV capacitors, LV capacitors, SVCs, series capacitors, and synchronous condensers.

Capacitive devices should be sized to ensure that voltage declines or rises at ***delivery point*** buses on switching operations will not exceed 4% of steady state rms voltage for line switching operations per Chapter 4 of the "Market Rules". This 4% is based on load flows before tap changer action using a voltage dependent load model (e.g. $P \alpha V^{1.5}$, and $Q \alpha V^2$).

4.4 Transient Voltage Criteria

In cases where protection or control coordination may be an issue, or where significant induction motor load is present, time domain simulations should be conducted to assess the dynamic voltage performance. These simulations should cover a time frame in which ULTCs operate (<30 seconds) and should include modeling of devices which affect voltage stability (such as induction motors, ULTCs, switched shunts, generator field current limiters, etc). Per section 3.3.1, due regard should be given to reclosure operations in the simulation.

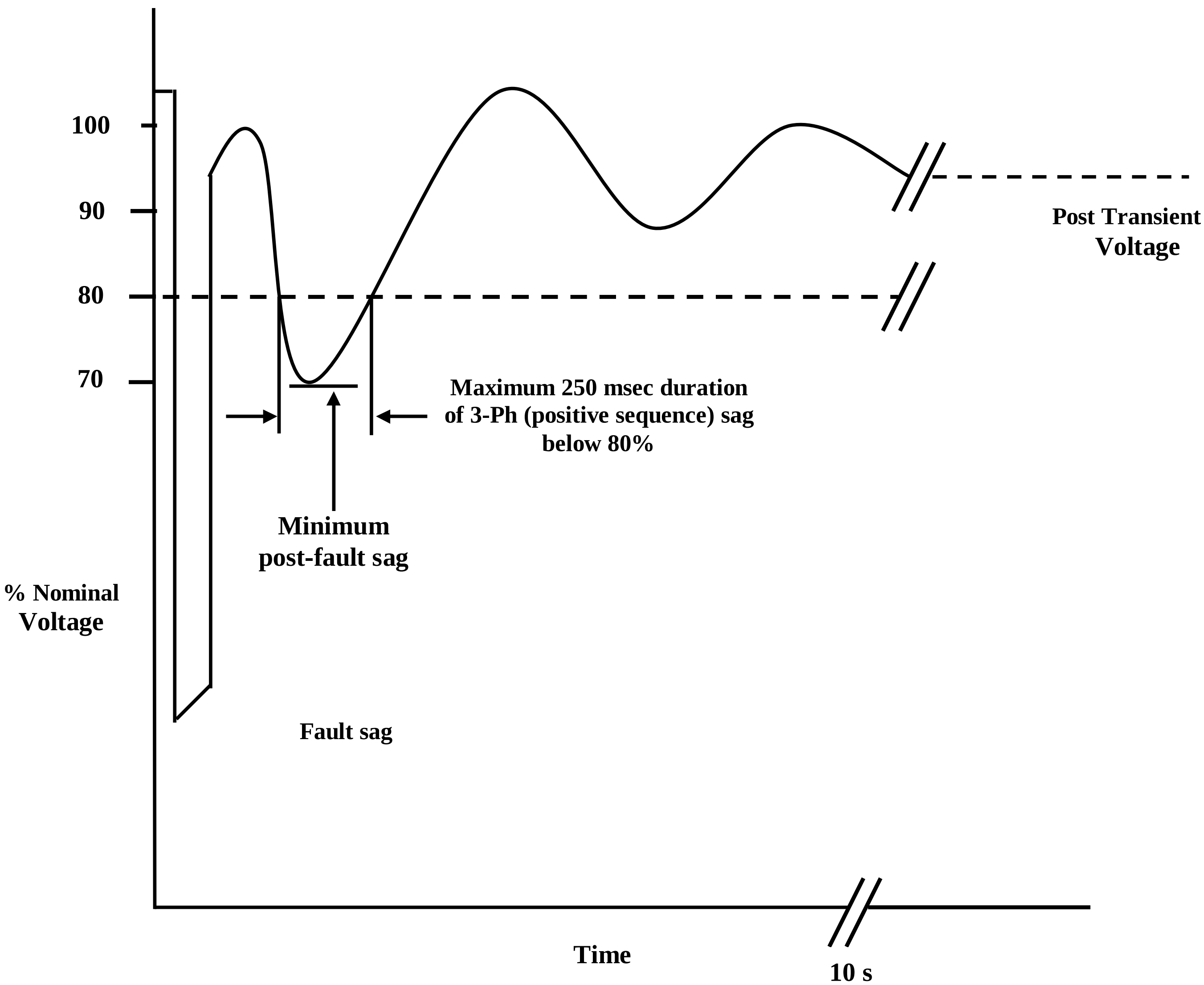
For transient voltage performance, studies should be done with a load model representative of the actual load. If that information is not available, the standard voltage dependent load model of P=50, 50, Q=0, 100 is to be used (see section 2.4 Load Forecasts and Load Modelling).

This criterion is not intended to be used as a standard of utility supply to individual customers, nor used for transmission and distribution protection design. Rather it is intended to avoid uncontrolled, significant load interruption that may lead to unintended *transmission system* performance. The starting voltage, sag and duration of post-fault transient undervoltages are a measure of the system strength, and its ability to recover promptly.

The following transient voltage criteria are to be used to evaluate system performance. The ***IESO*** will conduct periodic review of the IEEE standards and relevant literature to monitor the need to revise this section.

The minimum post-fault positive sequence voltage sag must remain above 70% of nominal voltage and must not remain below 80% of nominal voltage for more than 250 milliseconds within 10 seconds following a fault. Specific locations or grandfathered agreements may stipulate minimum post-fault positive sequence voltage sag criteria higher than 80%. IEEE standard 1346-1998 supports these limits.

Transient Voltage Sag Criteria



Mitigation options include high-speed fault clearing, *special protection systems*, field forcing, transmission reinforcements and transmission interface transfer limits.

While the determination of whether a transient stability test is stable or unstable is generally straightforward, issues such as transient load shakeoff, high voltage tripping of capacitors, and undamped oscillatory behaviour in the post-transient period should be considered using the following guidelines:

- occasional tests should be run out to about thirty seconds - first swing stability does not guarantee transient stability;
- high voltage swings will generally be considered acceptable unless the magnitude or duration of the high voltage swing could be sufficient to cause capacitor tripping. Typical maximum voltage and duration of swing to avoid damage to and tripping of high voltage capacitors are identified

below. The magnitude of the high voltage swing must be less than the capacitor breaker rating multiplied by the factor in the following table for the duration indicated.

Duration	**Maximum Permissible Voltage (Multiplying Factor To Be Applied to Rated RMS Voltage)**
½ cycle	3.00
1 cycle	2.70
6 cycles	2.20
15 cycles	2.00
1 second	1.70
15 seconds	1.40

4.5 Steady State Voltage Stability

Adequate voltage performance under 4.4 above does not guarantee system voltage stability. Steady state stability is the ability of the *IESO-controlled grid* to remain in synchronism during relatively slow or normal load or generation changes and to damp out oscillations caused by such changes.

The following checks are carried out to ensure system voltage stability for both the pre-contingency period and the steady state post-contingency period:

- Properly converged pre- and post-contingency powerflows are to be obtained with the critical parameter increased up to 10% with typical generation as applicable;
- All of the properly converged cases obtained must represent stable operating points. This is to be determined for each case by carrying out P-V analysis at all critical buses to verify that for each bus the operating point demonstrates acceptable margin on the power transfer as shown in the following section; and
- The damping factor must be acceptable (the real part of the eigenvalues of the reduced Jacobian matrix are positive).

The following sections provide more information on damping factor, use of P-V curves to identify stability limits, and dynamic voltage performance simulations.

4.5.1 Power – Voltage (P-V) Curves

To generate the P-V curve, loads should be modeled as constant MVA. In specific situations, if good data is available, voltage dependent loads and tap-changer action may be modeled in detail to assess the system voltage performance following the contingency and automatic equipment actions but before manual operator intervention.

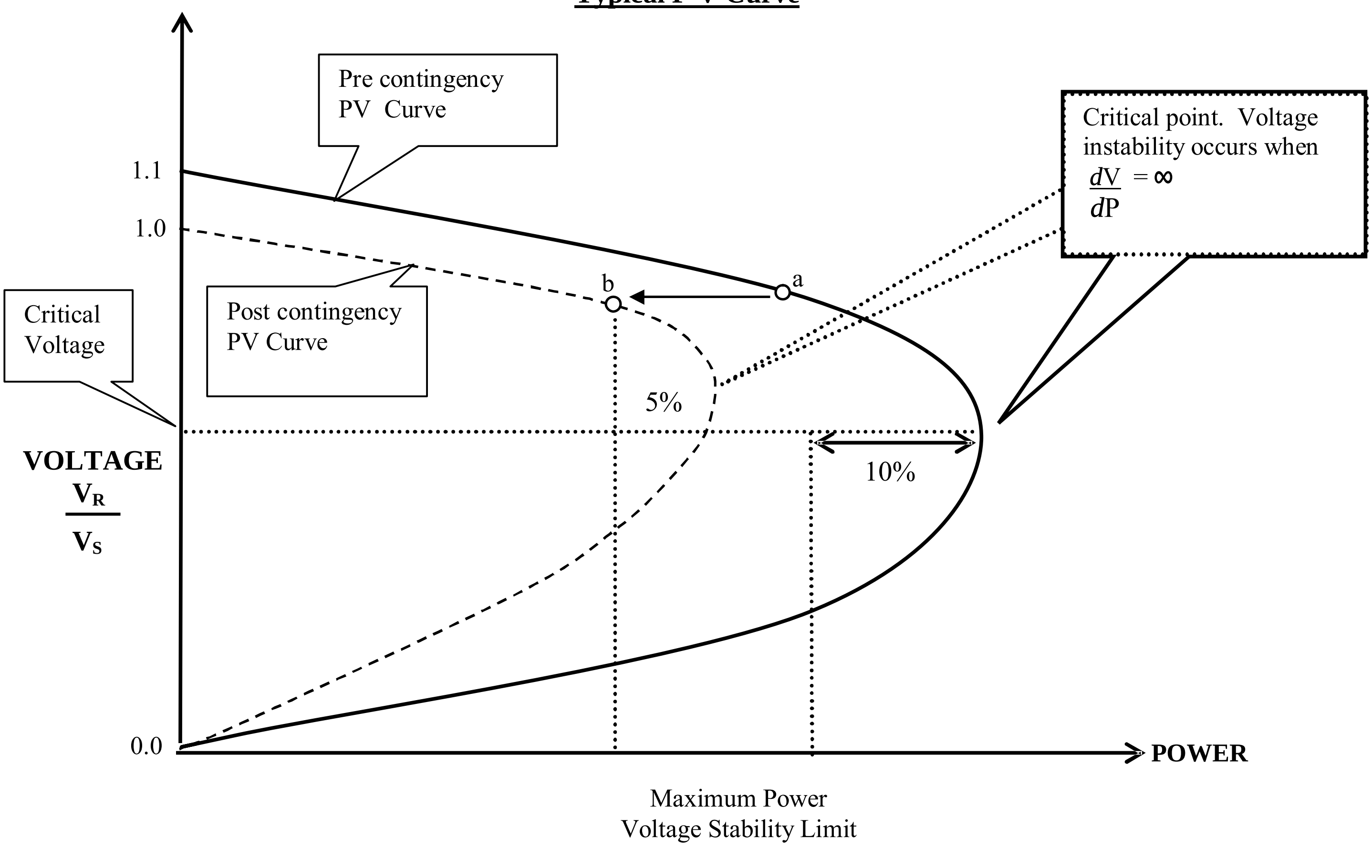
Power flow programs can be used to generate a P-V curve. In certain situations it may be desirable to manually generate a P-V curve to take into account specific remedies available.

A sample P-V curve is shown below. The critical point of the curve, or voltage instability point, is the point where the slope of the P-V curve is vertical. As illustrated, the maximum acceptable pre-contingency power transfer must be the lesser of:

- a pre-contingency power transfer (point a) that is 10% lower than the voltage instability point of the pre-contingency P-V curve, and
- a pre-contingency transfer that results in a post-contingency power flow (point b) that is 5% lower than the voltage instability point of the post-contingency curve

The P-V curve is dependent on the power factor. Care must be taken that the worst case P-V curve is used to identify the stability limit.

Typical P-V Curve



4.5.2 Damping Factor

The damping factor provides a measure of the steady-state stability margin of a power system. The damping factor can be derived from an eigenvalue state-space model of the power system. The damping factor (x) is:

$$\xi = \frac{-\delta}{\sqrt{\delta^2 + \omega^2}}$$

where δ and ω are the real and imaginary parts of the critical eigenvalue. If δ is negative, the oscillations will decay. Where the eigenvalues are not available δ and ω may be measured from time domain simulations by assuming that the oscillations are exponentially damped sinusoids in a second order system.

The damping factor determines the rate of decay of the amplitude of the oscillation. The following table provides pre and post contingency damping factor requirements.

Acceptable Damping Factors

System Condition	Damping Factor
Pre-Contingency	> 0.03
Post-contingency[1]	> 0.00
Post-Contingency[2]	> 0.01
Following Repreparation of the system[3]	> 0.03

1. Before automatic intervention
2. Following automatic intervention. Studies should assume **NO** manual intervention
3. Following all permissible control actions identified in section 3.4

For critical cases, there should be evidence of strong damping of system oscillations within about 10 seconds, otherwise, simulations should be run out to about 20 seconds and all modes of oscillations should show adequate damping behaviour. For swings characterized by a single dominant mode of oscillation, the damping can be calculated directly from the oscillation envelope; a 15% decrement between cycles is required to meet the damping factor criteria.

4.6 Congestion

Congestion is the condition under which the trades that *market participants* wish to implement exceed the capability of the *IESO-controlled grid*. It usually requires the system operator to adjust the output of generators, decreasing it in one area to relieve the constraint and to increase it in another to continue to meet customer *demand*.

For long term *adequacy* assessments, congestion should be flagged where observed. Congestion is flagged as the amount of time that interface flows exceed 100% of their limit where the limit has been increased by the use of applicable *SPSs*. Locational pricing data, where available, may be used to assess historical congestion costs.

4.7 Line and Equipment Loading

4.7.1 General Guidelines

All line and equipment loading limits, the limited time associated emergency ratings and the ambient conditions assumed in determining the ratings are defined by the equipment owner. Long-term emergency ratings are generally a 10-day limited time rating for transformers, and a continuous or 50 hour /year rating for transmission circuits. Short-term emergency ratings are generally 15-minute or 30-minute limited time ratings for transformers and transmission circuits. For each assessment, the applicable ratings will be confirmed with the equipment owner.

4.7.2 Loading Criteria

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings.

It is assumed that for the bulk power system, loading conditions and control actions are available to reduce the loading to the long-term emergency rating or less within 15 minutes.

Circuit breakers, current transformers, disconnect switches, buses and all other system elements must not be restrictive.

The ratings of tie lines are governed by agreements between the *facility* owners. The criteria to direct operation of the lines are governed by agreements between the system or market operators.

4.8 Short Circuit Levels

Short circuit studies are to be carried out with all existing *generation facilities* in service and with all *connection assessments* that have been approved, including those that did not require a formal *connection assessment* study. System voltages are to be assumed to be at the maximum acceptable system voltage identified in Section 4.2. The latest information from neighbouring systems that may have an impact on short circuit studies (including *NPCC* SS-38 and *NERC* MMWG representation) is to be used to define relevant *interconnection* assumptions. Short circuit levels must be within the maximum short circuit levels and duration specified in the Ontario Energy Board's (OEB's) "Transmission System Code".

No margin is used when comparing the short circuit value to *facility* ratings.

The *IESO* will accept make before break switching operations that temporarily increase fault levels beyond breaker interrupting capability as long as affected equipment owners are willing to accept the risk and its consequences.

4.9 Station Layout

Guidance on transformer and switching station layout is provided in Appendix B. The guidelines provide an acceptable way towards meeting the contingency criteria of section 2.7. However, other configurations and station layouts that meet those criteria are also acceptable.

– End of Section –

5. Transmission Connection Criteria

The term “transmission connection” is applied to any *facility* that establishes or modifies a connection to the *IESO-controlled grid* such that a *connection assessment* is required.

5.1 New or Modified Facilities

New or modified *facilities* must satisfy all *NERC* standards, Regional *Reliability* Council Criteria, and the requirements of the OEB's "Transmission System Code", the "Market Rules" and associated standards, policies, and procedures.

