PUBLIC

POLICY

Market Manual 7: System Operations

Part 7.4: IESO-Controlled Grid Operating Policies

Issue 2.0
December 3, 2025

This *market manual* provides policy statements for *reliable* operation of the *IESO-controlled grid*.

MAN-124

Document Change History

Issue	Reason for Issue	Date
Refer to Issue 41.0 (IMP_POL_0002) for changes prior to Market Transition.		
1.0	Market Transition	November 11, 2024
2.0	Issue released for Baseline 54.1.	December 3, 2025

Related Documents

Document ID	Document Title
MAN-121	Market Manual 7.1: IESO-Controlled Grid Operating Procedures

Table of Contents

List of Figures

List of Tables

Table of Changes

Reference	Description of Change
Introduction	Removed ‘zero series’ labelling and Market Transition section.
Section 1.2	Added examples of special practices the *IESO* may use to satisfy ORTAC criteria.
Section 1.3	Updated list of applicable *market rules*.
Section 2.3.2	Added content stating that *RAS* arming may be utilized in switching configurations for less than 15 minutes.
Section 2.6	Removed paragraph regarding inverter-based generation.
Section 2.7.4	Updated Control Actions to Increase Transfer Capability.
Section 2.7.6	Updated information related to *Remedial Action Schemes (RAS)*.
Section 2.7.8	Updated information related to Load Shedding.
Section 2.7.9	Added section for Station Service.
Section 3.3	Updated information on Commissioning Tests.
Section 3.4	Minor revisions for Area Reserve for Load Security.
Section 4.1	Updated content related to System Security Principles.
Section 4.2	Rewrote Methodology for Deriving System Operating Limits.
Section 4.3.3	Added condition where post-contingency voltage decline is expected to be more than 10%.
Section 4.3.4	Rewrote subsections related to Thermal.
Section 4.3.6	Rewrote content for Post-contingency Voltage Range.
Section 4.3.7	Added content related to Voltage Stability.
Section 4.3.8	Added content related to Transient Stability.
Section 4.3.9	Added content related to Small Signal Stability.
Section 4.3.10	Added content related to Transient Voltage Response.
Section 4.5.2	Updated content related to Principles for Restoration of System Security.
Appendix A	Updated information related to Recognized Contingencies.
Appendix C	Added information related to RAS Restrictions during High-Risk Operating State.
Appendix D	Added appendix for Special Considerations for Inverter-Based Resources.

Market Manuals

Market manuals set out procedural and administrative details with respect to *market rule* requirements. Where there is a conflict between the requirements described in a *market manual* or appended document, and those within the *market rules*, the *market rules* shall prevail.

Market Manual Conventions

The standard conventions followed for *market manuals* are as follows:

- the word 'shall' denotes a mandatory requirement;
- references to *market rule* sections and sub-sections may be appreviated in accordance with the following representative format: '**MR Ch.1 ss.1.1-1.2**' (i.e. *market rules,* Chapter 1, sections 1.1 to 1.2).
- references to *market manual* sections and sub-sections may be appreviated in accordance with the following representative format: '**MM 1.5 ss.1.1-1.2**' (i.e. *market manual* 1.5, sections 1.1 to 1.2).
- internal references to sections and sub-sections within this manual take the representative format: 'sections 1.1 – 1.2'
- terms and acronyms used in this *market manual* in its appended documents that are italicized have the meanings ascribed thereto in **MR Ch.11**; and
- data fields are identified in all capitals;

– End of Section –

1 Introduction

1.1 Purpose

This *market manual* contains *IESO* policies for *reliable* operation of the *IESO-controlled grid* (ICG). These policies are intended to:

- provide guidance for the development of *IESO* procedures;
- provide guidance to *IESO* operating staff when confronted with an operational situation that is not addressed in an operating procedure or a *market rule*; and
- help *market participants* meet their obligations to the *IESO* in the operating time horizon.

To the extent practicable, the *IESO* will use available market mechanisms to direct *reliable* operation of the *IESO-controlled grid*. Where the *IESO* determines such mechanisms are unable to achieve *reliable* operation, it will take actions in accordance with the policies contained in this *market manual*.

These policies apply to the *IESO* in its role to fulfill its legislated objects to direct the operation and maintain the *reliability* of *IESO-controlled grid* and to establish and enforce criteria and standards related to the *reliability* of the *integrated power system*.

Operating policies are applied to *facilities* connected to the *IESO-controlled grid*.

Procedural details necessary to implement these policies are outside of the scope of this *market manual*. These details shall be found in the applicable *market manual* of the **MM 7** series.

1.2 Hierarchy

Operating policies shall conform to the *Electricity Act 1998, market rules*, *NERC reliability standards* and *NPCC* directories. When the interpretation of an *IESO* operating policy is in question, *IESO* staff shall select the interpretation most consistent with the *market rules*. When the proper interpretation of a *NERC* standard is in question, *IESO* staff shall select the interpretation most consistent with the purpose of the standard and *NERC's* objects to maintain the minimum level of reliability. When the proper interpretation of *NPCC* criteria is in question, *IESO* staff shall select the interpretation most consistent with *NPCC's reliability* objects.

The operating policies of this *market manual* are built on the foundation that Ontario's power system is planned and designed in such a way as to satisfy the Ontario Resource and Transmission Assessment Criteria (ORTAC). Where existing equipment is insufficient to satisfy ORTAC criteria, special practices shall be documented in operating instructions and shall be followed until the required equipment is in operation. Special practices may include, but not limited to, voluntary *demand* management operating procedures, interim operating procedures that form part of a *market rule exemption* plan, interim operating procedures that form part of a *NERC* or *NPCC* corrective action plan.

In case of a discrepancy between this *market manual* and another *manual* in the **MM 7** series, the policies of this *market manual* shall apply. In case of discrepancy between this document and a more stringent *reliability standard*, the *reliability standard* shall apply.

1.3 Scope

This *market manual* supplements the following *market rules*:

- MR Ch.1 s.3.1.1: Market Objective
- MR Ch.4 App.4.1: IESO-Controlled Grid Performance Standards
- MR Ch.4 App.4.3: Requirements for Connected Wholesale Customers and Distributors Connected to the IESO-Controlled Grid
- MR Ch.4 App.4.4: Transmitter Requirements
- MR Ch.5 s.1.2.1
- MR Ch.5 s.2.2: Normal Operating State
- MR Ch.5 s.2.3: Emergency Operating State
- MR Ch.5 s.2.4: High-Risk Operating State
- MR Ch.5 s.2.5: Conservative Operating State
- MR Ch.5 s.3.2: Obligations of the IESO
- MR Ch.5 s.3.4.1.4
- MR Ch.5 s.3.4.1.5
- MR Ch.5 s.3.6.1.6
- MR Ch.5 s.4.5: Operating Reserve
- MR Ch.5 s.4.6: Reactive Support and Voltage Control
- MR Ch.5 s.4.9: Auditing and Testing of Ancillary Services
- MR Ch.5 s.5.1.2
- MR Ch.5 s.5.2.1
- MR Ch.5 s.5.2.2

- MR Ch.5 s.5.2.4
- MR Ch.5 s.5.2.5
- MR Ch.5 s.5.2.6
- MR Ch.5 s.5.3.2
- MR Ch.5 s.5.8: Operation Under an Emergency Operating State
- MR Ch.5 s.5.9: Operation Under a High-Risk Operating State
- MR Ch.5 s.5.9A: Operation Under a Conservative Operating State
- MR Ch.5 s.6.4: Submission of Outage Schedules and IESO Approval of Outage Schedules
- MR Ch.5 s.6.5: Information
- MR Ch.5 s.7.7.7: Advisory Notices
- MR Ch.5 s.8.2: Responsibilities of the IESO
- MR Ch.5 s.10.2: Demand Control Initiated by a Market Participant
- MR Ch.5 s.10.3: Demand Control Initiated by the IESO in an Emergency Operating State
- MR Ch.5 s.10.4: Under-Frequency Load Shedding

1.4 Contact Information

Changes to this *market manual* are managed via the *IESO* Change Management process. Stakeholders are encouraged to participate in the evolution of this *market manual* via this process.

To contact the *IESO*, you 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 Reliability

2.1 Principles

(MR Ch.5 ss.1.2.1, 3.2.1 and 3.2.2)

The *IESO-controlled grid* shall operate at a level of *reliability* such that the loss of a major portion of the power system (or unintentional separation of a major portion of the power system) will not result from reasonably foreseeable contingencies. This level of *reliability* is achieved by operating the *IESO-controlled grid* to meet *adequacy* criteria for anticipated *demand*, system *security* criteria for specified contingencies, and re-preparation criteria for restoring *reliability* following contingencies.

2.2 Communications

2.2.1 Policies

(MR Ch.5 s.3.2.2)

IESO communication procedures shall comply with *NERC reliability standards* and *NPCC* directories related to communications. *IESO* requirements for communications are published in MM 7.1.

2.3 Outage Management

2.3.1 Principles

(MR Ch.5 ss.3.2.2 and 6.4)

Criteria for outage approval– When assessing proposed *outages* of *market participant registered facilities* and associated equipment, the *IESO* shall base *outage* approval solely on maintaining *reliable* operation (including overall *adequacy* and operability) of the *IESO-controlled grid*. The *IESO* shall reject, revoke, or recall an *outage* if it presents a risk to the *reliable* operation of the *IESO-controlled grid*.

