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MDP_PRO_0040

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Market Manual 7: System Operations

# Part 7.1: IESO-Controlled Grid Operating Procedures

Issue 47.0

This document provides procedures and guidelines for market participants and IESO that are required to ensure the security and reliability of the interconnected power system. It covers the span from normal conditions to emergency conditions that are just less than a system-wide shutdown.

## Disclaimer

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This *market manual* may contain a summary of a particular *market rule*. Where provided, the summary has been used because of the length of the *market rule* itself. The reader should be aware, however, that where a *market rule* is applicable, the obligation that needs to be met is as stated in the *market rules*. To the extent of any discrepancy or inconsistency between the provisions of a particular *market rule* and the summary, the provision of the *market rule* shall govern.

## Document Change History

| Issue | Reason for Issue | Date |
|---|---|---|
| For document change history prior to 2011, refer to versions 18.0 and prior.<br>For document change history prior to 2015, refer to versions 31.0 and prior.<br>For document change history prior to 2018, refer to versions 45.0 and prior. | | |
| 34.0 | Issue released for Baseline 39.0 | March 7, 2018 |
| 35.0 | Issue released in advance of Baseline 39.1 | May 1, 2018 |
| 36.0 | Issue released in advance of Baseline 40.1 | November 14, 2018 |
| 37.0 | Updated to meet accessibility requirements pursuant to the *Accessibility for Ontarians with Disabilities Act.* | December 2, 2020 |
| 38.0 | Issue released in advance of Baseline 45.0 | December 18, 2020 |
| 39.0 | Issue released in advance of Baseline 45.0. Updated to include electricity storage participation. | February 26, 2021 |
| 40.0 | Issue released for Baseline 45.1 | June 2, 2021 |
| 41.0 | Issue released for Baseline 46.0 | September 15, 2021 |
| 42.0 | Issue released for Baseline 47.0 | March 2, 2022 |
| 43.0 | Issue released for Baseline 48.0 | September 14, 2022 |
| 44.0 | Issue released in advance of Baseline 48.1 | November 21, 2022 |
| 45.0 | Issue released for Baseline 49.1 | June 7, 2023 |
| 46.0 | Issue released for Baseline 52.1 | December 4, 2024 |
| 47.0 | Issue released for Baseline 53.0 | March 5, 2025 |

## Related Documents

| Document ID | Document Title |
|---|---|
| IMP_POL_0002 | Market Manual 7.4: IESO-Controlled Grid Operating Policies |

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| Reference (Section and Paragraph) | Description of Change |
|---|---|
| Appendix B.1 | • Reworded steps 21 and 33 of the EOSCA list to account for the 2024 capacity sharing agreement between the IESO and Hydro-Quebec.<br>• To account for Voluntary Demand Management (VDM):<br>  o Moved step 39: “Curtail withdrawals from self-scheduling electricity storage facilities.” to step 30; and<br>  o Added step 31: “Implement appropriate load curtailment according to Voluntary Demand Management (VDM) agreements.” |
| Appendix B.2 | Reworded step 10 of the EOSCA (Area Deficiency) list to account for the 2024 capacity sharing agreement between the IESO and Hydro-Quebec. |

# Market Manuals

The *market manuals* consolidate the market procedures and associated forms, standards, and policies that define certain elements relating to the operation of the *IESO-administered markets*. Market procedures provide more detailed descriptions of the requirements for various activities than is specified in the *market rules*. Where there is a discrepancy between the requirements in a document within a *market manual* and the "Market Rules", the "Market Rules" shall prevail. Standards and policies appended to, or referenced in, these procedures provide a supporting framework.

# Market Procedures

The "System Operations Manual" is Series 7 of the *market manuals*, where this document forms "Part 7.1: IESO-Controlled Grid Operating Procedures".

**– End of Section –**

# 1 Introduction

## 1.1 Purpose

This manual describes the key procedures used by the *IESO* and *market participants* to ensure the *reliability* of the *IESO-controlled grid (ICG)*. It should be read in conjunction with Market Manual 7.4: IESO-Controlled Grid Operating Policies (MM7.4), which defines the *IESO* policies for reliable operation of the *ICG*.

The procedures in this manual should be read in conjunction with their referenced *market rules*. The procedures describe how the *market rules* will be implemented when the method is not described in the rule itself. *Market participants* are expected to have local procedures in place to handle details not covered in this manual.

With regard to all parts of this manual, it is recognized that there may be situations in which an alternative procedure may be mutually agreeable to a *market participant* and the *IESO*. This is acceptable provided that the alternative is documented in an *operating agreement* in place between the *IESO* and the specific *market participant* and meets the intent of the *market rules*.

Terminology is intended to be consistent with the *market rules*.

## 1.2 Scope

These procedures apply to the *IESO* in its role to fulfill its legislated objects to direct the operation of the *ICG* and maintain its *reliability*, as well as establish and enforce criteria and standards related to the *reliability* of the *integrated power system*.

Operating procedures are applied to facilities connected to the *ICG*.

The procedures described in this manual are as per the operating policies outlined in MM 7.4. For any found discrepancy between the procedures in this manual and policies in MM 7.4, MM 7.4 shall take precedence and this manual shall be revised accordingly.

## 1.3 Overview

This manual sets out the activities that are undertaken by the *IESO* and other parties to ensure the *reliability* of the *ICG* and addresses the following areas:

- The responsibilities of the *IESO* and *market participants*,
- Operating states of the *ICG*,
- The communication requirements to be followed by the *IESO* and *market participants*,
- Grid control actions in relation to readiness programs, voltage control and reduction, and *non-dispatchable load* shedding,
- System *security* in relation to automatic reclosure and frequency *regulation*

## 1.4 Roles and Responsibilities

Responsibility for system operations is shared among the *IESO* and *market participants* as set out in the following sections of this procedure.

## 1.5 Contact Information

As part of the participant authorization process, *applicants* are able to identify a range of contacts within their organization that address specific areas of market operations. For system operations, these contacts will most likely be the *authority centre*, *dispatch* or *control centre*, *facility* location operator or the restoration plan coordinator as indicated in the participant registration data. If the *market participant* has not identified a specific contact, the *IESO* will seek to contact the Main Contact established during the participant authorization process. The *IESO* will seek to contact these individuals for activities within this procedure, unless alternative arrangements have been established between the *IESO* and the *market participant.*

If you wish to contact us, you can email *IESO* Customer Relations at customer.relations@ieso.ca or contact us by telephone or mail. Customer Relations staff will respond as soon as possible.

**– End of Section –**

# 2 Maintaining ICG Reliability

## 2.1 IESO Responsibilities

Reference: *Market Rules*, Chapter 5, Section 3 (*MR* Ch. 5, Sec. 3)

The *IESO* is responsible for directing operation and maintaining *reliability* of the *ICG*[1], pursuant to *applicable law* in accordance with section 1 of [Market Manual 7.4: IESO-Controlled Grid Operating Policies (MM7.4)](). The *market rules* grant the IESO authority to direct operation of *market participant* equipment connected to the ICG and meet the reliability objectives outlined in MM 7.4, Section 2. The *IESO* may delegate portions of this responsibility to *transmitters* in accordance with the terms and conditions of the applicable *operating agreements*.

### 2.1.1 Interconnected Systems

Reference: *MR* Ch. 5, Sec. 5.1.2.7

The *IESO* must use and support *interconnected systems* as necessary to maintain *reliability* of the *IESO-controlled grid* in accordance with agreements with other *security coordinators*, *balancing authorities* and *interconnected transmitters* operators.

### 2.1.2 System Re-preparation

The *IESO* control room operators, assisted by the Energy Management System (EMS), continuously monitor important power system variables such as power flows and voltages at different locations on the *ICG*, and continually update operating plans to deal with contingencies. These plans typically involve such actions as: generation *dispatch*, load transfers, under load tap changer movement, arming *remedial action schemes (RASs)*, recalling *outages*, curtailing *dispatchable loads*, etc. In *emergency* situations, *non-dispatchable load* shedding may be ordered.

The *IESO* will use market mechanisms to the extent feasible to solve system operating limit (SOL) exceedances. However, because of the short times permitted to return the *ICG* to a secure state, actions such as generation *dispatch* may be ordered with regard only to their effectiveness in solving the limit exceedance. Following a respected contingency[2] or exceedance, the IESO must re-prepare Bulk Power System (BPS) parts of the system and Interconnection Reliability Operating Limit (IROL)[3] interfaces to emergency condition operating limits within 30 minutes.

The following general activities are completed in order to restore power system *security* following a contingency:

1. Relevant *facility* operators report the event to the *IESO*.

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[1] This includes directing embedded *facilities* within the *IESO control area* that may affect the *reliability* of the *ICG*.

[2] Respected contingencies are outlined in MM 7.4, Appendix A: Recognized Contingencies.

[3] IROL is a subset of SOL, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.

2. *IESO* reviews and, if necessary, revises its operating plan.
3. *IESO* issues operating instructions to relevant *facility* operators.
4. Relevant *facility* operators execute operating instructions.

All reporting and execution of operating instructions are to be completed promptly[4]. The 30 minute system re-preparation timeframe includes reporting and operating plan preparation and execution. Relevant *facility* location operators shall execute directions from the *IESO*, as specified, and as soon as practical, with due regard to equipment, human and environmental safety (*MR* Ch. 5, Sec. 5.10.1). Any discussion between a *market participant* and the *IESO* about the relative merits of an alternative set of control actions shall take place after the *ICG* has been restored to a *normal operating state*.

## 2.2 Market Participant Responsibilities

References: *MR* Ch. 2 App 2.2, Sec. 1.5; *MR* Ch. 4, Sec. 7.3.1 and 7.3A1; *MR* Ch. 4, App 4.15 and 4.24

### 2.2.1 Independent Actions

The *IESO* recognizes a *market participant*'s authority to take independent actions to *disconnect* their equipment from the *ICG* if they reasonably believe there is an imminent risk to safety, environment or violation of *applicable law*.

The *market participant* must endeavor to provide as much advance notice as possible but shall, at a minimum, promptly inform the *IESO* thereafter. Also, if a *market participant* is unable to comply with a direction given by the *IESO* due to imminent risk to safety, environment or violation of *applicable law*, they must provide appropriate justification. The *market participant* is still required to comply with the direction to the fullest extent possible while avoiding these risks.

The *market participant* shall also provide the *IESO* with as much advance notice as possible of any situation that may prevent them from being able to comply with *IESO* directions. After taking independent actions to disconnect from the *ICG*, but prior to reconnecting to the *ICG* or continuing with participation in the *IESO-administered markets*, the *market participant* must provide the *IESO* with an explanation for their actions and any mitigating steps to prevent reoccurrence.

### 2.2.2 Non-ICG Facilities

Each *market participant* is authorized to direct the operation of any of its *facilities* that are not a part of the *ICG*. However, any *market participant* operating facilities not directly connected to the *ICG* but deemed impactive to the reliable operation of the *ICG* shall adhere to the same requirements, as applicable, as *market participants* operating equipment connected to the *ICG*. The impact assessment is determined during the market registration process. Any exceptions to requirements for operation of embedded facilities will be documented.

[4] 'Promptly' means *market participants* are expected to execute the operating instruction within five minutes unless told otherwise by the *IESO*.

## 2.3 Grid Operating States

The *IESO* operates under a set of grid operating states based on system conditions and the *IESO*'s ability to monitoring the *ICG*. The *IESO* will inform *market participants* of relevant operating states (other than a *normal operating state*) and possible actions to maintain the *reliability* of the *ICG*. The *IESO* will issue an advisory notice when transitioning from one operating state to another.

Policy information for grid operating states can be found in MM 7.4, Section 2.4.

The *ICG* can be in more than one operating state. Examples include:

- *High-risk operating state* for a certain area of the *ICG* while a *normal operating state* remains for rest of the *ICG*; and
- *Conservative operating state* for a certain area of the *ICG* while a *normal operating state* remains for rest of the *ICG*.

Certain actions are more likely to be taken during a *high-risk operating state, conservative operating state,* or *emergency operating state* than during a *normal operating state.*

### 2.3.1 High-Risk Operating State

Reference: *MR* Ch. 5, Sec. 2.4

Conditions may increase the risk of a contingency occurring on the ICG. A *high-risk operating state* may be declared by the *IESO* in the presence of any of the following conditions:

- Adverse weather such as lightning, freezing precipitation, or widespread or heavy fog within 50 km of a *facility* forming part of the *ICG*,
- Extreme weather such as tornadoes or wind gusts equal to or exceeding 80km/h within 50 km of a *facility* forming part of the *ICG*,
- Natural phenomena such as earthquakes, geomagnetic storms, floods, etc. that are either present or imminent,
- Confirmed or suspected degradation of protective relaying, including any associated communications media,
- *Outages*, deratings, or erratic behaviour of equipment such as *regulation* that affect the *security* of the *IESO-controlled grid*,
- Unusual hazards such as forest fires, bomb threats, etc., or
- Any other condition that the *IESO* believes will significantly increase the exposure of the *IESO-controlled grid* to contingencies beyond normal *reliability* criteria. In such cases, the *IESO*, if requested, will explain the reason after the incident has passed.

*High-risk operating states* frequently involve a reasonable probability that additional contingencies may occur before there has been time to re-prepare after the first one. During a high-risk operating state, the *IESO* may temporarily and selectively increase the level of system *security*. The IESO may take actions such as implementing high-risk system operating limits, re-dispatching generation or electricity storage, and recalling or cancelling relevant *outages*, in accordance with MM 7.4.

### 2.3.2 Conservative Operating State

Reference: *MR* Ch. 5, Sec. 2.5

Conditions may require the *ICG* to be operated in a *conservative operating state* in response to a *reliability* concern to help prevent an *emergency operating state*. In this state, operations of the *ICG* are expected to be stressed. However, there is no increased risk of a contingency occurring on the *ICG* so normal equipment and system *security* limits will be utilized. The impact of a *contingency event* on the *IESO-controlled grid* could be more severe than under a *normal operating state*. The *IESO* may reduce transfers on key interfaces to increase resiliency. A *conservative operating state* may be declared by the *IESO* in the presence of any of the following conditions:

- Forecasted or present extreme hot or cold weather;[5]
- Tight supply conditions including when the *IESO* anticipates or has issued an Energy Emergency Alert 1 (EEA-1);
- Forecasted strong or severe geomagnetic disturbance;
- Situations requiring an unplanned evacuation of the *IESO* primary control centre; and
- IT-related unplanned *outages* that impair *IESO* market or system applications or tools (e.g., Energy Management System (EMS), or Market Interface System (MIS)), resulting in an adverse impact on system security. The aforementioned disruptions can be triggered either by the *IESO*, external entities/providers, or reasons beyond the control of the *IESO.*

At the discretion of the IESO, *market participants* may be required to suspend any non-urgent maintenance or switching activities to minimize any potential risks to the *ICG*. In addition, the *IESO* may reject or revoke advance approval of relevant *outages*; commit additional resources; or return equipment to service in accordance with MM 7.4.