New or modified *facilities* must not materially reduce the level of *reliability* of existing *facilities*. Specifically:

- *facilities* within a common zone of protection, such as line taps or bus sections, must be built to meet or exceed the affected *transmitter's* standards prevailing at the time of construction;
- the *security* and dependability of protection equipment that forms a common zone of protection, or of protections that are required to operate in a coordinated fashion, must be of a standard of *reliability* that is equal to or higher than the *reliability standards* specified in the OEB's "Transmission System Code" prevailing at the relevant time;
- *facilities*, such as line taps, that significantly increase the line length and thereby its exposure to faults, may be required to use circuit breakers and separate zones of protection to limit the additional exposure to existing connections; and
- new or modified connections must not materially reduce the existing transfer capability of the *IESO-controlled grid*, and must not impose additional restrictions on the deployment of existing *connection facilities*.

5.2 Effect on Existing Facilities

New or modified connections must not materially reduce the load-meeting capability of existing *facilities*.

New or modified connections must not restrict the capability of existing *generation facilities* or loads to deliver to or receive power from the *IESO-controlled grid*.

Where there would be insufficient transmission capability to deliver the maximum registered capacity to the *IESO-controlled grid* while recognizing applicable contingency criteria:

- the proposal must be re-designed, e.g. the maximum registered capacity must be reduced to a level that can be delivered;
- the transmission *facilities* must be refurbished or replaced; or
- *special protection systems (SPS),* in limited circumstances, may be utilized to mitigate the effects of contingencies on the transmission *facilities*.

– End of Section –

6. Generation Connection Criteria

Transmission to incorporate new generation is defined as those new circuits that connect the generator to the *IESO-controlled grid*, plus any reinforcements to the *IESO-controlled grid* required as a direct and sole result of the new generation. With the new generation at its maximum output, all load levels should be considered.

6.1 Voltage Change

The loss of a generating *facility* due to a single-element contingency involving any element upstream of the generator bus (e.g. line or step-up transformer) should respect the voltage change criteria in section 4.3.

6.2 Wind Power

- For the purposes of *transmission system adequacy* and *connection assessments*, wind powered generators are to be treated as *non-dispatchable* (intermittent) units which are operating up to their maximum output.

- For *connection assessments*, transmission line ratings will be calculated using 15km/h winds, instead of the typical 4km/h, within the vicinity of the wind farm and, with the approval of the *transmission* asset owner, out to a 50 km radius.

Guidance on technical requirements related to wind turbine performance and wind farm station layout is provided in Appendix C. The guidelines provide a design that satisfies the contingency criteria of section 2.7. However, other configurations and station layouts that meet those criteria are also acceptable.

As the *IESO* gains more experience with the operating characteristics of wind powered generators, the above criteria may be revised.

6.3 Synchronous Generation

Transmission *facilities* for incorporating new generation must meet the requirements of section 5. Guidance on technical requirements related to synchronous generator performance, station layout, and connection to the *IESO-controlled grid* is provided in Appendix D. The guidelines provide a design that satisfies the contingency criteria of section 2.7. However, other configurations and station layouts that meet those criteria are also acceptable.

6.4 Station Layout

Guidance on transformer and switching station layout is provided in Appendix B. The guidelines provide an acceptable way towards meeting the contingency criteria of section 2.7. However, other configurations and station layouts that meet those criteria are also acceptable.

– End of Section –

7. Load Security and Restoration Criteria

The long-term *transmission system* planning criteria below establish default levels of load *security* and load restoration. The application of a lower level of load *security* may be acceptable in the non bulk portions of the *IESO-controlled grid* provided the bulk power system adheres to *NERC* and *NPCC* standards. Different criteria may be used for the facilities beyond the load side of the *connection point* to the *transmission system* (notionally the defined point of sale).

7.1 Load Security Criteria

The *transmission system* must be planned to satisfy *demand* levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The *transmission system* must exhibit acceptable performance, as described below, following the design criteria contingencies defined in sections 2.7.1 and 2.7.2. For the purposes of this section, an element is comprised of a single zone of protection.

With all transmission *facilities* in service, equipment loading must be within continuous ratings, voltages must be within normal ranges and transfers must be within applicable normal condition stability limits. This must be satisfied coincident with an outage to the largest local generation unit.

With any one element out of service[3], equipment loading must be within applicable long-term *emergency* ratings, voltages must be within applicable *emergency* ranges, and transfers must be within applicable normal condition stability limits. Planned load *curtailment* or load rejection, excluding voluntary *demand* management, is permissible only to account for local generation outages. Not more than 150MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 150MW load interruption limit reflects past planning practices in Ontario.

With any two elements out of service[4], voltages must be within applicable *emergency* ranges, equipment loading must be within applicable short-term *emergency* ratings and transfers must be within applicable *emergency* condition stability limits. Equipment loading must be reduced to the applicable long-term *emergency* ratings in the time afforded by the short-time ratings. Planned load *curtailment* or load rejection exceeding 150MW is permissible only to account for local generation outages. Not more than 600MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 600MW load interruption limit reflects the established practice of incorporating up to three typical modern day distribution stations on a double-circuit line in Ontario.

[3] For example, after a single-element contingency with all transmission elements in service pre-contingency.
[4] For example, after a double-element contingency will all transmission elements in service pre-contingency or after a single-element contingency with one transmission element out of service pre-contingency.

7.2 Load Restoration Criteria

The *IESO* has established load restoration criteria for high voltage supply to a *transmission customer*. The load restoration criteria below are established so that satisfying the restoration times below will lead to an acceptable set of *facilities* consistent with the amount of load affected.

The *transmission system* must be planned such that, following design criteria contingencies on the *transmission system*, affected loads can be restored within the restoration times listed below:

a. All load must be restored within approximately 8 hours.

b. When the amount of load interrupted is greater than 150MW, the amount of load in excess of 150MW must be restored within approximately 4 hours.

c. When the amount of load interrupted is greater than 250MW, the amount of load in excess of 250MW must be restored within 30 minutes.

These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility.

7.3 Control Action Criteria

The deployment of control actions and *special protection systems* must not result in material adverse effects on the bulk system.

The *transmission system* may be planned such that control actions such as generation re-dispatch, reactor and capacitor switching, adjustments to phase-shifter and HVdc pole flow, and changes to inter-Area transactions may be judiciously employed following contingencies to restore the power system to a secure state.

The reliance upon a *special protection system* must be reserved only for exceptional circumstances, such as to provide protection for infrequent contingencies, temporary conditions such as project delays, unusual combinations of system *demand* and *outages*, or to preserve system integrity in the event of severe *outages* or extreme contingencies.

Transmission expansion plans for areas that may have a material adverse effect on the interconnected bulk power system must not rely on *NPCC* Type I *special protection systems* with all planned transmission *facilities* in service.

7.4 Application of Restoration Criteria

Where a need is identified, for example via the *IESO's* outlooks or via the OPA's IPSP, *market participants* and the applicable *transmitter* will be notified of the need for a deliverability study.

Transmission customers and *transmitters* can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost. The *transmission customer* and *transmitter* may agree on higher or lower levels of *reliability* for technical, economic, safety and environmental reasons provided the bulk power system adheres to *NERC* and *NPCC* standards.

7.5 Exemptions to the Restoration Criteria

Where the *transmission customer(s)* and *transmitter(s)* agree that satisfying the security and restoration criteria on *facilities* not designated as part of the bulk system is not cost justified, they may jointly apply for an *exemption* to the *IESO*. In applying for this *exemption*, *transmission customer(s)* and *transmitter(s)* will identify the conditions (generally the timing and load level) under which they plan to satisfy the criteria. *IESO* will assess these on a case-by-case basis and grant the *exemption*, allowing a lower level of *reliability*, unless there is a material adverse effect on the *reliability* of the bulk power system.

End of Section

8. Resource Adequacy Assessment Criterion

8.1 Statement of Resource Adequacy Criterion

To assess the *adequacy* of resources in Ontario, the *IESO* uses the *NPCC* resource adequacy design criterion from *NPCC* A-02:

> "Each Area's probability (or risk) of *disconnecting* any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of *disconnecting* firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for *demand* uncertainty, scheduled *outages* and deratings, *forced outages* and deratings, assistance over *interconnections* with neighboring Areas and Regions, *transmission transfer capabilities*, and capacity and/or load relief from available operating procedures."

8.2 Application of the Resource Adequacy Criterion

The *IESO* uses the General Electric Multi-Area Simulation (MARS) computer program to determine the reserve margin required to meet the *NPCC* resource adequacy criterion. A detailed load, generation, and transmission representation for 10 zones in Ontario is modeled in MARS. Simple representations are used for the five external *control areas*[2] to which Ontario *connects*.

The reserve margin is expressed as a percent of *demand* at the time of the annual peak where the LOLE is at or just below 0.1 days per year. A reserve margin calculated on this basis represents the minimum acceptable reserve level needed to meet the *NPCC* resource adequacy criterion. At least once per year, *IESO* will calculate the required reserve margin at the time of annual peak for the next five years and will *publish* this value.

For operational planning purposes, just meeting the *NPCC* criterion is considered sufficient since frequent forecast updates combined with significant *outage* flexibility, external economic supply potential and the availability of *emergency* operating procedures have historically provided sufficient "insurance" against residual supply risk.

For capacity planning purposes, where longer term decisions must be made, additional reserves to cover residual uncertainties and project delays may be appropriate. Also, the *IESO* does not consider *emergency* operating procedures for longer term capacity planning because the relief provided by these measures is intended for dealing with *emergencies* rather than being used as a surrogate resource. Regular triggering of *emergency* operating procedures rather than developing appropriate resources could lead to the erosion of these options through overuse. The extent to which all uncertainty is covered becomes an economic decision which should be guided by the *NPCC* criterion.

8.3 Resource Assumptions

The Ontario system has a resource mix comprised of a variety of fuel types. Assumptions about resource availability vary by fuel type. Generally, resource availability forecasts are based on median assumptions. A complete description of the resource assumptions used in the *IESO's adequacy* assessments can be found in the methodology document entitled, "Methodology to Perform Long Term Assessments". This document is *published* quarterly with the release of the 18-Month Outlook Resource Adequacy Assessments.

End of Section

Appendix A: IESO/NPCC/NERC Reliability Rule cross-reference

IESO/NPCC/NERC Reliability Rule Cross-Reference

Section	Ontario Criteria	NPCC Criteria	NERC Standard
Resource *Adequacy*	Available *Capacity Reserve* Margin Requirement	A-2	TPL-005, 006; MOD-016 to MOD-021, 024, 025
Transmission Capability Planning **Bulk Power System**	Thermal Assessment	A-2	TPL-003; FAC-001, 002
	Voltage Assessment	A-2	
	Stability Assessment	A-2	
	Extreme Contingency Assessment	A-2	TPL-004
Transmission Capability Planning **Non Bulk *Local Areas***	Thermal Assessment		TPL-003; FAC-001, 002
	Voltage Assessment		
	Stability Assessment		
	Supply Deliverability Level		TPL-004

– End of Section –

Appendix B: Guidelines for Station Layout

This Appendix provides a guide to desirable configurations. Variations from this guide are permissible provided that such variations comply with the criteria of sections 2.7 and 4.

The specification of station layout requires consideration of the number of breakers required to trip all infeeds to a fault. Increasing the number of breakers to clear a fault results in the relaying systems becoming more complex and increases the chance of failure to clear all infeeds to the fault.

It is not practical to calculate mathematically the optimum balance of complexity, *reliability* and cost in specifying station layout. Therefore, a review of existing practices has been made and compiled as a guide to show the maximum complexity that should normally be permitted in design of station layout or switching connections for transformers or circuits.

In general, the specification of station layout and the number of breakers needed to trip to clear faults should take into account the following:

- probability of failure
- *reliability* studies of the layout
- effect on the *IESO-controlled grid*
- nature and size of the load affected
- typical duration of a failure
- operating efficiency

B.1 OEB's Transmission System Code

Any new connection or modification of an existing station layout must meet the requirements of the "Market Rules" and the OEB's "Transmission System Code".

The OEB's "Transmission System Code" specifies that all customers must provide an isolating *disconnect* switch or device at the point or junction between the *transmitter* and the customer. This device is to physically and visually open the main current-carrying path and isolate the Customer's *facility* from the *transmission system*. Details are provided in Schedule F of the OEB's "Transmission System Code".

Schedule G of the OEB's "Transmission System Code" specifies that a high-voltage interrupting device (HVI) shall provide a point of isolation for the generator's station from the *transmission system*. The HVI shall be a circuit breaker unless the *transmitter* authorizes another device.

B.2 Analysis of System Connections

The key factors that must be considered when evaluating a switching or transformer station include:

- *Security* and quality of supply
  Relevant criteria are presented in section 4.

- Extendibility
  The design should allow for forecast need for future extensions if practical.

- Maintainability
  The design must take into account the practicalities of maintaining the substation and associated circuits. It should allow for elements to be taken out of service for maintenance without negatively impacting *security* and quality of supply.

- Operational Flexibility
  The physical layout of individual circuits and groups of circuits must permit the required operation of the *IESO-controlled grid*.

- Protection Arrangements
  The design must allow for adequate protection of each system element

- Short Circuit Limitations
  In order to limit short circuit currents to acceptable levels, bus arrangements with sectioning *facilities* may be required to allow the system to be split or re-connected through a fault current limiting reactor.

The contingencies evaluated in assessing proposed station layout *adequacy* will be those outlined in section 2.7. The *IESO* will analyze the effect of various contingencies on the *adequacy* and *security* of the *IESO-controlled grid*. The *IESO* will also ensure that the proposed configuration allows for routine maintenance *outages* with minimal exposure to load interruption from subsequent contingencies. For example, for *facilities* classed as bulk power system, the *IESO* will examine the following contingencies for the proposed station layout:

- Fault on any element with delayed clearing because of a stuck breaker

- Maintenance *outage* on a breaker or bus followed by a single-element contingency

The resulting *IESO-controlled grid* performance must meet the criteria in section 4. As the *IESO-controlled grid* develops, the criteria under which a particular station layout is assessed may change (e.g. a *local area* station may become a bulk power system station).

The *IESO* will then evaluate the amount of load interrupted by single-element contingencies (or double circuit contingencies depending on the load level) with the proposed station layout". For example a *local area* switching station layout would be reviewed to ensure that a single-element or double circuit contingency would not result in an interruption that exceeds the criteria in section 7.1.

Evaluations of modifications to existing *facilities* will take into account the lower level of flexibility and layouts will be evaluated on the extent they meet the assessment criteria.

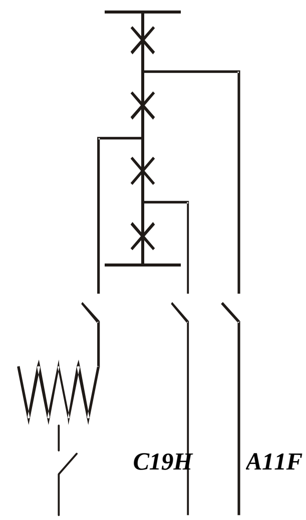
B.3 General Requirement's For Station Layouts

This section identifies general requirements for all station layouts based on *good utility practice* and operational efficiency. Acceptable system performance will dictate the acceptability of any proposed layout. This section provides the electrical single line diagram and does not reflect physical layouts. See section B.4 for information on physical layout.

B.3.1 "Breaker-And-A-Third" Layouts

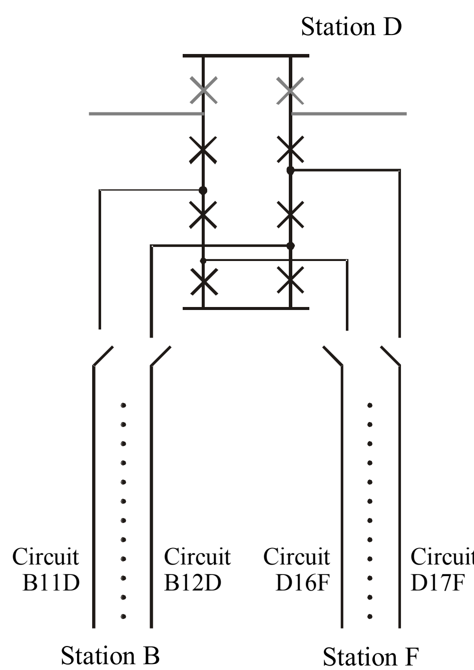
In "breaker-and-a-third" layouts the ideal location for autotransformers and generators is in the middle of the diameter as shown.

It is desirable to have one element (one autotransformer or one line) per position.



