

PUBLIC



Requirements

Ontario Resource and Transmission Assessment Criteria

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Table of Changes

Reference	Description of Change
Throughout	This entire document has been reorganized and updated.
Section 2	Renamed the section "Transmission Assessments" and incorporated and updated content previously in sections 3 through 7.
Section 2.2.1 (formerly 2.2)	Updated durations for some study periods.
Section 2.2.2 (formerly 2.3)	Clarified details about basecases.
Sections 2.2.3 and 2.2.4 (formerly 2.4)	Separated load forecast from load modelling.
Section 2.2.5 (formerly 3.1)	Added examples for generation and electricity storage dispatch.
Section 2.2.6 (formerly 3.2)	Clarified assumptions for imports and exports.
Section 2.2.7 (formerly 3.4)	Updated and clarified permissible control actions and removed redundant information.
Section 2.2.8 (formerly 3.4.1)	Renamed and updated provisions around the use of remedial action schemes.
Section 2.3 (formerly 2.7)	Updated and clarified (and removed redundant content) criteria for contingency-based assessment.
Sections 2.4.2 and 2.4.3 (formerly 4.2 and 4.3)	Clarified pre- and post-contingency voltage criteria.
Section 2.4.4 (formerly 4.5.1)	Aligned the method for power-voltage (P-V) analysis with the content in Market Manual 7.4 .
Section 2.4.6 (formerly 4.3.1)	Updated reactive element switching information.
Section 2.4-7	Added a new section for Large Motor Start.
Section 2.4.10 (formerly 4.7.2)	Updated loading criteria information.

Reference	Description of Change
Section 2.4.11 (formerly 4.8)	Updated short circuit criteria information.
Section 2.4.12 (formerly 7 and 7.2)	<ul style="list-style-type: none"> • Updated load security criteria to facilitate timely connection of new loads. • Clarified load restoration criteria.
Section 2.5 (old)	Removed Power Transfer Capability section, as the content is now redundant.
Section 2.5.1 (formerly 4.10, 6.3 and 6.4)	Clarified and consolidated station layout requirements.
Section 2.5.4 (formerly 5.2)	Updated Effect on Existing Facilities section.
Section 2.5.5	Added a new section for Considerations for Inverter-Based Resources.
Section 2.6 (old)	Removed Local Area Assumptions section, as the content is now redundant.
Section 2.7 (old)	Removed the tables containing sample system conditions.
Section 3 (formerly 8)	Renamed the section "Resource Adequacy Assessments" and updated content.
Section 3.2 (formerly 8.2)	The requirement to publish the reserve margins for the next five years is removed, as the reserve margins are published for all years in the Annual Planning Outlook timeframe.
Section 4.6 (old)	Removed Congestion section, as the content is now redundant.
Section 6.1 (old)	Removed Voltage Change section, as the content is now redundant.
Section 6.2 (old)	Removed Wind Power section, as the content is now redundant.
Section 7.3 (old)	Removed Control Actions section, as the content is now redundant.
Section 7.5 (old)	Removed Exemptions to the Restoration Criteria section, as the content is now redundant.
Appendix A	Updated cross-references to NERC and NPCC documents.
Appendix B	Updated requirements for station layouts.
Appendix C (old)	Removed Provisions for Wind Farms appendix, as the content is now redundant.
Appendix C (formerly Appendix D)	Updated and clarified acceptable generation and electricity storage connections. Removed redundant provisions that are already contained in Appendix 4.2 of the <i>market rules</i> .

1. Introduction

1.1 Purpose

The purpose of this document, herein also referred to as 'the ORTAC' or 'ORTAC', is to identify the technical criteria for use in the planning 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.

- This document describes the criteria used by the *IESO* to assess the current and future *security* and *adequacy* of the *IESO-controlled grid*.
- It does not identify operating or safety criteria, nor does it identify equipment performance standards, which are specified in appendices 4.1 to 4.4 of the *market rules*.
- It does not set the minimum standards that a *transmitter* must meet in designing, constructing, managing and operating its *transmission system*, which are specified in the *Ontario Energy Board's (OEB) Transmission System Code (TSC)*.

1.2 Scope

This document supplements the following *market rules*:

- MR App.4.1: IESO-Controlled Grid Performance Standards
- MR App.4.2: Requirements for Generation and Electricity Storage Facilities Connected to the IESO-Controlled Grid
- MR App.4.3: Requirements for Connected Wholesale Customers and Distributors Connected to the IESO-Controlled Grid
- MR App.4.4: Transmitter Requirements
- MR Ch.11: Definitions

1.3 Who Should Use This Document

This document is used by the *IESO* to discharge its responsibilities related to *adequacy* and *security* assessments in the planning timeframe.

While this document does not contain equipment standards, some provisions in this document (e.g. voltage ranges, allowable voltage changes, connection arrangements) could provide valuable information to participants in the sector that consider connecting their facilities to the *IESO-controlled grid*.

1.4 Contact Information

Changes to this document are managed via the [IESO Change Management process](#). Stakeholders are encouraged to participate in the evolution of this document via this process.

To contact the *IESO*, *market participants* can email *IESO* Customer Relations at customer.relations@ieso.ca or use telephone or mail. Telephone numbers and the mailing address can be found on the [IESO website](#). *IESO* Customer Relations staff will respond as soon as possible.

– End of Section –

2. Transmission Assessments

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

2.1 Purpose of Transmission Assessments

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

An evaluation of the results of the power system studies under normal and *outage* conditions (with normal and *outage* power flows) will determine:

- the need date for new *transmission* enhancement to 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 expected load growth or connection proposal is acceptable or that additional *facilities* or enhancements will be required.

2.2 Transmission Study Assumptions

These study assumptions must be chosen based on *good utility practice* and judgment, considering the circumstances and characteristics of the part of the *IESO-controlled grid* that is being assessed.

This section includes study guidelines for: study period, *basecase*, load forecast, load modelling, the dispatch¹ of generation resources and electricity storage resources, exports and imports, permissible control actions and the use of remedial action schemes (RASs) in assessments.

¹ In this document 'dispatch' is used to indicate the simulated output level of generation resources, electricity storage resources and/or load resources in the *basecase*.

2.2.1 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 facilities*, 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 *generation facilities* and *electricity storage facilities*, 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 facilities*, 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 and NERC transmission* reviews, the study period covers up to 10-year look ahead period from the report date, as required by the “NPCC Reliability Reference Directory #1: Design and Operation of the Bulk Power System” and “NERC TPL-001”, respectively.
- For transmission plan development studies, the study period generally covers up to 20-year look ahead period from forecast base year.

Note that, unless it is required by the applicable *reliability standards*, 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.

2.2.2 Basecase

Master *basecases* are used as the starting point for all studies. The master *basecases* include all *connection assessment* projects that are ‘committed’, including those that did not require a formal *connection assessment* study. *Local area* details are added as appropriate.

Connection assessment studies start with the master *basecases* and include *generation facilities*, *electricity storage facilities*, *load facilities* and *transmission facilities*, with proposed in-service dates prior to and during the study period, that completed or are undergoing the *connection assessment* process, and are ‘committed’, according to

[Market Manual 1.4](#) at the time of the study. The impact of adding conditionally approved projects that have not reached the 'committed' status should be reviewed to identify if they improve or worsen any identified deficiency, to identify if their conditional approval continues to be valid.

Transmission planning studies start with the master *basecase* and include all future facilities, 'committed' or 'non-committed', that are expected to be in service as part of the latest Annual Planning Outlook, or facilities that have been recommended or procured by the *IESO*, for the year of study.

2.2.3 Load Forecasting Principles

The load levels used in *connection assessments* and *transmission* planning studies shall be based on the *IESO's* latest long-term demand forecast or the latest regional planning forecast, informed by the *distributors* or by the *transmitters*. Load forecast uncertainty must be considered to reflect the assumptions made in the long-term demand forecast and for investigating the sensitivity of the need date to various items (e.g. higher and lower loads).

Load forecasts are intended to stress the *transmission system* to identify its limitations. As such, the summer or winter median growth forecast² (based on normal or extreme weather) must be used depending on the peak loading conditions of the area being studied.

Sensitivity studies are done with high-growth extreme weather forecasts and low-growth normal weather forecasts, and with light load scenarios. Under light load conditions, worst case ambient conditions are assumed.

If a *connection applicant* provides a detailed local forecast, that forecast must be used for its project.

Studies must indicate the source of the load forecast that was used and provide sufficient details on how that forecast was developed.

2.2.4 Load Modeling

For *local area* assessments, the master *basecase* is modified to ensure the forecast is representative of the most recent coincident peak load forecast for individual stations, and the power factors are based on billing data. Local load is modeled as accurately as

² The median growth forecast is generated accounting for expected economic, population, price, end-use equipment saturation, end-use equipment usage and government policy for the forecast period. To capture the variation in demand due to weather volatility, the *IESO* generates 465 simulated demand forecasts based on 31 years of historical weather data. The normal weather scenario demand forecast monthly peak demand is the 50th percentile monthly peak from the simulation from the dataset. The extreme weather scenario demand forecast monthly peak demand is the 95th percentile monthly peak from the simulated from the dataset. More detail is available in section 2: Demand Forecasts of the *IESO's* Methodology to Perform Reliability Outlooks that can be found on the *IESO's* website: [Reliability Outlook](#)

possible and any significant local *embedded generation facility*, *embedded electricity storage facility* or large motor is included.