### 2.3.3 Normal Operating State

Reference: *MR* Ch. 5, Sec. 2.2

It is expected that the *ICG* will be in a *normal operating state* most of the time. A *normal operating state* is characterized by the following:

- The *operating plan* is progressing as planned.
- There is no adverse weather threatening operation of the *ICG*.
- Equipment is operating within its normal ratings.
- Normal condition limits are being respected.
- The *IESO* has the ability to monitor and direct the operation of the *ICG,* and monitor the *IESO-administered markets.*

### 2.3.4 Emergency Operating State

Reference: *MR* Ch. 5, Sec. 2.3

[5] Extreme hot weather: Southern Ontario temperature forecast ≥35C or a humidex ≥40C.
Extreme cold weather: Southern Ontario temperature forecast ≤-20C or a wind chill ≤-30C ; Northern Ontario temperature forecast ≤-30C or a wind chill ≤-40C

There are primarily three types of *ICG emergencies* that may result in the IESO declaring an *emergency operating state*. These emergency types will typically apply to global issues but may also apply to local issues. The IESO will refrain from declaring an *emergency operating state* when there is no material benefit to doing so.

**Table 2-1: Types of Emergencies**

| Type | Description |
|---|---|
| *Energy* | When the *IESO* has exhausted all options and can no longer provide the expected *energy* requirements of the Ontario Balancing Authority area. |
| Capacity | When the operating capacity of the Ontario Balancing Authority area − plus purchases from other systems (to the extent available or limited by transfer capability) − is not adequate to meet Ontario *demand* plus regulating requirements. |
| *Security* | When the *ICG:*<br>• Is in an unstudied operating state, where for example there was an equipment failure that resulted in a system configuration for which limits were not derived (e.g., a stuck breaker), or<br>• Has a limit exceedance (e.g., voltage, circuit loading) that cannot be resolved through normal/routine control actions and requires shedding of non-dispatchable load. |

The *IESO* generally declares an *emergency operating state* when an *ICG emergency* requires the implementation of one or more of the following control actions (refer to Appendix B: Emergency Operating State Control Actions):

- Purchasing *emergency energy*
- Implementing 3% or 5% voltage reductions
- Operating to emergency condition limits[6]
- Shedding *non-dispatchable load*
- Disregarding normal regulatory or legal requirements

The *IESO* may also declare an *emergency operating state* when this state exists in a neighbouring *balancing authority area,* and respecting *normal operating state security limits* would restrict *IESO's* ability to assist that *balancing authority*.

When an *emergency operating state* has been declared:

- The *IESO* shall inform *market participants*, neighbouring *balancing authorities*, transmission operators and *reliability coordinators* as required. Notification will be through an advisory notice and other industry-related sites. The telephone or other available means may also be used.
- Emergency condition limits, representing the minimum acceptable level of *security*, will be respected.

[6] Described in MM 7.4 and referred to as "emergency condition operating limits".

- Through the use of operating instructions, the *IESO* shall direct relevant *facility* location operators to take actions and return the *ICG* to *normal operating state*.

The *IESO* shall also inform *market participants*, *balancing authorities*, and *reliability coordinators* for adjacent *balancing authority areas* when the *ICG* has returned to a *normal operating state* and the *emergency operating state* has concluded (*MR* Ch. 5, Sec. 2.3.3).

## 2.4 IESO Actions in Advance of Reliability Events

*NERC* Transmission Operations (TOP) and Emergency Preparedness and Operations (EOP) standards require the *IESO* to have a viable operating plan for reliable operations. This plan should be designed to evaluate options and set procedures for reliable operation through a reasonable future time period. Among other things, a viable operating plan must address expected generation resource commitment and dispatch, interchange scheduling, capacity and energy reserve requirements, and demand patterns.

To ensure the viability of the operating plan, there may be situations that require the *IESO* to take control actions outside of market timelines. These situations include:

- Extreme Conditions
- Variable Generation Events
- Degraded Transmission System Performance

In these situations, we will use normal market mechanisms to the extent feasible.

### 2.4.1 Extreme Conditions

The *IESO* may issue an extreme conditions advisory notice one day in advance of extreme conditions. The notice will notify the market of:

- The expected conditions in the forecast, and
- The action(s) the *IESO* is taking, or may take, should forecasted conditions materialize.

Forecasted extreme conditions may require action(s) in advance of a *high-risk operating state*, *conservative operating state*, or *emergency operating state*.

Table 2-2 provides examples of conditions that may require the *IESO* to take control actions, as well as examples of the potential actions, when the *IESO* anticipates or is experiencing extreme conditions.

**Table 2-2: IESO Actions to Manage Extreme Conditions**

| If … | Then… |
|---|---|
| The *IESO* experiences, or expects conditions such as:<br>• Extreme weather<br>• Forest Fires | The *IESO* may:<br>• Commit additional *generators* or *electricity storage units*,<br>• Reject or revoke *planned outages*, or<br>• Take other actions appropriate for the circumstances. |

### 2.4.2 System Flexibility Events

System flexibility is the ability of the system to respond to intra-hour differences between:

- Expected supply and actual production, and/or
- Expected demand levels and actual consumption.

System flexibility events occur when conditions are such that there is increased risk for material differences between supply and demand in future hours.

Table 2-3 provides examples of conditions that may require the *IESO* to take actions when we anticipate or are experiencing a system flexibility event.

The *IESO* may issue an advisory notice in advance of or during a system flexibility event as appropriate. The advisory notice will notify the market of:

- A system flexibility event is expected or in progress, and
- The action(s) the *IESO* is taking.

**Table 2-3: IESO Actions to Manage Variable Generation Events**

| If… | Then… |
|---|---|
| The *IESO* experiences or expects conditions that may require additional system flexibility to address, such as:<br>• Material differences between forecasted and actual *variable generation* output, or<br>• Significant *variable generation* ramp events, or<br>• Material differences between forecasted and actual Ontario demand[7] | The *IESO* may:<br>• Adjust the 30-minute *operating reserve* requirement to indicate the system flexibility need,<br>• Manually adjust the *variable generation* forecast to align it with expected *variable generation* output,<br>• Commit/constrain on/ constrain off *dispatchable* resources*,*<br>• Curtail export[8] transactions mid-hour, or<br>• Take other actions appropriate for the circumstances. |

### 2.4.3 Degraded Transmission System Performance

There may be times when some portion of the *transmission system* is showing a recent history of degraded performance. These situations are identified when there is:

- Higher than average *forced outage* rates, or,
- Unanticipated tripping, or
- Unanticipated failures to trip.

[7] Differences between forecasted and actual demand may be exacerbated by embedded generation output, which is reflected through Ontario demand.

[8] Except for capacity exports unless the backing generator resource that has committed its capacity has not been scheduled or is not generating to the full amount of the capacity export, at which point the capacity export may be curtailed to the lower of the resource's schedule or output.

The IESO will assess the risk level associated with degraded *transmission system* performance. These risk levels are as follows:

- **Elevated:** There have been a number of related issues with transmission equipment in the same transmission yard over the past few months.
- **Severe:** There have been a number of related issues with transmission equipment in the same yard over the past week, and the situation continues to deteriorate.

Table 2-4 provides examples of conditions that may require the *IESO* to take control actions associated with the risk level, as well as examples of the potential actions, when we anticipate or are experiencing a degraded *transmission system* performance event. Where time permits, the *IESO* will discuss control actions with the applicable transmitter before implementation.

The *IESO* may issue an advisory notice in advance of or during a degraded *transmission system* performance event as appropriate. The advisory notice will notify the market of:

- The type of degraded *transmission system* performance event expected or in progress, and
- The action(s) the *IESO* is taking.

**Table 2-4: IESO Actions to Manage Degraded Transmission System Performance**

| If the IESO… | The IESO may… |
|---|---|
| Declares an **Elevated** risk | • Limit the number of critical elements that are out-of-service,<br>• Revoke or reject *planned outages*,<br>• Prepare limits that are reflective of more severe contingencies,<br>• Adjust use of Remedial Action Schemes to reduce operation of affected *transmission system* elements, or<br>• Instruct *market participants* to staff switch yard for planned switching. |
| Declares a **Severe** risk (or increases an Elevated risk to Severe) | • Further restrict the number of critical elements that are out-of-service,<br>• Recall other critical elements that are out-of-service in the area,<br>• Respect limits that are reflective of more severe contingencies, or<br>• Instruct *market participants* to staff switch yard around the clock. |
| Decreases the risk level, or declares that there is no longer a risk | • Instruct *market participants* to return to normal staffing of switch yards. |

**– End of Section –**

# 3 Communication: General Requirements

References: *MR* Ch. 5, Sec. 3.5.1.2, 3.6.1.3, 3.8.1.3, 6.3.5, and 12;

Timely communication between *market participants* and *IESO* operating personnel is vital for reliable operation of the *ICG*. Comprehensive oral reports of relevant facts are necessary for reliable system operation. Prior communication is required whenever one party's planned operations may adversely impact the reliable operation of *ICG*.

Knowledge of adverse operating conditions or unusual occurrences often suggests actions that might be taken ahead of disturbances and allows for the implementation of strategies to ensure the *reliability* of the *ICG* (refer to Section 2.4). Accordingly, the *IESO* and *market participant* operating personnel shall endeavour to maintain an ongoing exchange of information on significant operating events, including planned and *forced outages*, routine switching, system tests, etc.

Although this manual stipulates communication requirements for *ICG* operation, it is not intended that dialogue between any of the operating entities at any time be restricted. Rather, it is encouraged. *Market participants* should not hesitate to approach and discuss with the *IESO* any *reliability* aspect of operation. Similarly, *market participants* may be approached by the *IESO* to contribute information based on their knowledge of transmission, distribution, connected wholesale, electricity storage, or *generation facilities*.

Sections 3 through 6 of this manual outline the minimum conditions, developments and items that must be communicated to ensure reliable operation of the *ICG*, and by extension, support market operations. Appropriate performance standards for communications are included where practical. In the absence of explicit standards, *market participants* are to act in accordance with *good utility practice*.

## 3.1 IESO General Requirements

*IESO* communication procedures shall comply with *NERC reliability standards* and *NPCC* directories related to communications. They shall also be consistent with the applicable *operating agreements*, *interconnection agreements*, *market rules* and other applicable market documentation.

### 3.1.1 Voice Communication

Reference: *MR* Ch. 5, Sec. 12.4.2

All voice communications between the *IESO* control room operators and *market participants* are recorded by the *IESO* and retained for regulatory, *settlement*, dispute resolution, compliance monitoring and other audit purposes for a period of no less than seven years. The *IESO* maintains an electronic operating log, also retained for regulatory, *settlement*, dispute resolution, compliance monitoring and other audit purposes. The IESO also has procedures that enable reliable operation of the ICG to be maintained during the loss of IESO telecommunication facilities.

### 3.1.2 Communication with Neighbouring Entities

Reference: *MR* Ch. 5, Sec. 5.1.2.7

The *IESO* shall communicate directly with *reliability* coordinators, transmission owners, transmission operators, and balancing authority operators in neighbouring jurisdictions in accordance with *reliability standards*, and *interconnection agreements* and their associated joint operating instructions.

### 3.1.3 Internal Post-contingency Communication

The *IESO* will, following contingencies or system events, communicate directly with the staff who exercise direct physical control of the affected *facility* in accordance with applicable agreements or procedures. This direct communication is essential so that the appropriate corrective action can be formulated and initiated promptly, based on first-hand information provided to the *IESO*.

## 3.2 Market Participant General Requirements

Reference: *MR* Ch. 5, Sec. 12.4.1

Communications by *market participants* shall, whenever possible, use approved standard operating terms, approved abbreviations and definitions (refer to Market Manual 7.6, Glossary of Standard Operating Terms) in accordance with *good utility practice*.

### 3.2.1 Communication Facilities

Reference: *MR* Ch. 2, App 2.2

Each *market participant* must provide communications *facilities* in accordance with Appendix 2.2 of the *market rules*. These specifications balance the importance of the communication link between the *IESO* and different classes of *market participant* with the cost of the *facilities*. If these *facilities* fail, the *IESO* and the affected *market participant* shall expeditiously re-establish contact via any other feasible medium (cell phone, satellite phone, e-mail, etc.).

Each *market participant* shall identify their *dispatch* or *control centre*, *authority centre*, *facility* location operator and their controlled equipment to the *IESO*. In the *normal operating state*, communication between the *IESO* and a *market participant* will be through the *market participant's authority centre.* In abnormal conditions (refer to Section 5), including *emergency* situations, or during a failure of normal communication channels, the *IESO* will typically communicate directly with the relevant facility location operator. After the situation has stabilized, subsequent calls may be directed to, or include the *authority centre*. Unless stated otherwise, communication is assumed to be between *IESO* control room operating personnel and the control room operating personnel of the relevant *market participants*.

### 3.2.2 Registration Data Updates

Each *market participant* shall update their registration data with any changes to relevant contact information.

## 3.3 Operating Instructions

All operating instructions issued by, or received by, the *IESO* will be communicated and processed in accordance with the requirements of *NERC* standard [COM-002: Operating Personnel Communications Protocols](). Three-part communication shall be used for issuing and receiving operating instructions. Three-part communication consists of:

1. The issuer issues the operating instruction in a clear, concise, and definitive manner.
2. The recipient repeats the operating instruction (not necessarily verbatim).
3. The issuer confirms whether the *response* is correct. If the response was not correct, re-issue the operating instruction with additional clarity. If the response was not received or if the operating instruction was not understood by the receiver, then take an alternative action.

### 3.2.1 Operating Instructions to Generators

Reference: *MR* Ch. 5, Sec. 3.6.1.6

If a controlled change of generation output is required for *reliability* concerns, then the *generating unit's* output change must be completed promptly. The *generator* will implement the change of generation output in a manner that supports the safe and secure operation of the *generation facility*.

If an immediate reduction is required, or if a requested controlled reduction cannot be completed by the specified time, the *IESO* will direct the *generation units* to be immediately removed from service. The *facility* location operator will proceed to remove the specified *generation unit(s)* from service immediately in a safe and secure manner.

### 3.2.2 Operating Instructions to Electricity Storage Participants

Reference: *MR* Ch. 5, Sec. 3.8.1.6

If a controlled change of an *electricity storage unit's* output is required for *reliability* concerns, then the *electricity storage unit's* output change must be completed promptly. The *electricity storage participant* will implement the change of the *electricity storage unit's* output in a manner that supports the safe and secure operation of the *electricity storage facility*.