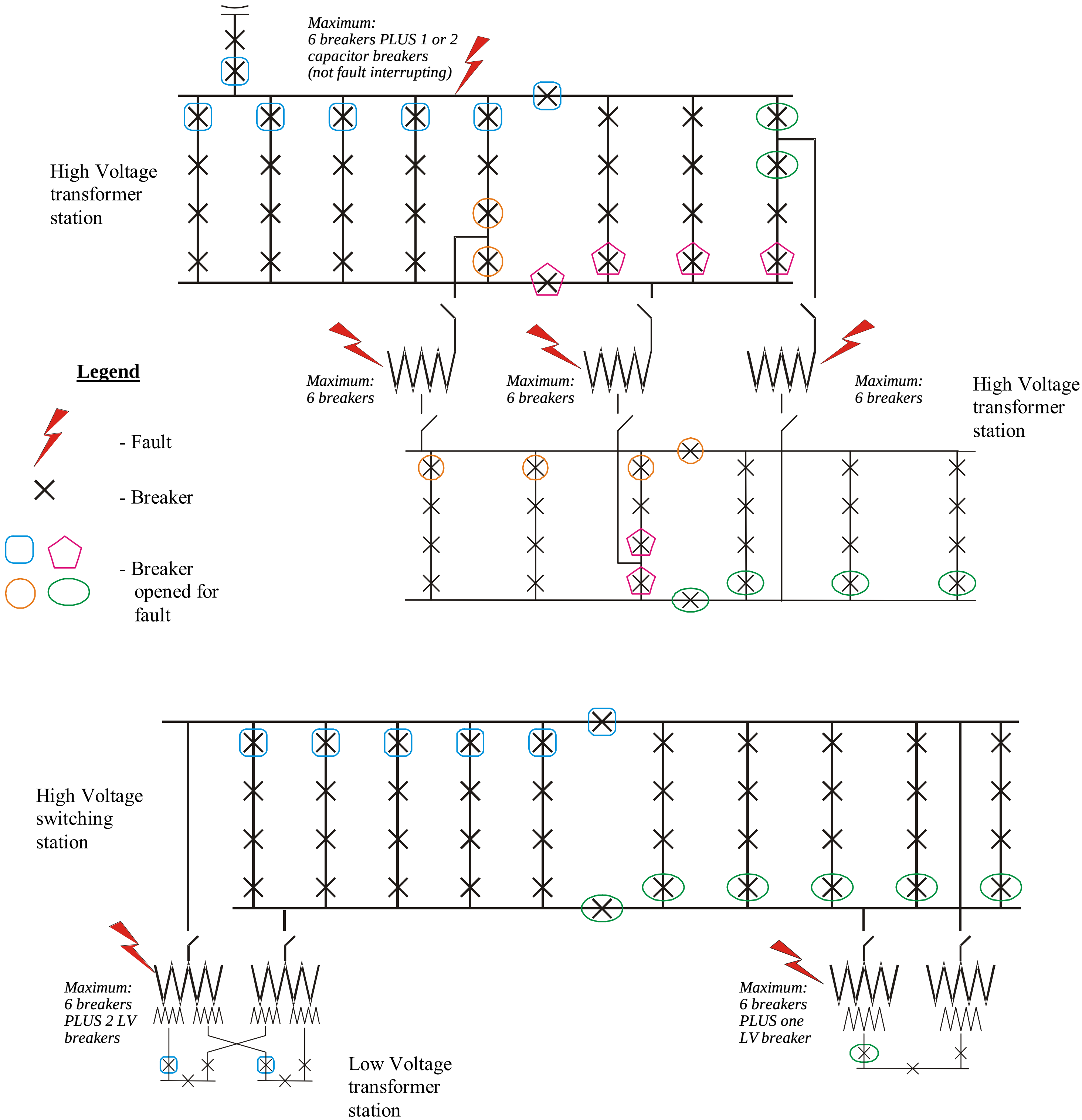
B.3.2 Bus Balance

The ideal arrangement for a double circuit line is to terminate each circuit on different diameters positioned so that there is maximum flexibility and *security* for a variety of fault and operating scenarios.



B.3.3 Maximum Breakers

Station layout should be such that a maximum of 6 High Voltage (500kV, 230kV and 115kV) and up to 2 capacitor or 2 Low Voltage breakers are needed to trip following any fault (operation of the capacitor breaker does not involve interruption of fault current). The following layouts illustrate these rules.



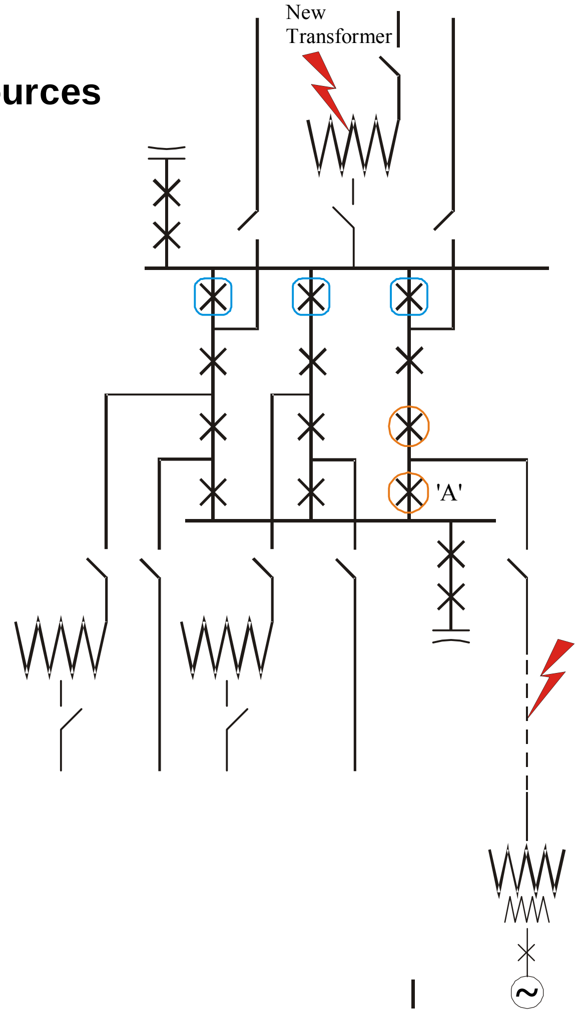
B.3.4 Separation of Reactive Power Sources

The goal of a good station layout is to minimize the effect of a contingency. Thus a contingency should result in the fewest possible number of elements removed from service.

In this vein, only one supply element should be connected directly to a bus. The intent is that a single contingency not result in the loss of two VAR sources.

For example, when terminating a new autotransformer, generator, circuit, or capacitor bank onto a bus, a single element contingency should not result in the loss of the autotransformer or line and the simultaneous loss of the capacitor bank or generator. (It would be acceptable to connect a step-down transformer and capacitor bank to the same bus.)

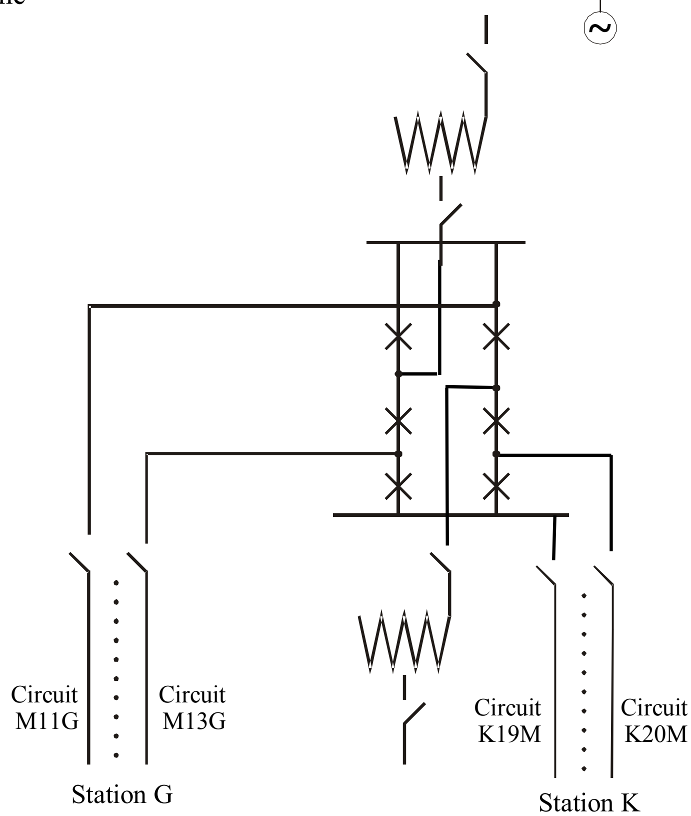
Per B.3.1, the ideal location of a generator is in the centre of a diameter (where the autotransformers are connected on the layout shown). The generator termination at the location shown is not ideal. A single-element contingency with breaker failure would result in the simultaneous loss of the generator and capacitor bank. To determine the acceptability of the layout shown it would be necessary to conduct a transmission assessment to class the *facility* as either bulk power system or local and then to evaluate the performance of the *IESO-controlled grid* for the appropriate contingencies.



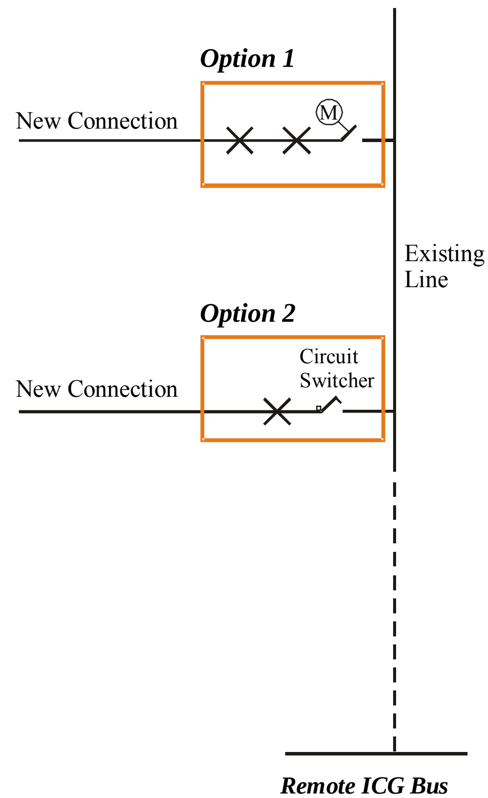
B.3.5 Ring Bus

A minimum of three diameters is desired. Alternatively if a ring bus is temporarily unavoidable, the station should be laid out for the future addition of another diameter.

During periods when breakers are out-of-service for maintenance, ring buses can impose significant operational constraints. The layout shown provides one way to optimize the layout of a ring bus and minimize the adverse effect of maintenance.



B.3.6 Connections Without Transfer Trip



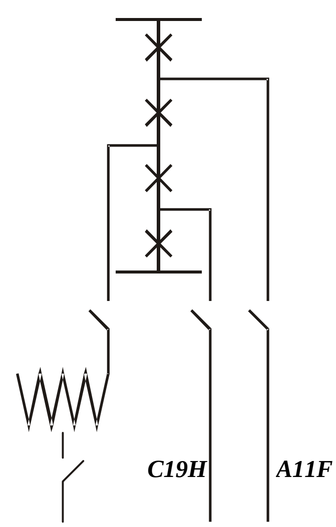
Where the *connection point* to the *IESO-controlled grid* is sufficiently remote that transfer trip is impractical, either of the two options shown would be acceptable.

In Option 1, a line fault would initiate tripping of both breakers simultaneously, thereby addressing concerns about possible breaker failure if only a single breaker were used. This arrangement must include a motorized *disconnect* to provide 'physical' isolation of the new line from the *IESO-controlled grid*.

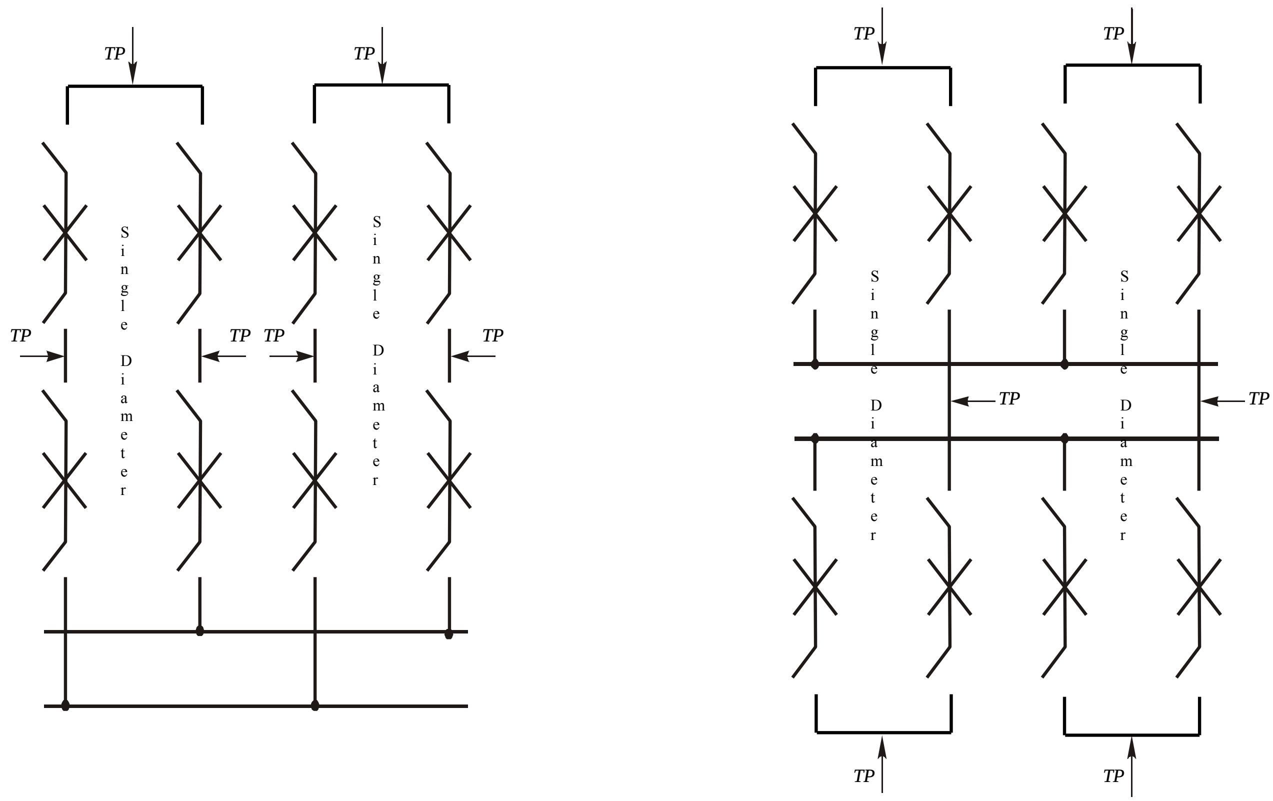
In Option 2, a line fault would initiate simultaneous operation of the single breaker and the circuit switcher. The integral *disconnect* switch of the circuit switcher would provide the required 'physical' isolation of the new line from the *IESO-controlled grid*.

B.4 Physical Station Layouts

The electrical single line diagram of a "breaker-and-a-third" arrangement is shown. Typical physical layouts for "breaker-and-a-third" follow.



Typical Physical Arrangement for a Breaker-and-a-Third Layouts



TP = Termination Point for a transmission element such as a circuit, transformer, etc.

Overhead connections omitted for clarity

– End of Section –

Appendix C: Wind Farms Connection Requirements

The following is intended to clarify the requirements for connection to the *IESO-controlled grid* of wind-generation proposals which are aimed at ensuring that the *reliability* of the system is preserved. This short list does not relieve proponents from any *market rule* obligation. *Transmitter* and *distributor* requirements are separate and are not addressed herein.

The key factors that must be evaluated when performing a *connection assessment* of a wind farm are:

1. Equipment must be suitable for continuous operation in the applicable transmission voltage range specified in Appendix 4.1 of the "Market Rules". Equipment must also be able to withstand over-voltage conditions during the short period of time (not more than 30 minutes) it takes to return the power system to a secure state. Plant auxiliaries must not restrict *transmission system* operation.

2. Generating units do not trip for contingencies except those that remove generation by configuration. This requires adequate low and high voltage ride through capability. If generating units trip unnecessarily, they will require enhanced ride-through capability to prevent such tripping or the *IESO* may restrict operation to avoid these trips.

3. Recognized contingencies within the wind-*generation facility*, except for transmission breaker failures, must not trip the connecting transmission circuit(s).