If unknown, the power factor is assumed to be 0.90 at the high (*transmission* level) voltage terminals of the main power transformer. If an *embedded generation facility* or *embedded electricity storage facility* is connected to a load bus, the 0.90 power factor is assumed with the *embedded generation facility* or *electricity storage facility* out-of-service. In certain circumstances detailed load models may be required if the behaviour of that specific load is expected to impact the *local area* performance.

Dispatchable loads are assumed to be consuming as required to stress the system.

Studies are done with a load model representative of the actual load. For steady state studies assessing the voltage stability of the *transmission system*, loads normally are modelled as constant megavolt-amperes (MVA). In assessing voltage change performance, either a constant MVA model or a voltage dependent model is used, as described in the following sections. For assessing transient performance, a voltage dependent load model is used. If specific information is not available, the voltage dependent load model in Ontario is indicated in the following table:

Table 2-1: Static Load Models for Simulation

ACTIVE 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 $Q \propto V^2$) is used. The load models for neighboring areas must be consistent with load models used in the Multiregional Modeling Working Group (MMWG) master *basecases*.

2.2.5 Generation and Electricity Storage Dispatch

Generation resources and *electricity storage resources* must be dispatched as required to stress the system, to identify limitations of the *transmission* transfer capability.

For example, the following set of dispatch assumptions may be used for load *security* assessments:

- for pre-contingency conditions, nuclear and run of river hydro-electric *generation resources* are assumed at a level that is available 98% of the time. Under outage conditions, nuclear and run of river hydro-electric *generation resources* are assumed at a level that is available 85% of time. The time period for deriving the percentages reflects the specific conditions of the study (e.g., drought season, summer peak demand hours, winter peak demand hours, etc.).

For run of river hydro-electric *generation resources* that contain multiple *generation units*, only the minimum number of *generation units* to achieve the desired output level is considered in service;

- for pre-contingency conditions, peaking hydro-electric *generation resources* are assumed at a level that is available 98% of the time over the duration of the peak hours (minimum 4 consecutive hours). Under outage conditions, peaking hydro-electric *generation resources* are assumed at a level that is available 85% of time over the duration of the peak hours (minimum 4 consecutive hours);
- intermittent ('variable') *generation resources* (wind and solar) are assumed at zero output or at the expected capacity contribution they can sustain for the duration of the peak (minimum 4 hours);
- the output of stand-alone *electricity storage resources* is at a level it can provide continuously for the duration of the peak load (minimum 4 consecutive hours), after accounting for any known local system restrictions that could impact its recharging cycle over the previous 24 hours starting from 'fully discharged';
- *electricity storage resources* that are part of hybrid *facilities* are assumed to operate according to the philosophy provided by the *facility* owner;
- hydro-electric *generation resources* and inverter-based resources (IBRs) that have the capability to provide reactive support at zero or near zero active power output can be used to provide reactive support as needed.

2.2.6 Exports and Imports

All exports and imports must be considered for the contingency based assessment described in section 2.3. The pre-contingency levels of the transfers selected are based on the existing and projected *interconnection* capability. To ensure studies evaluate the full range of power flow scenarios, the system must be stressed using combinations of maximum transactions coincident with high internal power flows. In addition, the effect of bilateral *interconnection* assistance up to the *tie-line* capability should be studied with all *transmission facilities* in service.

2.2.7 Permissible Control Actions

Following the occurrence of a contingency, the following control actions may be used to respect the performance criteria referenced in this document:

- Redispatch of *generation resources* or *electricity storage resources*;
- Automatic disconnection or run-back of *generation resources* or *electricity storage resources* ('generation or electricity storage rejection');
- Open circuits to change flow distributions;

- Disconnect or re-dispatch *dispatchable loads* that have demand response contracts or obligations;
- Switch reactors and/or capacitors out (switching in of capacitors in locations that are especially sensitive to voltage changes must be done only in such a manner as to ensure minimal impact on customers);
- Operate phase angle regulators ('phase shifters').

In addition to the above control actions, automatic or manual disconnection of *non-dispatchable load* may be considered for certain contingencies, as permitted under the criteria described in section 2.4.12 of this document.

2.2.8 Remedial Action Schemes (RASs)

A *RAS*³ (formerly known as "*special protection system*" or "*SPS*") detects abnormal or predetermined system conditions and takes corrective actions, other than the isolation of faulted elements, to maintain system *reliability*. Such action(s) may include changes in load levels, changes to the output of *generation facilities or electricity storage facilities*, or changes to system configuration to maintain system *stability*, acceptable voltages or power flows. The *NPCC Directory #1* criteria and *NERC PRC-012* provide for the use of a *RAS* under normal and *emergency* conditions.

A *RAS* shall be used judiciously and, when employed, shall be installed consistent with *good utility practice* and operating policy. A *RAS* associated with the BPS may be planned to preserve system integrity for infrequent contingencies, for temporary conditions such as project delays, for unusual combinations of system demand and *outages*, or in the event of severe *outages* or extreme contingencies. Further, the reliance upon a *NPCC* type I *RAS* for *NPCC Directory #1* design criteria contingencies with all *transmission* elements in service must be reserved only for transition periods until new *transmission* reinforcements are being brought into service.

The decision to employ a *RAS* shall consider the complexity of the scheme, its operability and the consequences of correct or incorrect operation as well as its benefits. The requirements of *RASs* are defined in *NPCC Directory #4* criteria, *NPCC Directory #7* criteria and *NERC PRC-012* standard. With all *transmission* elements in service, continued reliance on a *RAS* is a trigger for considering additional *transmission* upgrades.

A *RAS* proposed at the time of a *connection assessment* must have full redundancy and separation of the communication channels and must satisfy the requirements of the *NPCC* Type I *RAS* criteria and *NERC PRC-012* standard to be considered by the *IESO*. This is intended to avoid invalidating the conditional approval if *NPCC* classification is for a Type I *RAS* (for a *RAS* that was not proposed as Type I). If, subsequently, *NPCC* classifies the *RAS* as "limited impact" (formerly known as 'Type III'), the *connection*

³ This paragraph is intended to provide a high-level description of the functionality of a *RAS*. The definition of *RAS* is according to chapter 11 of the *market rules*.

applicant will retain its conditional approval if they choose to design and build the *RAS* to meet the limited impact *RAS* requirements. Nevertheless, as the power system evolves, if in the future *NPCC* reclassifies the *RAS* as Type I, the *connection applicant* shall bring the *RAS* into compliance with Type I *RAS*.

RASs classified as Type 1 *RAS* according to *NPCC* are required to strictly conform to the design requirements for Type 1 *RAS* in *NPCC's* Directory #7. Over-arming is not accepted, except for the lack of redundancy of the trip coil of low voltage breakers and subject to approval by the *IESO*.

2.3 Contingency-Based Assessment

In this document, a *contingency event* involves the loss of one or more elements with or without a fault.

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

Planning of the *IESO-controlled grid* shall comply with applicable *NERC* standards, *NPCC* criteria, and the *market rules*, that specify the contingencies the *IESO* shall simulate. The *IESO-controlled grid* contains the portion of the system that falls within the *NERC*-defined Bulk Electric System (BES), and the portion of the system that falls within the *NPCC*-defined Bulk Power System (BPS).

The applicable *transmission* planning performance requirements from *NERC* standards or from *NPCC* criteria may be different, and for portions of the *IESO-controlled grid* where multiple standards or criteria apply, all shall be satisfied.

The determination of the BES elements is based on the application of *NERC's* BES definition provisions and the *NERC* guideline, Bulk Electric System Definition Reference Document.

The *NERC*-defined BES portion of the *IESO-controlled grid* shall satisfy *NERC's* Standard TPL-001: Transmission System Planning Performance Requirements.

The *IESO*, as a member of *NPCC*, uses a contingency-based assessment to evaluate the *adequacy* and *security* of the bulk power system (BPS). The contingencies considered are identified in *NPCC's* Reliability Reference Directory #1: Design and Operation of the Bulk Power System (Directory #1). The *IESO* conducts studies with these contingencies applied throughout the *IESO-controlled grid*, assuming that *facilities* have not been designed to BPS standards, to test for the consequences. The *IESO* evaluates the study results to determine if a *facility* must be designated a BPS *facility*. If the consequence of the contingency has a significant adverse impact outside the *local area*, the *facilities* are deemed to be BPS *facilities* and must comply with Directory

#1. *NPCC* extreme contingencies shall be assessed periodically in accordance with Directory #1.

In local areas the *IESO* shall respect the contingencies described in section 2.3.3.

2.3.1 Bulk Power System Contingency-Based Assessment

In accordance with *NPCC* criteria mentioned in section 2.3, the BPS portion of the *IESO-controlled grid* shall be designed with sufficient *transmission* capability to serve forecasted loads under the conditions noted in Table 1: Planning Design Criteria: Contingency Events, Fault Type and Performance Requirements to be applied to bulk power system elements of *NPCC* Directory #1.

2.3.2 Bulk Electric System Performance Criteria

In accordance with *NERC* criteria mentioned in section 2.3, the BES portion of the *IESO-controlled grid* shall be designed with sufficient *transmission* capability to serve forecasted loads under the conditions noted in Table 1: Steady State & Stability Performance Planning Events of the *NERC* TPL-001 standard.