If an immediate reduction is required, or if a requested controlled reduction cannot be completed by the specified time, the *IESO* will direct the *electricity storage units* to be immediately removed from service. The *facility* location operator will proceed to remove the specified *electricity storage unit(s)* from service immediately in a safe and secure manner.

### 3.2.3 Operating Instructions to Transmitters and Distributors

Reference: *MR* Ch. 5

Load transfers, voltage reductions, load shedding, *RAS* arming and single element removal from service are expected to be done promptly when directed by the *IESO*.

*Transmitters* and *distributors* shall promptly inform the *IESO* if any control action cannot be completed promptly. In those instances, the *IESO* may direct that the control action be executed in advance of any contingency.

Switching procedures to remove or restore equipment in connection with *planned outages*, or following limited contingencies are specified in the relevant *operating agreements*.

**– End of Section –**

# 4 Communication: Normal Operating State

Reference: *MR* Ch. 5, Sec. 2.2

While the *ICG* is in a Normal Operating State, equipment is functioning normally or within known limitations, power transfers are within *security limits*, the outage plan is being executed as expected, there is no significant weather concern, etc.

## 4.1 IESO Communication

The *IESO* shall communicate promptly with *generators*, *electricity storage participants*, *transmitter*s, *distributors* and *connected wholesale customers* on matters of *ICG* operation that affect areas under their jurisdictions.

Communications from the *IESO* to *market participants* will normally be to their *authority centre*, in accordance with the *market rules*. However, the *IESO* will communicate directly with the *facility* location operator of a *facility*, where required, for matters relevant to the *reliability* of the *ICG*.

## 4.2 Market Participant Communication

### 4.2.1 Transmitters

Reference: *MR* Ch. 5, Sec. 3.4.1.4

*Transmitters* shall promptly report adverse operating conditions or unusual occurrences to the *IESO*. In addition, the *transmitter* shall advise the *IESO* if another operating authority (for example, an agent) has an assigned responsibility for part or all of the equipment.

*Transmitters* shall report to the *IESO* any actual or planned change in status of any of their *facilities* that are included in the *ICG*. These reports shall include times and shall be made as soon as possible. Examples include: planned switching, planned periods of unavailability of equipment, expected return to service times from *outage*, etc. Detailed reporting procedures are normally contained in the relevant *operating agreement*.

*Transmitters* that have operating control of portions of *distribution systems* shall abide by any communications requirements specified for *distributors*.

All communication by the *transmitter* shall be made by telephone to the *IESO* control room staff.

### 4.2.2 Generators

References: *MR* Ch. 5, Sec. 3.6.1.3 and 3.6.1.4; *MR* Ch. 7, Sec. 11.2 and 11.3

*Generators* connected to the *ICG*, or *embedded generators* designated by *IESO* to have an impact[9] on the *reliability* of the *ICG*, shall promptly report to the *IESO* all matters that affect the operation of the *ICG*. Such communication by the *generator* shall be made by telephone to the *IESO* control room staff

Matters that require prompt reporting to the *IESO* include *generation units* that are synchronized or separated from the *ICG*, *generation units* that become unavailable while shut down, expected changes in real or reactive capability, planned periods of unavailability of equipment, expected return to service times from *outage*, status of automatic voltage regulators, etc. These reports shall also include event times.

*Generators* shall follow these protocols for synchronization and de-synchronization:

- A *generator* that intends to synchronize a *generation unit* to the *ICG* or *embedded facility* must notify the *IESO* at least two hours in advance of synchronization. However, if the IESO issues an under-generation advisory notice, the *generator* will be subject to the conditions of the advisory notice.
- *A generator* intending to de-synchronize a *generation unit* must notify the *IESO* one-hour prior to intended de-synchronization time.
- Designated *generation units* that are able to synchronize to the *ICG* and follow *dispatch instructions* in five minutes (quick start units) are not required to notify the *IESO* before synchronizing their *generation unit*.
- Quick start units are required to notify the *IESO* five-minutes prior to de-synchronizing.

*Generators* who own a station with all, or part of a switchyard that is operated by another controlling authority, shall request authorization from the *IESO* to have devices operated that are not under their operating control. *Generators* and *transmitters* who are assigned operating control of elements contained in a common switchyard shall advise each other of proposed or actual equipment operations.

*Generators*, upon request, shall promptly report to the *IESO* the unit status information of available but not operating (ABNO) units.

*Generators* that operate portions of the *ICG* shall abide by any communications requirements that apply to *transmitters*.

### 4.2.3 Distributors and Connected Wholesale Customers

References: *MR* Ch. 5, Sec. 3.7.1.2 and 3.7.1.3

*Distributors* and *connected wholesale customers* shall promptly report to the *IESO* any matter that affects the reliable operation of the *ICG*. Such communication by a *distributor* or *connected wholesale customers* shall be made by telephone to the *IESO* control room staff

[9] Usually because the embedded *generation unit* affects a security limit. The designation is included in the registration data.

Matters that require prompt reporting to the *IESO* include status of low voltage static capacitors of 15 MVAR or larger nominal capacity that are *dispatchable* by the *IESO* for areas electrically South of Essa in Barrie, status of low voltage static capacitors of 10 MVAR or larger nominal capacity that are dispatched by the *IESO* for areas electrically North of Essa in Barrie, status of a distribution line that affects the output of an *embedded generator* or *embedded electricity storage facility* of 20 MW or greater, planned unavailability and return to service times of equipment included in the *ICG*, etc. These reports shall include event times.

The *IESO* must be informed, in advance, of any unusual planned single-point load pickup greater than 100 MW on the *ICG*, or greater than 50 MW on the *ICG* that is electrically North of Essa in Barrie. This is not intended to include large industrial loads that routinely change their *demand* by amounts that exceed these levels where the *IESO* is previously aware of this fact.

*Distributors* that operate portions of the *ICG* shall abide by any communications requirements that apply to *transmitters*.

If a *distributor* or *connected wholesale customer* has more than a single *connection point* to the *ICG*, for example a DESN transformer installation, the status of the breakers that can affect a parallel between the multiple *connection points* must be reported to *IESO*, as well as any planned operation of them. Distributors are not required to notify the IESO when a DESN transformer is required off-load for less than 15 minutes to perform switching on the distribution system.

### 4.2.4 Electricity Storage Participants

References: *MR* Ch. 5, Sec. 3.8.1.3 and 3.8.1.4; *MR* Ch. 7, Sec. 11.2 and 11.3

*Electricity storage participants* with facilities connected to the *ICG*, *and embedded electricity storage participants* whose *facilities* have been designated by *IESO* to have an impact[10] on the *reliability* of the *ICG*, shall promptly report to the *IESO* all matters that affect the operation of the *ICG*. Such communication by the *electricity storage participant* shall be made by telephone to the *IESO* control room staff

Matters that require prompt reporting to the *IESO* include *electricity storage units* that are synchronized or separated from the *ICG*, *electricity storage units* that become unavailable while shut down, expected changes in real or reactive capability, planned periods of unavailability of equipment, expected return to service times from *outage*, status of automatic voltage regulators, etc. These reports shall also include event times.

*Electricity storage participants* shall follow these protocols for synchronization and de-synchronization:

- An *electricity storage participant* that intends to synchronize an *electricity storage unit* to the *ICG* or embedded *facility* must notify the *IESO* at least two hours in advance of synchronization. However, if the IESO issues an under-generation advisory notice, the *electricity storage participant* will be subject to the conditions of the advisory notice.
- *An electricity storage participant* intending to de-synchronize an *electricity storage unit* must notify the *IESO* one-hour prior to intended de-synchronization time.

[10] Usually because the *embedded electricity storage unit* affects a security limit. The designation is included in the registration data.

- Designated *electricity storage units* that are able to synchronize to the *ICG* and follow *dispatch instructions* in five minutes (quick start units) are not required to notify the *IESO* before synchronizing their *electricity storage unit*.
- Quick start units are required to notify the *IESO* five-minutes prior to de-synchronizing.

*Electricity storage participants* who own a station with all, or part of a switchyard that is operated by another controlling authority, shall request authorization from the *IESO* to have devices operated that are not under their operating control. *Electricity storage participants* and *transmitters* who are assigned operating control of elements contained in a common switchyard shall advise each other of proposed or actual equipment operations.

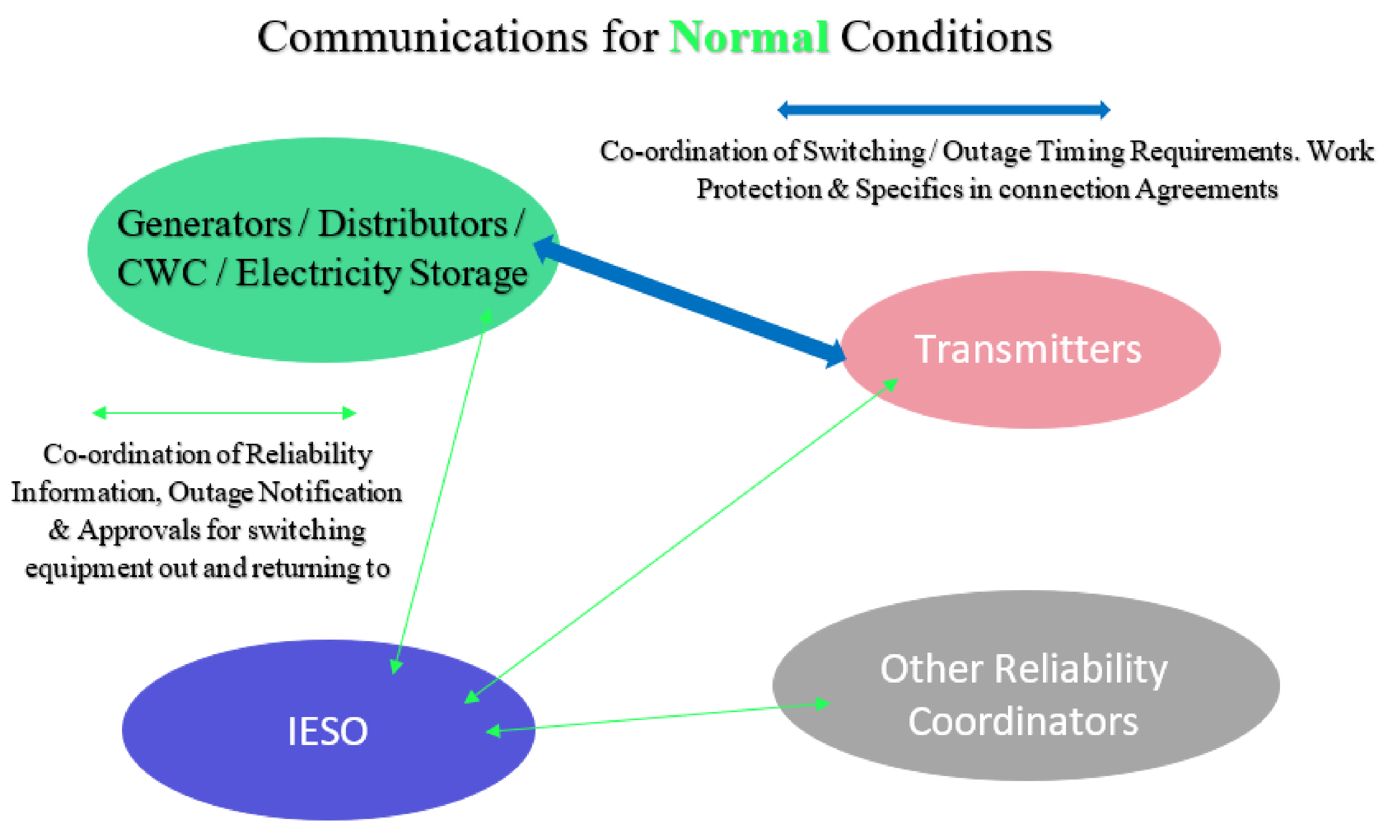
*Electricity storage participants*, upon request, shall promptly report to the *IESO* the unit status information of available but not operating (ABNO) units.

*Electricity storage participants* that operate portions of the *ICG* shall abide by any communications requirements that apply to *transmitters*.

### 4.2.5 Other Market Participants

Other *market participants* will promptly inform the *IESO* of any matters that affect the reliable operation of the *ICG* outside of the scope of commercially-related communications outlined in the *market rules*.

## 4.3 Normal Operating State Diagram




**– End of Section –**

# 5 Communication: Abnormal Conditions

Abnormal conditions include both *high-risk* and *emergency operating states*, as well as any unusual behaviour of equipment or loads.

## 5.1 IESO Communication

Reference: *MR* Ch. 5, Sec. 2.4.3

The *IESO* will issue operating instructions to direct the actions that are required by each *market participant* (refer to Section 3.3).

If more than two parties are involved in the conversation, the *IESO* will lead the discussion. The *IESO* shall direct a party to leave the conversation if a commercial advantage could be obtained by the party's presence, if matters of a confidential nature relating to another party are being discussed, or if, in the opinion of *IESO*, the party's presence is impeding the process.

The *IESO* will notify affected *market participants* of power system events or other situations that could affect the operation of the *ICG* using advisory notices. Examples of power system events include: declaration of a *high-risk operating state*, capacity or *energy* shortfalls, periods of reduced system *reliability*, weather and environmental advisories, etc.

In instances where the system conditions indicate that Emergency Operating State Control Actions (refer to Appendix B) may be required to mitigate *operating reserve* deficiency and/or *energy* deficiency, the principal medium for *reliability* related advisory notices from the *IESO* to *market participants* will be through advisory notices. The *market participant* will be informed of the anticipated system conditions and possible implementation of EOSCA. This is carried out through the *IESO* website, supplemented by the use of a pre-recorded broadcast telephone message.

The *IESO* will use advisory notices to inform *market participants* of any changes in the status of power system events, or of any relevant contingencies in other jurisdictions.

When aware of declared restrictions and equipment and auxiliaries that have been removed from service in other jurisdictions, the *IESO* will inform the affected *market participants.*

## 5.2 Market Participant Communication

When contingencies that meet the reporting requirements identified in the following sections occur, the *facility* location operator of the *facility* suffering the contingency shall contact the *IESO* prior to contacting either the *transmitter* or its own *authority centre*. Once contact is established with the *IESO*, the *IESO* will establish contact with the *transmitter* and/or *authority centre*, as necessary, and involve these parties in multi-party discussions with the *facility* location operator of the *facility* suffering the contingency, as required to return the *ICG* to a *normal operating state*.