No customer-specific reliability requirements – *Reliability standards* do not impose an absolute requirement to maintain a continuous supply of electricity to any specific customer.

2.3.2 Policy

(MR Ch.5 ss.3.2.1, 3.2.2, 6.4 and 6.5)

IESO outage coordination within Ontario – The *IESO* shall deal fairly and appropriately with *market participants,* and comply with the applicable *market rules* and *market manuals*. The *IESO* will provide *market participants* with timely and accurate information regarding the *IESO-controlled grid* to facilitate *market participant* coordination of *outages* and provide mechanisms to resolve *outage* conflicts.

IESO outage coordination outside of Ontario – The *IESO* shall coordinate *outages* to equipment external to Ontario with authorities in neighbouring jurisdictions to meet *NERC* and *NPCC* obligations, and to satisfy *IESO operating agreements* with interconnected neighbours.

Transmitter coordination of customer connection outages – The *IESO* will NOT coordinate *outages* to individual customer connections. This obligation rests with the associated *transmitter.*

Switching configurations for less than 15 minutes – For switching configurations expected to last not more than 15 minutes, the only system *security* criteria that will be observed are:

- equipment loading shall be within pre-contingency ratings supplied by asset owners; and
- transfers shall be restricted to prevent pre-contingency voltage collapse.

RAS arming, where available and practical, may be utilized during short duration switching periods to provide added system *security* beyond what is required by this policy, subject to restrictions listed in Appendix C: RAS Restrictions during High-Risk Operating State.

Additional provisions – The *IESO publishes* and maintains a *market manual* for *outage* management of *facilities* and equipment connected to the *IESO-controlled grid*, or which may affect the operation of the *IESO-controlled grid*. Refer to **MM 7.3**.

2.4 IESO-Controlled Grid Operating States

2.4.1 Principles

(MR Ch.5 ss.1.2.1, 2.2, 2.3, 2.4, 2.5, 3.2.1 and 3.2.2)

Normal, conservative, high-risk, and emergency operating states – The *IESO* operates under a set of grid operating states based on system conditions and the *IESO's* ability to monitor the *IESO-controlled grid*. The *IESO-controlled grid* has four operating states: the *normal operating state, conservative operating state*, *high-risk operating state* (including safe posture), and *emergency operating state*. In addition to the operating states, there is system restoration, which occurs immediately following a contingency that results in loss of load, cascading *outages*, islanding, etc.

Under certain operating conditions (e.g. adverse weather or equipment-related problems), the probability of experiencing certain contingencies increases. The *IESO* may temporarily and selectively increase the level of system *security* to improve *reliability* during a *high-risk operating state*.

Under stressed conditions (e.g. extreme hot or cold temperatures, anticipating energy or capacity deficiencies, or *outages* to *IESO* market or system applications that impact system *security*), the *IESO* will seek to minimize potential risks to the *IESO-controlled grid* or enhance grid resiliency in anticipation of (and after the declaration of) a *conservative operating state*. The *conservative operating state* is available to the *IESO* to help prevent an *emergency operating state*. Under critical conditions (e.g. experiencing *energy* or capacity deficiencies, or a *security* emergency), load shedding may be required. The *IESO* strives to mitigate or avoid load shedding when in an *emergency operating state* by maintaining a variety of control actions to be taken in anticipation of (and after the declaration of) an *emergency operating state*. Refer to the Emergency Operating State Control Actions (EOSCA) list in **MM 7.1 App.B**.

In *high-risk operating states*, *conservative operating states*, and *emergency operating states*, *IESO* control actions to maintain system *security* are more likely to be taken compared to during a *normal operating state.* These actions are structured to:

- preserve system *reliability*; and
- restore normal operation of *IESO-administered markets* as soon as practicable (**MR Ch.5 s.2**).

Mitigating impacts to the IESO-administered markets – The *IESO* will strive to mitigate adverse effects on *IESO-administered markets*, while at the same time observing the mutual protection and assistance provisions contained in agreements between the *IESO* and other *reliability* coordinators and balancing authorities*.*

2.4.2 Normal Operating State

(MR Ch.5 s.2.2)

In a *normal operating state,* the *IESO* will supply all *non-dispatchable loads* and *price responsive loads* while operating to normal condition limits.

The *IESO* shall direct *market participants* to act or to refrain from acting so as to maintain the *IESO-controlled grid* in a *normal operating state* (**MR Ch.5 s.2.2**). The *IESO* will also act or refrain from acting where doing otherwise is likely to lead to a *high-risk* or *emergency operating state* (**MR Ch.5 ss.2.3.2**, **2.4.2** and **5.1.2.6**).

2.4.3 High-Risk Operating State

(MR Ch.5 ss.2.4 and 5.9)

In a *high-risk operating state*, the *IESO* will temporarily and selectively increase the level of system *security* by applying high-risk operating limits. The *IESO* will take actions such as rejection, revocation, or recall of equipment and *facility outages* when necessary to:

- maintain the level of system *security* required during a *high-risk operating state;* and
- allow, after a recognized contingency, the *IESO* to re-establish an acceptable level of system *security* and to re-prepare the *IESO-controlled grid* within the time permitted by *reliability standards*.

The conditions under which a *high-risk operating state* may be declared (along with related policy implementation details) can be found in **MM 7.1**.

2.4.4 Conservative Operating State

(MR Ch.5 ss.2.5 and 5.9A)

The *IESO-controlled grid* can be operated in a *conservative operating state* in response to a reliability concern to help prevent an *emergency operating state*. In a *conservative operating state*, the *IESO* may reject, suspend or revoke equipment and *facility outages* to minimize any potential risks to the *IESO-controlled grid* that could occur from non-urgent/routine work or switching of equipment. The *IESO* may also take actions to commit additional *resources* or recall equipment and *resource outages* to enhance grid resiliency. Under a *conservative operating state,* the *IESO-controlled grid* will be operated within equipment and *security limits* established for a *normal operating state*.

For IT-related *outages* related to the *IESO-administered markets* and/or system applications or tools that affect system *security*, the *IESO* may also take actions such as requesting *market participants* or neighbouring *control area operators* to monitor the *IESO-controlled grid* or *interties*, respectively, on behalf of the *IESO*. In addition, *market participants* may need to implement manual workarounds to fulfill their obligations (e.g. receive and execute verbal dispatch instructions).

The conditions under which a *conservative operating state* may be declared can be found in **MM 7.1**.

2.4.5 Emergency Operating State

(MR Ch.5 ss.2.3, 5.8 and 10.3)

The *IESO* shall not plan to operate the *IESO-controlled grid* in an *emergency operating state* pre-contingency, including when considering *planned outages*.

The *IESO* strives to mitigate or avoid load shedding when in an *emergency operating state* by *publishing* and maintaining a hierarchy of control actions to be taken in anticipation of and after the declaration of an *emergency operating state* (refer to the EOSCA list in **MM 7.1**). Temporarily and selectively reducing the level of *system security* by applying *emergency* condition operating limits is one of the many control actions the *IESO* can take when in an *emergency operating state*.

At all times, the minimum acceptable level of *IESO-controlled grid* system *security* is the level afforded by observance of *emergency* condition operating limits. All necessary steps are to be taken, including the interruption of *non-dispatchable load* or *price responsive load*, to observe the *emergency* condition operating limits.

An *emergency operating state* will generally not be declared when normal or routine control actions can resolve the capacity or *energy* deficiency, or return the *IESO-controlled grid* to a studied operating state in a timely manner. Implementation details, including the conditions under which an *emergency operating state* may be declared can be found in **MM 7.1**.

2.5 Degraded Transmission Equipment Performance

(MR Ch.5 ss.1.2.1, 3.2.1, 3.2.2, 3.4.1.4, 3.4.1.5 and 3.6.1.6)

Degraded performance examples and IESO actions – A higher than long-term average *forced outage* rate, unanticipated tripping, or unanticipated failure to trip are typical examples of degraded transmission equipment performance. Where transmission equipment has shown degraded performance, or if degraded performance is anticipated, the *IESO* may perform control actions such as the following:

- reschedule routine maintenance work, except work to remedy degraded performance;
- reject or revoke any *planned outages* with Planned, Opportunity, or Information Priority Code anticipated to have an adverse impact on the *IESO-controlled grid*, except for *planned outages* to remedy degraded performance*;*
- recall any *planned outages* with Planned, Opportunity, or Information Priority Code that may have an adverse impact on the *IESO-controlled grid* associated with the affected portion of the *transmission system;*
- request staffing at transmission stations during periods of routine switching, during periods of high risk of equipment operation, or on a 24/7 basis depending on the severity of equipment degradation;
- adjust *IESO system security* assessments to account for additional elements anticipated to be removed from service due to equipment degradation;

- adjust use of *remedial action schemes (RASs)* to reduce operation of affected *transmission system* equipment; or
- direct *generators* and other *market participants* as required to enhance *reliability*.