2.3.3 Local Area Contingency-Based Assessment

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 *generation unit*, *transmission* circuit, transformer, or bus section with normal fault clearing.

Typically, only single-element contingencies are evaluated. The *IESO* defines a single element as a single zone of protection. Double-element contingencies will be considered and evaluated as described in section 2.3.

In *local areas*, where the contingency propagates to a higher voltage level or causes a net load loss in excess of 1000 MW, the *IESO* will apply the BPS contingencies described in section 2.3.1.

2.3.4 Extreme Contingencies

NPCC Directory #1 recognizes that the BPS 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.

2.3.5 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, as described in section 2.2. For steady state and transient stability studies, the system is studied with various pre-contingency conditions that stress the system. Various contingencies should then be evaluated to identify the most limiting contingencies and conditions.

Studies should start with 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 *basecase* to include approved, but not yet 'committed' projects. Various interface transfer levels should be considered to stress the system as required to uncover deficiencies. Also, additional contingencies to those covered under sections 2.3.1, 2.3.2 and/or 2.3.3 may be studies to confirm the *IESO-controlled grid* remains/is operable (can transition between different sets of system conditions considering the operating limitations of existing and 'committed' projects).

The purpose of the analysis is to identify the consequence of various scenarios, but not necessarily the worse possible contingencies under the worst load and ambient conditions. Study conditions need to be selected to support the scope of the study.

2.3.6 Extreme System Conditions

The BPS can be subjected to abnormal system conditions with a low probability of occurring such as peak load resulting from extreme weather conditions with applicable ratings of elements or fuel shortages. An assessment to determine the impact of these conditions on expected steady-state and dynamic system performance shall be done 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 indicated because of testing for such system conditions.

2.4 Pre- and Post-Contingency System Performance

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

- Power Transfer Capability Criterion;
- Pre-Contingency Voltage Criteria;
- Post-Contingency Voltage and Voltage Change Criteria;
- Steady State Voltage Stability Criteria;
- Small Signal Stability Criterion;

- Transient Stability Criteria;
- Transient Voltage Criteria;
- Line and Equipment Loading Criteria;
- Short Circuit Criteria;
- Load Security and Restoration Criteria.

If studies indicate that any criterion in this section is not met, the *IESO* will either require a bulk or regional system plan to identify the necessary upgrades to address the deficiency, notify the *IESO-administered market* of a system inadequacy or inform the *connection applicant* and/or the *transmitter* that the submitted proposal must be re-designed.

2.4.1 Power Transfer Capability Criterion

To evaluate the impact of a new or modified *connection* 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*, 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:

- Connecting a new *load facility*, *generation facility* or *electricity storage facility* to the most limiting circuit(s) of a *transmission* interface;
- where the connectivity of the *transmission* system is changed and a new contingency is created;
- where the electrical characteristics of a *generation facility* or *electricity storage facility* are changed by 5% or more, or exceed accepted design standards and tolerances, or are not in conformance with Appendix 4.2 of the *market rules* (e.g. the project contains equipment that is subject to exemptions or components that are 'grandfathered');
- where any of the key electrical characteristics of a *transmission facility* is changed by 10% or more; or
- where a new or modified *RAS* is proposed.

2.4.2 Pre-contingency Voltage Criteria

Under pre-contingency conditions with all *facilities* in service, or with any *transmission* element out of service after permissible control actions and with loads modeled as constant MVA, the *IESO-controlled grid* must be capable of achieving acceptable system voltages. The table below indicates the maximum and minimum voltages generally applicable. *Transmission* voltage levels are aligned with the performance requirements in Appendix 4.1 of the *market rules*. The values for *distribution* voltage levels are shown in accordance with the CSA standards.

Table 2-2: Pre-contingency Voltage Limits

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

Based on agreements with *transmitters*, certain buses can be assigned specific maximum and minimum voltages that could be outside of the limits presented in Table 2-2. Long-term planning should target the limits in Table 2-2, irrespective of the agreements with *transmitters*, unless the IESO and the *transmitter* agree that respecting the voltage limits in Table 2-2 requires solutions that could be prohibitively expensive. *Connection applicants* seeking to connect in areas where agreed upon voltage limits are outside the ranges in Table 2-2 will be required to install equipment capable to safely operate within the voltage range agreed by the *IESO* and the *transmitter*.

2.4.3 Post-contingency Voltage and Voltage Change Criteria

System voltage changes in the steady-state period immediately following a contingency are to be limited as follows:

Table 2-3: Post-contingency Voltage Change Limits

Nominal Bus Voltage (kV)	<u>500</u>	<u>230</u>	<u>115</u>	<u>Transformer Station Voltages</u>		
				<u>44</u>	<u>27.6</u>	<u>13.8</u>
% 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 re-dispatched, the output of *generation resources* and *electricity storage resources* is changed and power flows are adjusted, the system must return to within the maximum and minimum continuous voltages identified in section 2.4.2.

Transmission equipment must remain in service, and not automatically trip, for voltages up to 5% above the maximum continuous limit in Table 2-2 or the maximum continuous limits agreed between the *IESO* and the *transmitter*, whichever is higher, for up to 30 minutes, to allow the system to be re-dispatched to return voltages within their normal range.

Based on agreements with *transmitters*, certain buses can be assigned specific maximum and minimum voltages that could be outside of the limits presented in Table 2-2. Long-term planning should target the limits in Table 2-2, irrespective of the agreements with *transmitters*, unless the *IESO* and the *transmitter* agree that respecting the voltage limits in Table 2-2 requires solutions that could be prohibitively expensive. *Connection applicants* seeking to connect in areas where agreed upon voltage limits are outside the ranges in Table 2-2 will be required to install equipment capable to safely operate within the voltage range agreed by the *IESO* and the *transmitter*.

Before tap-changer action (immediate steady-state post-contingency period), a constant MVA load model can be used. If the voltage change exceeds the limits identified above, the voltage dependent load model described in section 2.2.4 should be used. After tap-changer action, a constant MVA load model should be assumed (the load should 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 voltage dependent load model in the longer-term post-contingency period may be acceptable.

In cases where voltage rises are a possibility (e.g. loss of load or islanded *generators*), transient stability tests must 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 Table 2-2, to avoid equipment damage due to high voltages.

2.4.3.1 Reactive Element Switching Change Criterion

Reactive elements include shunt high voltage (HV – higher than 50 kV) and low voltage (LV – lower than 50 kV) capacitors, series capacitors and reactors.

Reactive devices should be sized to ensure that voltage declines or rises at the HV terminals of load serving transformers on switching operations will not exceed 4% of steady state voltage before tap changer action using the voltage dependent load models.

2.4.3.2 Large Motor Start Criterion

Large motors, as the term is used in this document, are synchronous or induction motors with an output power larger than or equal to 500 HP, connected directly or via an inverter/converter to the *electricity system*, that may or may not employ a 'soft start' method, and include such motors or motor-*generation units* that are part of an *electricity storage facility*.

The severity of voltage decline at the high voltage terminal of load serving transformers, caused by large motor start must be limited to no more than 4% for motors starting less than four times a day. For more frequent starts, the flicker criteria, under Ref 5 of Appendix 2 of *OEB's* Transmission System Code applies.

A voltage decline that is larger than 4%, but not more than 10%, may be accepted for motors with very infrequent starts (e.g. once every 2-3 days or less) if the *transmitter* confirms, part of their Customer Impact Assessment (CIA), that such decline is unlikely to have a significant adverse impact on the affected customers.

2.4.4 Steady State Voltage Stability Criteria

Adequate voltage performance under section 2.4.3 does not guarantee system voltage stability. Steady state stability is the ability of the *IESO-controlled grid* to maintain voltage stability during relatively slow changes of normal load, changes to the output of *generation facilities* or *electricity storage facilities* 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 power-flows must be obtained with the critical parameter increased up to 10% with typical dispatch of *generation facilities* and *electricity storage facilities*, as applicable;
- All of the properly converged cases obtained must represent stable operating points. This must 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 sub-section below; 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.

2.4.4.1 Power – Voltage (P-V) Curves

For planning and *connection assessments* studies, to generate the P-V curve, loads must be modeled as constant MVA. In specific situations, if good data is available, accurate voltage dependent load models and tap-changer action may be used to assess the system voltage performance following the contingency and automatic equipment actions, but before manual operator intervention.

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 power transfer corresponding to Point 'A', which if increased by 10%, is less than the power at the critical point of the pre-contingency P-V curve, and
- A power transfer corresponding to Point 'B', which if increased by 10%, is less than the power at the critical point of the post-contingency P-V curve.

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

When producing a pre-contingency P-V curve, manual actions such as reactive shunt switching together with transformer tap-changer action, are permitted. When producing a post-contingency P-V curve, only automatic control actions (e.g. generation automatic voltage regulation, *RASs*, and automatic underload tap-changes) are modelled.