4. Induction generators are required to have the reactive power capabilities described in Appendix 4.2 Reference 1 of the "Market Rules". Induction generating units injecting power into the *transmission system* are required to have the same reactive capabilities as synchronous units that have similar apparent power ratings. They are required to have the capability to inject at the *connection point* to the *IESO-controlled grid* approximately 43.6 MVAr for every 90 MW of active power (0.9 power factor at the low voltage terminals of the *connection point*). The requirement to provide the entire range of reactive power for at least one constant transmission voltage limits the impedance of the connection between the generating units and the *transmission system* to about 13% impedance on the generator's rated output base. Generating units not injecting power into the *transmission systems* must be able to reduce reactive flow to zero at the point of connection and must have similar reactive capabilities as units connected to the *transmission system*. The *IESO* may require any reactive power deficiencies of *facilities* injecting into the *transmission system* to be corrected by reactive compensation devices.

    - For wind turbine technologies that have dynamic reactive power capabilities described in 4.2 Reference 1 of the "Market Rules", additional shunt capacitors may be required to offset the reactive power losses over the wind farm collection system that are in excess of those allowed by the "Market Rules".

    - For wind turbine technologies that do not have dynamic reactive power capabilities described in 4.2 Reference 1 of the "Market Rules", dynamic reactive compensation (static var compensator) equivalent to the "Market Rules" requirement must be installed. In addition, shunt capacitors may be required to offset the reactive power losses that are in excess of those allowed by the "Market Rules", over the wind farm collection system.

5. *Facilities* shall have the capability to regulate voltage as specified by the *IESO*. Operation in any other mode of *regulation* (e.g. power factor or reactive power control) shall be subject to *IESO* approval.

6. *Facilities* shall be installed to participate in any *special protection system* identified by the *IESO* during the CAA process. In most cases, this will be generation rejection and the associated telecommunication *facilities*.

7. Generating units will meet the voltage variation and frequency variation requirements described in Appendix 4.2 Reference 2 and Reference 3 of the "Market Rules".

8. Real-time monitoring must be provided to satisfy the requirements described in Appendix 4.15 and Appendix 4.19 of the "Market Rules".

9. *Revenue metering* must be provided to satisfy the Market Rule requirements. No commissioning power will be provided until the *revenue metering* installation is complete.

10. The *facility* does not increase the duty cycle of equipment such as load tap changing transformers or shunt capacitors beyond a level acceptable to the associated *transmitter* or *distributor*.

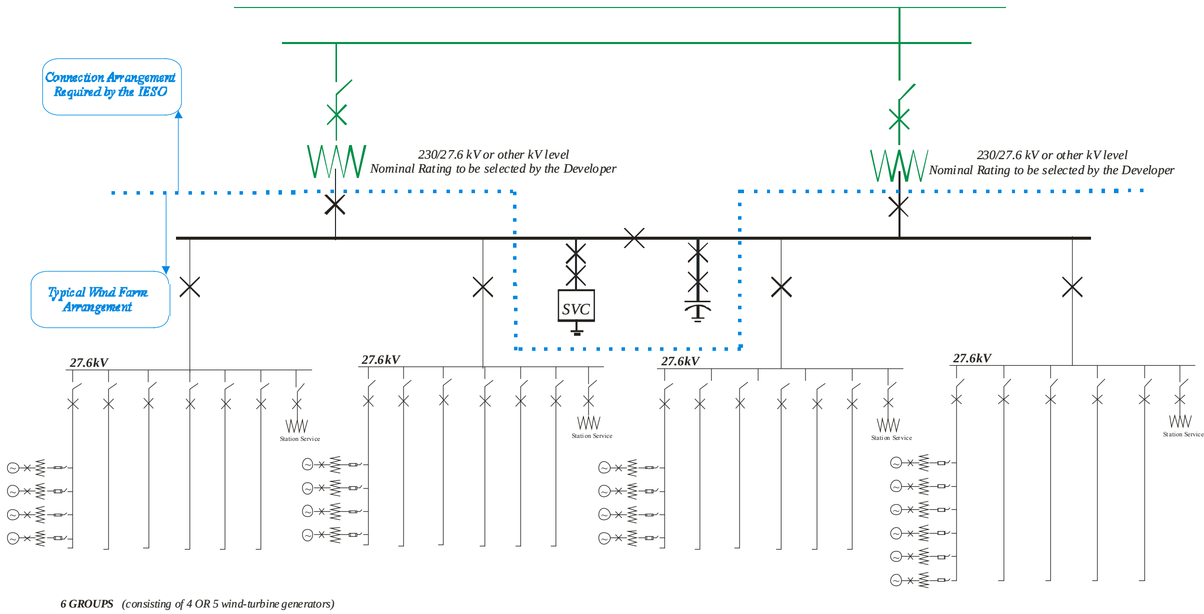
11. Line taps and step-up transformers connect to both circuits of a double-circuit-line (figure attached). The *facility* must be designed to balance the loading on both circuits of a double-circuit line.

12. Equipment must be designed so the adverse effects of failure on the *transmission system* are mitigated. This includes ensuring all transmission breakers fail in the open position.

13. Equipment must be designed so it will be fully operational in all reasonably foreseeable ambient conditions. This includes ensuring that certain types of breakers are equipped with heaters to prevent freezing.

14. The equipment must be designed to meet the applicable requirements of the OEB's "Transmission System Code" or the OEB's "Distribution System Code" in order to maintain the *reliability* of the grid. They include requirements identified by the *transmitter* for protection and telecommunication *facilities* and coordination with the exiting schemes. The protection systems for equipment connected to the *IESO-controlled grid* must be duplicated and supplied from separate batteries.

15. Disturbance monitoring equipment capable of recording the post-contingency performance of the *facility* must be installed. The quantities recorded, the sampling rate, the triggering method, and clock synchronization must be acceptable to the *IESO*.



Typical Configuration

Appendix D: Synchronous Generation Connection Requirements

The following summarizes the requirements for connection to the *IESO-controlled grid* of single-cycle or combined-cycle generation proposals of medium to large size which are aimed at ensuring that the *reliability* of the system is preserved. This short list does not relieve proponents from any m*arket rule* obligation. This document may be used by *market participants* to help them understand *IESO* criteria and further their *connection assessment* work.

Transmitter and d*istributor* requirements are separate and are not addressed herein. The Proponent is expected to follow other approvals processes to ensure the other aspects of *reliability* such as detailed equipment design, environmental considerations, power quality, and safety are properly addressed.

Generating Unit Performance

Excitation System

The requirements for exciters on *generation unit* rated at 10 MVA or higher are listed in Reference 12 of Appendix 4.2 in the "Market Rules" as follows:

- A voltage response time not longer than 50 ms for a voltage reference step change not to exceed 5%;
- A positive ceiling voltage of at least 200% of the rated field voltage, and
- A negative ceiling voltage of at least 140% of the rated field voltage.

In addition, the requirements for power system stabilizers (PSS) are described in Reference 15 of Appendix 4.2:

- Each synchronous generating unit that is equipped with an excitation system that meets the performance requirements described above shall also be equipped with a power system stabilizer. The power system stabilizer shall, to the extent practicable, be tuned to increase damping torque without reducing synchronizing torque.

Governor

Reference #16 of Appendix 4.2 of the "Market Rules" requires that every synchronous generator unit with a name plate rating greater than 10 MVA or larger be operated with a speed governor, which shall have a permanent speed droop that can be set between 3% and 7% and the intentional dead band shall not be wider than ± 36 mHz.

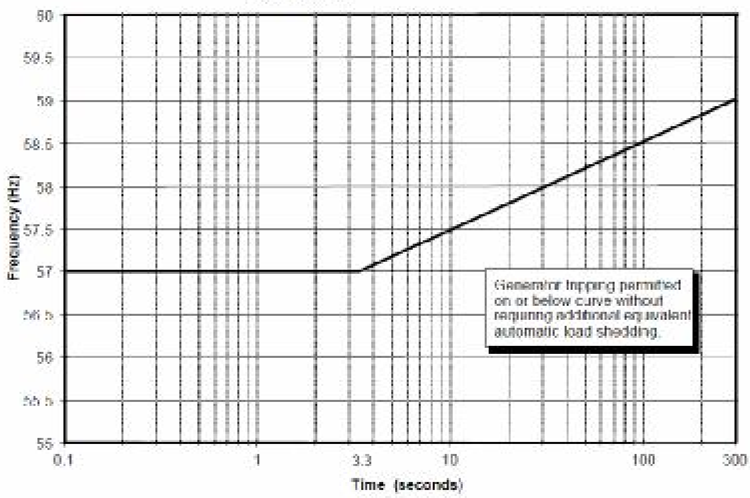
Automatic Voltage Regulator

Reference #13 of Appendix 4.2 of the "Market Rules" requires each synchronous generating unit to be equipped with a continuously acting *automatic voltage regulator* (*AVR*) that can maintain the terminal voltage under steady state conditions within ±0.5% of any voltage set point. Each synchronous *generation unit* shall regulate voltage except where permitted by the *IESO*.

Generator Underfrequency Performance

Reference #3 of Appendix 4.2 of the "Market Rules" requires that generating *facilities* be capable of operating continuously at full power for a system frequency range between 59.4 to 60.6 Hz. In accordance with *NPCC* criteria A-03, "Emergency Operation Criteria", generators shall not trip for under-frequency system conditions for frequency variations that are above the curve shown below. However, if this cannot be achieved, and if approved by the *IESO*, then automatic load shedding equivalent to the amount of generation to be tripped must be provided in the area. This criterion is required to ensure the stability of an island, if formed, and to avoid major under-frequency load shedding in the area.

Figure 1 - Standards for setting underfrequency trip protection for generators



Generation Facility Connection Options

The *IESO*, in its review of the various generation projects that propose to connect to the *IESO-controlled grid*, has developed typical connection arrangements for generation developments. Variations to the typical connection arrangements may be accepted by the *IESO* provided that *reliability* criteria are met and that the *connection assessment* studies prove that the system is not adversely affected. Connection of *generation facilities* larger than 500 MW that propose to use arrangements that are typical for the developments under 500 MW may be accepted subject to *IESO* approval.

Generation Facilities Rated between 250 MW and 500 MW

All projects rated between 250 MW and 500 MW are required to connect to two circuits (where available) and as a minimum provide one of the connectivity arrangements shown in Figure 1, 2 or 3. Station arrangements that connect two like elements next to each other separated by only one breaker should be avoided.

The configurations shown in Figure 1 and Figure 2 are suitable for coupled gas and steam turbines pairs.

- A contingency associated with one of the transmission lines will be cleared at the terminal stations and by the breaker on the corresponding generator line tap. If the post-contingency rating of the remaining line permits, the *facility* can remain connected to one circuit.

- A bus-tie breaker failure condition will send transfer trip to the line tap breakers and the entire *facility* will be tripped off. If the *IESO's* assessment indicates that tripping the entire generating *facility* will have a negative impact on the system then the *IESO* will recommend alternative connection arrangements.
- For the configuration in Figure 1, a contingency associated with one of the step-up transformers or a generator unit will be cleared by opening the bus-tie breaker and the HV synchronizing breaker.
- The configuration in Figure 2 is more economical because it allows the connection of two units via one step-up transformer but is less reliable since a contingency associated with one step-up transformer results in the loss of two generating units.
- For an *outage* associated with one of the HV breakers the entire *generation facility* could remain connected unless limited by equipment ratings, voltage, or stability.

For the connectivity shown in Figure 3:

- A contingency associated with one of the transmission lines will be cleared at the terminal stations and the corresponding breakers in the ring bus. If the post-contingency rating of the remaining line permits, the *facility* can remain connected to one circuit.
- An HV breaker failure contingency could trip two generating units or a line and a generating unit. If *IESO's* assessment indicates that tripping two generating units will have a negative impact on the system then the *IESO* will require either additional breakers to be installed or the size of the development to be reduced to an acceptable level.
- For an *outage* associated with one of the HV breakers the entire *generation facility* could remain operational unless limited by equipment ratings, voltage, or stability.

In addition the *generation facilities* will have to comply with the OEB's "Transmission System Code" requirements and other protection system requirements established by the *transmitter*.

Generation Facilities Rated Above 500 MW

All projects rated above 500 MW are required to connect to at least two circuits and provide one of the connectivity arrangements shown in Figure 4 or Figure 5. Station arrangements that connect two like elements next to each other separated by only one breaker should be avoided.

The full switchyard arrangement shown in Figure 4 is required when large generating *facilities* propose to connect to a main transmission corridor of considerable length that *connects* two transmission stations.

The ring bus arrangement shown in Figure 5 is acceptable when the development is connecting to a radial double circuit line.

Typical Connection Arrangements
for Generation Facilities Rated between 250MW and 500 MW

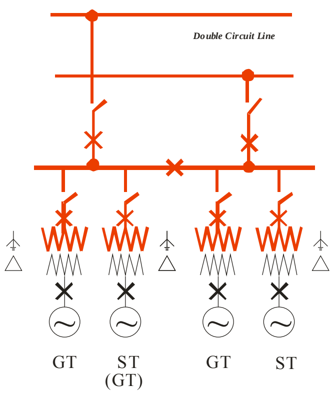


Figure 1 (Low Voltage Breakers are Optional)

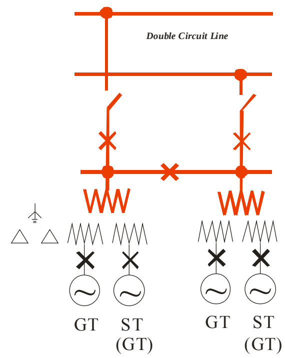


Figure 2

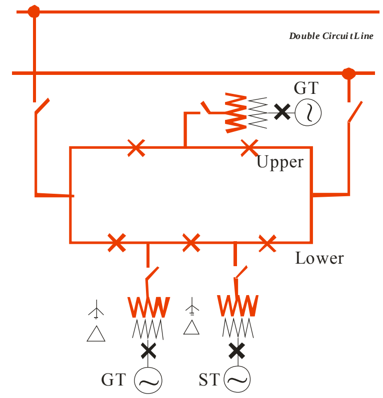


Figure 3

Typical Connection Arrangements
for Generation Facilities Rated Higher than 500 MW

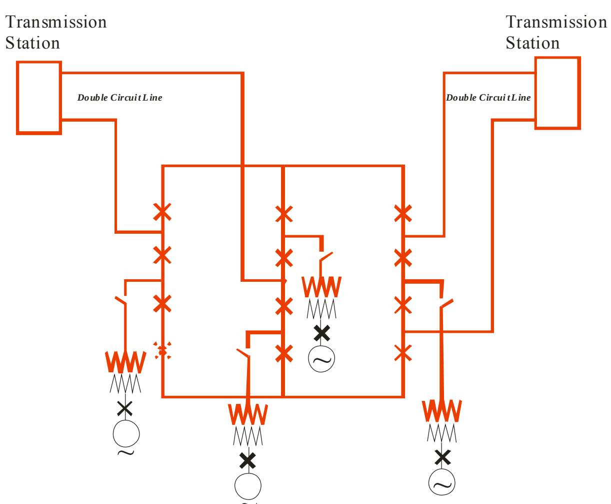


Figure 4

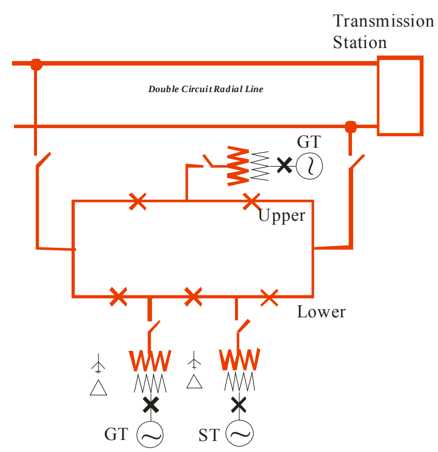


Figure 5

End of Section

References

Document ID	Document Name
NPCC A-01	Criteria for Review and Approval of Documents
NPCC A-02	Basic Criteria for Design and Operation of Interconnected Power Systems
NPCC A-04	Maintenance Criteria for Bulk Power System Protection
NPCC A-05	Bulk Power System Protection Criteria
NPCC A-11	Special Protection System Criteria
NPCC B-04	Guideline for NPCC AREA transmission Review
NPCC Criteria, Guides and Procedures can be found at http://www.npcc.org/document/abc.cfm	

– End of Document –

PUBLIC

IMO_GDL_0021

GUIDELINE

IESO Supply Deliverability Guidelines

Issue 3.0

This document is to be used to evaluate long-term system *adequacy* and *connection assessments*

Disclaimer

Document ID	IMO_GDL_0021
Document Name	IESO Supply Deliverability Guidelines
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Reason for Issue	Name and logo changed to IESO.
Effective Date	September 14, 2005

Document Change History

Issue	Reason for Issue	Date
1.0	First release	June 4, 2003
2.0	Issue released for Baseline 10.0	September 10, 2003
3.0	Name and logo changed to IESO.	September 14, 2005

Related Documents

Document ID	Document Title
IMP_PRO_0021	Internal Manual 2: Market Operations & Forecasts Part 2.10: Connection Assessment and Approval
MDP_PRO_0048	Market Manual 2: Market Administration Part 2.10: Connection Assessment and Approval

(** This page must be removed before the document is released to the public. This page is only pertinent to *IESO* internal staff, not the public. **)

Document Control

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Distribution List

Name	Organization
BIRM	IESO

Table of Contents

Table of Changes

Reference (Section and Paragraph)	Description of Change
Entire Document	Name and logo changed to IESO.