### 5.2.1 Transmitters

Reference: *MR* Ch. 5, Sec. 3.4.1.4

The relevant *operating agreement* will normally define the communication process between a *transmitter* and the *IESO* after a contingency. Otherwise, the following will apply:

- Following a contingency, immediate communication shall be initiated from the relevant *facility* location operator to the *IESO* and, at the *transmitter's* option, simultaneously to the *transmitter's authority centre*.
- Contact with the *IESO* must not be delayed if the *transmitter's authority centre* is not immediately available.
- The *IESO* will formulate a planned respons*e* to the contingency and will lead the conversations necessary to do so.

*Transmitters* shall report the following contingencies/conditions:

- Automatic operations of all circuit breakers that form part of the *ICG,*
- Operation of power system auxiliaries such as *RASs* and under-frequency protection,
- Degradation of auxiliary equipment[11], control equipment, or staffing that reduces *security* of the *ICG,*
- Degradation of switchyard auxiliaries, such as air compressors and *station service* transformers, that could affect the *reliability* of the *ICG,*
- Any indication of a power system event, such as, oscillations of real or reactive power, voltage declines of 10% or greater, operation of disturbance recorders, etc.,
- Loss of reactive power capability or resources of 15 MVAR or greater for areas electrically South of Essa in Barrie, or 10 MVAR or greater for areas electrically North of Essa in Barrie, and
- When frequency drops below 59.8 Hz (refer to Section 9.1.2).

*Transmitters* will inform the *IESO* of restrictions on equipment in the *ICG* and of any extraneous factors that may affect the operation of the *ICG*, such as inclement weather, forest fires, or

[11] Auxiliary equipment includes:

- All protection systems (including line, transformer, overvoltage, overcurrent, and high resistance open phase)
- All communications *facilities* associated with protections
- All dynamic control systems: AVRs, power system stabilisers, other excitation system components
- All *remedial action schemes*
- All under-frequency load shedding relays
- All automatic reclosure schemes
- All automatic tap changer controls on 500kV/230kV and 230kV/115kV autotransformers
- All voltage reduction *facilities* that are used for *demand* control
- Ferroresonance protection schemes
- All voice communications *facilities* that are required by the *Market Rules*
- *Regulation facilities*
- SCADA *facilities*

directions from civil authorities (i.e., fire or police). Any change in such conditions shall also be communicated.

Such communication by the *transmitter* shall be made by telephone to the *IESO* control room staff.

### 5.2.2 Generators

References: *MR* Ch. 5, Sec. 3.6.1.3 and 3.6.1.4

The operator of *generation units* connected to the *IESO-controlled grid*, or of *embedded generation units* that are designated by the *IESO* to have an impact on the *reliability* of the *IESO-controlled grid* shall report the following contingencies promptly and directly to the *IESO*:

- Unscheduled step changes in a *generation unit's* output of greater than 50 MW or 10 MVAR,
- Deratings in a *generation unit's* output of greater than 50 MW or 10 MVAR,
- Automatic removal from service of generation, or *generation facilities* of 20 MW nominal capacity or greater,
- Degradation of auxiliary equipment[11] that reduces *ICG reliability*,
- Operation of power system auxiliaries such as *RASs*,
- Unavailability of any *generation units* that are included in *operating reserve*, and
- Frequency outside the range of 59.8Hz to 60.2Hz (refer to Section 11.2).

Such communication by the *generator* shall be made by telephone to the *IESO* control room staff. For *reliability* purposes, conversations will directly involve the appropriate *control centre*. Normal conversations may involve the appropriate authority centres.

*Generators* will inform the *IESO* of restrictions on equipment in the *ICG*. If *generation unit* breakers are within the jurisdiction of another *market participant*, that *market participant* shall also be advised as soon as conditions permit.

*Generators* shall advise the *IESO* of any extraneous factors that may affect the operation of the *ICG*. Examples include but are not limited to:

- Inclement weather,
- Environmental factors such as air pollution advisories/control orders,
- Depleted fuel inventories, or unavailability of fuel switching capabilities
- Abnormal water flow conditions, loss of water control and/or dam safety concerns,
- Forest fires,
- Received directions from civil authorities (i.e., fire or police).

Any change in such conditions shall also be communicated.

*Generators*, upon request, shall promptly report to the *IESO* the unit status information of available but not operating (ABNO) units.

*Generators* who have operating control of portions of the *ICG* shall abide by any communications requirements specified for *transmitters*.

### 5.2.3 Distributors

References: *MR* Ch. 5, Sec. 3.7.1.2 and 3.7.1.3

Following a contingency on the *distribution system*, the *distributor* shall immediately communicate from the relevant *facility* location operator to the *IESO* and, at the *distributor's* option, simultaneously to the *distributor's authority centre*. However, contact with the *IESO* must not be delayed if the *distributor's authority centre* is not immediately available. The *IESO* will lead these conversations. Such communication by the *distributor* shall be made by telephone to the *IESO* control room staff. The *facility* location operator shall report promptly and directly to the *IESO* after the following contingencies:

- Any automatic loss or forced manual interruption of load greater than 100 MW, or 50 MW electrically north of Essa TS in Barrie,
- Automatic removal from service of reactive capability of 15 MVAR or greater for areas electrically south of Essa in Barrie, or 10 MVAR or greater for areas electrically north of Essa in Barrie,
- Operation of power system auxiliaries[11] such as *RASs* and under-frequency protection,
- Degradation of power system auxiliaries[11] that reduces *security* of the *ICG*, and
- Loss of any distribution line(s) that affects the output of an *embedded generation facility* of 20 MW or greater in nominal capacity.

An *exception* to the above communication requirement is as follows:

- After an automatic operation of step-down transformer low voltage breakers and bus tie breakers, where this type of contingency is:
    - Solely due to a low tension problem and there is no indication of a problem on the *transmission system*, and
    - The loss of customer load is not greater than 100 MW (or 50 MW electrically north of Essa TS in Barrie),

  the *distributor* should attempt to restore the load from its normal supply before contacting the *IESO*. This is to avoid prolonging customer interruptions in these circumstances. The *IESO* should be informed of the success or failure of the attempt.

*Distributors* will advise the *IESO* of any operating restrictions or equipment removed from service as this could affect the *reliability* of the *ICG*.

*Distributors* will inform the *IESO* of any extraneous factors that may affect the operation of the *ICG*, including but not limited to, inclement weather, forest fires, or directions from civil authorities (i.e., fire or police). Any change in such conditions shall also be communicated to the *IESO*.

*Distributors* that control portions of the *ICG* shall abide by any communications requirements that apply to *transmitters*.

### 5.2.4 Connected Wholesale Customers

Reference: *MR* Ch. 5, Sec. 3.5.1.2

Following a contingency, the *connected wholesale customer* shall immediately communicate from the relevant *facility* location operator to the *IESO* and, at the *connected wholesale customer's* option, simultaneously to the *connected wholesale customer's authority centre*. However, contact with the *IESO* must not be delayed if the *connected wholesale customers's authority centre* is not immediately available. The *IESO* will lead these conversations. Such communication by the *connected wholesale customers* shall be made by telephone to the *IESO* control room. The *facility* location operator shall report promptly and directly to the *IESO* after the following contingencies:

- Any automatic loss or forced manual interruption of load greater than 100 MW, or 50 MW electrically north of Essa TS in Barrie,
- Automatic removal from service of reactive capability of 15 MVAR or greater that are *dispatchable* by the *IESO* for areas electrically south of Essa in Barrie, or 10 MVAR or greater that are dispatchable by the *IESO* for areas electrically north of Essa in Barrie,
- Operation of power system auxiliaries[11] such as *RASs* and under-frequency protection,
- Degradation of power system auxiliaries[11] that reduces *security* of the *ICG*, and
- Loss of any internal distribution line(s) that affects the output of an *embedded generation facility* of 20 MW or greater in nominal capacity or *dispatchable load*.

An exception to the above communication requirement is as follows:

- After an automatic operation of step-down transformer low voltage breakers and bus tie breakers, where this type of contingency is:
    - Solely due to a low tension problem and there is no indication of a problem on the *transmission system*, and
    - The loss of load is not greater than 100 MW (or 50 MW electrically north of Essa TS in Barrie),

  the c*onnected wholesale customers* should attempt to restore the load from its normal supply before contacting the *IESO*. This is to avoid prolonging interruptions in these circumstances. The *IESO* should be informed of the success or failure of the attempt.

Connected *wholesale customers* will advise the *IESO* of any operating restrictions or equipment removed from service that could affect the *reliability* of the *ICG*.

C*onnected wholesale customers* will inform the *IESO* of any extraneous factors that may affect the operation of the *ICG*, including but not limited to, inclement weather, forest fires, or directions from civil authorities (i.e., fire or police). Any change in such conditions shall also be communicated to the *IESO*.

*Connected wholesale customers* that control portions of the *ICG* shall abide by any communications requirements that apply to *transmitters*.

### 5.2.5 Embedded Market Participants

*Embedded market participants* shall notify the *IESO* of any loss of load greater than 100 MW (50 MW electrically north of Essa TS in Barrie) or generation in excess of 20 MW. Such communication by the *embedded market participant* shall be made by telephone to the *IESO* control room staff.

*Embedded market participants* that control portions of the *ICG* shall abide by any communications requirements that apply to *distributors*.

### 5.2.6 Electricity Storage

References: *MR* Ch. 5, Sec. 3.8.1.3 and 3.8.1.4

The operator of *electricity storage units* connected to the *IESO-controlled grid*, or of embedded *electricity storage units* that have been designated by the *IESO* as having an impact on the *reliability* of the *IESO-controlled grid* shall report the following contingencies promptly and directly to the *IESO*:

- Unscheduled step changes in an *electricity storage unit's* injection of greater than 50 MW or 10 MVAR,
- Deratings in an *electricity storage unit's* injection capability of greater than 50 MW or 10 MVAR,
- Any automatic loss or forced manual interruption of withdrawal greater than 100 MW, or 50 MW electrically north of Essa TS in Barrie,
- Automatic removal from service of *electricity storage facilities*, with an *electricity storage facility size* of 20 MW nominal capacity or greater,
- Degradation of auxiliary equipment[11] that reduces *ICG reliability*,
- Operation of power system auxiliaries such as *RASs and under –frequency protection*,
- Unavailability of any *electricity storage units* that are included in *operating reserve*, and
- Frequency outside the range of 59.8Hz to 60.2Hz (refer to Section 11.2).

Such communication by the *electricity storage participant* shall be made by telephone to the *IESO* control room staff. For *reliability* purposes, conversations will directly involve the appropriate *control centre*. Normal conversations may involve the appropriate authority centres.

*Electricity storage participants* will inform the *IESO* of restrictions on equipment in the *ICG*. If *electricity storage unit* breakers are within the jurisdiction of another *market participant*, that *market participant* shall also be advised as soon as conditions permit.

*Electricity storage participants* shall advise the *IESO* of any extraneous factors that may affect the operation of the *ICG*. Examples include but are not limited to:

- Inclement weather,
- Environmental factors such as air pollution advisories/control orders,
- Depleted fuel inventories,
- Abnormal water flow conditions, loss of water control and/or dam safety concerns,
- Forest fires,
- Received directions from civil authorities (i.e., fire or police).

Any change in such conditions shall also be communicated.

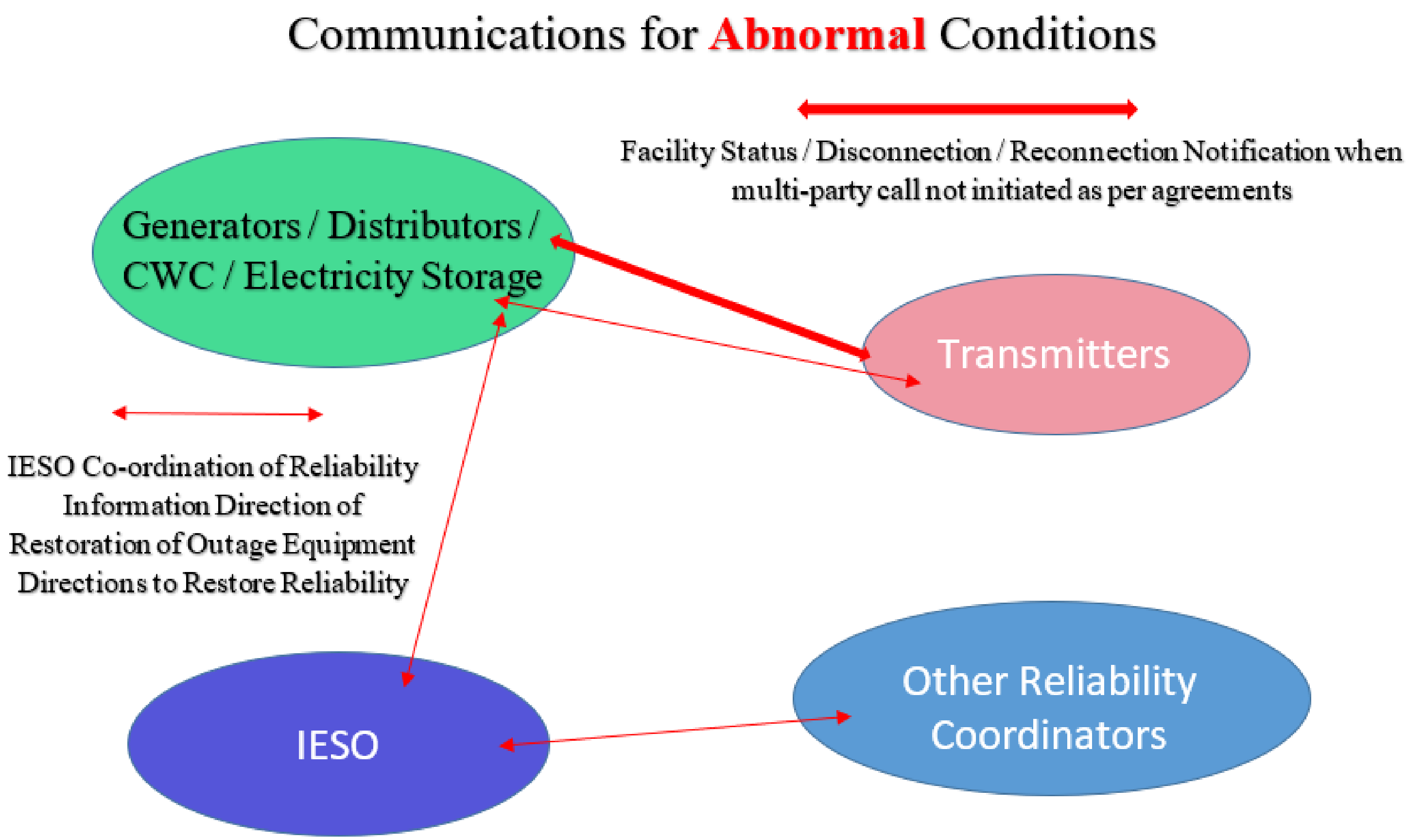
*Electricity storage participants*, upon request, shall promptly report to the *IESO* the unit status information of available but not operating (ABNO) units.