Where time permits, the *IESO* will discuss control actions with the applicable *transmitter* before implementation. Affected *market participants* and *reliability* coordinators shall be advised as appropriate, which may include *publishing* information on areas with degraded transmission equipment performance.

2.6 Islanding

(MR Ch.5 ss.1.2.1, 3.2.1, 3.2.2, 3.2.3, 7.7.7 and 8.2.3)

Notice to generators and storage – The *IESO* shall notify *generators* and *electricity storage participants* of *outages* that would put their units in an electrical island following a single element contingency to inform their operating decisions.

No manual constraints down – The *IESO* shall NOT manually constrain down *resources* pre-contingency in order to assist a rapid collapse of an electrical island.

No manual constraints up – The *IESO* shall NOT manually constrain up *resources* pre-contingency in order to assist the survival of an electrical island.

IESO actions to assist collapse – The *IESO* shall take available pre-contingency control actions (other than constraining *resources*, such as a configuration change or *RAS* arming) to assist the rapid collapse of an electrical island formed by a single element contingency if:

- *IESO* studies pre-determine that voltage and frequency will not be controlled within acceptable ranges; or
- *IESO* cannot obtain voltage and frequency measurements in the island.

IESO actions to assist survival – The *IESO* shall take available pre-contingency control actions (other than constraining *resources*, such as a configuration change or *RAS* arming) to assist the survival of an electrical island formed by a single element contingency if:

- *IESO* studies pre-determine that voltage and frequency will be controlled within acceptable ranges; and
- *IESO* can obtain voltage and frequency measurements in the island.

Synchronization of Islands – The *IESO* shall synchronize islands only by using breakers that have synchrocheck relays, or a mechanism of ensuring that the circuit breaker closes only if voltages on both sides of the circuit breaker fulfill conditions of magnitude, phase, and slip frequency.

Special operating practices for islands – If special islanding practices are developed that differ from the above general policy, these practices shall be documented in operating instructions.

2.7 Grid Control Actions

2.7.1 Principles

(MR Ch.1 s.3.1.1)

Maximizing transfer capability – To satisfy the objective of the *IESO-administered markets*, all practicable control actions shall be taken to maximize transfer capability while observing all *system security* or *adequacy* constraints.

2.7.2 Readiness Programs

(MR Ch.5 ss. 4.9.1 and 4.9.2)

Periodic Testing – To maintain confidence that control actions will be available when called upon, the *IESO* shall test or require *market participants* to test *facilities* that are connected to the *IESO-controlled grid*. This testing could be to prepare for the next peak season, or to prepare for extreme conditions that are expected in the next few days. For example, voltage reduction, *operating reserve* activation, and reactive capability will be periodically tested.

Additional provisions – *IESO* readiness program implementation details can be found in **MM 7.1**.

2.7.3 Network Configuration Change Request

(MR Ch.5 ss.3.2.3 and 6.4)

IESO assessment – The *IESO* shall assess proposed network configuration requests to manage individual *delivery point* performance and, through the *outage* management process, approve proposals that do not:

- degrade the *reliability* of the *IESO-controlled grid*;
- reduce a System Operating Limit[1] (SOL) or transfer capability;
- result in inconsistent application of established system *security* criteria and *reliability standards*;
- impose additional exposure to loss of essential *station service* supply to nuclear generating stations;

[1] Refer to *NERC* Glossary of Terms. System Operating Limit is used interchangeably with *security limit*.

- expose the *IESO-controlled grid* to additional contingencies that have a material adverse effect on the *reliability* of the *IESO-controlled grid*;
- impose additional risk/restrictions related to post-contingency response to recognized contingencies; and
- interfere with the operation of *IESO-administered markets* (i.e., do not result in changes in generation *dispatch* or *market price*).

Inclusion in operating instructions – During normal situations, the *IESO* will include such advance-approved proposals in its operating instructions ahead of real-time operations.

Abnormal situations – During abnormal situations (e.g., *forced outages*, responding to contingencies, system restorations, etc.), the *IESO* may deviate from the above provisions while respecting their intent to the extent possible.

2.7.4 Control Actions to Increase Transfer Capability

(MR Ch.5 ss.1.2.1 and 3.2.1)

IESO control actions – Consistent with the principles stated in s.2.7.1, to maximize transfer capability the *IESO* will assess and may implement control actions such as:

- changing reactive *dispatch*;
- changing transformer winding or phase angle taps;
- load transfers;
- arming *RASs*;
- manually constraining *generation resources* and *electricity storage resources* up or down;
- opening breakers or switches, including high or low voltage bus tie breakers;
- taking equipment off load; or
- removing equipment from service.

Transmitter concurrence – The applicable *transmitter* must concur with control actions that involve removal of a step-down transformer or a bus-tie breaker which reduces supply redundancy to a *load facility*.

Transmission reconfiguration – The *IESO* may prioritize reconfiguring the *transmission system* to increase system adequacy by alleviating conditions that restrict *generation facility* or *electricity storage facility* output with due consideration to *reliability* of the *IESO-controlled grid*, supply redundancy to a *load facility* and *delivery point* performance.

Implementation exceptions – The *IESO* will implement these control actions, or include them as part of its operational planning assessment of *outage* requests, unless the action:

- fails to conform to a policy contained in this document;
- exposes nuclear generating stations to loss of essential station service supply following an Appendix A, Group 1 contingency; or
- causes post-contingency configurations expected to exceed system *security* restoration timelines.

2.7.5 Voltage Control

(MR Ch.5 s.4.6)

System voltage control actions – To maintain *IESO-controlled grid* voltages within ranges, to respect SOLs*,* and to respect equipment ratings, the *IESO* will *dispatch* the following:

- *generation unit* and *electricity storage unit* reactive power within unit capability;
- reactive control devices subject to *operating agreements*; and
- reactive control devices subject to procurement contracts.

Load facility voltage control actions – The *IESO* will *dispatch* the following to meet *connected wholesale customer* or *distributor* voltage needs, as long as these actions do not exceed SOLs and equipment ratings:

- *generation unit* and *electricity storage unit* reactive power within unit capability; and
- reactive control devices subject to operating agreements.

2.7.6 Remedial Action Schemes

(MR Ch.5 ss.8.2.1, 8.2.2, 8.2.2A and 8.2.3)

RAS operation – The *IESO-controlled grid* system *security* must be returned to a secure state within times prescribed by *reliability standards* following operation of a *RAS*. The *IESO* will direct the use of *RAS* as outlined in *transmitter operating agreements*.

RAS deployment – A *RAS* shall not be deployed until it has been classified in the *NPCC* process as Type I, II, or Limited Impact.

Acceptable use of RAS – The acceptable use cases for *RAS* are described as follows:

- a Type I *RAS* may be utilized to increase the *security limit* of any SOL, including an Interconnection Reliability Operating Limit[2] (IROL);
- a Type II *RAS* may be utilized to increase the *security* of the *IESO-controlled grid* for extreme contingencies, such as the loss of a right-of-way due to a tornado risk or a loss of a station due to a flashover risk; and
- a Limited Impact *RAS* may be utilized to increase the *security limit* of an SOL that is not an IROL.

Additional provisions – Specific criteria for selection of load rejection (L/R), generation rejection (G/R), and generation runback are contained in Appendix B. The use of a *RAS* during a *high-risk operating state* shall be subject to the restrictions contained in Appendix C.

Exclusion from load rejection – The *IESO* will allow *market participants* to request an exclusion from L/R for the following reasons:

- public safety hazard;
- potential damage to equipment;
- potential violation of any *applicable law*;
- *outages* to equipment directly associated with L/R tripping or restoration; or
- *outages* to equipment which may degrade the integrity of L/R tripping or restoration (such as, but not limited to, relaying or station supervisory control equipment).

Restoration of rejected load – The *IESO* shall direct the restoration of rejected load. Load may be restored following rejection by interrupting other load (i.e., rotating blackout) as a substitute.

2.7.7 Voltage Reductions

(MR Ch.5 ss.4.5.2A, 5.8.1.2, 5.9.1.3 and 10.3.1)

The *IESO* may direct a *market participant* to initiate voltage reductions to prevent or to mitigate an *emergency operating state* resulting from events including:

- equipment thermal overloads;
- insufficient *generation capacity* and *electricity storage capacity* to satisfy non-dispatchable *demand*;
- violations of high-risk, normal, or emergency SOLs; or

[2] Refer to *NERC* glossary of terms

- an event requiring the *IESO* to activate *operating reserve* that is provided by voltage reductions.

2.7.8 Load Shedding

(MR Ch.5 ss.5.8.1.2, 5.9.1.3 and 10.3.1)

Purpose of load shedding – Load shedding is a permissible *IESO* control action to maintain grid integrity, or to respect safety, equipment, or *applicable law* constraints.

Avoiding or deferring load shedding – When an SOL is exceeded, load shedding may be avoided or deferred by taking the following steps as required:

1) <u>Disregard high-risk limits and apply normal limits.</u>

   This step will allow an increase in transfer limits constrained by *RAS* arming restrictions and other restrictions due to a *high-risk operating state*.

2) <u>Disregard normal limits and apply emergency condition operating limits.</u>

   This step will allow an increase in transfer limits constrained by contingencies involving more than one element.