1. Introduction

Historically, the level of *reliability* provided to a customer point of supply was in accordance with Ontario Hydro's "Guide to Planning Regional Supply *Facilities*" (also known at the "E2" Guide) and summarized in Appendix A. The deliverability levels listed in the E2 Table are also defined in Appendix A and assume that loading and voltages on the system (after the occurrence of the contingency) meet applicable limits.

The basic premise of the E2 guide was to relate the level of *reliability* of supply to the size of load being served, i.e. the larger the load, the greater the level of *reliability*. *Reliability* for these cases is measured by the deliverability of supply and is defined as the maximum duration of interruption for each of the contingent events specified.

The E2 guide tried to capture the cost of interruptions by relating transmission *facilities* to load size. However, the guide did not directly specify the level of *reliability* to be provided in terms of typical measures such as frequency, duration, loss of load probability, *energy* unsupplied, Customer Delivery Interruption Index (CDII) or customer impacts.

Ontario Hydro made decisions on new *facilities* or enhancements on a case-by-case basis. They were not made solely on the provision of the E2 Guide. For example, higher levels of customer *reliability* may have been provided for technical, economic, safety and environmental reasons.

The *IESO* has a mandate to "maintain the *reliability* of the *IESO-controlled grid*". In that role, the *IESO* has reviewed the historically used E2 guide and translated it to meet today's electricity marketplace environment. The E2 guide has been modified to provide a deliverability guide for High Voltage supply **to** a *transmission customer*. The *IESO* will use this deliverability guide as a flag to notify the market of the need for a joint planning study between interested *market participants* and the *transmitter*(*s)* to evaluate future supply requirements.

The goal of this document is to provide the deliverability levels that the *IESO* will use to identify the need for a deliverability study. The deliverability levels in this document apply equally to the bulk power system and to *local areas* of the *IESO-controlled grid* and provide a consistent level of deliverability across the province based on the amount of load impacted by a *contingency event*.

If the *transmission customer*(*s*) and the *Transmitter(s*) agree that the results of the deliverability study are acceptable, the *IESO* will consider that the deliverability criteria have been met. Resultant *Connection Assessment* proposals will be evaluated with respect to the "*IESO* Transmission Assessment Criteria". If the *transmission customer*(*s*) and *Transmitter*(*s*) cannot agree on the measures required to address the concerns identified by the deliverability study, the *IESO*, if requested, will assist to the extent possible. Ultimately, in some such situations, it is anticipated that the *Ontario Energy Board* will be required to decide. In those situations, the *IESO* will take a position at the Ontario *Energy* Board and will provide technical information and support to the *Ontario Energy Board.*

The deliverability guidelines and the technical criteria complement each other. A *connection assessment* proposal can meet all the technical criteria but not the deliverability guidelines. It is also possible for a *connection assessment* proposal to meet the deliverability guidelines but not the technical criteria. A *connection assessment* proposal that does not meet the technical criteria in the document "*IESO* Transmission Assessment Criteria" is not acceptable.

This document is not meant to provide either operating or safety criteria.

1.1 Purpose

This purpose of this document is to identify the deliverability guidelines the *IESO* uses in its assessments of the *adequacy* and *security* of the *IESO-controlled grid* and for *connection assessments*.

1.2 Scope

This document is to be used for *IESO* assessment purposes only. It is used for High Voltage supply to a *transmission customer*. Thus it typically includes High Voltage lines and autotransformers but excludes transformer stations stepping down from a High Voltage line to a Low Voltage (< 50kV) bus.

1.3 Who Should Use This Document

This document is used by the *IESO* for evaluating *connection assessments* and for its contingency-based *reliability* assessment. Use of this document should ensure consistent *response* from the *IESO* to all *connection assessments* and in system *adequacy* reports. It is also for *market participants* to understand *IESO* criteria to further their planning process.

- End of Section –

2. Load Level and Deliverability

2.1 Overview

Deliverability of supply is a function of the probability that the elements that make up the supply *facilities* will be in service. Non-deliverability of supply is the condition under which load has been interrupted because one or more elements of the system are out of service for some reason.

The planned deliverability to be provided to a load should take into account contingencies, past performance, probability of failure, the size of the load involved, the cost of interruptions to the customers, and the cost of remedial measures.

Supply *reliability* of certain transmission *facilities* of the *IESO-controlled grid* is evaluated by considering the impact of specific contingencies on the load supplied. Based on each contingency, the resulting impact on load is estimated by considering the extent to which load is interrupted and the duration of such interruption. In general, the greater the load affected, the shorter the duration of the interruption is desired. The most reliable area supply is one in which continuous supply to the load continues, despite the contingency. For some contingencies, it is recognized that load may be restored after a period of time to allow for switching operations or maintenance crew repair. Depending on the size of load affected by the contingency, and what type of contingency has occurred, various switching times are acceptable.

2.2 Planned Deliverability

The basic premise is to relate the level of *reliability* of supply to the size of load being served, i.e. the larger the load, the greater the level of *reliability*. *Reliability* for these cases is measured by the deliverability of supply and is defined as the maximum duration of load loss for each of the contingent events.

The deliverability level to be planned for and provided should generally be a function of the size of the load in accordance with the table below. The load shown is the peak load in Megawatts for the most critical month for the station or group of stations being considered, at the indicated completion date for new *facilities* or remedial action. The load shown is also the load that would be interrupted by the occurrence of the contingency. It is assumed that there is no load loss during routine operations and/or maintenance.

The deliverability level shown in the following table is to be used for supply to *transmission customer*(*s*). Thus it typically includes the High Voltage transmission *facilities*, switching stations, and autotransformers but excludes step down transformer stations. Thus single element contingencies include loss of a High Voltage transmission line and/or autotransformer but ignore the loss of a step-down transformer (to a Low Voltage bus <50kV). A single element contingency can include a line and an autotransformer by configuration.

IESO's **Guide to Deliverability Levels for the ICG**					
	Load Level of Station or Group Affected by Fault or *Outage* (Megawatts)				
TYPE OF FAULT OR *OUTAGE*	0 To 75	76 To 150	151 To 250	251 To 500	501 To More
Single Element*	R8	RS	RR	C	C
2 circuits of Multicircuit Line	X	X	X	RS	C
Two Cables in Same Trench	X	X	RS	RS	RS
Two Cables in Different Trenches	X	X	X	X	RS
Double-Circuit Line	X	X	X	RS	C
Breaker	R8	R8	R8	R8	R8
C –Continuous RR – Restorable Rapidly by Switching (2 seconds) RS – Restorable by Switching (30 minutes) R8 – Restorable in 8 hours by Maintenance Crews X- No Special Provision					
The above deliverability levels are described in detail below:					
For loads greater than 500MW: *With all transmission elements in service, any single element or double circuit contingency should not result in an interruption of supply to a load level of 500MW or more.*					
For loads between 250MW and 500MW: *With all transmission elements in service pre-contingency, any single element contingency should not result in an interruption of supply to a load level greater than 250 MW.* *With all transmission elements in service, for any double circuit contingency that results in a supply interruption of between 250MW and 500MW, all load should be restored by switching operations within a typical period of 30 minutes.*					
For loads between 150MW and 250MW: *With all transmission elements in service, for any single element contingency that results in a supply interruption of between 150MW and 250MW, all load should be restored rapidly within a typical period of 2 seconds.*					
For loads between 75MW and 150MW: *With all transmission elements in service, for any single element contingency that results in a supply interruption of between 75MW and 150MW, all load should be restored by switching operations within a typical period of 30 minutes.*					
For loads below 75MW: *With all transmission elements in service, for any single element contingency that results in a supply interruption to a load less than 75MW, all load should be restored within a maximum period of 8 hours*					

*A single element is a single zone of protection. Descriptions of the interruption duration are included in Appendix A.

2.2.1 Application of Planned Deliverability Levels

The *IESO* will identify situations where a designated contingency results in a violation of the *IESO's* Deliverability Levels in Section 2.2. For such cases, the *IESO* will then flag the need for *market participants* to conduct a deliverability study.

Transmission customers and *Transmitters* can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost. The *transmission customer* and *transmitter* may agree on higher or lower levels of deliverability for technical, economic, safety and environmental reasons.

If a situation arises where the *transmission customer*(*s)* and *Transmitter*(*s*) cannot agree on the results of an deliverability planning study, the *IESO*, if requested, will assist to the extent possible. Ultimately, in some such situations, it is anticipated that the *Ontario Energy Board* will be required to decide. In those situations the *IESO* will take a position at the *Ontario Energy Board* and will provide technical information and support to the *Ontario Energy Board*.

– End of Section –

Appendix A: Historical Deliverability Levels

Ontario Hydro's Guide to Planning Regional Supply *Facilities* (also known at the "E2" Guide) are summarized and shown in the table below.

Table 5.1 Guide to Planning Regional Supply System Deliverability

	Load Level of Station or Group Affected by Fault or *Outage* (Megawatts)						
TYPE OF FAULT OR *OUTAGE*	1 To 15	16 To 40	41 To 75	76 To 150	151 To 250	251 To 500	501 To More
Transformer	R8	R2*	RS**	RS	RR	C	C
Overhead Circuit	R8	R8	R8	RS	RR	C	C
Cable Circuit	X	X	R8	RS	RR	C	C
Bus	R8	R2*	R2	R2	R2	C	C
Breaker	R8	R8	R2	R2	R2	R2	R2
Maintain an Element	Same as for Fault						
Two Transformers	X	X	X	X	X	X	X
Double-Circuit Line (Non-Catastrophic)	R8	R8	R8	R8	R8	RS	C
Double-Circuit Line (Catastrophic)	X	X	X	X	X	RS	C
2 circuits of Multicircuit Line	R8	R8	R8	R8	R8	RS	C
Multicircuit Line (Catastrophic)	X	X	X	X	X	X	X
Two Cables in Same Trench	X	X	X	X	RS	RS	RS
Two Cables in Different Trenches	X	X	X	X	X	X	RS
Two Breakers	R8	R8	R8	R8	R8	R8	R2
	*Up to 15 MW can be R8 **Up to 40 MW can be R2						

C – Continuous
RR – Restorable Rapidly
RS – Restorable by Switching (30 minutes)
R2 – Restorable in 2 hours by Travelling Operator
R8 – Restorable in 8 hours by Maintenance Crews
X – No Special Provision

The deliverability levels listed in the E2 Table are defined below and assume that loading and voltages on the system after the occurrence of the contingency are within applicable limits.

C -Continuous

This is the highest level. There should be no interruption in supply as a result of the occurrence of the contingency. The voltage may collapse for a few cycles while a fault is being cleared but it may rise immediately after fault clearance, and must be restorable to an acceptable *emergency* level by automatic action such as on load tap changing. Transfer of such load to another source is permissible to relieve overload, but the transfer must be done without interrupting load.

RR -Restorable Rapidly

An interruption of two seconds is permissible at the time of a contingency or at the later time of load transfer. Restoration within two seconds must be accomplished automatically by operation of breakers without operator intervention.

RS -Restorable by Switching (3 minutes)

Load may be interrupted at the time of the contingency, but it must be restorable within one half hour, for example by the action of a control room operator using remote or supervisory control, or by use of automatically operated switching at the affected station.

R2 -Restorable in 2 hours by Travelling Operator

Load may be interrupted at the time of contingency, but it must be restorable within two hours. It is assumed there will be switches, quick openers or other devices available that can be operated by a travelling operator or maintenance person to restore service. Means of quick transfer of metering and relaying will also be required.

R8 -Restorable in 8 hours by Maintenance Crews

Load may be interrupted at the time of the contingency, but restoration must be within eight hours. Restoration is assumed to be the result of repair work or temporary connections that can be made by a maintenance crew. This may comprise such line work as replacement of a pole, crossarm or insulators, repair or replacement of a defective low voltage breaker, connecting of an on-site spare transformer (including metering, relaying, and service supply). Station design must be suitable for transformer connection to be accomplished within eight hours.

X –No Special Provision

Each case must be considered separately, taking into account the cost, probability of occurrence of the contingency, length of repair time, and the extent of hardship caused. In any specific case, the deliverability will be at a level no higher than R8 and may be as low as to permit the *outage* to extend for several days.

– End of Document –

OEB - INTERROGATORY #2 List 1

Interrogatory

2.0 Alternatives Considered

Reference: Exh. B, Tab 3, Sch. 1

Preamble

The evidence indicates that Hydro One (then Ontario Hydro) carried out a study in 1998 to develop a long term plan for electricity supply in Norfolk County. Three alternatives were considered in that study. It is indicated that stage I of the preferred alternative has already been implemented and that the proposed work that is the subject of this application is the next stage.

Questions / Requests

i. Please provide a table showing the various projects that were implemented as part of stage 1, including brief descriptions of the projects, in-service dates and costs.

ii. Does the current project complete the work of the preferred alternative from the 1998 study or are there additional stage(s) to be implemented?

iii. Please provide details including timing and cost of any additional stage(s).

Response

i. Please see table below

Project	Description	In-Service Year	Approximate Costs
Installation of 230/115kV auto transformer at Caledonia	The installation of two 230-115 kV autotransformers at Caledonia TS to supply Norfolk TS, as a replacement for the old 115 kV line supplied from Allanburg TS that was the previous source of supply. The Caledonia TS autotransformers are connected to two 230 kV Nanticoke TS x Middleport circuits	2004	$13.6 M
Refurbishment of A8N/A11N line	The refurbishment of the 115 kV A8N/A11N line (in particular the Caledonia TS x Hartford Junction section) to supply Caledonia TS.	2004	$9.8 M

Project	**Description**	**In-Service Year**	**Approximate Costs**
Refurbishment of A1N Line	The installation of the 115kV line A1N from Vanessa Junction to Norfolk TX. The line structures were designed and built at the time to accommodate a second circuit	1999	$4.2 M

ii. Yes, the current project would complete the project plan of 1998 and no additional stages would be required.

iii. No additional stages would be required to complete the 1998 plan, after installation of the second line between Vanessa Junction and Norfolk TS.

OEB - INTERROGATORY #3 List 1

Interrogatory

3.0 Project Economics and Cost responsibility
References: (1) Exh. B, Tab 4, Sch. 2
(2) Exh. B, Tab 4, Sch. 3
(3) Section 6.6 of the Transmission System Code

Preamble

The evidence indicates that the estimated total cost of the proposed project is $3.58 million. Of this, $2.792 million is for transmission line work which will be included in the Line Connection Pool and $0.447 million is for transformation facilities which will be included in the Transformation Connection Pool. The remaining $0.341 million is for the line tap to Bloomsburg MTS and associated facilities and will be funded 100% by Norfolk Power.

Ref (2) indicates that Hydro One carried out a 25-year Discounted Cash Flow (DCF) calculation for each pool based on the economic evaluation requirements of the Transmission System Code.

Ref (2) also indicates that the $2.792 estimate for transmission line work is broken down as follows:

- Upgrading Existing Circuit $ 1.1 million
- Adding New Circuit $ 1.7 million
- Total $ 2.8 million

Hydro One also indicates that:

(i) the cost of upgrading the existing circuit ($1.1 million) was assigned to customers for cost responsibility purposes. The DCF analysis shows that this will result in a customer contribution amount of $0.5 million.

(ii) the cost to add the new circuit ($1.7 million) has been assigned to the line connection pool for cost responsibility purposes and has therefore been excluded from the DCF analysis.

Board staff seeks a better understanding of Hydro One's rationale for excluding the cost of adding the second circuit in the DCF analysis and thus requiring that the cost ($1.7 million) be paid through rates by all transmission customers.

Questions / Requests

i. Please explain Hydro One's rationale for assigning the cost of adding the second 115 kV circuit to the line connection pool even though the line is radial and supplies only two transmission customers. Also, please explain why this qualifies as an exception under 6.3.6 of the Transmission System Code.

ii. Hydro One states that the addition of the second circuit was identified and planned for several years. To explore this further:

(a) Please provide details of the plan development including timing, activities, reports, approvals etc.

(b) What parties if any, other than Hydro One, were involved in the studies to identify need, alternatives and preferred plan?