*Electricity storage participants* who have operating control of portions of the *ICG* shall abide by any communications requirements specified for *transmitters*.

### 5.2.7 Other Market Participants

Other *market participants* will promptly advise the *IESO* of any commercially induced load *curtailments* (e.g., water heaters) that they initiate beyond the scope of such advisement that are contained within the *market rules*. Confirmations of the load *curtailment* and amounts, cessation of load *curtailment* requests and load restoration times will also be communicated.

## 5.3 Abnormal Conditions Diagram




**– End of Section –**

# 6 Communication: Event Reporting

The *IESO* and *market participants* must report any event that:

- Impacts, or may impact, the *reliability* of the *IESO-controlled grid*;
- Causes a potential or actual *market rule* violation; or
- Meets the reporting criteria defined in:[12]
    - *NERC* standard EOP-004: Event Reporting,
    - NERC standard CIP-003: Cyber Security — Security Management Controls (if applicable to the market participant).
    - *NERC* standard CIP-008: Cyber Security – Incident Reporting and Response Planning (if applicable to the *market participant*).

These reporting obligations apply to *market participants* for whom:

- *NERC* standard CIP-003 applies, and with Low impact BES Cyber System(s)[13]; or
- *NERC* standard CIP-008 applies, and with Medium or High impact BES Cyber System(s)[14].

The *IESO* and *market participants* shall maintain accurate and complete records for use in preparing reports and for subsequent inquiries and analysis. The intent is to provide a factual account of events, actions taken and data records.

## 6.1 IESO Reporting Responsibilities

For actual or potentially reportable events relating to criteria outlined in section 6 above, the *IESO* will do the following:

- Report to *NERC*, *NPCC*, and the *Ontario Energy Board (OEB)* within the timelines identified in the applicable regulations and *reliability standards*.
- Report physical and NERC CIP Reportable Cyber Security Incident related events occurring at the *IESO* or *market participant facilities* to proper authorities as outlined in section 6.3.
- Depending on the specifics of the event and its relevance to Ontario's electricity market and system operation, as determined by the IESO, communicate the event to *market participants* and neighbouring *reliability coordinators*.
- Coordinate the collection of data and information as required from market participants, including the IESO itself to satisfy all applicable regulatory and *reliability standards* requirements.

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[12] In its roles as *balancing authority* and *reliability coordinator*, the *IESO* is also subject to the reporting requirements in *NERC* standard EOP-011: Emergency Operations and the *NERC* Electric Reliability Organization (ERO): Event Analysis Process.

[13] BES Cyber Systems categorized as Low impact according to the identification and categorization processes per *NERC* Standard CIP-002.

[14] BES Cyber Systems categorized as Medium impact or High impact according to the identification and categorization processes per *NERC* Standard CIP-002.

- Issue requests to *market participants* for data and information, including protection relay settings, equipment descriptions, data records, NERC Reportable Cyber Security Incident details, and other specifications and details as deemed necessary.
- Perform event analysis by reviewing the sequence of events and assessing the correctness of factors, including operating procedures, equipment operation, relay settings, training needs, NERC Reportable Cyber Security Incident related processes, procedures, and events.
- Complete an initial review of any potential non-compliance with *market rules* by a *market participant* refer to the *IESO* Market Assessment and Compliance Division (MACD) for appropriate action.
- Produce required reports and make recommendations to involved parties on corrective actions to prevent recurrence.

The *IESO* may use information obtained from logs, recording equipment, relays, and operating procedures to analyze a reportable event and the *response* of the *interconnected* system. This information can be used for further analysis, to identify lessons learned, correct deficiencies, and improve system *reliability* in the future.

## 6.2 Market Participant Reporting Responsibilities

References: *MR* Ch. 5, Sec. 14 (Information and Reporting), 14.1.4 and 14.1.5

For actual or potentially reportable events relating to criteria outlined in section 6 above, *market participants* will do the following:

- Provide the *IESO* with data, information and reports as required by regulatory entities, standards authorities, and/or the *IESO* for an event analysis to be performed, and reports to be prepared by the *IESO*.
- Provide the *IESO* with event monitoring equipment data as requested by the *IESO*.
- Promptly notify the *IESO* of any event monitoring equipment failure, malfunction, or cyber incident that could affect the timely collection and reporting of event data.
- When requested by the *IESO*, provide a preliminary report to the *IESO* for a *NERC*-reportable event or any resulting in a *reliability* concern, within the timeline specified by the *IESO* in the request.
- When requested by the *IESO*, provide a detailed final report of the event to the *IESO* at a timeline agreed to between the *market participant* and the *IESO*.
- Notify the *IESO* Shift Control Specialist (SCS) by phoning the number 905-855-6200:
    - within 60 minutes of confirming a *NERC* Reportable Cyber Security Incident[15] had occurred at a *market participant's facility* or *facilities*. Additionally, email scs@ieso.ca for this *NERC* Reportable Cyber Security Incident with the completed form located in Appendix C.4 of this *market manual*; or
    - by the end of the next calendar day after confirming the determination by the *market participant* that a *NERC* Cyber Security Incident was attempted to compromise a BES Cyber System (BCS), Electronic Security Perimeter (ESP), or an

[15] Cyber Security Incident and Reportable Cyber Security Incident are terms defined in NERC's Glossary of Terms Used in NERC Reliability Standards.

Electronic Access Control or Monitoring System (EACMS) (as per CIP-008, or as identified in the *market participant's* Cyber Security Incident Response Plan). Additionally, email scs@ieso.ca for this NERC Cyber Security Incident with the completed form located in Appendix C.5.

- Within seven calendar days of determination of any new or any changed information that was previously not reported, email the updated reporting form (C.4 for a a NERC Reportable Cyber Security Incident or C.5 for a NERC Cyber Security Incident) to email address scs@ieso.ca. *Security*-sensitive information must not be included in the emailed report. Report the updated information to other parties as identified in the *market participant's* Cyber Security Incident Response Plan(s) (as per CIP-008).
- Promptly notify the *IESO* Control Room Manager – Operations by telephone of any physical *security* events. The Manager – Operations will escalate the call as necessary. The *IESO* will report the event to the appropriate authorities on behalf of the *market participant*. Refer to section 6.3.

## 6.3 Physical and Cyber Event Reporting

Reference: *MR* Ch. 3, Sec. 5.3

The *IESO* reports physical and confirmed[16] cyber *security* incidents to the *NERC* Electricity Information Sharing and Analysis Centre (E-ISAC), and, as appropriate, the Canadian Centre for Cyber Security (CCCS), the Royal Canadian Mounted Police (RCMP), Ontario Ministry of Energy (MOE), local law enforcement agencies, and other operating authorities, within the parameters defined in *MR* Ch. 3, Sec. 5.3.

### 6.3.1 NERC E-ISAC Reporting

If the confirmed cyber *security* incident was a NERC Reportable Cyber Security Incident as determined by the IESO, the *IESO* reports this confirmed NERC Cyber *Security* Incident that occurred at a *market participant facility or facilities,* including the events occurred at the relevant IESO sites to E-ISAC within 60 minutes of confirming the event.

If the confirmed NERC Cyber *Security* Incident was an attempt to compromise a BES Cyber System, Electronic Security Perimeter (ESP), or an Electronic Access Control or Monitoring System (EACMS), the *IESO* reports this confirmed cyber *security* incident that occurred at a *market participant facility or facilities,* including the events occurred at the relevant IESO sites to E-ISAC by the end of the next calendar day of confirming the event.

If there is any new or changed information to a previously reported confirmed NERC Cyber *Security* Incident, the *IESO* reports this updated information that occurred at a *market participant facility,* including the events occurred at the relevant *IESO* sites to E-ISAC within seven calendar days of confirmation of determination of any new or any changed information.

[16] Cyber *security* incidents shall be considered confirmed if they are attested to be as such by either the reporting *market participant* and/or a supporting cyber *security* expert/agency acting on behalf of or in conjunction with the *market participant* in the context of the incident(s) in question.

The *IESO* also reports incidents that have, could have, or are expected to have a material and detrimental impact on the *reliability* of the *IESO-controlled grid* to *NERC* E-ISAC when determined necessary.

E-ISAC serves the electricity sector 24/7 by facilitating communication between sector entities, U.S. and Canadian federal governments, and other critical infrastructure sectors. The E-ISAC promptly disseminates threat indications, analysis, and warnings to assist sector entities to evaluate the situation and take appropriate actions.

In addition to reporting on NERC Reportable Cyber Security Incidents and NERC Cyber Security Incident attempted, *market participants* are encouraged to report to the *IESO* of any other cyber *security* incidents that are known or expected to have a material and detrimental impact on the *IESO-controlled grid*.

**– End of Section –**

# 7 Grid Control Actions: Readiness Programs

Testing or simulation of *emergency* procedures is done to keep relevant staff familiar with the procedures, and to identify any deficiencies in the procedures so that they can be corrected. Readiness program policy information can be found in MM 7.4, Section 2.7.2.

## 7.1 Voltage Reduction Test

For the purpose of this section, *transmitters* and connected *distributors* with directly connected load facilities of 20 MVA and greater who have control of their own voltage reduction facilities (i.e. under-load tap changing step-down transformers) are referred to as test participants.

### 7.1.1 Purpose

Tests of voltage reduction procedures will not be simulations. Actual voltage reductions will be implemented. The purpose of these tests is to:

- Identify any equipment problems and customer concerns of test participants due to reduced voltage so that corrective action may be taken,
- Measure the total amount of load reduction that is attainable, and
    - Measure the relationship between the magnitude of the voltage reduction and the amount of the load reduction.

### 7.1.2 Scheduling and Responsibilities

Reference: *MR* Ch. 5, Sec. 11.7.5

Province-wide tests are normally scheduled about every 18 months. If there has been an actual use of voltage reduction in that period that delivered similar information, the normally scheduled test may be postponed or cancelled. Additional local or province-wide tests may be scheduled if the *IESO* and the affected *market participants* so agree. The *IESO* will set the date for the test and will schedule it through the *outage* management process.

As necessary, voltage reduction test meetings will be held with test participants before and after each scheduled test.

Each test participant will maintain a plan to initiate customer notification, handling of customer concerns during reductions procedures, and follow up on correction of customer problems after reduction termination.

Test participants will examine conditions in their respective areas for abnormal set-ups, which could result in intolerable voltage conditions during the test period.

### 7.1.3 Notification

The *IESO* will notify test participants at least four weeks in advance of the test. This notice will normally align with the voltage reduction meeting that is held before and after each scheduled test.

The *IESO* notification shall specify the times, duration, and percent voltage reduction of each exercise. The test may include a 3% reduction, a 5% reduction, or both.

The *IESO* will post notification of the voltage reduction tests on the *IESO* website. Additional notification will also be included through an advisory notice, posted one week in advance of the test.

Each test participant required to participate in the test is responsible for notifying their customers of the voltage reduction test as they deem necessary. This customer notification should be in addition to the *IESO* notifications.

To facilitate the aforementioned notification requirements, the *IESO* and test participants communication departments may consider a joint communication notification where possible.

### 7.1.4 Reporting

*Distributors* and *transmitters* involved in the exercise will report the following on the load that they control:

- Test participant name,
- Amount of load (MW) excluded prior to the commencement of the voltage reduction test, the location of the load and the reason for the exclusion request,
- Amount of load (MW) excluded after commencement of the voltage reduction test, the location of the load and the reason for the exclusion request, and
- Any comments, complaints or relevant observations identified during the voltage reduction test.

The required data will be provided electronically in a table format specified by the *IESO* as set out in Appendix A or in another format as agreed to by the *IESO.*

Within one week of the exercise, data from the test participants shall be forwarded to the *IESO,* along with a plan that details corrective actions to be implemented to minimize the need to exclude load in subsequent tests.

The *IESO* relies on our own data to determine the official voltage reduction amounts. Therefore voltage reduction facilities do not need to send MW readings to the *IESO*. However, voltage reduction facilities are still required to collect data as the *IESO* may request that data if further analysis is required for specific issues.

The following data will be collected:

- Amount of load (MW) subjected to a 3% or 5% reduction test,
- Amount of load (MW) reduced (by transformer or transformer pair) as a result of the test, and
- Amount of load (MW) restored (by transformer or transformer pair) at the conclusion of the test.

If the voltage reduction facilities do not have automated data collection and archiving capability, they are required to take megawatt readings for each scheduled exercise. All readings should be taken as close as possible to the scheduled reduction times and restoration times. We suggest that the readings be taken in the three or four minute period immediately before and after the voltage reduction, and again in the three or four minute period immediately before and after the voltage restoration. In either case, the voltage reduction *facility* will keep the data for at least one month after the exercise has been completed.

### 7.1.5 Requests for Exclusion from Voltage Reduction Test

Test participants should submit all requests for exclusion from voltage reduction tests to the *IESO* using the *outage* management process. All requests should be received no later than 10:00 AM EST three *business days* prior to the scheduled day for the voltage reduction test. The *IESO* will approve or reject exclusion requests based on the decision criteria below and advise the test participant making the exclusion request within two *business days* prior to the test. The following decision criteria will be used by the *IESO* and the test participant in determining whether to approve requests for exclusion from the voltage reduction test. The same criteria will be applied to requests made while the test is in progress:

- Safety of the employees or the public,
- Damage to equipment,
- Loss of production, and
- Violation of any *applicable law*.

During a voltage reduction test, customers connected to or embedded in a test participant are expected to notify their test participant and request an exclusion to mitigate the risks described above. The test participant will promptly restore the voltage of the transformer station from which the entity is supplied and notify the *IESO* by telephone.

In the event that the *IESO* receives an exclusion request directly, the *IESO* will promptly direct the affected test participant to take the appropriate mitigating action.

As outlined in this instruction, each test participant is responsible for customer notification and handling of customer concerns, both during and after the exercise.

## 7.2 Simulation of Load Shedding

This exercise is a simulation. No load will actually be shed.

Load shedding is usually simulated during two periods each year. The following practices are conducted during each period, and scheduled to obtain maximum operating staff exposure. Communication will occur directly between the *IESO* and the relevant *facility* location operators of *transmitters*, *distributors* and *connected wholesale customers* since that would be the path in a real situation. No significant advanced warning will be given for the exercise.

The *IESO* control room staff shall:

1. Select an amount of load (MW) to be simulated shed in each electrical area of the *ICG*.
2. Notify each operator, in advance, of the time that the simulation of load shedding is to occur. The notification shall include the amount of load reduction that the *transmitters*, *distributors* and *connected wholesale customer* is expected to simulate, the electrical area in which the simulation is to be conducted, and whether or not *RAS* load rejection is to be excluded.
3. Instruct the operators at the time of the exercise to simulate load shedding.
4. Order simulated load restoration.