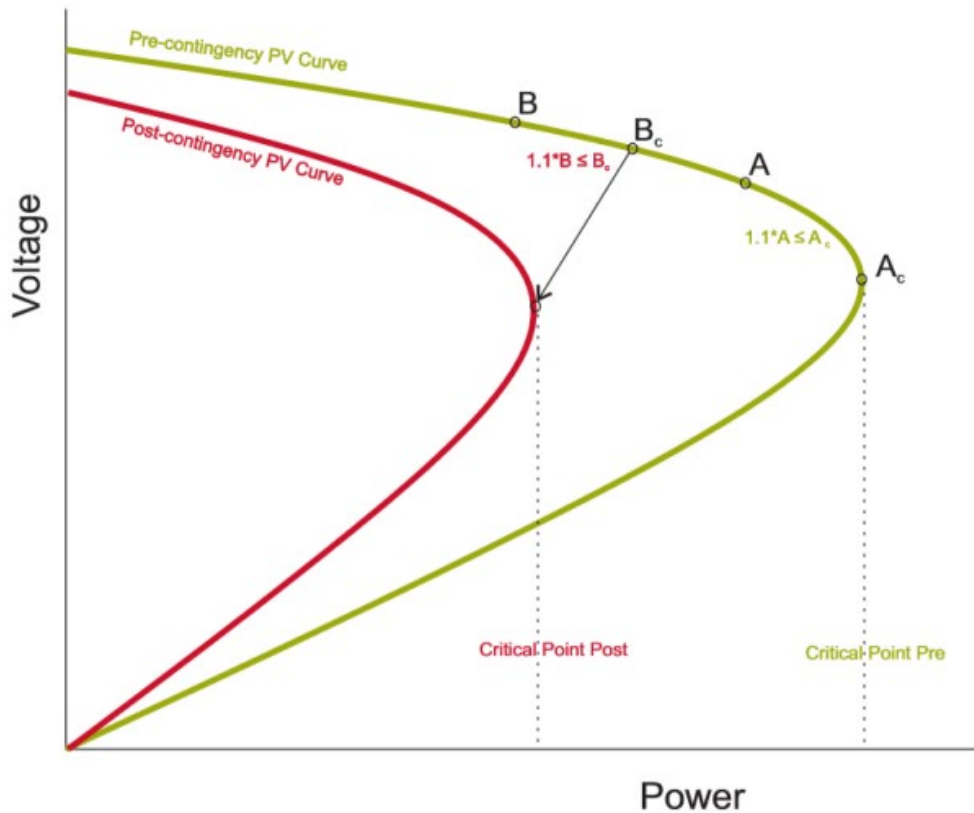


Figure 2-1: Sample P-V Curve

2.4.5 Small Signal Stability Criteria

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 (ξ) 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.

Table 2-4: Acceptable Damping Factors

System Condition	Damping Factor
Pre-Contingency	> 0.03
Post-contingency, before automatic intervention	> 0.00
Post-Contingency, after automatic intervention, before any manual adjustments	> 0.01
Following Re-preparation of the system, after permissible actions (section 2.2.7)	> 0.03

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

2.4.6 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 are conducted to assess the dynamic voltage performance. These simulations cover a time frame in which ULTCs operate (<30 seconds) and include modeling of devices that affect voltage stability (such as induction motors, ULTCs, switched shunts, *generation unit* field current limiters, etc.). Due regard is given to reclosure operations in the simulation.

For transient voltage performance, studies are done with a load model representative of the actual load. If that information is not available, the standard voltage dependent load model described in section 2.2.4 is used.

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 under-voltages are a measure of the system strength, and its ability to recover promptly.

The following transient voltage criteria must be used to evaluate system performance.

The minimum post-fault positive sequence voltage sag must remain above 70% of nominal voltage at all times and must not remain below 80% of nominal voltage for more than 250 milliseconds within the first 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.

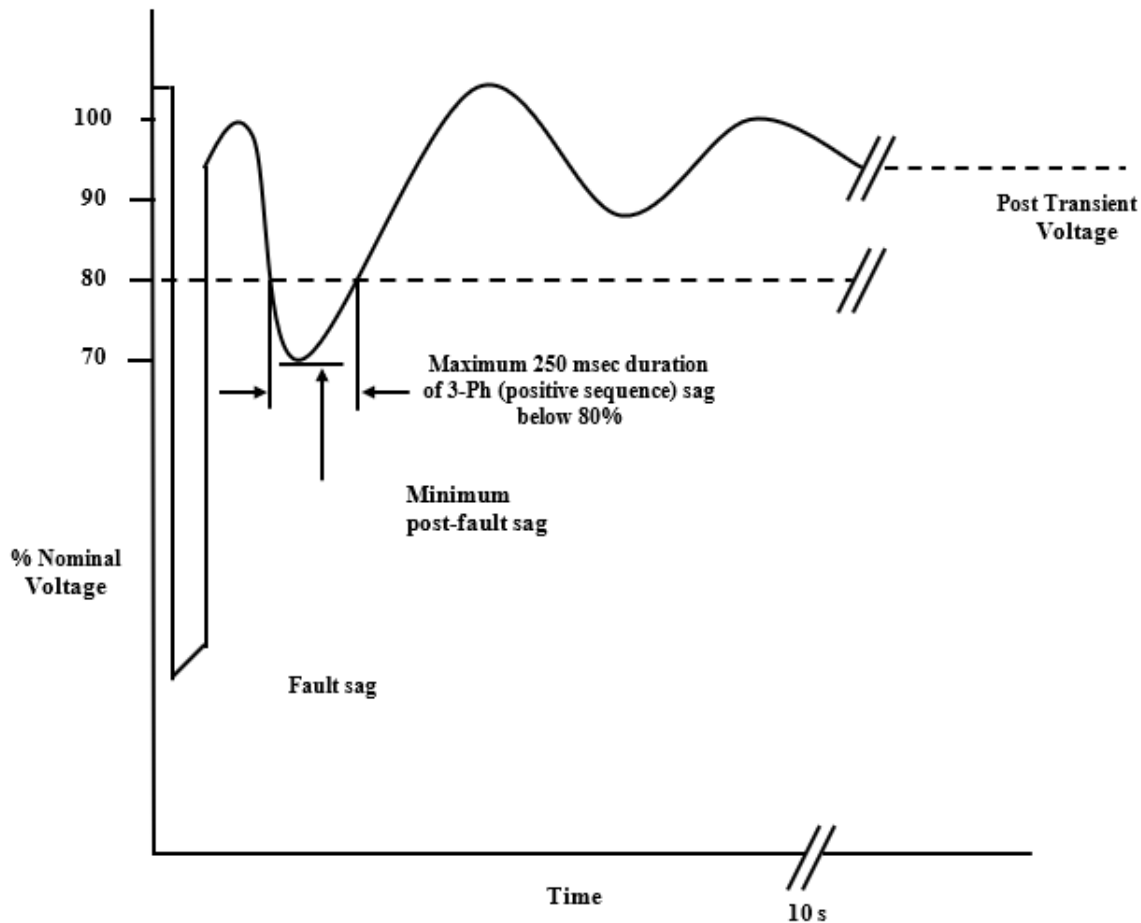


Figure 2-2: Transient Voltage Sag Criteria

If this criterion is not met, potential mitigation options include high-speed fault clearing, *RASs*, field forcing, *transmission* reinforcements and reductions in *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 30 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, or other phenomenon of concern for the *transmitter* (e.g. effect on surge arrestors). 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.

Table 2-5: Capacitor Tripping Voltage Levels

Duration	Maximum Permissible Voltage⁴
½ cycle	3.00
1 cycle	2.70
6 cycles	2.20
15 cycles	2.00
1 second	1.70
15 seconds	1.40

2.4.7 Transient Stability Criteria

The system shall remain stable during and after the most severe of the contingencies listed in sections 2.3.1, 2.3.2 and 2.3.3 with due regard to reclosing.

All stability limits must 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 changes to the output of *generation resources* or *electricity storage resources*, or changes to load levels even beyond the forecast, provided changes do not lead to invalid results. Negative values of local load are preferable to increasing the output of local *generation resources* or *electricity storage resources* ('discharging') beyond its maximum capability.

2.4.8 Line and Equipment Loading Criteria

2.4.8.1 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

⁴ Multiplying Factor to be Applied to Rated RMS Voltage

time ratings for transformers and *transmission* circuits. For each assessment, the applicable ratings will be provided by or confirmed with the equipment owner.

2.4.8.2 Loading Criteria

All line and equipment loading 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.

Equipment owners are responsible to ensure that circuit breakers, current transformers, disconnect switches, buses and all other system elements are not more restrictive than the lines and/or the transformers they connect.

The ratings of *intertie* lines are governed by agreements between the *facility* owners. The criteria to direct operation of the *intertie* lines are governed by agreements between neighboring *control areas*.

2.4.9 Short Circuit Criteria

Short circuit studies for *connection assessments* are to be carried out with all existing *generation facilities* and *electricity storage facilities* and with all 'committed' projects in service. Short circuit studies for *transmission* planning will further include all future projects that are 'committed' and future projects that have been recommended or procured by the *IESO* and expected to be in service during the year of study. System voltages must be assumed to be at the maximum acceptable system voltage identified in section 2.4.2. The latest information from neighbouring systems that may have an impact on short circuit studies (e.g. *NERC* MMWG representation) must be used to define relevant *interconnection* assumptions. Short circuit levels must be within the maximum short circuit levels and duration specified in Ref 2 of Appendix 2 of the *OEB's* Transmission System Code.

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

The *IESO* may only accept 'make before break' switching operations that temporarily increase short circuit levels beyond circuit breaker interrupting capability if affected equipment owners accept the risk and its consequences.

2.4.10 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 during interim periods, until *transmission* upgrades are brought in service, provided that the *BES* and *BPS* continue to adhere 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* (within a *distributor's distribution system* or within a *wholesale consumer's system*).