Conditions requiring load shedding – The *IESO* shall shed load during an *emergency operating state* under the following conditions, which are consistent with the minimum acceptable level of *reliability*:

- to alleviate a capacity or *energy emergency*;
- to alleviate or avoid exceeding pre- and post-contingency equipment ratings;
- to alleviate or avoid exceeding pre-contingency voltage collapse;
- to alleviate or avoid exceeding an IROL; or
- if specified by special operating practices for unique circumstances.

Operation outside of known and secure states – Note that when a transfer is near its SOL, both the SOL and its associated boundary conditions (e.g. minimum voltages, flows on other *IESO-controlled grid* interfaces, or interchange with a *neighbouring electricity system* etc.) are equally important considerations. When a boundary condition is not satisfied, the *security* of the *IESO-controlled grid* is no longer in a known and secure state. In the case of IROLs, this implies an unknown risk of system instability, cascading or uncontrolled separation, and consistent with the *NERC* "Reliability Guideline on Methods for Establishing IROLs", must be managed back to a known secure state within 30 minutes (which may require shedding *non-dispatchable load*).

Selecting which load to shed – When an *emergency operating state* has been declared and reduction in *demand* is required to safeguard the *reliability* of the

IESO-controlled grid, the *IESO* shall direct manual load shedding to reduce *demand* on the following basis:

- Priority customer loads (refer to MM 7.10) such as hospitals and water treatment plants without backup generators, and electrically driven gas compressors should be avoided when determining what load to shed.
- The amount and location of load to be shed will be selected to solve the operating problem to maintain an adequate level of *IESO-controlled grid adequacy* or system *security*.
- When time permits, load cuts via manual rotational load shedding schemes should be spread equitably across the *IESO-controlled grid* to the extent practicable. Equitable considerations will include magnitude, duration, and frequency of load reductions.

2.7.9 Station Service

(MR Ch.5 ss5.2.5 and 6.5.1)

Market participant notification to IESO – When a recognized *contingency event*, as indicated in Appendix A: Recognized Contingencies, results in the loss of *station service* supply to a *facility*, the *market participant* that owns the *facility* shall promptly notify the *IESO* of any adverse impacts, such as:

- reduced *facility* ratings;
- loss of control, monitoring, or visibility of equipment; and
- any other operational limitations.

Planned or prolonged outages – For planned or prolonged *station service outages* lasting more than 24 hours and impacting equipment critical to IROLs, the *market participant* shall: Implement viable redundancy measures within 30 minutes, such as:

- activating backup generation;
- staffing the station locally; and/or
- recalling the *outage* or preparing affected equipment for quick recall.

– End of Section –

3 Adequacy

3.1 Principles

(MR Ch.5 ss.1.2.1 and 3.2.1)

IESO adequacy assessment – The *IESO* shall maintain an adequate supply of generation and transmission to meet forecast Ontario *demand* in the operational timeframe. When assessing generation and transmission *adequacy*, the *IESO* will consider factors including the following:

- *demand* forecast;
- *variable generation* (e.g., wind and solar) forecast;
- load forecast uncertainty;
- additional contingency allowance;
- *operating reserve* requirements;
- generation, electricity storage and *demand* response availability forecast, which includes the available but not operating (ABNO) units, and generation external to Ontario and associated tie-line capability;
- transmission *facility* capability forecast;
- applicable SOLs; and
- acceptable voltage ranges.

3.2 Resource and Transmission Adequacy

(MR Ch.5 ss.7.3.1.4 and 7.3.1.5, Ch.7 ss.12.1.1.6, 12.1.1.7 and 12.1.1.8)

Assessment frequency – When assessing *adequacy*, the *IESO* shall compare forecasted *demand* to available *resource* capacity and *energy*, including available *resources* external to Ontario. The *IESO* shall assess *adequacy* for *normal operating states* on a daily basis in its short-term operating assessments, on a weekly basis in its medium-term assessments, and on a less frequent basis in longer-term assessments. For these operating horizons, criteria to identify an acceptable level of *adequacy* (and corrective actions if this level cannot be achieved), can be found in MM 7.2.

Criteria for transmission adequacy – When assessing transmission *adequacy*, the *IESO* shall compare transmission flow forecasts with the applicable SOLs under an anticipated range of power system conditions. Transmission is adequate if *demand* forecasts can be supplied without exceeding applicable SOLs, and acceptable system voltages can be maintained.

3.3 Operating Reserve Policy

(MR Ch.5 ss.4.5.1, 4.5.2 and 4.5.5)

Extent of operating reserve scheduling – *Operating reserve* shall be scheduled (**MR Ch.5 s.4.5.1**) to ensure *resources* are available to:

- cover or offset unanticipated increases in *demand* during a *dispatch day* or *dispatch hour*;
- cover or offset capacity lost due to a forced or urgent *outage* of generation, injecting *electricity storage facilities*, or transmission equipment; or
- cover uncertainty associated with the performance of *generation facilities*, *electricity storage facilities*, or *dispatchable loads* in responding to *IESO dispatch instructions*.

Commissioning tests – No additional *operating reserve* shall be required during a commissioning period when no tests are scheduled that materially increase the risk of unit tripping.

Distribution of operating reserve – *Operating reserve* shall be scheduled in sufficient quantity and shall be distributed so as to ensure that it can be utilized for any single contingency that results in either generation loss, electricity storage injection loss or both without exceeding equipment or *transmission system* limitations.

Voltage reductions may be used to provide operating reserve.

3.4 Area Reserve for Load Security

(MR Ch.5 ss.4.5.1, 4.5.2 and 4.5.5)

Area reserves (i.e. reserves that are scheduled or *resources* that are pre-committed to avoid shedding load) shall be scheduled as follows:

- For all **SOLs:** All available *resources* shall be committed to avoid shedding load before a contingency.
- For **IROLs**: Non-*energy* limited *resources* shall be pre-committed so that following a single-element contingency, the system can be re-prepared within 30 minutes to operate to IROL emergency condition limits, without shedding *non-dispatchable load* or *price responsive load* to the extent possible.

Additional area reserve – From time to time, the *IESO* may choose to carry additional area reserve beyond those required here for circumstances such as extreme weather forecasts, system flexibility events (**MM7.1 s.2.4.2**), physical security threats, etc.

– End of Section –

4 System Security

4.1 Principles

(MR Ch.5 ss.3.2.2, 5.1.2, 5.2.1, 5.2.2, 5.2.4, and 5.2.6)

This section describes the level of *security* that must be achieved so that the risk of loss or separation of a major portion of the *interconnected system* is reduced to an acceptable level.

The *IESO-controlled grid* must display satisfactory performance before and after *contingency events*. All *IESO* performance criteria must be satisfied, not only the transient and voltage stability criteria, for an operating condition to be deemed stable.

The *IESO-controlled grid* must be operated such that in a normal, planned state, voltages will be within normal limits, equipment loading will be within continuous ratings as supplied by *facility* owners, and transfers will be within SOLs. For *planned outages* with Planned, Opportunity, or Information Priority Code, *market participants* may provide less restrictive equipment ratings, such as long-term *emergency* ratings (e.g., 10-day limited time ratings) to be applied pre-contingency pertaining to equipment that they own. Operation within authorized ratings shall be considered sufficient to avoid physical damage, protect safety, and avoid violation of any *applicable law* unless otherwise notified.

The *IESO* will use the following policies to develop operational plans, establish SOLs and instructions, and operate the *IESO-controlled grid*.

4.2 Methodology for Deriving System Operating Limits

(MR Ch.5 ss.3.2.2, 5.1.2, 5.2.1, 5.2.2, 5.2.4, and 5.2.6)

SOL and IROL Methodology – System operating limits shall be established in the following manner:

1. Simulate and monitor the effect of recognized *contingency events* as follows:
    a. Contingencies listed in Appendix A Group 1 shall be monitored on the *NPCC*-defined bulk power system (BPS), in accordance with *NPCC* Directory #1.
    b. Contingencies listed in Appendix A Group 2 shall be monitored onto the *NERC*-defined bulk electric system (BES), for the contingency occurring anywhere in Ontario.

c. Contingencies listed in Appendix A Group 3 shall be monitored onto the *IESO-controlled grid*, for the contingency occurring anywhere in Ontario.

2. Evaluate the effect of recognized *contingency events* with respect to *security* criteria as follows:

   a. The resulting performance from 1a shall be evaluated with respect to *security* criteria for Widespread Voltage Stability, Widespread Transient Stability, Widespread Small Signal Stability, Uncontrolled Separation, and Cascading[3].

   b. The resulting performance from 1b shall be evaluated with respect to all *security* criteria.

   c. The resulting performance from 1c shall be evaluated with respect to all *security* criteria.

3. Establish SOLs and identify the subset that are IROLs, as follows:

   a. A SOL is established to ensure that the resulting performance from the evaluation in 2 meets the applicable *security* criteria.

   b. An IROL is established in the case that the SOL is securing for Widespread Voltage Stability, Widespread Transient Stability, Widespread Small Signal Stability, Uncontrolled Separation, or Cascading *security* criteria.