The involved operators shall:

1. Simulate and record the operation of specified feeder breakers.
2. Record the times and amounts (MW) of load that was simulated shed and/or restored at each step in the exercise.
3. Report all actions and conditions to the *IESO* and respond as though the simulation were an actual event.

### 7.2.1 System Restoration

Testing the various aspects of system restoration is covered in *Market Manual* 7.8: Ontario Power System Restoration Plan.

## 7.3 Unit Readiness Program

References: *MR* Ch. 5, Sec. 1.2.1 and 2.3.2 and NERC standard EOP-011: Emergency Operations.

The *IESO* conducts the unit readiness program as required for reliability in order to ensure a set of plans are available to mitigate operating emergencies for insufficient generating capacity. The *IESO* may request *dispatchable*, non-quick start *generation facilities* to start up in order to exercise their readiness. These exercises could occur any time in the calendar year and would generally involve units that have not been on for the previous 31 days or more, or have had a history of start-up problems.

The exercises would be conducted as follows:

- At least five (5) *business days* in advance of any exercise, a message indicating that the seasonal readiness program may be occurring will be communicated via an advisory notice.
- At least three (3) *business days* in advance of any exercise, specific *generators* will be contacted by the *IESO* for exercise details.
- In the day-ahead timeframe, the resource will have a *constraint* applied to *generate* at least to their *minimum loading point (MLP)* for the duration of at least their *minimum generation block run time (MGBRT),* after the completion of the DACP.
- The *registered market participant* for the *facility* must ensure that *offers* are submitted related to the exercise.
- If a *generation facility* being exercised reaches at least the constrained value for the constrained period, the exercise will be deemed a success.
- Failure of the unit readiness exercise will require a follow-up phone call to the *IESO* control room with a status update from the *market participant* as per the current *outage* reporting protocols detailed in *Market Manual* 7.3: Outage Management. The exercise may be conducted again as conditions allow. Cost recovery for these exercises shall be consistent with the DA-PCG settlement process.

**– End of Section –**

# 8 Grid Control Actions: Voltage Control / Voltage Reduction

The *IESO* is responsible for maintaining voltage levels in order to ensure *security* of the *ICG*. This section includes the procedures for voltage control and voltage reduction.

## 8.1 Voltage Control

Policy information for voltage control can be found in MM 7.4, Section 2.7.5.

### 8.1.1 Transformer Taps

Reference: *MR* Ch. 5, Sec. 9.2.1 and 9.3.1

The *IESO* and *market participants* shall give due consideration to equipment and power system limitations when specifying fixed taps or when operating under load tap changers.

The *IESO* will specify tap positions on *generation unit* and *electricity storage unit* step-up transformers that are connected to the *ICG*.

The *IESO* will determine the fixed tap settings of autotransformers rated above 50kV. The *IESO* will direct the operation of under load tap changers on these transformers.

*Transmitters, distributors* and *connected wholesale customers* will determine fixed tap settings on their step-down transformers and obtain approval from the *IESO* before making any changes.

The *IESO* will obtain agreement with neighbouring *security coordinators* for any changes to tap settings on *interconnection* transformers. The owner of the transformer will implement any changes.

### 8.1.2 Related Generation Unit and Electricity Storage Unit Equipment

Reference: *MR* Ch. 4, Sec. 5 and App 4.2

Performance requirements for automatic voltage regulators, excitation limiters, and power system stabilizers, as applicable, will be specified by the *IESO* for all *generation units and electricity storage units* that affect the *ICG.*

*Generators*, *embedded generators, electricity storage participants* and *embedded electricity storage participants* shall implement settings within the time specified by the *IESO* and will confirm the performance of the equipment immediately following any change in settings

Any settings must not be changed without the prior approval of the *IESO*.

Performance retesting will be conducted as frequently as is required by the applicable *NERC* Modeling, Data, and Analysis (MOD) standard- or at shorter intervals if specified by the *IESO*

The *IESO* is responsible for dispatching VARs on *generators* and *electricity storage participants* connected to the ICG in order to ensure reliable operation of the *ICG*.

A *generator* or *electricity storage participant* operating its facility at a MW output above its rated maximum output (*generators*) or its rated maximum injection or withdrawal output (*electricity storage facilities*) must independently reduce its MW output in order to be able to achieve Q max and Q min values corresponding to rated maximum power, unless instructed otherwise by the *IESO*.

### 8.1.3 Static Reactive Resources

The *IESO* shall specify settings for continuously variable reactive resources such as synchronous condensers and static VAR compensators that are connected to the *ICG*.

The *IESO* shall specify delay times and voltage levels for automatically switched capacitors and reactors that can affect the *ICG*. Due regard will be given to limitations on equipment and on customer voltage levels.

The IESO is accountable for the deployment of reactive resources directly connected to the *ICG* and low tension (LT) resources >10 MVar north of Essa, >15 MVar south of Essa to maintain acceptable voltage levels to ensure reliable operation of the *ICG*.

## 8.2 Voltage Reduction

References: *MR* Ch. 5, Sec. 10.2 and 10.3.6

Policy information for voltage reduction can be found in MM 7.4, Section 2.7.7.

The *IESO* may direct *transmitters* and *distributors* to reduce voltage by 3% or 5% to prevent or mitigate operating conditions that cannot be resolved by market mechanisms. These operating conditions include, but are not limited to:

- Equipment limitations
- *SOL* exceedance
- Activation of reserve
- Load/generation balance

The *IESO* will instruct the entity that has direct operational control of the *facilities* to execute the voltage reduction. This entity will be identified by *market participants* during the registration process and updated as required.

*Distributors* may institute voltage reductions to reduce *demand* within their service areas in accordance with *MR* Ch. 5, Sec. 10.2. *Distributors* must notify the *IESO* via the *outage* management process in accordance with procedures in *Market Manual* 7.3: Outage Management.

*Distributors* that have remote supervisory control of the regulating transformers downstream of the location at which a voltage reduction was implemented, must block the action of these regulators during a voltage reduction ordered by the *IESO*.

The *IESO* will notify *market participants* that voltage reductions are anticipated or are occurring via an advisory notice.

After a voltage reduction, *market participants* shall provide the required post-voltage reduction data electronically in a table format specified by the *IESO* as set out in Appendix A or in another format as agreed to by the *IESO.*

**- End of Section -**

# 9 Grid Control Actions: Non-Dispatchable Load Shedding

It may be necessary to interrupt *non-dispatchable load* to alleviate:

- A global or local capacity or *energy* deficiency,
- An equipment limitation, or
- A *System Operating Limit (SOL)* exceedance.

Load shedding will be undertaken in accordance with the policies outlined in MM 7.4, Section 2.7.8. In some instances, load shedding will be automatic through under-frequency protection (refer to Section 11.3) or *remedial action schemes*. In other instances, manual intervention and customer appeals will be required.

## 9.1 Non-Dispatchable Load Shedding via Manual Intervention

Manual load shedding may be initiated by:

- A *market participant* to reduce *demand* within their service area,
- The *IESO* as an *emergency* control action (refer to Appendix B), or
- A *transmitter* or *distributor* as an independent action.

### 9.1.1 Non-Dispatchable Load Shedding Initiated by IESO

The *IESO* shall direct *emergency load shedding* under the following conditions:

- To alleviate a capacity or *energy emergency*,
- To alleviate or avoid exceeding pre- and post-contingency equipment ratings,
- To alleviate or prevent a pre-contingency voltage collapse, or a steady-state instability, or
- To alleviate or avoid exceeding an Interconnection Reliability Operating Limit (IROL) or Bulk Power System (BPS) limit.

The *IESO* direction will include either the MW of relief to *transmitters* and large connected *distributors* or the percentage of prevailing load relief to small connected *distributors* and small *connected wholesale customers* and the electrical area(s) impacted (if relevant). Load shedding should not take place in an area where prevailing transmission conditions prevent it from alleviating the *reliability* concerns.

The *market participant* shall migrate into their rotational load shedding schedule from the *emergency* load block shed if the conditions are going to be sustained for a period of time. When rotating the load shed, the next block shall be shed before re-loading a block.

The *IESO* will communicate with the entity that has direct operational control of the facilities used to execute load shedding. The IESO will communicate directly with *transmitters*, large connected *distributors*, and large *connected wholesale customers*. The *IESO* will communicate via an automated messaging *facility* to small connected distributors and small *connected wholesale customers*.

The *IESO* will notify all *market participants* that load shedding is anticipated or is occurring via an advisory notice. Upon returning to a *normal operating state*, the *IESO* shall release an advisory notice to all *market participants*, providing an estimate of the aggregate load curtailed (*MR* Ch. 5, Sec. 10.3.7).

### 9.1.2 Non-Dispatchable Load Shedding For Frequency

References: *MR* Ch. 5, Sec. 10.4.3 and 10.4.8; *MR* Ch. 4 App. 4.15 and 4.16

If automatic under-frequency load shedding (refer to Section 11.3) fails to maintain frequency at an acceptable value, manual control actions may be required. The magnitude of the frequency deviation determines whether the action is directed by the *IESO* or done independently by *transmitters*.

*Transmitters* shall have annunciation of under-frequency set at 59.8 Hz.

For frequencies 59.0Hz and above, the *IESO* shall direct the actions.

For frequencies between 59.0 Hz and 58.5 Hz, *transmitters* shall shed 25% of their controlled load. For frequencies below 58.5 Hz, *transmitters* shall shed load until the frequency returns to 59.0 Hz, or as close to 60 Hz as practical if an island is known to have formed within the *ICG. Market participants* shall ensure that frequency metering is available to the entity that has operating control of their feeder breakers.

No load that has been shed to correct low frequency shall be restored without the approval of the *IESO*.

### 9.1.3 Non-Dispatchable Load Shedding Schedules: Transmitters and Connected Distributors

Reference: *MR* Ch. 5, Sec. 10.3.6

The *IESO* has identified electrical areas defined by System Operating Limits. Each *transmitter* and connected d*istributor* shall maintain up-to-date load shedding schedules for any such areas within its jurisdiction. These schedules should divide the load into approximately equal blocks; indicate the approximate percentage of the load in each block, and the approximate MW in each block at any time. *Transmitters* and connected *distributors* shall ensure equitable treatment of different loads within the schedules. Priority customer loads as defined by *Market Manual* 7.8: Ontario Power System Restoration Plan are to be excluded from rotational load schedules. To the extent practical, load being shed by *RASs* should also be excluded*.* Exclusion from manual load shedding schedule should be kept to a minimum to facilitate rapid load shedding.

Because of the varying load profiles, each *transmitter* and connected *distributor* operating staff is responsible for determining where cuts can be made at any given time during the shift.

Load shedding should be such that it does not interfere with *emergency* services deployed in the vicinity of a disaster.

### 9.1.4 Non-Dispatchable Load Shedding Schedules: Connected Wholesale Customers

Each *connected wholesale customer* is encouraged to prepare a manual load shedding schedule that divides its load into at least two blocks and prioritizes the blocks for shedding. The size of each block, in MW, should be known and kept up to date. This will facilitate protecting loads that affect human and environmental safety and sensitive industrial processes to the extent possible.

### 9.1.5 Non-Dispatchable Load Shedding via Local Appeals

Reference: *MR* Ch. 5, Sec. 10.2

*Transmitters* or *distributors* may encounter situations in which equipment *reliability* is compromised. An example might be an overloaded transformer that feeds radial loads and there is no ability to transfer enough of the load to alleviate the transformer overload.

In such situations, *transmitters* and/or *distributors* may, after notifying the *IESO*, initiate local appeals for voluntary load reduction in the relevant area.

The *transmitter* or *distributor* who wishes to implement the local appeal shall handle the public communication required to initiate, and subsequently, cancel the local appeal when the need has disappeared.

### 9.1.6 Non-Dispatchable Load Shedding via Global Appeals

Reference: *MR* Ch. 5, Sec. 10.3

If the market *response* is expected to leave all, or significant portions of, the *ICG* deficient of generation, the *IESO* may initiate warnings via public appeals to encourage customers to reduce electricity consumption voluntarily.

**- End of Section -**

# 10 System Security: Automatic Reclosure

Reference: *MR* Ch. 4, App 4.4

Policy information for automatic reclosure can be found in MM 7.4, Section 4.3.11.

The *IESO* will review automatic reclosure settings that are recommended by *transmitters*, and, if necessary for the *reliability* of the *ICG*, request changes in those settings or capabilities. The *IESO* will specify all automatic reclosure settings for all circuits on the *ICG*.

Requests to have automatic reclosure blocked (hold-offs) on specific circuits (during planned work in a station, for example) are processed through the normal *outage* management system and in real-time as required.

**- End of Section -**

# 11 System Security: Frequency Regulation

## 11.1 Generation and Electricity Storage Units

References: *MR* Ch. 4, Sec. 5 and App 4.2

Performance requirements, as applicable, for governors or equivalent devices that regulate active power output based on frequency will be specified by the *IESO* for all *generation units and electricity storage units* that affect the *ICG*.

*Generators, electricity storage participants*, *embedded generators,* and *embedded electricity storage participants* shall implement settings within the time specified by the *IESO* and will confirm the performance of the equipment immediately following any change in settings.

Any settings must not be changed without the prior approval of the *IESO*.

Performance retesting will be conducted as required by applicable standards, or at shorter intervals if specified by the *IESO.*

## 11.2 Generators and Electricity Storage Participants Experiencing Abnormal Frequency

References: *MR* Ch. 5, Sec. 10.5 and 10.5A

Abnormal frequency is anything outside the normal range of 59.98 – 60.02 Hz.

All *generators and electricity storage participants* must take actions at the frequency trigger-points shown below in Figure 11-1. During periods of abnormal frequency, unit voltage should be maintained within normal ranges with the automatic voltage regulator kept in service where possible.