To facilitate the connection of new *load facilities* prior to system reinforcements being in place, the *IESO* may allow connections with a lower level of load *security* than established in this section on an interim basis, provided that:

- the *IESO-controlled grid* continues to exhibit the performance criteria described in section 2.4 following the design criteria contingencies defined in section 2.3;
- a plan to restore the load *security* to the level stipulated below is being developed; and
- the affected load customers accept the additional risk.

2.4.10.1 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 section 2.3. For the purposes of this section, an element is comprised of a single zone of protection.

Adequate load *security* requires that all conditions specified in sections 2.4.1 to 2.4.10 must be met. Additionally:

- With all transmission *facilities* in service, all loads must be supplied coincident with an outage to the largest local *generation unit*.
- With any one element out of service⁵, planned load *curtailment* or load rejection, excluding voluntary *demand* management, is permissible only to account for local *generation* outages. Not more than 150 MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 150 MW load interruption limit reflects past planning practices in Ontario.
- With any two elements out of service⁶, planned load *curtailment* or load rejection exceeding 150 MW is permissible only to account for local *generation* outages. Not more than 600 MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 600 MW load interruption limit reflects the established

⁵ For example, after a single-element contingency with all *transmission* elements in service pre-contingency.

⁶ For example, after a double-element contingency with all *transmission* elements in service pre-contingency or after a single-element contingency with one *transmission* element out of service pre-contingency.

practice of incorporating up to three typical modern day distribution stations on a double-circuit line in Ontario.

2.4.10.2 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 adequate set of *facilities*, methods and procedures that *transmitters* and/or *distributors* can deploy or implement to mitigate the impact of *transmission* system outages/contingencies onto *transmission* customers.

Following the design criteria contingencies described in section 2.3, affected loads are restored as described below:

- a. All loads must be restored within eight hours.
- b. When the amount of load interrupted is greater than 150 MW, the amount of load in excess of 150 MW must be restored within approximately four hours.
- c. When the amount of load interrupted is greater than 250 MW, the amount of load in excess of 250 MW must be restored within 30 minutes.

In practice, the restoration times could be longer than those presented in this section, depending on the severity of the fault, weather conditions, accessibility, distance from the staffed centres, etc. For planning purposes, the *IESO* must target these times, to ensure that sufficient facilities exist to support the load restoration process.

2.4.10.3 Application of Restoration Criteria

Where a load restoration need is identified, for example via the *IESO's* outlooks (e.g. bulk or regional plans), *market participants* and the applicable *transmitter* will be notified of the need for a local study.

Transmission customers and *transmitters* can consider each case separately considering 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 *BES* and *BPS* continue to adhere to *NERC* and *NPCC* standards.

2.5 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.

2.5.1 Station Layout

Acceptable transformer and switching station layouts are provided in Appendix B. Other configurations and station layouts may be permitted provided they meet the performance criteria in this document and are acceptable to the *IESO*.

2.5.2 New or Modified Facilities

New or modified *facilities* must satisfy all *NERC* standards, *NPCC* 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 and must not limit the capability of the existing elements within the common zone of protection;
- *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 (refer to section 2.4.1) the existing transfer capability of the *IESO-controlled grid* and must not impose additional restrictions on the operation of existing *connection facilities*.

2.5.3 Generation and Electricity Storage Connection Criteria

Transmission to incorporate new *generation facilities* or *electricity storage facilities* is defined as those new circuits that connect the new *generation facility* or *electricity storage facility* to the *IESO-controlled grid*, plus any reinforcements to the *IESO-controlled grid* required as a direct and sole result of the new *generation facility* or *electricity storage facility* connection. With the new *generation facility* or *electricity storage facility* at its maximum output, the most relevant load levels must be considered in studies.

Transmission *facilities* for incorporating new *generation facilities* or *electricity storage facilities* must meet the requirements of section 2.5. Acceptable technical requirements related to *generation facility* and *electricity storage facility* performance, station layout, and connection to the *IESO-controlled grid* is provided in Appendix C. Other configurations and station layouts may be permitted provided they meet the performance criteria in this document and are acceptable to the *IESO*.

2.5.4 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, electricity storage facilities or load facilities* to deliver to or receive power from the *IESO-controlled grid*.

2.5.5 Considerations for Inverter-Based Resources

To maintain system *security* for all foreseeable operating conditions, it is necessary to give special consideration for the sub-synchronous oscillatory phenomena that may result from inverter-based resources (IBR); namely sub-synchronous resonance (SSR) and sub-synchronous control interactions (SSCI). Phenomena such as SSR and SSCI can result in *generation units or electricity storage units* tripping unexpectedly or exhibiting underdamped oscillatory response, among other things, which can result in violation of the *security* criteria or equipment damage. Assessing phenomena such as SSR and SSCI requires the application of Electromagnetic Transient (EMT) assessment techniques, which have significant computational and time demands, and so, it is not practical to perform EMT assessment for all foreseeable operating conditions. Instead, the criteria identified below are recommended to identify operating configurations that have an unacceptable risk of SSR and SSCI, or to trigger EMT assessment on an as-needed basis.

2.5.5.1 Minimum Short Circuit Ratio

The short-circuit ratio (SCR) is used to assess if there is an unacceptable risk of SSR, SSCI or other EMT phenomena. All recognized contingencies that are expected to lower the SCR must be assessed.

The SCR will be calculated as the ratio of the short circuit power (S_{sc}) at the point of connection to the power rating of the converter or *generator* (P_{rated}):

$$SCR = S_{sc}/P_{rated}$$

The following criteria will be used to determine if an EMT assessment is needed:

- If the SCR of IBRs is below 5, an EMT assessment must be performed;
- If the SCR of IBRs is between 5 and 7, an EMT assessment is needed for facilities that were brought in service pre-2023;
- An SCR level above 7 is considered sufficiently high to substantially reduce the risk of SSR, SSCI or other EMT phenomena, so an EMT assessment is not needed.

If there are multiple IBRs within close electrical proximity, the SCR metric is no longer a suitable metric, and the available fault level (AFL) is a more representative metric. The *IESO* developed a tool to assess the AFL for such conditions.

Circuit configurations that could result in IBRs to remain radially connected pre or post contingency on circuits with series compensation must be avoided as this will result in SSR. This is particularly concerning for type 3 wind turbines.

– End of Section –

3. Resource Adequacy Assessments

This section is intended to provide guidance in carrying out the technical studies to assess the *adequacy* of the *IESO-controlled grid* to meet electricity demand, taking into consideration the *demand* forecast, *generation facility* and *electricity storage facility* availability, and *transmission* constraints for 18-month and long-term time frames.

3.1 Statement of Resource Adequacy Criterion

To assess the *adequacy* of *resources* in Ontario, the *IESO* uses the *NPCC resource* adequacy design criterion from *NPCC Regional Reliability Reference Directory #1: Design and Operation of the Bulk Power System*. The criterion states that the loss of load expectation (LOLE) of disconnecting firm load due to *resource* deficiencies is, on average, no more than 0.1 days per year. In doing so, the Planning Coordinator is required to make due allowances for *demand* uncertainty, scheduled *outages* and deratings, *forced outages* and deratings, assistance over *interconnections* with neighboring Planning Coordinator Areas, *transmission transfer capabilities*, and capacity and/or load relief from available operating procedures.

3.2 Application of the Resource Adequacy Criterion

The *IESO* uses a probabilistic *resource adequacy* model to assess to what extent a system meets *NPCC* criterion. A detailed load, *generation*, and *transmission* representation for different zones in Ontario are modeled in the probabilistic *resource adequacy* assessment. Ontario's neighbouring jurisdictions are not explicitly modelled.

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.

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. The *IESO* does consider an amount of *interconnection* assistance or non-firm imports for capacity planning purposes. The methodology to calculate the amount of non-firm imports is established. The *IESO* does not consider *emergency* operating procedures for 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 of certainty that is covered becomes an economic decision which should be guided by the *NPCC* criterion.

3.3 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 and methodology used in the *IESO's adequacy* assessments can be found in the methodology documents published along with the quarterly Reliability Outlooks and Annual Planning Outlooks.

– End of Section –

Appendix A: IESO/NPCC/NERC Reliability Rule Cross-Reference

Table A-1: IESO/NPCC/NERC Reliability Rule Cross-Reference

Section	Ontario Criteria	NPCC Criteria	NERC Standard
Resource <i>Adequacy</i> Assessment Criterion	<i>Reserve</i> Margin Requirement	D-1	
Transmission Capability Planning Bulk Electric System Bulk Power System	Thermal Assessment	D-1	TPL-001
	Voltage Assessment	D-1	FAC-001, 002
	Stability Assessment	D-1	
	Extreme Contingency Assessment	D-1	TPL-001
Transmission Capability Planning Non-Bulk Local Areas	Thermal Assessment		TPL-001
	Voltage Assessment		FAC-001, 002
	Stability Assessment		
	Supply Deliverability Level		TPL-001

– End of Appendix –

Appendix B: Station Layouts

This appendix provides acceptable configurations for station layouts. Variations from these layouts might be permitted provided they meet the performance criteria in this document and are acceptable to the *IESO*.

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 in this appendix to show the maximum complexity that should normally be considered 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 consider 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.