(c) Were the studies/plan development carried out by Hydro One on its own initiative, or was it at the request of a third party? Please explain.

(d) If the studies/plan development were carried out by Hydro One on its own initiative, what triggered this?

iii. If the Board were to decide that capital contributions are required for adding the second circuit, please provide an estimate of what the contribution amounts would be from the transmission customers involved including details of calculation.

Response

i. Hydro One believes it is appropriate to assign the costs of adding the second circuit to the line connection pool for the following reasons:

- Hydro One is obligated under the TSC (section 6.3.6) to *"develop and maintain plans to meet load growth and maintain the reliability and integrity of its transmission system. The transmitter shall not require a customer to make a capital contribution for a connection facility that was otherwise planned by the transmitter, except for advancement costs."*

The Vanessa to Norfolk project was originally included in Ontario Hydro's plans in the late 1990's, as noted in the evidence under Alternatives at Exhibit B, Tab 3, Schedule 1. Provision was made for the second circuit in those plans and the structures that were built in the first stage of the ensuing plan implementation were designed to accommodate a second circuit. Since that time, the other elements of the original Ontario Hydro plan have been adopted by Hydro One in a series of follow-on projects that were implemented over the period from the late 1990's to 2004. The project now applied for in respect of the addition of the second circuit is the final part of that original plan. Accordingly, it is clear that the plan to improve reliability of the Vanessa to Norfolk single-circuit line has long been in existence. On this basis, Hydro One believes that the proposed treatment for exemption of the costs related to the addition of the second circuit from a capital contribution requirement complies with the meaning of Section 6.3.6 of the Code.

The Board's approach in these matters was clarified in the Connection Procedures Decision (EB-2006-0189) as follows:

- *"Section 6.3.6 of the Code is an expression of the concept that an individual customer ought not to bear any unique responsibility for projects within established plans for things such as additions or improvements to the system for reliability and integrity improvements which have been already identified and planned for by the transmitter, except for any additional costs associated with the advancement of the improvements at the request of the customer"* [p. 21]. As noted elsewhere in this response, the plan to add the second circuit was identified by Ontario Hydro and adopted by Hydro One. This plan was not based on a request from Norfolk Hydro.

- *Integrating load growth projections, reliability and safety needs is at the heart of the transmitter's planning process. It is the product of that activity that can give rise to the exception contained in Section 6.3.6 of the Code."* [p. 23]

- *"The plan should demonstrate that the projects embedded in it are designed to have a long term positive effect on system reliability and integrity."* [p. 23]

Other than the existing Vanessa to Norfolk single-circuit line section, the rest of the Hydro One transmission system in the Norfolk area is designed and built with a dual-element configuration providing continued supply under an n-1 contingency. This means that due to the single-element design of the existing Vanessa to Norfolk section, the entire load in Norfolk County will be interrupted due to a single contingency on the 115 kV system supplying Norfolk TS and Bloomsburg MTS.

Based on the extent of load that would be at risk of being interrupted due to a single contingency on the 115 kV system, causing hardship in Norfolk County, Hydro One submits a second circuit on the existing line should be built at this time and the cost absorbed by the line connection pool. The second circuit will have a long-term positive impact on the reliability and integrity of the local area supply system. This approach is consistent with past planning practice in Ontario, specifically Ontario Hydro's former E2 planning guide and the IESO's Supply Deliverability Guidelines ("SDG"), which is adapted from the E2 guide. The SDG suggested that load between 76 MW and 150 MW should be restorable by switching within 30 minutes for a single-element contingency (see table on p. 4 in SDG, filed as part of the response to Board Staff IR 1). Existing peak load on the Vanessa to Norfolk circuit is 81MW and is forecast to grow to close to 122 MW by 2034, based on the load forecast included in the evidence at Exhibit B, Tab 4, Schedule 3, p. 15. It was on the basis of the SDG planning standard that the IESO noted in its 2002 SIA report (p. 5) that the single-circuit Vanessa to Norfolk line did not comply with the "proposed IMO load supply guidelines", as they were then called, and the supply to a load of that size "should be restorable by switching."

As indicated in the response to Board Staff 1 (i), Hydro One's understanding is that the SDG were superseded by the IESO's Ontario Resource and Transmission Assessment Criteria ("ORAT") issued in August, 2007. The "Load Security and Restoration Criteria" in the ORAT require in section 7.2 (a) that all load should be restorable within approximately 8 hours and in part (b) that load that is greater than 150 MW should be restorable within approximately 4 hours, following any design contingency. The section also notes that the above are approximate restoration times and are intended for locations near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility.

The ORAT criteria are somewhat different from the previous standards contained in the SDG and E2 documents. Under the ORAT criteria, the case is less clear than under the former standards that a second circuit on the Vanessa to Norfolk line is required to meet reliability standards. Hydro One does note, however, that the restoration times in the ORAT are intended to be approximate. As well, the Vanessa to Norfolk circuit is at the edge of the territory serviced by a Hydro One service centre in London, approximately 120 km. away. Due to the distance, Hydro One crews may not be able to restore supply after a contingency within the 8 hour limit prescribed by the IESO criteria (ORAT Section 7.2 (b)), especially in adverse weather, where heavy equipment may be needed. On this basis, Hydro One suggests that the addition of a second circuit, which would allow for load restoration by switching, meets the applicable reliability standards. In the alternative, Hydro One proposes that as the addition of the second circuit was planned for under the previous reliability criteria, the previous reliability criteria should apply. Using those criteria, the second circuit clearly meets the standard, as discussed above.

Based on all of the above, Hydro One submits that the addition of the second circuit is reliability-driven, and that the applied-for project is part of a long-standing plan to eventually improve reliability in Norfolk County through the addition of a second circuit. On that basis, Hydro one proposes that there should be no cost contribution anticipated for the second circuit from customers, consistent with section 6.3.6 of the Code. In this regard, Hydro One notes that with respect to the other parts of the project (namely the line upgrade, the line tap to Bloomsburg MTS and the station modifications), the costs are proposed to be subject to capital contributions, where required.

ii (a)The existing A1N line was planned, designed and built by Ontario Hydro in the late 1990's. Line capacity has now reached its limit. At the time the line was built, the A1N line structures were designed and installed for the two-circuit line and a decision was made to string only one circuit in the late 1990's and defer the installation of the second circuit.

(b) The need to upgrade the existing conductor was identified by Hydro One based on the current peak loading on the line. Both Hydro One Distribution and Norfolk Power were advised of the existing load and capacity situation. Both LDCs were also aware that the line was designed to accommodate a second circuit. Customers were advised of the plan to upgrade the existing line and install the second circuit. The LDCs were involved in providing the load forecasts that resulted in establishing the ratings of the line conductors and making use of the existing pole structures. These customers were advised of the plan of action to address the situation and the fact that final treatment of investment costs will be approved and/or decided by the OEB.

(c) The current plan to install a second circuit is a continuation of the planned but deferred work in the late 1990's from Ontario Hydro which Hydro One has adopted.

(d) The need to upgrade the existing conductor was identified by Hydro One based on the current peak loading on the line, and the future need to add the second circuit was identified, as previously mentioned, in the original plan developed by Ontario Hydro in the late 1990's.

iii. If the Board were to decide that capital contributions are required for adding the second circuit, customers would be required to pay for 100% of the cost as there is no incremental load associated with the second circuit. This cost would be allocated between Norfolk Power and Hydro One in proportion to their load. The total contribution amount, for both the second circuit and the line upgrade, will be $1.7 million for Norfolk Hydro and $0.7 million for Hydro One Distribution.

Table 2 – DCF Analysis, Line Connection Pool, page 1

Date:	27-May-08
Project #	11101

SUMMARY OF CONTRIBUTION CALCULATIONS

hydro one

Facility Name: Norfolk Project 1 - Reconductor A1N & 2nd circuit

Scope: Full Cost Capital Contribution

		Cumulative PV @ 5.68%	In-Service Date Apr-30 2009	Apr-30 2010	Apr-30 2011	Apr-30 2012	Apr-30 2013	Apr-30 2014	Apr-30 2015	Apr-30 2016	Apr-30 2017	Apr-30 2018	Apr-30 2019	Apr-30 2020	Apr-30 2021
Month / Year				← Project year ended - annualized from In-Service Date →											
				1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast															
Load Forecast (MW)				0.2	1.3	3.1	4.9	6.4	7.4	8.5	9.5	10.5	11.6	12.7	13.7
Tariff Applied ($/kW/Month)				0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59
Gross Revenue - $M				0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
OM&A Costs (Removals & On-going Incremental) - $M			(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Ontario Capital Tax and Municipal Tax - $M			0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M			(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
Income Taxes (incl. LCT)			0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Operating Cash Flow (after taxes) - $M			(0.1)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
PV Operating Cash Flow (after taxes) - $M	(A)	0.7	(0.1)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital Expenditures - $M															
Upfront - capital cost before overheads & AFUDC			(2.4)												
- Overheads			(0.2)												
- AFUDC			(0.0)												
Total upfront capital expenditures			**(2.7)**												
On-going capital expenditures				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures			0.0												
Total capital expenditures - $M			**(2.7)**												
PV Proceeds on disposal of assets - $M			**0.0**												
PV CCA Residual Tax Shield - $M			**0.0**												
PV Working Capital - $M			**(0.0)**												
PV Capital (after taxes) - $M	(B)	(2.7)	(2.7)												
Cumulative PV Cash Flow (after taxes) - $M	(A) + (B)	(2.1)	(2.7)	(2.7)	(2.6)	(2.6)	(2.6)	(2.5)	(2.5)	(2.5)	(2.4)	(2.4)	(2.4)	(2.4)	(2.3)

Discounted Cash Flow Summary

(Based on Economic Study Horizon - Years): 25

Discount Tariff - % 5.68%

		Before Contribution $M		After Contribution $M	Impact of Contribution $M
PV Incremental Revenue		1.1		1.1	
PV Incremental OM&A Costs		(0.7)		(0.7)	
PV Ontario Capital Tax and Municipal Tax		(0.3)		(0.0)	0.2
PV Income Taxes and LCT		(0.1)		(0.2)	(0.1)
PV CCA Tax Shield		0.5		0.1	(0.5)
PV Capital - Upfront	(2.7)		(2.7)		
Add: PV **Capital Contribution**	**0.0**	(2.7)	**2.4**	(0.3)	2.4
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(0.0)		(0.0)	
PV Surplus / (Shortfall)		**(2.1)**		**0.0**	**2.1**
Profitability Index*		**0.2**		**0.9**	

*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Start Date:	1-Aug-08
In-Service Date:	30-Apr-09
Payback Year:	2034
No. of years required for payback:	25

Contribution Required (before GST) - $M	2.4
GST @5% - $M	0.1
Contribution Required (incl. GST)* - $M	2.5

* Payment from customer must include GST.

1 **Table 2 – DCF Analysis, Line Connection Pool, page 2**

Date:	27-May-08
Project #	11101

SUMMARY OF CONTRIBUTION CALCULATIONS

Facility Name: Norfolk Project 1 - Reconductor A1N & 2nd circuit

Scope: Full Cost Capital Contribution

		Apr-30	Apr-30	Apr-30	Apr-30	Apr-30	Apr-30	Apr-30	Apr-30	Apr-30	Apr-30	Apr-30	Apr-30	Apr-30
Month / Year		**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (MW)		14.8	15.9	17.0	18.1	19.3	20.4	21.6	22.7	23.9	25.1	26.3	27.5	28.8
Tariff Applied ($/kW/Month)		0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59
Gross Revenue - $M		0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
OM&A Costs (Removals & On-going Incremental) - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Ontario Capital Tax and Municipal Tax - $M		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Revenue/(Costs) before taxes - $M		0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Income Taxes (incl. LCT)		0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Cash Flow (after taxes) - $M		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV Operating Cash Flow (after taxes) - $M	**(A)**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
PV Proceeds on disposal of assets - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**(2.3)**	**(2.3)**	**(2.2)**	**(2.2)**	**(2.2)**	**(2.2)**	**(2.1)**	**(2.1)**	**(2.1)**	**(2.0)**	**(2.0)**	**(2.0)**	**(2.0)**

2
3

OEB - INTERROGATORY #4 List 1

Interrogatory

4.0 System Impact Assessment (SIA)
Reference: (1) Exh. B, Tab 6, Sch. 3, Attachment B
(2) Exh. B, Tab 6, Sch. 3, Attachment A
Preamble
Hydro One submitted two SIAs for the Project:

(1) Reference (1) is an SIA dated November 12, 2002 which covers the upgrading of Norfolk TS and adding a second 115 kV circuit between Vanessa Jct. and Norfolk TS. In this SIA, it was assumed that the existing circuit would be upgraded by retensioning, not replacement of conductors, as is now proposed.

(2) Reference (2) is an SIA dated January 18, 2008 which covers the work associated with the line tap to Bloomburg MTS and concluded that this work is not expected to a material adverse impact on the IESO - controlled grid.

The original SIA (1) is about 5.5 years old. It is labelled as final but is not signed and there is no Notification of Approval for this SIA.
The more recent SIA (2) makes mention of the second 115 kV circuit but its intent and focus is the short line tap to Bloomburg MTS. It is unsigned and accompanied by an unsigned Notification of Approval.
Questions / Requests

i. Please provide the Notification of Approval for the SIA dated November 12, 2002.

ii. Please provide signed versions of the SIA and "Notification of Conditional Approval of Connection Proposal" dated January 18, 2008.

iii. Because of the age of the SIA in Ref (1), please provide written confirmation from the IESO that it is in agreement with and approves the entire project as <u>now</u> proposed by Hydro One.

iv. Please confirm that the IESO's connection requirements for the proposed project will be implemented.

Response

i. Please see attached letter from Bob Gibbons at IMO dated November 12, 2002.

ii. The Assessments by IESO are provided to Hydro One unsigned at this time. Discussions are on going with IESO on the signature protocols.

iii. Barbara Constantinescu, from the IESO, in an e-mail dated July 3, 2007 confirmed that the original assessment is still valid. She noted that the original assessment concluded that the addition of a second 115kV circuit from Vanessa Junction to Norfolk TS, of a summer rating of 575A, will improve the supply reliability and benefit the connected customers. The modifications to include the installation of a higher rated circuit and also the upgrading of the existing circuit A1N did not impact the validity of the original SIA (see attached e-mail from Barbara Constantinescu).

iv. Hydro One intends to implement the IESO's connection requirements.

File NW2

IMO Independent Electricity Market Operator

November 12, 2002

File No: OP-1600

Mr. Bob Singh,
Manager, Connection & Distribution Development
Investment Planning Division
Hydro One
483 Bay Street
Toronto, Ontario, M5G 2P5

Dear Mr. Singh:

Installation of the Second 115 kV Circuit from Vanessa Jct. to Norfolk TS and Upgrading of the Existing Circuit
Notification of Approval of Connection Proposal
CAA ID Number: 2002-EX070

Thank you for the detailed information that you provided on the plan for stringing a second 115 kV circuit between Vanessa Jct. and Norfolk TS on the existing double circuit towers, and upgrading of the existing circuit.

The supply to Norfolk TS load has already been studied as part of the *Preliminary Assessment* performed for the incorporation of Caledonia TS (CAA ID 2002-056). This assessment recommended that Hydro One consider completing the double circuit line from Caledonia TS to Norfolk TS to decrease the risk of load loss in case of a single element contingency. Consequently, it was decided that your connection application for the installation of the second 115 kV circuit between Vanessa Jct. and Norfolk TS does not require a formal CAA study.

Our assessment concluded that the addition of the second 115 kV circuit section between Vanessa Jct. and Norfolk TS and the upgrading of the existing single circuit section will result in an improved level of load supply reliability for the load connected to Norfolk TS.

The IMO is therefore pleased to grant approval for the installation of the second 115 kV circuit between Vanessa Jct. and Norfolk TS and the upgrading of the existing circuit. However, this approval is subject to the full implementation of the IMO's requirements, as detailed in the Preliminary Assessment Report, a copy of which is attached. Also, a copy of the Report will be posted on the IMO web site: www.theimo.com.

The Ontario Energy Board (OEB) will be advised of the completion of this assessment and the approval of this Project.

Please follow the necessary procedures and obtain the required approvals, licences and permits as may be required by the OEB, and other regulatory authorities.

From: BAHRA Devinder
Sent: Friday, May 30, 2008 6:05 PM
To: RICHARDSON Joanne; SKALSKI Andrew; GHAI Raj; PANESAR Harneet; GARG Ajay
Cc: BAHRA Devinder
Subject: FW: PA Report-NorfolkTSA8N.pdf - Adobe Reader

Email from IESO that confirms original assessment (2002-070) is still valid because the changes represent improvements compared to the
original plan and will not have a material adverse effect on the system reliability. Hence the notification of conditional approval is also valid.