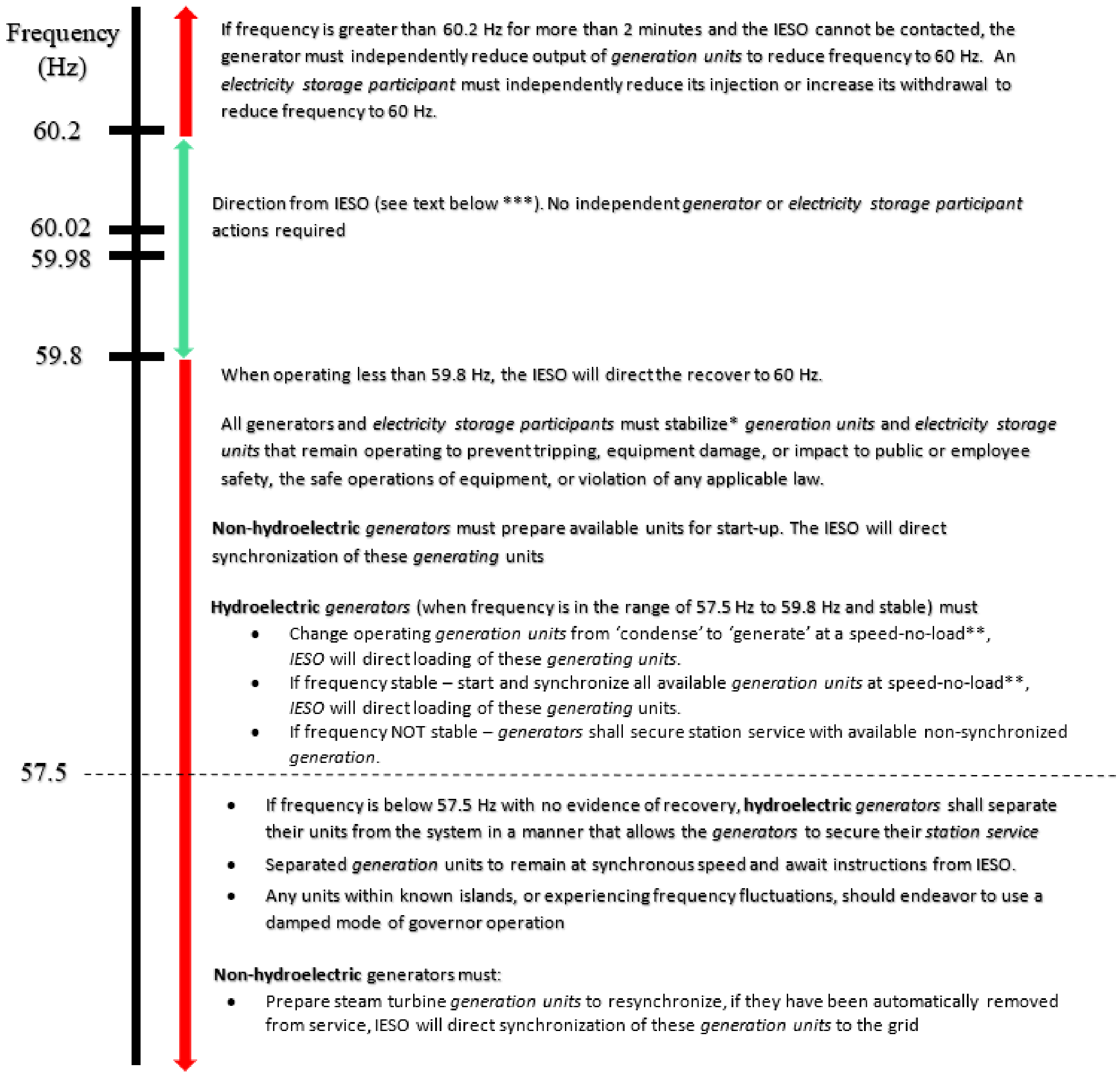


**Figure 11-1: Generator and Electricity Storage Participant Actions During Abnormal Frequency**

*Stabilize in this context means to take action to adjust plant processes and parameters to enable steady, sustained operation while remaining synchronized to the grid.

**Speed-no-load means the *generation unit* is in service, running at synchronous speed with its unit breaker closed without any appreciable load on the unit. Some *facilities* are pre-set to automatically load restarted *generation units* with certain in-house loads, which is acceptable during restoration, since the unit is not synchronized to an island. This configuration must be documented in a *Restoration Participant Attachment*. Refer to [Market Manual 7.8: Ontario Power System Restoration Plan (OPSRP)](#).

***For frequencies in the range of **59.8 Hz** to **60.2Hz**, *generators* and *electricity storage participants* shall not act without instructions from the *IESO,* except for the purpose of protecting the safety of its equipment, its employees, or the public, or to prevent the violation of any *applicable law*. If a *generator* or *electricity storage participant* cannot maintain frequency within this range, the *IESO* should be notified prior to taking any corrective action that would alter the electrical output of the unit. Unit operators shall take all necessary measures to prevent units from tripping, while observing operating restrictions. If the unit operator must take immediate and independent action, the *IESO* should be contacted as soon as possible after.

## 11.3 Automatic Under-Frequency Load Shedding

Reference: *MR* Ch. 5, Sec. 10.4.6

Policy information for automatic UFLS can be found in MM 7.4, Section 4.3.10.

Automatic UFLS is intended to improve system reliability by mitigating the risk of loss of generating units via their under-frequency protection. *MR* Ch. 5, Sec. 10.4.6 requires at least 30% of load to be connected to automatic UFLS relaying for this purpose.

To ensure that at least 30% of load is automatically shed during a low frequency event, the *IESO* requires that 35% of the total peak load of *connected wholesale customers* and *distributors* be connected to automatic UFLS relays. The additional 5% above requirement provides flexibility to accommodate UFLS feeder and relay *outages,* as well as *generation units* that trip for low frequencies above the curve specified in *MR* Ch. 4, App 4.2, Category 1.

Automatic UFLS must be done in stages as specified in applicable standards.

(a) For the purpose of UFLS implementation, the province of Ontario is divided into five UFLS areas, (Northwest, Northeast, West, East, and Central). The boundaries of those areas are given below.

| **UFLS Area** | Boundaries |
|---|---|
| **Northwest** | Bounded by the Manitoba and Minnesota *interconnections* and west of the East-West interface. |
| **Northeast** | Bounded by east of the East-West interface and north of the Flow South interface. |
| **West** | Bounded by the Michigan *interconnection* and west of the BLIP interface. |
| **East** | Bounded by the New York *interconnection* at St Lawrence and east of Cherrywood and Bowmanville. |
| **Central** | All of Ontario, excluding the Northwest, Northeast, West, and East areas. Bounded by the North-South interface, the BLIP interface, and Cherrywood and Bowmanville. |

(b) In all automatic UFLS areas, there must be at least 30% of area load[8] *connected* to under-frequency relays. In order to ensure at least 30% of area load shedding is achieved while taking into account UFLS relay and feeder *outages* as well as *generation units* that trip prematurely for low frequencies[9], 35% of the load of those *distributors* and *connected wholesale customers* with a peak load of 25 MW or greater must be *connected* to UFLS relays. *Distributors* and *connected wholesale customers* with a peak load less than 25 MW are not required to provide UFLS. *Distributors* whose load spans more than one UFLS area must ensure that the required amount of UFLS is provided for their load in each UFLS area.

(c) Each *distributor* and *connected wholesale customer* shall select load for UFLS based on their load distribution at a date and time specified by the *IESO* that approximates system peak.

(d) The discrete load shedding requirements are given in (e), (f), and (g). Each *distributor* and *connected wholesale customer*, in conjunction with the relevant *transmitter*, shall submit to the *IESO* their proposed implementation plan for meeting their UFLS requirements within the time set by the Ontario UFLS Program Implementation Plan.

(e) For *distributors* and *connected wholesale customers* with a peak load of 100 MW or greater, the UFLS relay *connected* loads shall be set to achieve the amounts to be shed stated in the following table.

| UFLS Stage | Frequency Threshold (Hz) | Total Nominal Operating Time(s) | Load Shed at stage as % of MP Load | Cumulative Load Shed at stage as % of MP Load |
|---|---|---|---|---|
| 1 | 59.5 | 0.3 | 7 - 9 | 7 - 9 |
| 2 | 59.3 | 0.3 | 7 - 9 | 15 - 17 |
| 3 | 59.1 | 0.3 | 7 - 9 | 23 - 25 |
| 4 | 58.9 | 0.3 | 7 - 9 | 32 - 34 |
| Anti-Stall | 59.5 | 10.0 | 3 - 4 | 35 - 37 |

(f) For *distributors* and *connected wholesale customers* with a peak load of 50 MW or more and less than 100 MW, the UFLS relay *connected* loads shall be set to achieve the amounts to be shed stated in the following table.

| UFLS Stage | Frequency Threshold (Hz) | Total Nominal Operating Time(s) | Load Shed at stage as % of MP Load | Cumulative Load Shed at stage as % of MP Load |
|---|---|---|---|---|
| 1 | 59.5 | 0.3 | ≥ 17 | ≥ 17 |
| 2 | 59.1 | 0.3 | ≥ 18 | ≥ 35 |

(g) For *distributors* and *connected wholesale customers* with a peak load of 25 MW or more and less than 50 MW, the UFLS relay *connected* loads shall be set to achieve the amounts to be shed stated in the following table.

| UFLS Stage | Frequency Threshold (Hz) | Total Nominal Operating Time(s) | Load Shed at stage as % of MP Load | Cumulative Load Shed at stage as % of MP Load |
|---|---|---|---|---|
| 1 | 59.5 | 0.3 | ≥ 35 | ≥ 35 |

(h) *Distributors* and *connected wholesale customers*, in conjunction with the relevant *transmitter* shall also shed those capacitor banks *connected* to the same station bus as the load to be shed by the UFLS *facilities*, at 59.5 Hz with a time delay of three seconds.

(i) Any electrical area in Ontario that may become isolated from the rest of the *IESO-controlled grid* but remain *connected* to a neighboring system during a disturbance, must contain sufficient automatic UFLS capability so that the recovery of the neighboring system will not be prejudiced.

(j) Inadvertent operation of a single under-frequency relay during the transient period following a System Disturbance should not lead to further system instability. For this reason, the maximum amount of load that can be *connected* to any single under-frequency relay is 150 MW.

The *IESO* will review the requirements annually, and inform the relevant *market participants* (*transmitters*, *distributors*, and *connected wholesale customers*) of their automatic UFLS obligations.

**– End of Section –**

# Appendix A: Voltage Reduction Form

## Voltage Reduction Test / Event Reading Sheet

| | |
|---|---|
| **Market Participant:** | |
| **Date** *(YYYY/MM/DD)***:** | |

**Exclusions Prior to the voltage reduction (actual or test):**

| Customer Name | Station Name | 3% Test Load (MW) | 5% Test Load (MW) | Reason for Exclusion |
|---|---|---|---|---|
| | | | | |
| | | | | |
| | | | | |
| **TOTAL** | | **0.00** | **0.00** | |

**Exclusions During the voltage reduction (actual or test):**

| Customer Name | Station Name | 3% Test | | | 5% Test | | | Reason for Exclusion |
|---|---|---|---|---|---|---|---|---|
| | | From (hh:mm) | To (hh:mm) | Load (MW) | From (hh:mm) | To (hh:mm) | Load (MW) | |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| **TOTAL** | | | | **0.00** | | | **0.00** | |

**Comments (complaints, observations):**

Please add/delete rows and space for comments as required.

**NOTES:**

**– End of Section –**

# Appendix B: Emergency Operating State Control Actions

The following tables reflect control actions available to the *IESO* leading up to and during an "*emergency operating state*". Section B.1 addresses the actions initiated both in advance of the declaration of and during the *Emergency Operating State* where only the *IESO control area* is deficient. Section B.2 however addresses the scenario where the *IESO* and an external *control area* are both faced with generation deficiency.

While the tables provide the anticipated order of control actions, **the *IESO* may initiate control actions at any point in the table depending on the specific circumstances and conditions of the *IESO* or external *control area*.** In addition, the *IESO* may alter the order in which the control actions are implemented to respond to *reliability* concerns. The *IESO's* ability to initiate control actions at any point in the table, and to alter the order in which control actions are implemented, takes precedence over any implied or explicit conditions within the tables.

It should also be stressed that as a general principle the *IESO* will not take any control actions that do not provide a **net** benefit to the operating condition. Adherence to this principle may lead to scenarios where exports from congested regions within Ontario continue to flow while *non-dispatchable load* elsewhere in Ontario is being curtailed.

*NERC* standards require simultaneous *curtailment* of *energy* injections and withdrawals associated with a linked wheeling transaction. Where injections and withdrawals are simultaneously curtailed there is no benefit to supply *adequacy*. Therefore, the *IESO* will not curtail linked wheeling transactions to support the overall supply *adequacy* of the *IESO-controlled grid.* The *IESO* may, however, curtail a linked wheeling transaction where the transaction was contributing to transmission *security* concerns or overloads which are causing either global or local *reliability* concerns.

Legend applied to the last four columns of the table, indicating the status of the *IESO-controlled grid* associated with each control action:

**A** 30-minute *operating reserve*, 10-minute *operating reserve* and *regulation* reserve maintained

**B** 10-minute *operating reserve* and *regulation* reserve maintained

**C** 10-minute synchronized *operating reserve* and *regulation* reserve maintained

**D** *Regulation* reserve maintained

## B.1 Actions in Advance of and During the IESO Controlled Grid Emergency Operating State

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| **1** | Issue Adequacy Report | These assessments are *published* 0-34 days out and would identify any forecast capacity and/or *energy* deficiencies. | *Market Rules* – Chapter 5 Sections 7.3.1.4 & 7.4.4<br>Market Manual Part 7.2 – Near-Term Assessments and Reports | Y | | | |
| **2** | *Outage* Management Process – reject *outage* applications | This rejection applies only to those *outages* that have not received *advance approval*. *Advance approval* is received between 1 and 3 *business days* prior to the start of an *outage*. | *Market Rules* – Chapter 5 Section 6.4.4.1<br>Market Manual Part 7.3 - Outage Management | Y | | | |
| **3** | Issue advisory for under generation via advisory notice | An advisory notice may be published (0-2 days in advance of real-time) with an under generation advisory, indicating a lack of installed resources. | *Market Rules* – Chapter 7 Section 12.1.3.2<br>Market Manual Part 7.2 – Near-Term Assessments and Reports | Y | | | |
| **4** | Issue Standby Notification for Hourly Demand Response (HDR) Resources[17] | This notification can be issued from HE16 day-ahead through HE07 day-at-hand. Notifications can be issued to all participants or regionally based on system need. | *IESO* internal procedures. | Y | | | |
| **5** | Issue an advisory notice for the declaration of a Conservative Operating State | This declaration acknowledges a reliability concern and signals that actions may be required to prevent an *emergency operating state*. This declaration is made during real-time.<br>The IESO will issue a RCIS message. | *Market Rules* – Chapter 5 Section 2.5 and 5.9A<br>Market Manual Part 7.1 – IESO-Controlled Grid Operating Procedures and Part 7.4 – IESO-Controlled Grid Operating Policies | Y | | | |

[17] When selecting HDR resources as control actions from the EOSCA list, the IESO will adhere to the timelines associated with placing the resources on standby and activating the resources.