Schedule E of Appendix 1, Versions A, B and C of the *OEB's* Transmission System Code specifies that all customers shall provide an isolating *disconnect* switch or device at the point or junction between the *transmitter* and the customer, i.e. at the point of the interconnection, which physically and visually opens the main current-carrying path and isolate the customer's *facility* from the *transmission system*. More information is provided in Schedule E of Appendix 1, Versions A, B and C of the *OEB's* Transmission System Code.

Schedule F of Appendix 1, Version A of the *OEB's* Transmission System Code specifies that a high-voltage interrupting device (HVI) shall provide clearing of faults in the load

customer's system. HVIs shall be provided with appropriate back-up protection. The HVI shall be a circuit breaker located at the connection point unless the *transmitter* authorizes another device or location.

Schedule F of Appendix 1, Version B of the *OEB's* Transmission System Code specifies that a HVI shall provide a point of isolation for the generator's station from the *transmission system*. HVIs shall be provided with appropriate back-up protection. The HVI shall be a circuit breaker unless the *transmitter* authorizes another device.

Schedule F of Appendix 1, Version C of the *OEB's* Transmission System Code specifies that a HVI shall provide a point of isolation for the customer's storage facility from the *transmission system*. HVIs shall be provided with appropriate back-up protection. 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:

Table B-1: Key Factors for Evaluating a Switching or Transformer Station

Factor	Description
<i>Security</i> and quality of supply	Relevant criteria are presented in section 2.4.
Extendibility	The design should allow for future extensions if practical.
Maintainability	The design must consider the practicalities of maintaining the substation and associated circuits. It should allow for elements to be taken out-of-service for maintenance without adversely impacting <i>security</i> and quality of supply.
Operational Flexibility	The physical layout of individual circuits and groups of circuits must permit the required operation of the <i>IESO-controlled grid</i> .
Protection Arrangements	The design must allow for adequate protection of each system element.
Short Circuit Limitations	To limit short circuit currents to acceptable levels, bus arrangements with sectioning <i>facilities</i> 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 2.3. 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 BPS, 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 2.4. 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 BPS station).

The *IESO* will then evaluate if the amount of load interrupted by single-element contingencies (or double circuit contingencies depending on the load level) with the proposed station layout meets the load *security* criteria in section 2.4.12.

Evaluations of proposed modifications to existing *facilities* will consider the level of flexibility and layouts will be evaluated on the extent they meet the assessment criteria.

B.3 General Requirements 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. Refer to 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 in Figure B-1.

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

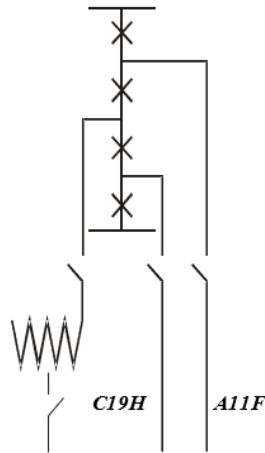


Figure B-1: Breaker-And-A-Third Layout

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.

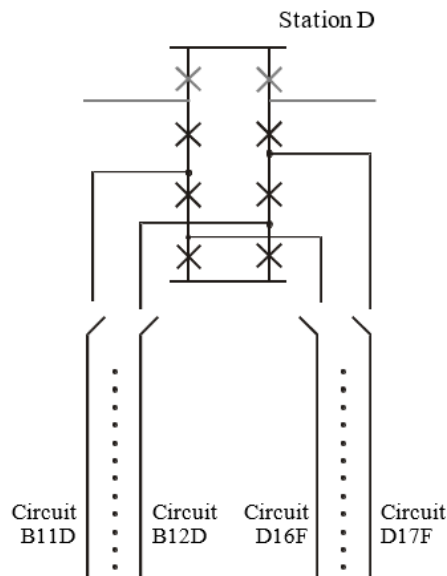


Figure B-2: Bus Balance Layout

B.3.3 Maximum Breakers

Station layout should be such that a maximum of six high voltage (500 kV, 230 kV and 115 kV) and up to two capacitor or two low voltage (below 50 kV) breakers are needed to trip following any fault (operation of the capacitor breaker does not involve interruption of fault current). Figures B-3 and B-4 illustrate these rules.

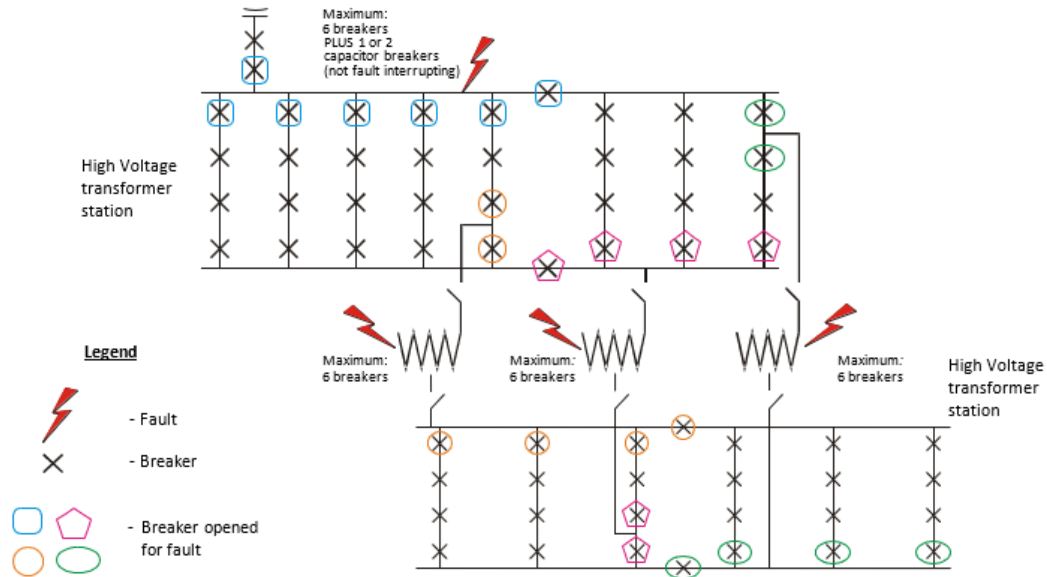


Figure B-3: High Voltage Station Layout with Capacitor Breakers



Figure B-4: High Voltage Station Layout with Low Voltage Breakers

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 does not result in the loss of two reactive power sources.

For example, when terminating a new autotransformer, *generation facility*, 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.

As stated in Appendix B.3.1, the ideal location of a *generation facility* or *electricity storage facility* connection is in the centre of a diameter (where the autotransformers are connected on the layout shown).

The *generation facility* or *electricity storage facility* connection termination at the location shown in Figure B-5 is not ideal. A single-element contingency with breaker failure would result in the simultaneous loss of the *generation facility* or *electricity storage facility* 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 *BPS* or otherwise and then to evaluate the performance of the *IESO-controlled grid* for the appropriate contingencies.

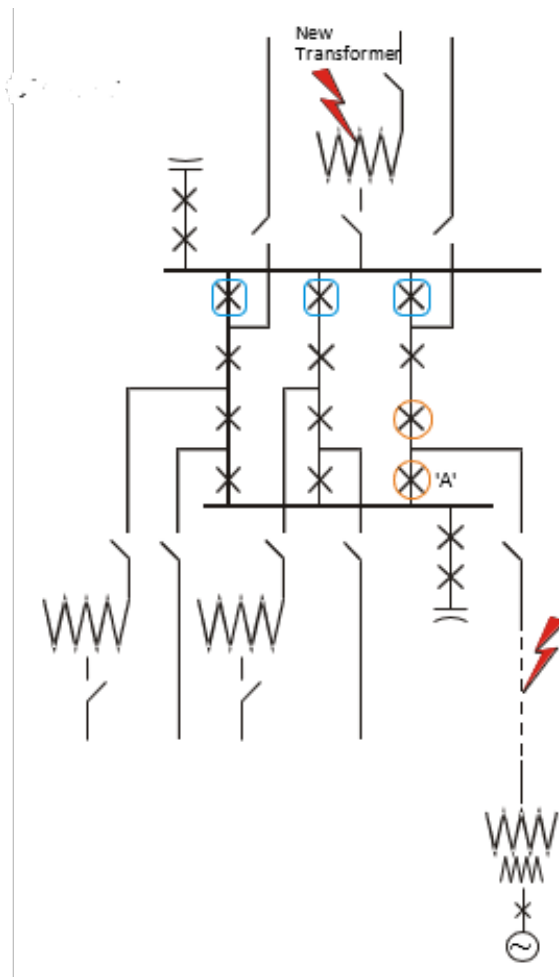


Figure B-5: Non-ideal Connection Layout

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 in Figure B-6 provides one way to optimize the layout of a ring bus and minimize the adverse effect of maintenance.