Devinder Bahra

From: Constantinescu Barbara [mailto:barbara.constantinescu@ieso.ca]
Sent: Tuesday, July 03, 2007 2:16 PM
To: BAHRA Devinder
Cc: GARG Ajay
Subject: RE: PA Report-NorfolkTSA8N.pdf - Adobe Reader

Hello Devinder,
I appreciate you keeping us informed and thanks for the update.
The original assessment concluded that the addition of a second 115 kV circuit from Vanessa Jct. to Norfolk TS, of a summer rating of 575 A, will
improve the supply reliability and benefit the connected customers. The original plan was slightly modified and now includes the installation of a
higher rated circuit and also the upgrading of the existing circuit A1N. Based on the information below the IESO concluded that the original
assessment (2002-070) is still valid because the changes represent improvements compared to the original plan and will not have a material
adverse effect on the system reliability. Hence the notification of conditional approval is also valid.

Regards,

Barbara Constantinescu
tel. (905)855-6406
fax (905)855-6372

From: d.s.bahra@HydroOne.com [mailto:d.s.bahra@HydroOne.com]
Sent: June 29, 2007 2:17 PM
To: Constantinescu Barbara
Cc: ajay.garg@HydroOne.com; d.s.bahra@HydroOne.com
Subject: FW: PA Report-NorfolkTSA8N.pdf - Adobe Reader

Hi Barbara

We would appreciate confirmation requested in the email below by July 16, 2007 or earlier if possible.

Please do not hesitate to call me if additional information is required.

Thanks

Devinder Bahra

From: BAHRA Devinder
Sent: Tuesday, June 12, 2007 12:35 PM
To: 'Constantinescu Barbara'
Cc: GARG Ajay; BAHRA Devinder
Subject: PA Report-NorfolkTSA8N.pdf - Adobe Reader

<<PA Report-NorfolkTSA8N.pdf>>
Barbara

We are planning to install the second 115 kv circuit from Vanessa Jct. to Norfolk TS and upgrade the existing circuit for expected

in-service in April 2009.

The plan is to install conductors suitable for 640 amp both for the new second circuit and upgrade of the existing circuit.

Please confirm that the Connection Assessment completed CAA ID 2002-EX070 (File attached for reference) completed by IESO

in 2002 will still be valid or you may want to update it with new information.

Regards

Devinder Bahra
Hydro One Networks Inc.
483 Bay Street, 15th Floor North Tower
Toronto, Ontario, Canada
M5G 2P5
Office: 416-345-5276
Cell : 416-276-5276
Fax: 416-345-6029
E.MAIL: d.s.bahra@Hydroone.com

Please note that the new facilities will also have to meet the requirements of the IMO's Facility Registration process before being placed in service.

For further information, please contact the undersigned.

Yours truly,

Bob Gibbons
Manager - Long Term Forecasts & Assessments
Telephone: (905) 855-6482
Fax: (905) 855-6129
E-mail: bob.gibbons@theimo.com

BC:gb

Attach:

cc: IMO Records

OEB - INTERROGATORY #5 List 1

Interrogatory

5.0 Customer Impact Assessment (CIA)
Reference: (1) Exh. B, Tab 6, Sch. 1, Section 2.0
(2) Section 6.4.3 of the Transmission System Code
(3) Section 2.4 of the Hydro One Connection Procedures
(EB-2006-0189)

Preamble

Hydro One submitted that, consistent with the Transmission System Code requirements a formal CIA is not required since the addition of the second circuit does not negatively impact the customers.

Ref (2) states that a transmitter shall carry out a CIA for any proposed new or modified connection where:

(a) the connection is one for which the IESO's connection assessment and approval process requires a system impact assessment; or

(b) the transmitter determines that the connection may have an impact on existing customers.

Ref (3) also states that:
"Where the IESO's CAA process triggers an SIA, the CIA procedure is mandatory."

Questions / Requests

i. Please provide the rationale for Hydro One's statement that a formal CIA is not required for the subject project.

ii. Has Hydro One advised the transmission customers involved that a CIA is not required?

iii. If it is determined that a CIA is required, what is the earliest date that the CIA can be completed?

Response

i. IESO confirmed in their notification letter, which accompanied the 2002 SIA Report, that it was decided that the installation of the second circuit between Vanessa Jct. and Norfolk TS does not require a formal CAA study. Therefore, with no CAA process required there was no need for a CIA.

Additionally the SIA report confirmed that there is minimal impact on customer facilities as a result of the project. The information is as follows:

In 2002, the IESO decided to cluster the following projects and performed a single assessment as per Page 1 of the 2002 SIA CAA2002-EX070 ("2002 SIA Report"), included in Exhibit B, Tab 6, Schedule 3, Attachment B. These projects are:

a. installation of two 110-28.4 kV 50/66.6/83.3 MVA transformers at Norfolk TS to replace the lower rated transformers (Reference: CAA ID 2002-EX058) which are already placed in service, and
b. Installation of second circuit between Vanessa Jct to Norfolk TS which will provide a dual supply to Norfolk TS (Reference: CAA ID 2002-EX070).

Section 2.5 of the 2002 SIA Report, states on page 4, that with the Norfolk load connected to the new Caledonia TS autotransformers, the maximum symmetrical fault levels at Norfolk TS 27.6 kV bus will be about 8.2 kA. This value is well within the fault interrupting capability of the existing LV breakers. The short circuit study conducted by Hydro One in 2008 confirms that the fault levels have not changed materially since IESO had completed the assessment in 2002 and are within the limits specified in the Transmission System Code.

Section 3 of the 2002 SIA Report states on page 6, that the proposed addition of the second 115 kV circuit between Vanessa Jct. and Norfolk TS and upgrading of the existing circuit will result in an improved level of load supply reliability to Norfolk TS connected customers.

Based on the above Hydro One considers that a formal CIA is not required for this project.

ii. No. Hydro One has not advised the transmission customers involved that a CIA is not required. However, the two transmission connected customers have been aware of the assessment, fault levels and SIA.

iii. A CIA could be completed in 6 to 8 weeks if it was determined that one was required. It is possible that this additional requirement could have an impact on meeting the target in-service date of April 2009.

OEB - INTERROGATORY #6 List 1

Interrogatory

6.0 Environmental Assessment
Reference: Exh. B, Tab 6, Sch. 1, Section 4.0
Preamble
Hydro One submitted that:

- it completed and filed an Environmental Study Report ("ESR") in March 1999 with the Ministry of the Environment in relation to the upgrading of the existing 115 kV line from Vanessa Jct. to Norfolk TS which was carried out later that year;
- because of this, there are no requirements under the Environmental Assessment Act for the Project; and
- for due diligence purposes it has completed an environmental screening which included updating of existing data bases and a field visit. The screening has been completed and the Ministry of the Environment notified.

Questions / Requests

i. Did the ESR filed in March 1999 include the addition a second circuit to the transmission line? Please explain.
ii. Is there an expiry date for any EA approvals granted in 1999? If so, what is it?
iii. Please provide appropriate documentation confirming that all requirements under the Environmental Assessment Act for this project have been fulfilled.

Response

i. The original project constructed in 1999 required the replacement of the wood poles for the 12 km. 115 kV transmission line, therefore it fell under the Class Environmental Assessment for Minor Transmission Facilities. The ESR stated that "construction is tentatively scheduled from May 1999 to September 1999 with the second circuit probably in 2000 or sooner." Therefore the report made mention that the stringing of the circuits was going to be staggered.

ii. There is no expiry date for an EA approval unless specified directly. Although there was no direct requirement, it was felt that we would do a Screening under our Class EA to update our information and let the Ministry of the Environment know we were intending to string the second circuit.

iii. Hydro One provided the Ministry of Environment ("MOE") with the screening report on January 8, 2008 (see Attachment A). There have been no concerns expressed by the MOE.

January 8, 2007

Ms.Agatha Garcia-Wright, Acting Director
Environmental Assessment and Approvals Branch
Ministry of the Environment
2 St. Clair Avenue West, Floor 12A
Toronto, Ontario, M4V 1L5

Vanessa Junction X Norfolk TS
115 kV Line Refurbishment

Dear Ms Garcia-Wright:

This is further our letter dated May 28, 2007, where we notified Mr. Jim O'Mara that we are planning work on Vanessa Jct X Norfolk TS line. At that time, we anticipated that the work would entail only the stringing of the second circuit. We are now planning to install possibly two new transmission structures, one at Vanessa Junction beside an existing structure and another at Norfolk TS . Additional arms and hardware will be installed on the existing wood poles. The existing circuit will also have to be re-strung along with the stringing of the second circuit.

In March 1999, Ontario Hydro submitted a class Environmental Assessment, Environmental Study Report: *Vanessa Junction X Norfolk TS 115kV Line Refurbishment.* The report describes the technical and environmental studies carried out by Ontario Hydro to maintain a reliable electrical supply and to meet the future demand of the City of Nanticoke and Regional Municipality of Haldimand-Norfolk. The assessment was for single circuit wood pole structures to be replaced with two-circuit structures and one line strung with plans to string the second line at a future date. At the time of the Class EA, there was no expressed opposition to this project and all concerns raised were satisfactorily resolved. Hydro One is planning the stringing of the second circuit.

As a matter of due diligence, we have completed an Environmental Screening for this project. Correspondence with Ron Gould, Species at Risk Biologist for the Ministry of Natural Resources and Paul Gagnon, Lands and Water Supervisor, Long Point Region Conservation Authority has been attached for your information. Public notification will be completed prior to the commencement of construction.

We will be ensuring that all necessary permits and approvals are acquired. All environmental requirements will be consistent with our Environmental Guidelines for the Construction and Maintenance of Transmission Facilities. It is our understanding that our obligations under the Class EA have been met.

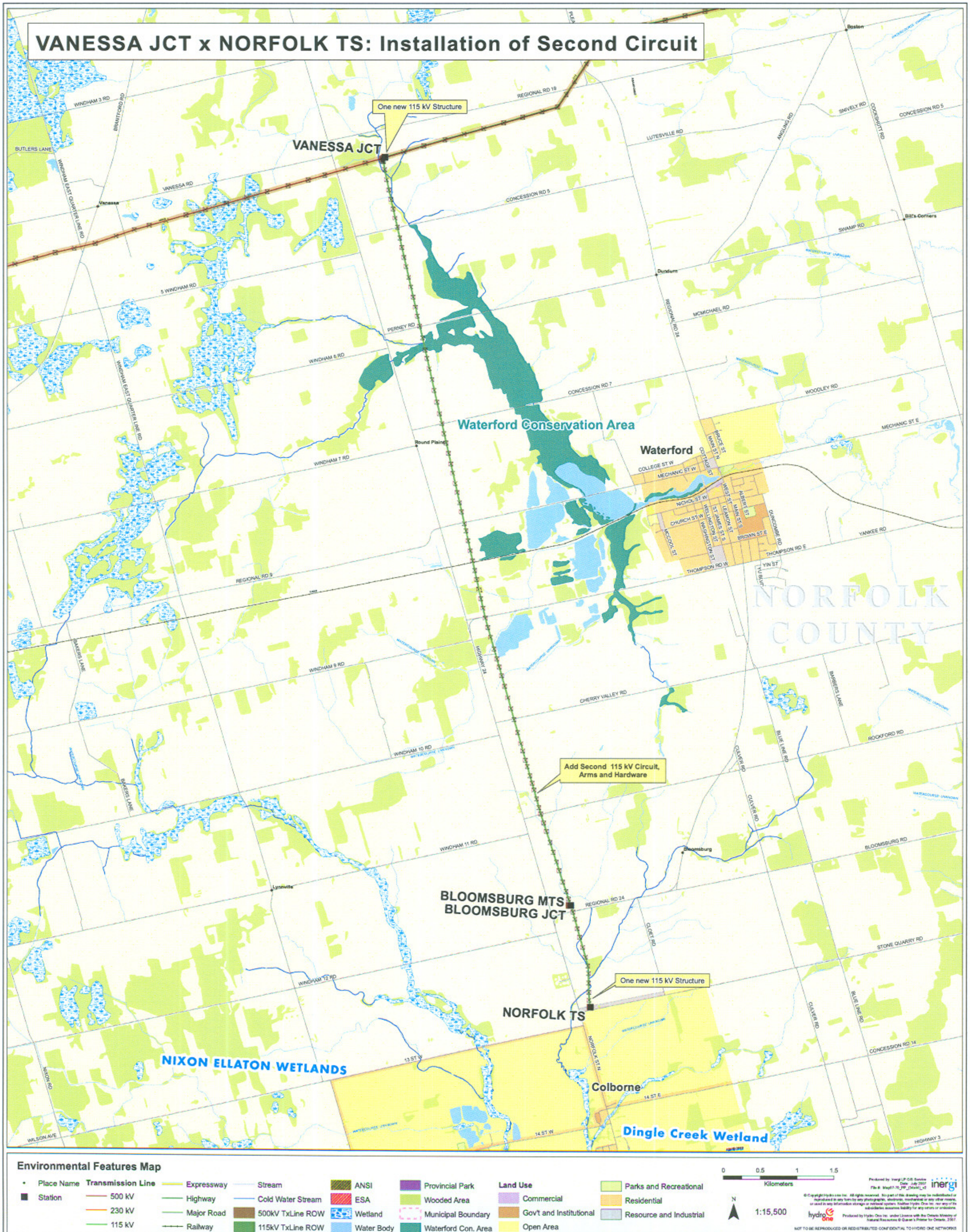
The in-service date is scheduled to be April 2009. If you have any questions or would like to discuss this further, please do not hesitate to contact me.

Sincerely,

Brian J. McCormick, Manager
Environmental Services and Approvals
Hydro One Networks Inc.
483 Bay St. (13th Floor - North Tower)
Toronto, Ontario M5G 2P5

Phone: 416 345 6597
Fax: 416 345 6919

Cc Barbara Ryter, Hamilton Regional Office


VANESSA JCT x NORFOLK TS: Installation of Second Circuit
One new 115 kV Structure
VANESSA JCT
Waterford Conservation Area
Waterford
NORFOLK COUNTY
Add Second 115 kV Circuit, Arms and Hardware
BLOOMSBURG MTS
BLOOMSBURG JCT
One new 115 kV Structure
NORFOLK TS
NIXON ELLATON WETLANDS
Colborne
Dingle Creek Wetland
REGIONAL RD 19
WINDHAM 3 RD
BRANTFORD RD
BUTLERS LANE
VANESSA RD
CONCESSION RD 5
LUTESVILLE RD
SNIVELY RD
COCKSHUTT RD
CONCESSION RD 5
Boston
Bill's Corners
SWAMP RD
Dunduro
5 WINDHAM RD
PERNEY RD
WINDHAM 6 RD
MCMICHAEL RD
REGIONAL RD 24
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WINDHAM 9 RD
CHERRY VALLEY RD
HIGHWAY 24
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WINDHAM 10 RD
BLUE LINE RD
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Bloomsburg
BLOOMSBURG RD
Lynnville
REGIONAL RD 24
STONE QUARRY RD
WINDHAM 12 RD
CONCESSION RD 14
13 ST W
14 ST E
14 ST W
NORFOLK ST N
WILSON AVE
NIXON RD
HIGHWAY 3
Environmental Features Map
Place Name
Station
Transmission Line
500 kV
230 kV
115 kV
Expressway
Highway
Major Road
Railway
Stream
Cold Water Stream
500kV TxLine ROW
115kV TxLine ROW
ANSI
ESA
Wetland
Water Body
Provincial Park
Wooded Area
Municipal Boundary
Waterford Con. Area
Land Use
Commercial
Gov't and Institutional
Open Area
Parks and Recreational
Residential
Resource and Industrial
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NOT TO BE REPRODUCED OR REDISTRIBUTED CONFIDENTIAL TO HYDRO ONE NETWORKS

MOE SCREENING PROCESS

Class EA for Minor Transmission Facilities

Project: Vanessa Jct X Norfolk TS, Stringing of the second circuit

Location: Norfolk County

File: 430.02 T5 – Vanessa Jct. X Norfolk TS

Parties Consulted: Ministry of Natural Resources,
Long Point Region Conservation Authority

Prepared by: Patricia Staite

Date: Dec. 12, 2007

PROJECT TYPE	COMMENTS
x Modifying or upgrading of existing transmission lines involving: 1. replacement of no more than 25 suspension structures; and 2. installation of no more than 20 additional structures	Addition of one structure in the vicinity of Norfolk TS and one at Vanessa Jct. Addition of a new 115kV circuit with associated arms and hardware on all existing poles. Restringing of existing circuit. An Environmental Study Report was completed in March 1999 when the existing line was initially refurbished.
Minor overhead transmission lines up to 4km in length.	
Underground transmission lines in urban areas.	
Modifying or expanding of existing transformer/switching stations involving a site extension of no more than 4ha.	
115kV distributing stations	
Telecommunication towers	

SCREENING CRITERIA	NO	YES or POSSIBLY	COMMENTS
Determine whether the proposed undertaking will:			
1. conflict with the environmental objectives, plans, standards, policy statements or guidelines adopted by the Province of Ontario, or the Community where the project is to be located.	X		
2. have significant effects on persons or property, including lands zoned residential.	X		
3. necessitate the irreversible commitment of any significant amount of nonrenewable resources, including high capability agricultural lands.	X		
4. pre-empt the use, or potential use, of a significant natural resource for any other purpose.	X		
5. result in a significant detrimental effect on air or water quality, or on ambient noise levels for adjoining areas.	X		
6. cause significant interference with the movement of any resident or migratory fish, wildlife species, or their respective habitats.	X		
7. establish a precedent or involve a new technology, either of which is likely to have significant environmental effects now or in the future.	X		
8. be a precondition to the implementation of another larger and more environmentally significant undertaking.	X		
9. be likely to generate significant secondary effects directly caused by Hydro One's activities, which will adversely effect the environment.	X		
10. block pleasing views or significantly affect the aesthetic image of the surrounding area.	X		
11. significantly change the social structure or demographic characteristics of the surrounding neighbourhood or community.	X		
12. overtax existing community services or facilities (e.g. transportation, water supply, sanitary or storm sewers, solid waste disposal system, school, parks, health care facilities).	X		
13. result in undesired or inappropriate access to previously inaccessible areas.	X		
14. create the unnecessary removal of timber resources	X		
15. result in significant detrimental effect to manmade or natural heritage resources	X		

From: Paul Gagnon [watercare@lprca.on.ca]
Sent: Wednesday, October 17, 2007 11:20 AM
To: STAITE Patricia
Subject: RE: Stringing of second circuit of transmission line - Norfolk Area
Patricia,

Thanks for sending me Ron's comments.