Reassessing IROLs for prevailing conditions – The *IESO* may reassess IROLs leading up to, or during, real-time operations, and confirmed to not be IROLs for prevailing conditions. In such circumstances, assessments shall be documented and policies associated with IROLs need not be followed. If the prevailing conditions are such that the *IESO-controlled grid* is no longer in a known and *secure* operating state, the *IESO* shall take control actions that prioritize returning the *IESO-controlled grid* to a known and *secure* operating state and not on establishing an SOL or IROL in real-time.

Contingencies outside Ontario – If the *IESO* becomes aware of a contingency outside Ontario that materially affects the *IESO-controlled grid,* the *IESO* will treat that as a recognized contingency for the *IESO-controlled grid*.

[3] Remaining *security* criteria need not be evaluated, as *NPCC* Directory #1 allows for the loss of small or radial portions of the system, provided consequence is demonstrably contained to the *IESO-controlled grid* and the rest of the BPS demonstrates acceptable performance. The *security* criteria listed are consistent with the aforementioned requirement.

Contingencies inside Ontario – A neighbouring jurisdiction will determine the criteria for assessing effects of contingencies within the *IESO-controlled grid* on their system.

Special considerations for inverter-based resources – In addition to the *security* criteria contained within this document, special considerations for inverter-based resources, and requirements to assess electromagnetic transient phenomena are stated in Appendix D: Special Considerations for Inverter-Based Resources.

Communicating equipment critical to IROLs – The *IESO* fulfills its obligations under *NERC* Standard FAC-014-4 R5 by ensuring that all elements critical to the derivation of IROLs and associated critical contingencies are documented within operating instructions. *Market participants* that own or operate *facilities* containing elements critical to IROLs are provided the subject operating instructions at the time any version of the document is released, and pursuant to *operating agreements*. Thus, the *market participant* will always have access to the most current information pursuant to critical elements, and in alignment with timelines established in the *NERC* requirements.

4.3 System Security and Modelling Criteria

4.3.1 Principles

(MR Ch.5 ss.5.2.1, 5.2.2, 5.2.4, and 5.2.6)

Overview – The derivation of SOLs shall be done in accordance with the system *security* and modelling criteria described in the following sections.

4.3.2 Study Conditions and System Model

(MR Ch.5 ss.5.2.1, 5.2.2, 5.2.4, and 5.2.6)

Expected conditions – The study conditions used shall cover expected operating conditions (e.g. generation *dispatch* and load levels) and shall reflect changes to system topology (e.g. *facility outages*).

Model Extent – The study model for determining SOLs must include at least the entire reliability coordinator area, as well as the critical modelling details from other reliability coordinator areas that would impact the *facility* or *facilities* under study.

Model detail – The study model must contain a sufficient amount of detail, including representation of the physical and control characteristics of modelled *facilities*, to ensure fulfillment of the *IESO's* mandate to operate the *IESO-controlled grid* reliably.

4.3.3 Load Representation

(MR Ch.5 ss.5.2.1, 5.2.2, 5.2.4, and 5.2.6)

Pre-contingency – Constant megavolt-amp (MVA) load models shall be used to assess a pre-contingency state.

Post-contingency – Voltage-dependent load models may be used to assess a post-contingency state before and after tap-changer action. The default voltage-dependent load model shall be used unless a different model has been approved by the *IESO*. The default voltage dependant for active (P) and reactive (Q) load shall be defined as follows:

$$P(V) = 0.5 \times P_0 \times \frac{V}{V_0} + 0.5 \times P_0 \times \left(\frac{V}{V_0}\right)^2$$

$$Q(V) = Q_0 \times \left(\frac{V}{V_0}\right)^2 \quad V_0\ P_0,\ Q_0 \text{ are pre-contingency values}$$

In areas where representation of load is critical, such as areas with a material amount of motor load or where post-contingency voltage decline is expected to be more than 10%, a detailed representation of transient load behaviour should be attempted.

4.3.4 Thermal

(MR Ch.5 ss. 5.2.1, 5.2.2, 5.2.4, 5.2.5, and 5.2.6)

4.3.4.1 Equipment Loading Criteria

Pre-contingency criteria – Prior to a *contingency event*, steady state flow through equipment comprising the *IESO-controlled grid* shall be within continuous ratings provided by the relevant *market participants*. Limited time ratings may be used in special circumstances, such as switching, so long as the application is acceptable to the relevant *market participants* via documented instruction or during real-time conditions.

Post-contingency criteria – Following a *contingency event*, steady-state flow through equipment comprising the *IESO-controlled grid* shall be within applicable emergency ratings provided by the relevant *market participants*.

4.3.4.2 Cascading Criteria

Demonstrably contained – Following a contingency, if steady-state flow through equipment comprising the *IESO-controlled grid* overloads equipment and causes it to trip, successive overloading and tripping shall be demonstrably contained (i.e. bounded) such that a new steady-state is reached, and the remaining portion of the *IESO-controlled grid* meets applicable *security* criteria. Particularly, the magnitude of any net loss of load or supply shall not result in a redistribution of flow that results in an adverse impact to *interties*.

Simulation considerations – For the purpose of simulations testing cascading, equipment that is loaded in excess of the emergency rating provided by the *market participant* shall be assumed to trip. Assuming the equipment trips is reasonably conservative to account for the probability of either overcurrent relay activation, fault isolation due to underbrush contact, or the *market participant* exercising their authority to remove equipment from service in accordance with **MR Ch.5 ss.1.2.3 and 6.1.6**.

4.3.4.3 Thermal Rating Policy

Respect equipment ratings – The *IESO* shall not deliberately operate or plan to operate equipment comprising the *IESO-controlled grid* in excess of thermal ratings for such equipment as communicated to the *IESO* by relevant *market participants*.

Use of limited time ratings – Limited time ratings shall be utilized only if control actions are available to reduce loading to a longer time rating within the interval afforded by a limited time rating. For example, a 15-minute rating may only be utilized if control actions are available to reduce loading to a longer term rating (e.g. a 10-day rating) within 15 minutes. Post-contingency loading shall not exceed the shortest applicable limited time rating.

Monitoring – Thermal IROLs shall be identified in advance of real-time operation to establish whether overloading of equipment results in unbounded cascading. Typically, the limit values of thermal SOLs are established in real-time operation by the *IESO*'s real-time operating tools based on the *facility* ratings submitted by *market participants*. The scope of thermal monitoring will be established in *operating agreements* between *IESO* and *transmitters*.

4.3.5 Pre-contingency Voltage Range

(MR Ch.5 ss.5.2.1, 5.2.2, 5.2.4, and 5.2.6)

IESO-controlled grid ranges – The *IESO-controlled grid* shall be operated in the voltage ranges shown in Table 4-1 under pre-contingency conditions and following re-preparation unless affected equipment owners have agreed to a wider range.

Transmission and distribution ranges – For transmission voltages, the values are from **MR Ch.4**. For distribution voltages, the values are based on Canadian Standards Association (CSA) Standard 235.

Table 4-1: Pre-Contingency Voltage Limits

Nominal Bus Voltage	Transmission Stations			Transformer Station (Load Facility) Low Voltage at
	500 kV	230 kV	115 kV	44 kV, 27.6 kV, 13.8 kV
Maximum Continuous	550 kV	250 kV	127 kV*	106% of nominal
Minimum Continuous	490 kV	220 kV	113 kV	98% of nominal

* In portions of northern Ontario, the maximum continuous voltage for the 115 kV system can be as high as 138 kV.

Exceptions – Exceptions to maximum and minimum voltages must be documented in relevant operating instructions.

4.3.6 Post-contingency Voltage Range

(MR Ch.5 ss.5.2.1, 5.2.2, 5.2.4, and 5.2.6)

Post-contingency limits – *IESO-controlled grid* voltages following recognized contingencies (i.e., after the contingency has been cleared, automatic schemes have acted, and the *IESO-controlled grid* has reached a new steady state) shall be limited to the values and applicability as shown in Table 4-2.

Greater post-contingency maximum voltages may be observed if the equipment owner has agreed to different voltage limits. Operating instructions must document exceptions to voltage limits.

If post-contingency voltages on the low-voltage side of load transformer station are observed to decline by greater than 10%, the *IESO* shall inform the *transmitter* of the voltage performance. This is in recognition that load power quality is the responsibility of the *transmitter*. If the suppressed voltage performance is determined to be unacceptable by either the *transmitter* (per power quality requirements from the *OEB's* transmission system code or other relevant *reliability standards*) or the *IESO* (per the policies contained herein), the *IESO* shall establish a boundary condition to prevent more than 10% voltage decline at the low-voltage side of the load transformer station.

Table 4-2: Post-Contingency Voltage Range

	Nominal Bus Voltage			
	500 kV	**230 kV**	**115 kV**	**Applicability**
Post-contingency Maximum	575 kV	263 kV	133 kV*	Only at *transmission stations* and at points of interconnection of *generation facilities* and *electricity storage facilities,* for a duration of up to 30 minutes
Post-contingency Minimum	450 kV	207 kV	104 kV	Only at point of interconnection of *generation facilities* and *electricity storage facilities*

* Where the *maximum continuous* voltage for the 115kV system is above 133kV, the post-contingency maximum voltage limit is the same as the applicable *maximum continuous* voltage.