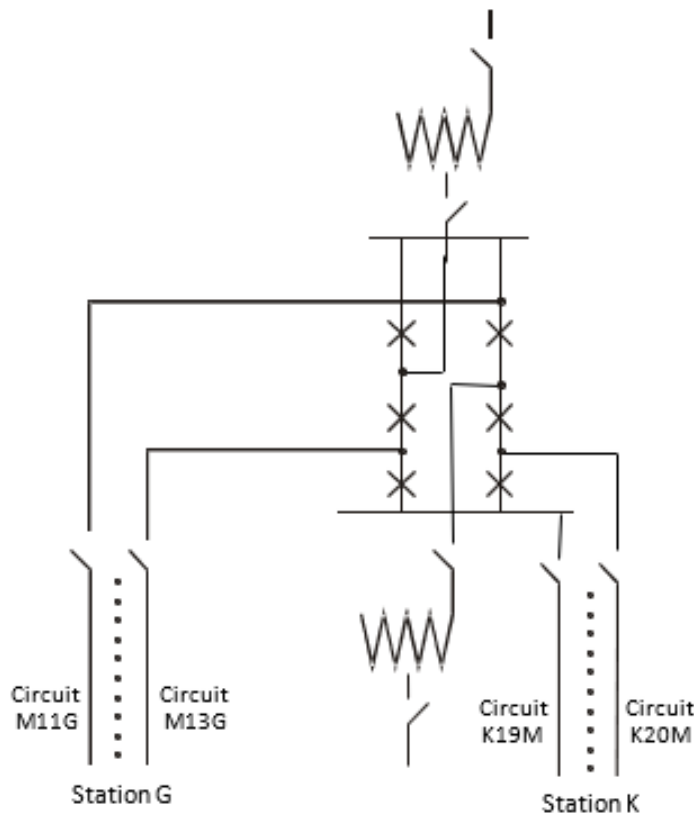


Figure B-6: Ring Bus Optimization

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 in Figure B-7 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 switch to provide 'visible' 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 'visible' isolation of the new line from the *IESO-controlled grid*.

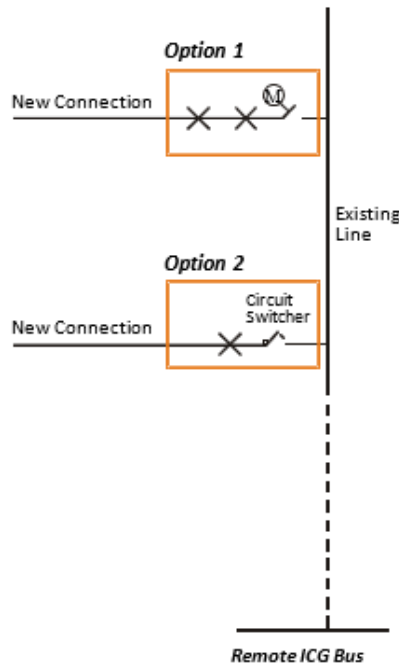


Figure B-7: Connections Without Transfer Trip

B.4 Physical Station Layouts

The electrical single-line diagram of a breaker-and-a-third arrangement is shown in Figure 5-8. Typical physical layouts for breaker-and-a-third are shown in Figure 5-9.

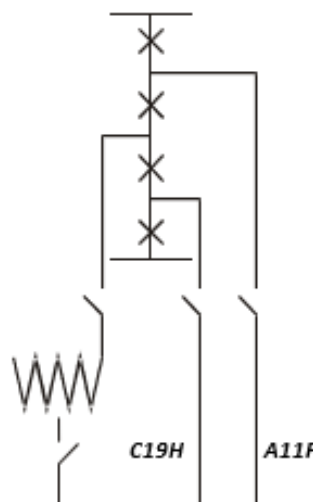


Figure B-8: Electrical Single-Line diagram of a Breaker-and-a-Third Arrangement

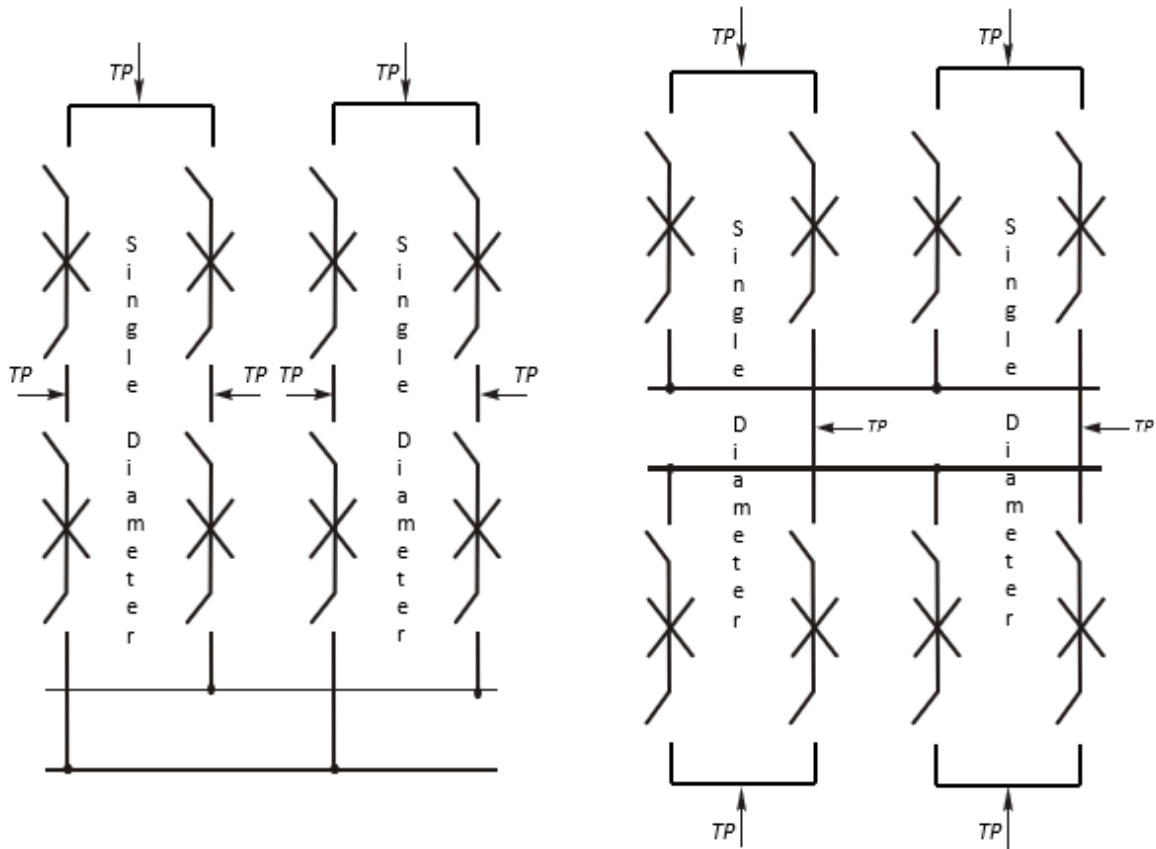


Figure B-9: Typical Physical Arrangement for Breaker-and-a-Third Layouts

* TP = Termination Point for a transmission element such as a circuit, transformer, etc.
Overhead connections omitted for clarity.

– End of Appendix –

Appendix C: Acceptable Generation Facility and Electricity Storage Facility Connections

The following summarizes the acceptable configurations for connection to the *IESO-controlled grid* of *generation facilities* and *electricity storage facilities* of medium to large size which are aimed at ensuring that the *reliability* of the system is preserved. This short list does not relieve *connection applicants* from any *market rule* or applicable *reliability standards* obligation. This document may be used by *market participants* to help them understand the *IESO's* criteria and further their *connection assessment* work.

Transmitter and *distributor* requirements are separate and are not addressed herein. A proponent of a *connection* to a *distribution system* or a *connection applicant* are 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.

C.1 Generation Unit and Electricity Storage Unit Performance

The requirements for *generation units* and *electricity storage units* that are connecting to the *IESO-controlled grid* are in Appendix 4.2 of the *market rules*. *Distributors* and *wholesale consumers* connecting *generation units* or *electricity storage units* to their systems must ensure that the applicable requirements of Appendix 4.3 of the *market rules* are met.

C.2 Generation Facility and Electricity Storage Facility Connection Options

The *IESO*, in its review of the various *generation facilities* and *electricity storage facilities* that proposed to *connect* to the *IESO-controlled grid*, has developed acceptable *connection* arrangements for *generation facilities* and *electricity storage facilities*. Variations to the typical *connection* arrangements may be permitted provided they meet the performance criteria in this document and are acceptable to the *IESO*.

C.2.1 Generation Facilities and Electricity Storage Facilities Rated between 250 MW and 500 MW

All *generation facilities* and *electricity storage facilities* 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 Figures C-1, C-2 or C-3 below.

Station arrangements that *connect* two like elements next to each other separated by only one breaker should be avoided.

The configurations shown in Figure C-1 and Figure C-2 are suitable primarily for coupled gas and steam turbines pairs but can also be used for other types of *generation facilities* or *electricity storage facilities*.

- A contingency associated with one of the *transmission* lines will be cleared at the terminal stations and by the breaker on the corresponding *generation unit* or *electricity storage unit* 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 *generation facility* or *electricity storage facility* will be tripped off. If the *IESO's* assessment indicates that tripping the entire *generation facility* or *electricity storage facility* will have a negative impact on the *IESO-controlled grid*, then the *IESO* will recommend alternative *connection* arrangements.
- For the configuration in Figure C-1, a contingency associated with one of the step-up transformers or a *generation unit* or *electricity storage unit* will be cleared by opening the bus-tie breaker and the high voltage synchronizing breaker.