Here are mine.

- No disturbance of the stream bed or bank is to occur. An undisturbed buffer of 10 feet on either side of the watercourse is to be maintained (larger if possible). If temporary crossings are required, site specific approvals are required (send specific plans to the Conservation Authority for review).
- No in-stream work or crossing is to occur between October 1st and June 30th (to protect fish spawning & egg incubation).
- The local tree commissioner should be contacted to address any concerns related to the tree cutting bi-law.

Hope this helps,

Regards,

Paul Gagnon
Lands & Water Supervisor
Long Point Region Conservation Authority
R.R. #3, Simcoe ON, N3Y 4K2
email : watercare@lprca.on.ca
website: www.lprca.on.ca
Phone : 1-519-428-4623 or 1-888-231-5408
Fax : 1-519-428-1520

From: patricia.staite@hydroone.com [mailto:patricia.staite@hydroone.com]
Sent: October 15, 2007 3:16 PM
To: Paul Gagnon
Subject: FW: Stringing of second circuit of transmission line - Norfolk Area

---

From: Gould, Ron (MNR) [mailto:ron.gould@ontario.ca]
Sent: Tuesday, August 21, 2007 10:17 AM
To: STAITE Patricia
Subject: RE: Stringing of second circuit of transmission line - Norfolk Area

Greetings Patty,

I can offer the following technical guidance regarding this second circuit work.

- From review of NHIC/MNR records, the only species at risk known from this corridor is an American Badger (END) observation from 1982. Although there is likely still habitat in the area for the species, this occurrence is considered to be historical, and the proposed work is not expected to have any impacts on a local badger population.
- No roads or structures should be constructed within identified wetlands. Any access or crossing of wetland areas should be done by small all terrain vehicles as much as possible to minimize impacts while stringing the second circuit.
- Crossing within streams should be avoided, but if necessary due to a lack of an existing bridge or culvert crossing, then crossing though the stream bed should be made by all terrain type vehicles, and no fill or other materials should be deposited in the stream to facilitate crossing. In stream crossings should not occur between September and February to protect cold water spawning habitats. Further permitting and direction will be required from the Department of Fisheries and Oceans since these areas are protected under the federal Fisheries Act.
- To be consistent with municipal and provincial woodland protection policies, no roads or structures should be constructed in woodlands that are 4 hectares or greater in size. No tree removal, brushing, or use of low-flying aircraft should be conducted between May 1 and July 31 to protect breeding birds in wooded areas.

Ron Gould
Species at Risk Biologist
Ministry of Natural Resources
615 John St. North
Aylmer, ON N5H 2S8
Ph. (519) 773-4745 - Aylmer
(519) 354-4050 - Chatham
Email: ron.gould@ontario.ca

From: patricia.staite@HydroOne.com [mailto:patricia.staite@HydroOne.com]
Sent: July 30, 2007 5:45 PM
To: Gould, Ron (MNR); Hunter, Pud (MNR)
Subject: Stringing of second circuit of transmission line - Norfolk Area

Ron/Pud
This is to advise you that Hydro One is planning to string the second circuit of an existing wood pole 115kV transmission north of the Town of Colborne, to the east of Highway 24, to our line in the vicinity of Regional Road 19, as shown in the attached map. It will involve putting arms and hardware on the existing poles and stringing the line. There will be two new structures installed, one to the north of Norfolk TS and one in the vicinity of Vanessa Jct.

There was a class EA done on the upgrade of the line in March 1999, the work was done in 1999, and it was anticipated that the second circuit would be strung in 2000. At the time, the Ministry of Natural Resources, the Long Point Region Conservation Authority, and the Regional Municipality of Haldimand-Norfolk Department of Planning were consulted with regard to potential effects of this project on the natural environment. Since the study area is predominantly agricultural there were only a few concerns.

The transmission line crosses 3 tributaries to the Nanticoke Creek and 2 streams flowing into Waterford Ponds, a provincially significant area. As well, the line crosses Davis Creek adjacent to the TS. The upper tributaries to the Nanticoke Creek, Massecar Creek and Davis Creek are classified as cold water streams. The watercourses within cultivated fields have been channelled and have minimal adjacent woody vegetation. Wherever possible, existing roads and lanes will be used. We will be using track vehicles and will not be building new road unless they are required for the construction of the two new structures. Avoidance of any stream crossing is preferred, and we only crossed one intermittent creek in 1999.

We will be following the Environmental Guidelines for the Construction and Maintenance of Transmission Facilities, along with updated environmental specifications and the access plans that will be put together for this specific project.

It is anticipated that the second circuit will be strung in 2009/2010. We are getting all of the upfront planning work completed as soon as possible. All property owners will be notified prior to the commencement of work.

Please let me know if you have any questions or concerns regarding this project, or there is addition environmental information of which we should be aware.

Patricia Staite
Environmental Planner
Environmental Services and Approvals
Hydro One Networks Inc.

o-416-345-6686
c- 416-819-0456
fax-345-6919

OEB - INTERROGATORY #7 List 1

Interrogatory

7.0 Land Related Matters and Other Approvals
References (1) Exh. B, Tab 6, Sch. 6
Preamble
Hydro One submitted that:

- it will be using its existing land rights along the corridor from Vanessa Junction to Norfolk TS, and no additional land rights are expected to be required. Temporary access rights may be required.

- Some temporary access rights are also required to construct the proposed facilities.

Questions / Requests

i. Please provide details of the temporary access rights required and the status.
ii. Please provide a list of all outstanding approvals and permits needed to complete construction of the proposed facilities.

iii. Is Hydro One required to negotiate/renegotiate easement agreements with any of the property owners? If so, have the affected property owners been presented with a form of easement agreement? Please provide copies of any forms of easement agreements that have been or will be presented to the affected landowners.
iv. What is the status of any negotiations/discussions with landowners Allan and Carol Skoblenick of A&C Skoblenick Produce Ltd.? Have their concerns/issues been resolved? If not, what is Hydro One's proposal and expected timing for resolving any outstanding issues?

Response

i. Temporary access rights may be required for construction purposes on certain properties. These rights have not been identified at this point. When access route requirements are identified, Hydro One will discuss with the property owners optimal routes.

ii. There are a limited number of approvals/permits required for this project because it is an upgrade of an existing transmission line. Hydro One will apply for permits and approvals required to do the work when the engineering drawings/plans have been finalized, the access plans are developed and the work scheduled. The usual approval/permits on a project of this nature are:

- entrance and work permits from the County of Norfolk
- Occupational Permit from MTO,
- Crossing Agreement and construction work permit from the railway,
- permit to cross pipelines,
- acceptance letter for archaeological reports from the Ministry of Culture,
- permits for any water crossings under Fisheries Act and Lakes and Rivers Approvals Act.

iii. As Hydro One will be using its existing land rights along the corridor from Vanessa Junction to Norfolk TS, no new easement rights will be required.

iv. Regulatory Affairs on receiving the letter from the landowners, Allan and Carol Skoblenick of A&C Skoblenick Produce Ltd., provided a copy of the Application and Evidence for the Vanessa Junction to Norfolk TS Reinforcement Project. The Application and Evidence outlined the scope of the project. No further inquiries have been received to date, from the Skoblenicks since the evidence was provided to them from Regulatory Affairs. The Property Agent as a representative of Hydro One, will as part of the owner contact program, advise affected landowners of the construction timing and advise them to call him/her on any questions concerning the project.

It should be noted that Hydro One will make every attempt to minimize any damage to the property of landowners. However, if damage does occur, Hydro One will fully compensate landowners for all actual damages to crops, fences, tile drains, rut damage to fields and other such incidents.

OEB - INTERROGATORY #8 List 1

Interrogatory

8.0 Aboriginal Peoples Consultations
References (1) Exh. B, Tab 6, Sch5
Preamble
Board staff requires certain information/updates with respect to consultations that the Applicant has engaged in with Aboriginal Peoples.
Questions / Requests

i. Has Hydro One made inquiries to determine if there are Aboriginal groups who may be affected by the proposed project?

ii. If there are Aboriginal groups who are affected by the proposed project, has Hydro One consulted with them? If so, have those groups identified any specific issues or concerns in respect of the project? How have those issues or concerns been mitigated or accommodated?

iii. Has Hydro One determined if any Aboriginal groups have any filed and outstanding claims or litigation concerning their treaty rights or treaty land entitlement or aboriginal title or rights, which may potentially be affected by the project? If so, what is the status of those claims or litigation?

iv. If Hydro One has not made inquiries to determine if there are Aboriginal groups who may be affected by the proposed project, please advise if Hydro One intends to do so.

v. Provide details of any known Crown involvement in consultations with Aboriginal groups in respect of the applied-for project.

Response

i. Hydro One has contacted The Ontario Ministry of Aboriginal Affairs (“OMAA”) and the Department of Indian and Northern Affairs Canada (“INAC”) to identify potentially affected Aboriginal communities.

ii. There are five Aboriginal groups that may be potentially affected or have an interest in this project. Four of these groups were included in the prefiled application based on initial feedback from OMAA. An additional group was identified by INAC subsequent to the prefiling. Information about the project has been sent to all of the groups and follow-up contacts are underway.

There were discussions with one of the groups, but no issues were identified with this project.

iii. It is our understanding that there are not any Aboriginal claims or litigations in this area. Correspondence from MAA and INAC is attached.

iv. Please see (i) above

v. Hydro One is not aware of any Crown involvement in consultations with the potentially affected Aboriginal groups.

GAUVREAU Diane

From: RICHARDSON Joanne
Sent: Friday, May 30, 2008 5:24 PM
To: RICHARDSON Joanne
Subject: FW: Vanessa Jct. X Norfolk TS

Attachments: Map07-70_PP.pdf

Map07-70_PP.pdf

-----Original Message-----
From: Wood, Michelle (OSAA) [mailto:Michelle.Wood@ontario.ca]
Sent: Monday, July 30, 2007 5:21 PM
To: ZAJDEMAN Marcie
Subject: Vanessa Jct. X Norfolk TS

Dear Ms. Zajdeman,

The mandated responsibilities of MAA include conducting land claim negotiations and finalizing and implementing land claim settlement agreements on behalf of the Province. Based on a review of the preliminary information provided to MAA regarding this project, MAA is not aware of any First Nation land claims that may be impacted by this project.

Currently, Ontario is negotiating with Six Nations of the Grand River concerning their claims related to the Haldimand Tract (which is east of the proposed transmission line). These claims and negotiations are not related to the 1701 Treaty noted below. If you need further information regarding these negotiations, please contact Chris Maher, Project Lead, (416) 327-9634.

While the proposed transmission line does not appear to impact any claims that are currently being advanced against Ontario, the project could impact or be of interest to aboriginal communities in the area. Many First Nations either have or assert rights to hunt and fish in their traditional territories which often include lands and waters outside of their reserve. In some instances as well, project work may impact archaeological and burial sites. First Nations with an interest in such sites may extend beyond those First Nations in the immediate vicinity of the proposed project work.

The transmission line appears to run through an area where the Six Nations of the Grand River, as well as the Oneida Nation of the Thames, claim hunting and fishing rights further to the 1701 Treaty of Albany, sometimes referred to as the Nanfan Treaty.

MAA recommends that you contact the following First Nations regarding the proposed transmission line:

Six Nations of the Grand River

The Six Nations of the Grand River can be reached by contacting both Chief David General and Chief Allen MacNaughton at the following addresses:

Chief D. M. General
1695 Chiefswood Road
PO Box 5000
Ohsweken, ON, NOA 1MO
Phone: (519) 445-2201

-and-

Chief A. MacNaughton
RR 2
Ohsweken, ON, NOA 1M0
Phone: (519) 755-2769

Mississaugas of the New Credit First Nation

The Mississaugas of the New Credit First Nation may be contacted at the following address:

Chief Bryan LaForme
Mississaugas of the New Credit First Nation
2789 Mississauga Td., R.R. #6
Hagersville, Ontario
N0A 1H0
Phone: (905) 768-1133

Oneida Nation of the Thames

The Oneida Nation of the Thames may be contacted at the following address:

Chief Randall Philips
Oneida Nation of the Thames
2212 Elm Avenue Southworld, Ontario
NOL 2GO
Phone: 519-652-3244
Fax: 519- 652-9287

Chippewas of the Thames

The Chippewas of the Thames may be contacted at the following address:

Chief Kelly Riley
Chippewas of the Thames
R.R. #1
Muncey, Ontario
NOL 1YO
Phone: 519-289-5555
Fax: 519-289-2230

The Government of Canada sometimes receives claims that Ontario does not receive, or with which Ontario does not become involved. For information about possible claims in the area, MAA recommends that you contact the following federal contacts:

Don Boswell
A/Sr Claims Analyst
Ontario Research Team
Indian and Northern Affairs Canada
10 Wellington St.
Gatineau, QC K1A 0H4
Tel: (819) 953-1940
Fax: (819) 997-9873

Mr. Jean-Francois Tardif
Director, Financial Issues and Cost Sharing
10 Wellington St., 8th Floor
Indian and Northern Affairs Canada
Gatineau, QC K1A 0H4
Tel: (819) 994-1211
Fax: (819) 953-3109

Please let me know if you have any questions concerning the information provided above.

Yours sincerely,

Michelle Wood <<Map07-70_PP.pdf>>
Counsel
Ministry of Aboriginal Affairs
720 Bay St., 4th Fl., Toronto, ON M5G 2K1
Tel: 416-326-2835
Fax:416-326-4017
Email: michelle.D.wood@ontario.ca

Affaires indiennes et du Nord Canada | Indian and Northern Affairs Canada

February 19, 2008

Brian McCormick
Manager Environmental Services and Approvals
Hydro One Networks Inc.
483 Bay Street, TCT13, North Tower
TORONTO, ON M5G 2P5

RE: Transmission Line Upgrade, Vanessa Jet X Norfolk TS

Dear Mr. McCormick:

I am responding to your request for information sent to the Comprehensive Claims Branch, by mail, on January 24, 2008.

We can confirm that there are no comprehensive claims in Norfolk County, Ontario. We cannot make any comments regarding potential or future claims, or claims filed under other departmental policies. This includes claims under Canada's Specific Claims Policy or legal action by the First Nation against the Crown. For more information, I suggest you contact the Director General of Specific Claims Branch at (819) 994-2323 and the Director General of Litigation Management and Resolution Branch at (819) 997-3582.

INAC- Comprehensive Claims Branch does not have any specific interest in the project and would request to be taken out of the mailing list.

Yours truly,

Kevin Clement, A/ Director
for
Lynn Bernard, Director General
Comprehensive Claims Branch

Canada