4.3.7 Voltage Stability

(MR Ch.5 ss.5.2.1, 5.2.2, 5.2.4, and 5.2.6)

Overview - For acceptable voltage stability, the *IESO* shall apply the following *security* criteria and policy.

4.3.7.1 Local Voltage Stability Criteria

Local Criteria – For all anticipated operating states, voltage stability shall be demonstrated in accordance with the voltage stability policy.

4.3.7.2 Widespread Voltage Stability Criteria

Demonstrably Contained – Successive loss of equipment that experience voltage collapse and trip due to low voltage, distance relay or other protection activations, shall be demonstrably contained, i.e., bounded, such that a new steady state is reached, and the remaining portion of the *IESO-controlled grid* demonstrates performance that meets applicable *security* criteria. Particularly, the magnitude of any net loss of load or supply shall not result in a redistribution of flow that results in an adverse impact to *interties*. Analysis shall be demonstrated in accordance with the voltage stability policy.

4.3.7.3 Voltage Stability Policy

Power-voltage analysis – Voltage stability for power transfers for all anticipated operating states shall be demonstrated using power-voltage (PV) analysis accordingly:

- 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 PV 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 PV curve.

Power-voltage curves – When producing a pre-contingency PV curve, manual actions such as reactive shunt switching together with transformer tap-changer action, are permitted. When producing a post-contingency PV curve, only automatic control actions (e.g. generation *automatic voltage regulation (AVR)*, *RASs*, and automatic under-load tap-changes) shall be modelled.

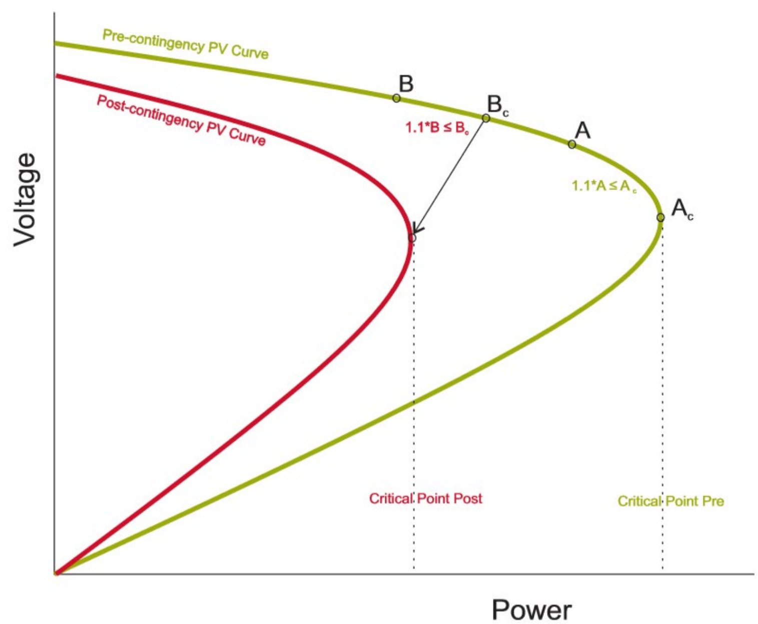

Figure 4-1: Typical Power-Voltage Curves

4.3.8 Transient Stability

(MR Ch.5 ss.5.2.1, 5.2.2, 5.2.4, and 5.2.6)

Overview – For acceptable transient angle stability, the *IESO* shall apply the following *security* criteria and policy.

4.3.8.1 Local Transient Stability Criteria

All supply resources remain synchronized – No *generation unit* or *electricity storage unit* shall pull out of synchronism for any Group 3 contingencies in Appendix A with due regard to reclosure.

4.3.8.2 Widespread Transient Stability Criteria

Demonstrably contained – For all applicable contingencies in Appendix A, any *generation units* or *electricity storage units* that pull out of synchronism (and trip due to protection activation) shall not result in unbounded successive loss of equipment. Any loss of equipment shall be demonstrably contained such that a new steady state is reached, and the remaining portion of the *IESO-controlled grid* demonstrates performance that meets applicable *security* criteria. Particularly, the magnitude of any net loss of load or supply shall not result in a redistribution of flow that results in an adverse impact to *interties*.

4.3.8.3 Transient Stability Policy

Disconnection vs. loss of synchronism – A *generation unit* or *electricity storage unit* that is disconnected from the *IESO-controlled grid* as a result of fault clearing action or by rejection from a *RAS* is not considered pulling out of synchronism.

Required margin – Transient angle stability shall be maintained if the critical parameter is increased by 10% to allow margin.

Simulation – The 10% increase in the critical parameter can be simulated by generation or load changes beyond the forecast load or generation capabilities even after eliminating *station service* load. Conditions at margin shall be as realistic as reasonably achievable. The use of negative values of local load is preferable to increasing local generation beyond its maximum capability. Negative load used for margin must have a constant MVA characteristic.

Simulating operating times – Design operating times of fault detectors, auxiliary relays, trip modules, communication media, breakers, etc., may be used for calculating switching times when reliable field-measured data are not available.

4.3.9 Small Signal Stability

(MR Ch.5 ss.5.2.1, 5.2.2, 5.2.4, and 5.2.6)

Overview – For acceptable small signal stability, the *IESO* shall apply the following *security* criteria and policy.

4.3.9.1 Local Small Signal Stability Criteria

Damped behaviour intra-area – For all anticipated operating states, *generation units* or *electricity storage units* shall demonstrate sufficiently damped behaviour, in accordance with the small signal stability policy.

4.3.9.2 Widespread Small Signal Stability Criteria

Damped behaviour inter-area – For all anticipated operating states, inter-area oscillations shall demonstrate sufficiently damped behaviour. That is, a coherent group of *generation units* or *electricity storage units* shall not oscillate against any other group(s) of *generation units* or *electricity storage units* in external *control area(s)* in a manner that does not meet the damping requirements governed by each reliability coordinator of the respective *control area(s)*. Damping requirements for the *IESO-controlled grid* are per the small signal stability policy, below.

4.3.9.3 Small Signal Stability Policy

Damping factors – The required damping factors at various conditions on the *IESO-controlled grid* are tabulated in Table 4-3.

Table 4-3: Acceptable Damping Factors

System Condition	Damping Factor
Pre-contingency	> 0.03
Post-contingency: Before any automatic *response*	> 0.00
Post-contingency: After automatic *responses*, before manual system adjustments	> 0.01
Following re-preparation of the system: After system adjustments	> 0.03

Calculating damping factors – For swings characterized by a single dominant mode of oscillation, the damping may be calculated directly from the oscillation envelope. For a damping factor of 0.03, the magnitude of oscillations must be reduced to 39% of initial values within five periods. For a damping factor of 0.01, the magnitude of oscillations must be reduced to 39% of initial values within 15 periods. For swings not characterized by a single dominant mode, then the damping factors should be derived via a more detailed modal analysis.

4.3.10 Transient Voltage Response

(MR Ch.5 ss.5.2.1, 5.2.2, 5.2.4, and 5.2.6)

Overview – Following fault clearing, or the loss of an element without a fault, the transient voltage response shall not result in the protective relays activating with due regard for the margins specified below.

4.3.10.1 Local Relay Margin Criteria

Local element relay margins – For any Group 3 contingencies in Appendix A with due regard to reclosure, the margin on all relays, generator loss of excitation and out-of-step protections on *generating units*, or those associated with transformer backup protections, must be at least 15% on all instantaneous relays, and 0% on all timed relays having a time delay setting less than or equal to 0.4 seconds. For all relays having a time delay setting greater than 0.4 seconds, the apparent impedance may enter the timed tripping characteristic, provided that there is a margin of 50% on time. That is, the apparent impedance does not remain within the tripping characteristic for a period of time greater than one-half of the relay time delay setting. The margin on all system relays, such as change of power relays, must be at least 10%.

4.3.10.2 Uncontrolled Separation Criteria

Demonstrably contained – For all applicable contingencies in Appendix A with due regard to reclosure, the consequence of protective relays activating shall not result in uncontrolled separation of a portion of the system. That is, any separation (including islanding) due to protective relays activating shall be demonstrably contained such that a new steady state is reached, that any electrical island is treated in accordance with section 2.6, and the remaining portion of the *IESO-controlled grid* demonstrates performance that meets applicable *security* criteria. The magnitude of any redistribution of flow due to the separation (including any net loss of load or supply from the collapse of an island) shall not result in an adverse impact to *interties*.

Uncontrolled separation relay margin – The margin on all instantaneous and timed distance relays at stations that, if activated risk uncontrolled separation, including generator loss of excitation and out-of-step relaying, must be at least 20% and 10% respectively.

4.3.11 Automatic Reclosure

(MR Ch.5 ss.5.1.2 and 5.2.1, 5.2.2, 5.2.4, and 5.2.6)

Application – The *IESO* will use automatic reclosure to more quickly restore the integrity of the *IESO-controlled grid* following contingencies that are not permanent. Experience has shown many faults on the overhead transmission circuits to be temporary. Automatic reclosure for transformer, bus, or cable protection should only be approved in exceptional circumstances, as these faults are more likely to be permanent.