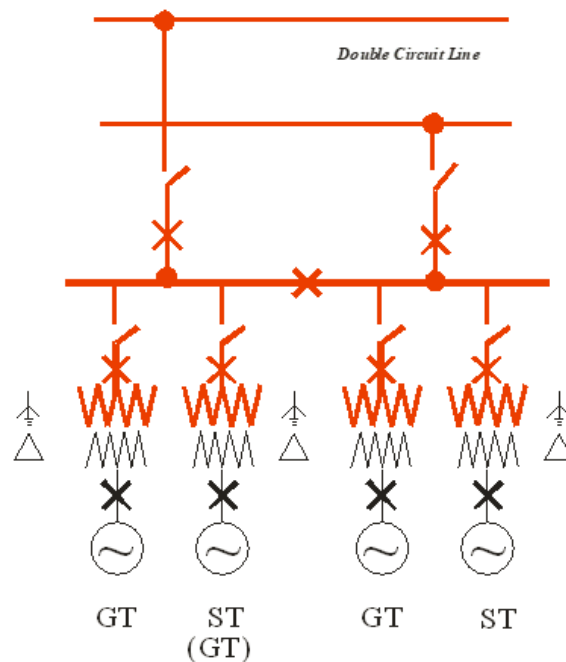


Figure C-1: Configuration for Generation Facilities and Electricity Storage Facilities Rated between 250 MW and 500 MW (1 of 3)

* Low Voltage Breakers are Optional.

- The configuration in Figure C-2 is more economical because it allows the *connection* of two *generation units* or *electricity storage 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 *generation units* or *electricity storage units*.

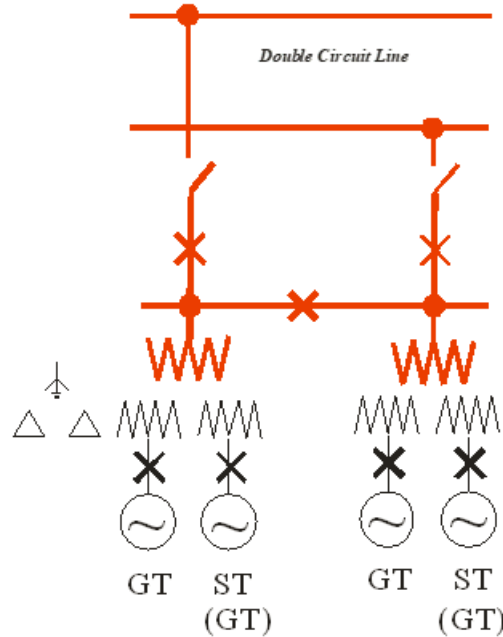


Figure C-2: Configuration for Generation Facilities and Electricity Storage Facilities Rated between 250 MW and 500 MW (2 of 3)

- For an *outage* associated with one of the high voltage breakers the entire *generation facility* or *electricity storage facility* could remain connected unless limited by equipment ratings, voltage, or stability.

For the connectivity shown in Figure C-3 below:

- 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 *generation facility* or *electricity storage facility* can remain connected to one circuit.
- A high voltage breaker failure contingency could trip two *generation units* or *electricity storage units* or a line and a *generation unit* or *electricity storage unit*. If *IESO's* assessment indicates that tripping two *generation units* or *electricity storage units* will have a negative impact on the *IESO-controlled grid* then the *IESO* will require either additional breakers to be installed or the size of the *generation facility* or *electricity storage facility* to be reduced to an acceptable level.

- For an *outage* associated with one of the high voltage breakers the entire *generation facility* or *electricity storage facility* could remain operational unless limited by equipment ratings, voltage, or stability.

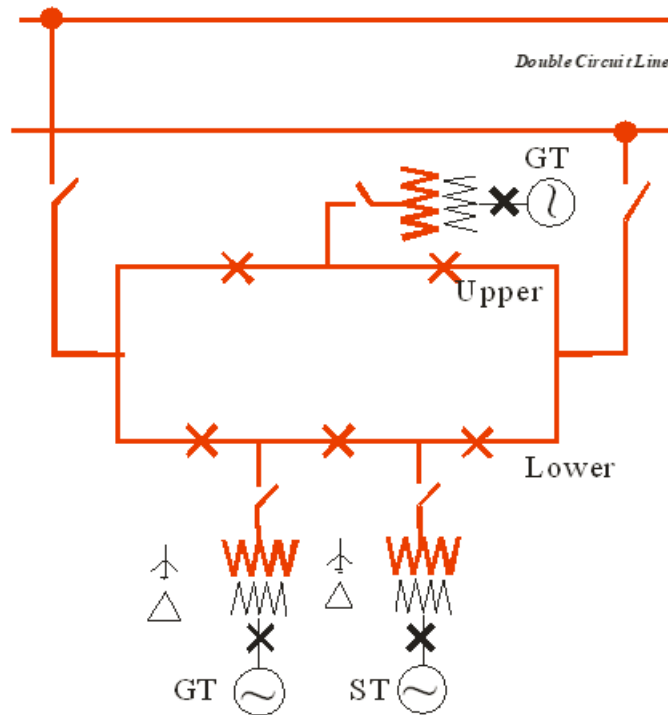


Figure C-3: Configuration for Generation Facilities and Electricity Storage Facilities Rated between 250 MW and 500 MW (3 of 3)

In addition, the *generation facilities* or *electricity storage facilities* will have to comply with the *OEB's* Transmission System Code requirements and other transmission interconnection and protection system requirements established by the *transmitter*.

C.2.2 Generation Facilities and Electricity Storage Facilities Rated Above 500 MW

All *generation facilities* or *electricity storage facilities* rated above 500 MW are required to connect to at least two circuits and provide one of the connectivity arrangements shown in Figure C-4 or Figure C-5 below. 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 C-4 is required when large *generation facility* or *electricity storage facilities* propose to *connect* to a main *transmission* corridor of considerable length that *connects* two *transmission* stations.

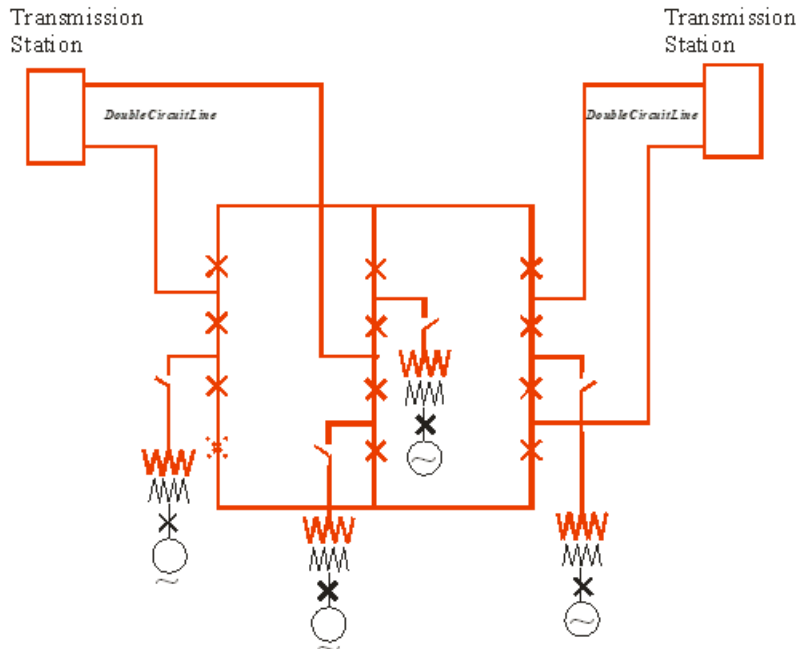


Figure C-4: Configuration for Generation Facilities and Electricity Storage Facilities Rated Above 500 MW (1 of 2)

The ring bus arrangement shown in Figure C-5 is acceptable when the *generation facility* or *electricity storage facility* is connecting to a radial double circuit line.

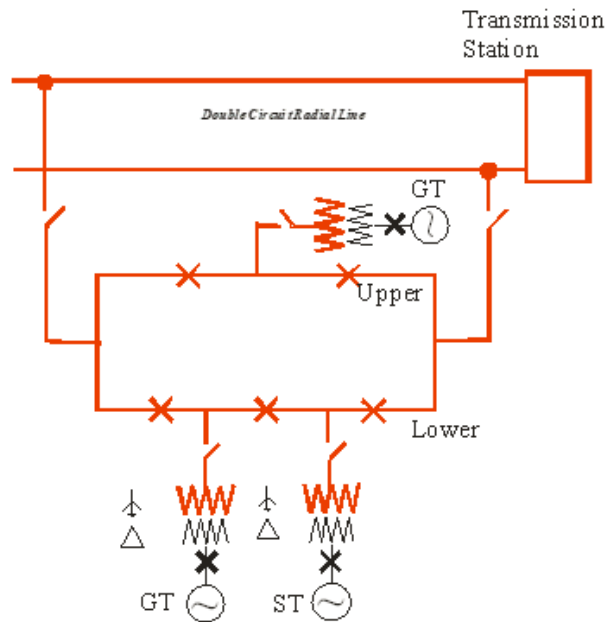


Figure C-5: Configuration for Generation Facilities and Electricity Storage Facilities Rated Above 500 MW (2 of 2)

– End of Appendix –

References

Document ID	Document Title
RUL-6 to RUL-24	Market Rules
NPCC D-01	Design and Operation of the Bulk Power System
NPCC D-04	System Protection Criteria
NPCC D-07	Remedial Action Schemes
Directory #1the Bulk NPCC criteria can be found here https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories	
NERC TPL-001	Transmission System Planning Performance Requirements
NERC standards can be found at https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx	

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