Two stages of reclosure – Automatic reclosure is normally comprised of two stages; re-energization from a single preferred breaker with under-voltage supervision and time delay followed by reclosing of the remaining breakers with synchrocheck supervision.

Settings and selection requirements – Circuits are normally automatically re-energized following a fault clearing by protection systems. Upon successful re-energization, the remaining breakers shall be automatically reclosed. Failure to automatically re-energize from the single preferred breaker is deemed to be unsuccessful reclosure. The following sub-sections outline settings and selection requirements for automatic reclosure:

4.3.11.1 Re-energization

- A faulted circuit should be automatically re-energized from a single preferred breaker with under-voltage supervision and a minimum time delay of five seconds. Automatic re-energization shall be initiated following damping of system oscillations. Stability-sensitive areas should have a nominal time delay of 10 seconds or longer to initiate automatic re-energization. Areas where studies indicate that higher speed reclosure has no material adverse effects on the system *security* of the *IESO-controlled grid*, re-energizing with a time delay of less than five seconds is permitted.
- The breaker chosen for the re-energization of the circuit shall be the one that would result in the least disruption in the event of a breaker failure upon an unsuccessful re-energization. Experience has shown there is a higher-than-average risk of breaker failure in an open-close-open sequence.
- The re-energizing breaker shall be at a terminal remote from steam turbine units. If possible, re-energizing should be initiated at a breaker at a terminal remote from *generation units*.
- Automatic re-energization time delay settings for adjacent transmission circuits on common towers are selected to mitigate the risk of re-energizing onto two faulted circuits at the same time.

4.3.11.2 Reclosing of the Remaining Breakers

- The remaining breakers shall automatically reclose with synchrocheck supervision. Where there is no electrically close generating station, voltage presence supervision with a nominal time delay of 0.5 seconds may be used.
- Automatic reclosing must not result in a sudden power change exceeding 0.5 per unit of its MVA rating on steam turbine *generation units* rated greater than 10 MVA. *Market participant* agreement shall be obtained prior to allowing a higher value of sudden power change.
- Automatic reclosure shall not be used to re-synchronize a *generation unit* that has separated from the transmission system.
- On those circuits where only high speed (i.e. less than one second) unsupervised automatic reclosure is available, it should normally be blocked.

Withstanding unsuccessful automatic re-energization – System operating limits shall be derived such that the system must successfully withstand an unsuccessful automatic re-energization (i.e., an open-close-open sequence) operation.

4.3.12 Manual Reclosure

(MR Ch.5 ss.5.1.2, 5.2.1, 5.2.2, 5.2.4, and 5.2.6)

Application – Following an unsuccessful automatic reclosure, or an *outage*, a circuit will normally be manually re-energized from the preferred breaker used for automatic reclosure.

Withstanding manual energization – The *IESO-controlled grid* must be able to withstand manual energization of a faulted element without prior readjustment of generation levels, unless specific operating instructions to the contrary are provided. Manual reclosure of the remaining breakers after energization must not result in a sudden power change exceeding 0.5 per unit of its MVA rating on steam turbine *generation units* rated greater than 10 MVA. *Market participant* agreement shall be obtained prior to allowing a higher value of sudden power change.

4.4 Frequency Regulation

(MR Ch.5 App.4.2)

Requirements – *Generation facilities* and *electricity storage facilities* are required to be able to operate within the range of frequencies specified in **MR Ch. 4 App. 4.2**: Requirements for Generation and Electricity Storage Facilities Connected to the IESO-controlled Grid. This appendix also specifies the required settings for speed/frequency regulation.

Additional provisions – **MM 7.1** explains how *generators* and *electricity storage participants* are required to operate during abnormal system frequencies.

4.4.1 Automatic Under Frequency Load Shedding

(MR Ch.5 s.10.4.1)

IESO administration – The *IESO* shall administer an automatic under-frequency load shedding (UFLS) program to stabilize frequency. This program shall take into consideration the manner in which the *IESO-controlled grid* is likely to separate in the event of a system disturbance, compensation for early generation tripping, and *planned outages* with Planned, Opportunity, or Information Priority Code to UFLS equipment.

Additional provisions and priority customers – *IESO* requirements for the UFLS program are contained in **MM 7.1**. Priority customer loads (refer to **MM 7.10**) such as hospitals and water treatment plants without backup generators, and electrically driven gas compressors should be considered by *distributors* and *connected wholesale customers* when satisfying UFLS program requirements.

4.5 Restoration of System Security

4.5.1 Principles

(MR Ch.5 s.5.10.2)

Re-prepare as soon as possible – The *IESO* shall use all appropriate means to re-prepare the system to satisfy SOLs corresponding to *emergency* condition operating limits as soon as possible. The *IESO* will endeavour to shorten the duration of an *emergency operating state*.

Control actions have foreseen and acceptable consequences – The consequences of control actions to return to a studied operating state must be both foreseen and acceptable. The intentional loss of a major portion of the system, or the intentional separation of a major portion of the system, are unacceptable consequences.

4.5.2 Policies

(MR Ch.5 s.5.10.2)

Minimum acceptable level of security– The minimum acceptable level of *IESO-controlled grid* system *security* is the level afforded by observance of *emergency* condition operating limits. All necessary steps are to be taken, including the interruption of *non-dispatchable load* and *price responsive load*, in accordance with section 2.7.8 of this *market manual* to observe *emergency* condition operating limits.

Time to re-prepare IROLs – The *IESO* shall use all available means to re-prepare IROLs to *emergency* condition operating limits within the IROL Tv[4] following any respected contingency. In the case of IROLs that secure the system for thermal cascading, the IROL Tv is the time associated with the limited time rating of the overloaded equipment. In the case of all other IROLs, the IROL Tv is 30 minutes. The re-preparation time period starts following the occurrence of the contingency.

Re-preparation plans for IROLs – The *IESO* must have plans to re-prepare IROLs to *emergency* condition operating limits within the IROL Tv following the occurrence of respected contingencies. Re-preparation plans shall not utilize control actions that increase *non-dispatchable load* and *price responsive load* shedding until *resources* have been committed in accordance with the Area Reserve criteria in section 3.4 of this *market manual*.

Power system restoration plan – The *IESO publishes* and maintains a power system restoration plan for Ontario in the event of a complete or partial blackout of the *IESO-controlled grid* (refer to MM 7.8).

[4] Refer to *NERC* Glossary of Terms

– End of Section –

Appendix A: Recognized Contingencies

Recognized contingencies applicable to elements[5] that form the BPS and BES are, at a minimum, specified by *NPCC* and *NERC*, respectively. Additional recognized contingencies applicable to the *IESO-controlled grid* are specified by the *IESO*. The consequences of Group 1, Group 2, and Group 3 contingencies shall be applied in accordance with s.4.2 with due regard for how auxiliaries at generation, electricity storage and transmission stations are supplied by the *IESO-controlled grid*. If the recognized contingencies within this document are inconsistent with other *reliability standards*, such as due to any updates by *NERC* or *NPCC*, the most stringent of the subject recognized contingencies is adopted.

Single-element contingencies result in the clearing of a single protection zone, with the exception of inadvertent breaker opening contingencies. A single protection zone may comprise more than one element. To restore system *security*, it can be assumed that only one element was faulted, and the other elements comprised within a single protection zone can return to service. The timing of the return to service depends upon the particulars associated with the fault location. System *security* must be restored considering all elements that cannot be returned to service within 30 minutes.

When the *IESO-controlled grid* is in a *high-risk operating state*, the *IESO* may operate the system to withstand contingencies more severe than those specified below for a *normal operating state*.

A.1 Group 1 – Contingencies

A.1.1 Normal Operating State

When the *IESO-controlled grid* is in a *normal operating state*, the Group 1 contingencies are:

(i) A permanent three-phase fault on any element with normal fault clearing.

(ii) Simultaneous permanent single-phase-to-ground faults on the same or different phases of each of two adjacent transmission circuits on a multiple transmission 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 is excluded.

[5] An element is defined as *generation unit*, transmission circuit, transformer, shunt device, or bus section.

(iii) A permanent single-phase-to-ground fault on any element with delayed fault clearing.

(iv) Loss of any element or circuit breaker without a fault.

(v) A permanent single-phase-to-ground fault on a circuit breaker, with normal fault clearing.

(vi) Simultaneous permanent loss of both poles of a direct current bipolar *facility*.

(vii) The failure of a circuit breaker associated with a RAS to operate when required following the loss of any element or circuit breaker without a fault, or a permanent single-phase-to-ground fault (with normal fault clearing) on any element.

A.1.2 Emergency Operating State

When the *IESO-controlled grid* is in an *emergency operating state*, the Group 1 contingencies are:

(i) A permanent three-phase fault on any element with normal fault clearing.

(ii) A permanent single-phase-to-ground fault on any element with normal fault clearing.

(iii) Single pole block with normal clearing in a monopolar or bipolar high voltage direct current (HVDC) system.

(iv) Loss of any element or circuit breaker without a fault.

A.2 Group 2 – Contingencies

When the *IESO-controlled grid* is in a *normal operating state* or *emergency operating state* the Group 2 contingencies are:

(i) A permanent three-phase fault on any element with normal fault clearing.

(ii) A permanent single-phase-to-ground fault on any element with normal fault clearing

(iii) Loss of any element or circuit breaker without a fault.

(iv) Single pole block with normal clearing in a monopolar or bipolar HVDC system.

A.3 Group 3 – Contingencies

When the *IESO-controlled grid* is in a *normal* or *emergency operating state*, the Group 3 contingencies are:

(i) A permanent phase-to-phase-to-ground fault on any element with normal fault clearing.

(ii) A permanent single-phase-to-ground fault on any element with normal fault clearing

(iii) Loss of any element or circuit breaker without a fault.

– End of Appendix –

Appendix B: Load and Generation Rejection and Generation Runback Selection Criteria

B.1 Load Rejection (L/R) Selections

a. L/R should be selected to satisfy the following in order of priority:

(i) **System security:** L/R selections must satisfy system security requirements for specific station and/or a specific megawatt requirement (to within an acceptable deadband). L/R must be selected such that the resulting transmission conditions do not prevent L/R actions to alleviate the system *security* concerns. L/R selections in the vicinity of a natural or man-made disaster must not hamper *emergency* measures.

(ii) **Sensitivity:** Priority customer loads (refer to Market Manual 7.10: Ontario Electricity Emergency Plan) such as hospitals and water treatment plants without backup generators, and electrically driven gas compressors should be avoided when determining what load to shed.

(iii) **Minimize Number of Stations:** The number of stations selected for rejection should be minimized.

(iv) **Trip History:** L/R selections should attempt to equalize the number of L/R operations for each station over the long term and minimize the exposure of any station to two successive L/R operations.

(v) **Area Fairness:** Where L/R may be available for selection in more than one area, the stations selected for L/R should be distributed among each participating area. This *distribution* should be in approximate proportion to the percentage of the total load supplied by all areas involved in the scheme.

b. Opening bus tie breakers to increase *non-dispatchable load* or *price responsive load* lost by configuration shall be considered as L/R.

c. L/R selections will be minimized where affected *IESO-controlled grid delivery points* are not within *reliability* performance standards.

d. L/R selected to relieve post-contingency thermal overloading shall be:

(i) Sufficient to comply with the thermal rating policy.

(ii) Sufficient to prevent loading beyond the long-time ratings if the lack of fast-acting control actions combined with the complexities of post-rejection operation will jeopardize respecting long-time ratings within the appropriate "limited" time.

B.2 Generation Rejection Selections

a. Generation Rejection (G/R) should be selected to satisfy the following in order of priority:

 (i) **System Security:** G/R requirements must satisfy system *security* requirements for specific unit selections and/or specific megawatt requirement (to within an acceptable deadband).

 (ii) **Minimize Number of Units:** The number of units selected and total amount selected for G/R should be minimized within the constraints imposed by plant and system operating conditions.

 (iii) **Trip History:** Selections should attempt to equalize the number of unit trips based on history.

b. G/R selections for single element contingency events shall be minimized.

c. G/R selected to relieve post-contingency thermal overloading shall be:

 (i) Sufficient to comply with the thermal rating policy.

 (ii) Sufficient to prevent loading beyond the long-time ratings if the lack of fast-acting control actions combined with the complexities of post-rejection operation will jeopardize respecting long-time ratings within the appropriate "limited" time.

d. G/R selections should avoid manual corrective measures following a G/R operation,

e. G/R selections should be made on a reasonable effort basis to address *market participant resource* concerns such as the:

 (i) Maximum number of units selected within a single control center,

 (ii) Minimum number of unselected *generation units*, and

 (iii) Unavailability or preferences of specific units for G/R selection.

B.3 Generation Runback Selections

All policies in place for G/R apply equally to Generation Runback.

– End of Appendix –

Appendix C: RAS Restrictions during High-Risk Operating State

During a *high-risk operating state*, there is a significantly higher than normal probability of one or more *contingency events* and associated consequences (**MR Ch.5 s.2.4.1**). Since *RAS* are complex systems that have unique risks, restrictions are placed on their use in a *high-risk operating state* to mitigate adverse impacts to the *IESO-controlled grid*.

The following contingency types apply to **115 kV**, **230 kV** and **500 kV** systems.

Table C-1: RAS Restrictions during High-Risk Operating State

<table>
<tr><th>Contingency Type</th><th>High-Risk Operating State Due to Adverse Weather within the Weather Advisory Area
(refer to notes A, B, C and D)</th><th>High-Risk Operating State Due to Conditions not within the Weather Advisory Area
(refer to notes A, B and C)</th></tr>
<tr><td>Recognized Double Element</td><td>No restrictions to G/R or L/R</td><td rowspan="2">The primary concern is adverse effects of a false RAS operation. The following restrictions therefore apply:
G/R or runback is permissible provided its use is minimized.
L/R is permissible, provided IESO-controlled grid system security criteria could not otherwise be satisfied.</td></tr>
<tr><td>Recognized Single Element</td><td>G/R or runback is permissible, provided:
Arming is limited to outage periods or short-duration periods, or
Its magnitude is reduced during adverse weather periods
G/R is permissible, provided the only other alternative is to remove the unit from service, or the unit would be automatically removed from service as a result of the initiating contingency.

L/R is permissible provided IESO-controlled grid system security criteria could not otherwise be satisfied.</td></tr>
</table>

A. A RAS must NOT be utilized if a fail-to-trip condition is suspected.

B. A RAS may be selectively used to provide additional system *security* beyond normal criteria, provided the restrictions in Table C-1 are observed.

C. The restrictions in this table do not apply to RAS selections for extreme contingencies.

D. The Weather Advisory Area is within 50 km of the circuits for which the RAS is selected.

– End of Appendix –

Appendix D: Special Considerations for Inverter-Based Resources

To maintain system *security* for all foreseeable operating conditions, it is necessary to give special consideration for the electromagnetic transient (EMT) 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 units pulling out of synchronism unexpectedly or underdamped oscillatory response, among other things, which can result in *security* criteria to not be met or equipment damage.

Assessing phenomena such as SSR and SSCI requires the application of 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, bright-line criteria are used to restrict operating configurations that have an unacceptable risk of SSR and SSCI, or to trigger EMT assessment on an as-needed basis.

These criteria do not guarantee *security* against SSR or SSCI, and so, the *IESO* has discretion to take any control action to prevent or correct SSR or SSCI during real-time operation of the *IESO-controlled grid*.

D.1 Minimum Short Circuit Ratio

The *IESO* shall use short-circuit ratio (SCR) to assess if there is an unacceptable risk of SSR, SSCI or other EMT phenomena. The *IESO* shall consider the effects of all recognized contingencies included in Appendix A: Recognized Contingencies in determining SCR. The following criteria apply:

- The SCR of IBRs shall not be allowed to fall below 5.
- For SCR of IBRs below 7, a facility-based assessment shall be done. If time permits, the *IESO* may perform a detailed EMT study to confirm whether there is an unacceptable risk of SSR or SSCI. If time does not permit, *IESO* will take necessary actions to prevent the SCR of the IBR from falling below 7. For example, during the outage management process, this may correspond to rejection of an outage.

SCR is calculated as the following:

$$SCR_k = \frac{AFL_k}{P_{max,k}}$$

Where,

- SCR_k is the short-circuit ratio of IBR facility "k";
- AFL_k is the available fault level at the point of interconnection of IBR facility "k"; and
- $P_{max,k}$ is the registered maximum rated active power[6] of IBR facility "k".

D.2 Resonant Circuit Configurations

Configurations that result in IBR to be connected radially with series compensation shall be avoided. Due regard shall be given to post-contingency configurations.

– End of Appendix –

[6] See Appendix 4.2 of MR Ch.4.

List of Acronyms

Acronym	Term
ABNO	available but not operating
AVR	*automatic voltage regulation*
BES	bulk electric system
BPS	bulk power system
DESN	dual element spot network
EOSCA	*emergency operating state* control actions
G/R	*generation* rejection
HVDC	high voltage direct current
IROL	interconnection reliability operating limit
kV	kilovolt
L/R	load rejection
MM	*market manual*
MR	*market rules*
MVA	megavolt-amp
NERC	*North American Electric Reliability Corporation*
NPCC	*Northeast Power Coordinating Council, Inc.*
ORTAC	Ontario Resource and Transmission Assessment Criteria
PV	power-voltage
RAS	remedial action scheme
SOL	system operating limit
UFLS	under-frequency load shedding

– End of Section –

References

Document ID & Link	Document Title
RUL-6 to RUL-24	Market Rules for the Ontario Electricity Market
MAN-108	Market Manual 1.5: Market Registration Procedures
MAN-138	Market Manual 2.8: Reliability Assessments Information Requirements
MAN-111	Market Manual 4.3: Operation of the Real-Time Markets
MAN-122	Market Manual 7.2: Near-Term Assessments and Reports
MAN-123	Market Manual 7.3: Outage Management
MAN-157	Market Manual 7.8: *Ontario Power System Restoration Plan*
MAN-158	Market Manual 7.10: Ontario Electricity Emergency Plan
MAN-161	Market Manual 11.2: Ontario Reliability Compliance Program
IMO_REQ_0041	Ontario Resource and Transmission Assessment Criteria (ORTAC).

– End of Document –