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| **6** | Issue General or Public Appeal | This is a public appeal for the general populous to conserve *energy* and is usually a media based appeal.<br>The *IESO* will normally issue an appeal under the following conditions:<br>• If the system is strained and requires additional flexibility<br>• If the situation is expected to progress to the point of a 3% or a 5% voltage reduction or if the *IESO* expects to enter EEA-2 | *IESO* internal procedures.<br>*NERC Reliability Standard* – EOP-011, Attachment 1 | Y | | | |
| **7** | Issue advisory for under generation via advisory notice | This report is produced no more than one day in advance and would include the under generation advisory. The report could be issued very close to real-time if needed. In this case the advisory would indicate a lack of *offers* and *bids*. | *Market Rules* – Chapter 7 Section 12.1.3.2<br>Market Manual Part 7.2 – Near-Term Assessments and Reports | Y | | | |
| **8** | *Outage* Management Process – revoke approved *outages* | Revoke impactive *outages* that have received *advance approval* (from between 1 and 3 *business days* in advance of *outage* start up to real-time). This may trigger compensation of *generators* and *electricity storage participants* that intend to inject. | *Market Rules* - Chapter 5 Sections 6.4.4.1 and 6.4.9<br>Market Manual Part 7.3 – Outage Management | Y | | | |
| **9** | Manage Inadvertent Payback | When inadvertent is owed by the *IESO*, the *IESO* may unilaterally or bilaterally payback the inadvertent. To the extent that this payback is contributing to the deficiency, such payback shall be discontinued. If the payback benefits the situation in the *IESO control area*, it will continue. | *IESO* internal procedures | Y | | | |
| **10** | Manage Time Error Correction | When time-error correction requires an over-generation of *IESO control area* resources, time-error correction shall be discontinued.<br>The time error correction monitor will issue a RCIS[18] message. | *IESO* internal procedures | Y | | | |

[18] RCIS message: A message on the Reliability Coordinators Information System which allow all *Reliability Coordinators* to be aware of the status of neighbouring *control areas*.

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| **11** | *Outage* management process – recall *outages* or suspend outages and switching | *Outages* that can be recalled in a timely fashion will be recalled. This may trigger compensation of *generators* and *electricity storage participants* that intend to inject.<br><br>IESO may request participants to suspend outages and switching operations if their work poses a reliability risk to the *ICG* | *Market Rules* - Chapter 5 Sections 6.4.4.1 and 6.4.11<br>Market Manual Part 7.3 – Outage Management | Y | | | |
| **12** | Constrain Dispatch of energy limited resources | These control actions, where available and implemented, are intended to <u>avoid the declaration</u> of an *emergency operating state*. Daily Energy Limited resources would be constrained off at this time to allow for them to run in future deficient hours. | *Market Rules:* Chapter 5<br>Sections 1.2.1 and 2.3.2<br>Chapter 7<br>Sections 7.2.1.1, 7.2.5.1 and 11.3.3 | Y | | | |
| **13** | Discontinue Commissioning Tests | During the commissioning of a *generation unit* or an *electricity storage unit* the *IESO* may be required to carry additional reserve due to the increased likelihood of unit failure. The *IESO* may request that all commissioning tests halt so that the reserve requirement is returned to normal levels. | *Market Rules* – Chapter 5 Section 4.5.1.3 | Y | | | |
| **14** | Issue *NERC* Energy Emergency Alert 1 (EEA-1) | The *IESO control area* has (or expects to have) all available resources in use.<br>The *IESO* will issue a RCIS message and an advisory notice. | *NERC Reliability Standard* – EOP-011, Attachment 1 | Y | | | |
| **15** | Issue an advisory notice to indicate the potential to declare an *emergency operating state* | The advisory notice will indicate the potential for the declaration of an *emergency operating state*. | *Market Rules - Chapter 7 Section 12.1.3.3* | Y | | | |
| **16** | Run Short of 30-minute *operating reserve* | If the 30-minute *operating reserve* shortfall is expected to last less than 4 hours: Run short of 30-minute *operating reserve* | | | | | |
| *Solve 30-minute operating reserve shortfall.*<br>*The following 7 control actions may be used if the 30-minute operating reserve shortfall is forecasted to last beyond four hours from the time the shortfall was first identified, or if a shortfall is forecasted of any duration beyond a four-hour horizon.*<br>**Implement control actions 17 through 23 in a timely manner as to resolve the 30-minute operating reserve *shortfall prior to the end of the 4-hour period.*** | | | | | | | |

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| **17** | Include any 3% or 5% voltage reductions not already included through market mechanisms as 30-minute *operating reserve* | This action will help to maintain the 30-minute *operating reserve* and will only be included if all available *offers* for *operating reserve* are utilized. | *Market Rules* – Chapter 5 Section 4.5.6A | Y | | | |
| **18** | Constrain Dispatch of Resources on a reasonable effort economic basis | These control actions, where available and implemented, are intended to avoid the declaration of an *emergency operating state.*<br>This action could include, if not recognized by the pre-dispatch or real time *dispatch algorithms*:<br>• Issue *capacity import call* to *generator-backed capacity import resources*<br>• Constraining imports on, which may include *system-backed* and *generator-backed capacity imports*<br>• Constraining down *dispatchable loads* and dispatchable *electricity storage facilities* that are withdrawing.<br>• Constraining linked wheels off only if it frees up available transfer capability<br>• Constraining exports off[19], except for capacity backed exports (provided the backing generation is covering the MW)<br>**Note:** O*perating reserve* may be sold as a recallable export in an emergency situation (e.g., to help prevent a neighboring entity from having to shed load).<br>• Activate Hourly Demand Response (HDR) Resources<br>**Note:** This activation can be issued to any HDR resource that was previously sent a standby notification. Resources | Market Manual Part 4.3, Section 6.8<br>*Market Rules:* Chapter 5 Sections 1.2.1 and 2.3.2<br>Chapter 7 Sections 7.2.1.1, 7.2.5.1 and 11.3.3<br>*IESO* internal procedures | Y | | | |

[19] If a resource has committed its capacity externally, Ontario cannot include that capacity towards Ontario *adequacy* in a planning timeframe, nor for real-time operations under certain real-time circumstances. The *IESO* will not curtail a capacity export for global/local *adequacy* **unless the backing resource is not scheduled or is not operating to the full amount of the capacity export**, at which point the *IESO* can curtail a capacity export to the lower of the schedule or output amount of the resource that has committed its capacity externally.

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| | | must be activated approximately 2.5 hours in advance of their expected load curtailment time.<br>The use of Daily Energy Limited resources may be used at this time provided adequate resources are available. | | | | | |
| **19** | Solicit *Bids/Offers* | The *IESO* will solicit *bids* and *offers* at this time.<br>The *IESO* will open the *offer* / *bidding* window and issue an advisory notice. | | Y | | | |
| **20** | Reconfigure *Transmission system* | Where an evaluation has deemed it beneficial to do so, the *IESO* will reconfigure the *transmission system* to avoid the declaration of an *emergency operating state.* | | Y | | | |
| **21** | Issue a reliability declaration[20] to call on Hydro Quebec capacity (only during summer periods in which Hydro Quebec has committed capacity to the *IESO*) | A reliability declaration must be made to obligate Hydro Quebec to provide firm *energy* per the requirements of the IESO/Hydro Quebec Amended and Restated Capacity Sharing Agreement and/or the 2024 Capacity Sharing Agreement.<br>The *IESO* will issue an advisory notice. | *IESO* internal procedures | Y | | | |
| **22** | Issue an advisory for the declaration of an *emergency operating state* | Issue an advisory notice to indicate the declaration of the *emergency operating state*.<br>The *IESO* will issue a RCIS message. | *Market Rules* – Chapter 7 Section 12.1.3.3 | Y | | | |
| **23** | Purchase *emergency energy* and request *emergency* assistance | Purchase resources not made available through market mechanisms to eliminate the deficiency. These purchases are made to maintain 30-minute *operating reserve* and are not providing support to the exports that may be flowing at the time. The source of the purchases must be the seller's surplus *energy*.<br>The *IESO* will issue an advisory notice. | Market Rules - Chapter 5 Section 2.3.3A | Y | | | |
| The *IESO* is now no longer able to operate to respect the 30-minute *operating reserve* requirement. The preceding control actions were insufficient to meet the full 30-minute *operating reserve* requirement. | | | | | | | |

[20] Reliability **declaration** is a term used in association with the IESO/Hydro Quebec Amended and Restated Capacity Sharing Agreement and 2024 Capacity Sharing Agreement.

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| **24** | Include any 3% or 5% voltage reductions not already included through market mechanisms as 10-minute *operating reserve*. | This action will help to maintain the 10-minute *operating reserve*. | *Market Rules* – Chapter 5 section 10.3 | | Y | | |
| **25** | Constrain ramp limited units up to maximize 10-minute *operating reserve* | This *IESO* may take this action where necessary, in order to utilize higher ramp rates to schedule additional 10-minute operating reserve. | | | Y | | |
| **26** | Bring a sufficient amount of 30-minute *operating reserve* imports to 10-minute *operating reserve* status. | This *IESO* will ask the external *control area* if they can deliver the scheduled 30-minute *operating reserve* imports in 10 minutes. If the external *control area* cannot deliver the imports in 10 minutes, the *IESO* will constrain on the import to allow internal *energy* to be made available for 10 minute *operating reserve.* | | | Y | | |
| **27** | Constrain Dispatch of Resources on a reasonable effort economic basis. | These control actions, where available and implemented, are intended to avoid the declaration of an *emergency operating state.*<br>This action could include, if not recognized by the pre-dispatch of real time *dispatch* sequence algorithms:<br>• Issue *capacity import call* to *generator-backed capacity import resources*<br>• Constraining imports on, which may include *system-backed* and *generator-backed capacity imports*<br>• Constraining down *dispatchable loads* and *dispatchable electricity storage facilities* that are withdrawing<br>• Constraining linked wheels off only if it frees up available transfer capability<br>• Constraining exports off[19], except for capacity backed exports (provided the backing generation is covering the MW)<br>**Note:** O*perating reserve* may be sold as a recallable export in an emergency situation (e.g., to help prevent a | Market Manual Part 4.3, Section 6.8<br>*Market Rules:* Chapter 5<br>Sections 1.2.1 and 2.3.2<br>Chapter 7<br>Sections 7.2.1.1, 7.2.5.1 and 11.3.3 | | Y | | |

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| | | neighboring entity from having to shed load).<br>• Activate Hourly Demand Response (HDR) Resources<br>**Note:** This activation can be issued to any HDR resource that was previously sent a standby notification. Resources must be activated approximately 2.5 hours in advance of their expected load *curtailment* time.<br>The use of Daily Energy Limited resources may be used at this time provided adequate resources are available for future hours. | | | | | |
| **28** | Solicit Bids/Offers | The *IESO* will solicit *bids* and *offers* at this time.<br>The *IESO* will open the offer / bidding window and issue an advisory notice. | | | Y | | |
| **29** | Reconfigure *Transmission system* | Where an evaluation has deemed it beneficial to do so, the *IESO* will reconfigure the *transmission system* to avoid the declaration of an *emergency operating state.* | | | Y | | |
| **30** | Curtail withdrawals from self-scheduling electricity storage facility | These control actions, where available and implemented, are intended to avoid the operation to emergency condition limits.<br>The IESO will issue an advisory notice. | IESO internal procedures | | Y | | |
| **31** | Implement appropriate load curtailment according to Voluntary Demand Management (VDM) agreements | These control actions, where available and implemented, are intended to avoid the declaration of an emergency operating state. | | | Y | | |
| **32** | Issue *NERC* Energy Emergency Alert 2 (EEA-2) | The *IESO control area* has or is about to initiate load management procedures.<br>The *IESO* will open the *bidding / offer* window and issue a RCIS message and an advisory notice. | *NERC Reliability Standard* – EOP-011, Attachment 1 | | Y | | |

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| **33** | Issue a reliability declaration to call on Hydro Quebec capacity (only during summer periods in which Hydro Quebec has committed capacity to the *IESO*) | A reliability declaration must be made to obligate Hydro Quebec to provide firm *energy* per the requirements of the IESO/Hydro Quebec Amended and Restated Capacity Sharing Agreement and/or the 2024 Capacity Sharing Agreement.<br>The *IESO* will issue an advisory notice. | *IESO* internal procedures | | Y | | |
| **34** | Issue an advisory notice for the declaration of an *emergency operating state* | Issue an advisory notice to indicate the declaration of the *emergency operating state*.<br>The IESO will issue a RCIS message. | *Market Rules* – Chapter 7 Section 12.1.3.3 | | Y | | |
| **35** | Give advance warning to the Ministry of the Environment, Conservation and Parks (MECP) Spills Action Centre (by phone<br>1-800-268-6060) and the Ministry of Natural Resources and Forestry (MNRF) Provincial Emergency Response Coordinator (1-866-898-7372) of potential for Environmental Variance request from *market participants*. | This will allow MECP and MNRF time to alert their Regional Offices and be prepared to approve Environmental Variance Requests.<br>The *IESO* will only provide this notification if the situation is expected to progress to the point where environmental variance requests will be required. | *IESO* internal procedures | | Y | | |
| **36** | Request *market participants* to seek prior approval of environmental variances | The *IESO* will request *market participants* to seek prior approval for environmental variances.<br>The *IESO* will issue an advisory notice. | *IESO* internal procedures | | Y | | |
| **37** | Purchase *emergency energy* and request *emergency* assistance | The *IESO* will purchase resources not made available through market mechanisms. These purchases are made to maintain 10-minute *operating reserve* and are not providing support to the exports that may be flowing at the time. The source of the purchases should be the seller's surplus *energy* or 30-minute *operating reserve*. | *Market Rules* – Chapter 5 Section 2.3.3A | | Y | | |

<table>
<tr><th>No.</th><th>Action</th><th>Description</th><th>References</th><th>A</th><th>B</th><th>C</th><th>D</th></tr>
<tr><td></td><td></td><td>The IESO will issue an advisory notice.</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="8">The IESO is no longer operating to respect the 30-minute or 10-minute non-synchronized operating reserve requirement and has only enough resources available to meet the 10-minute synchronized operating reserve and minimum regulation requirements. The preceding control actions were insufficient to maintain 10-minute non-synchronized operating reserve.</td></tr>
<tr><td>38</td><td>Give warning to the Ministry of the Environment, Conservation and Parks (MECP) Spills Action Centre (by phone 1-800-268-6060) that the IESO is about to request market participants to implement thermal environmental variances.</td><td>This will allow MECP to alert their Regional Offices that the market participants are about to be requested by the IESO to implement their nuclear and gas environmental variances.</td><td>IESO internal procedures</td><td></td><td></td><td>Y</td><td></td></tr>
<tr><td>39</td><td>Implement MECP thermal environmental variances.</td><td>The IESO will request market participants to implement available MECP environmental variances to allow thermal generators (nuclear, gas) to increase their output.<br>The IESO will open the offer / bidding window and issue an advisory notice.</td><td>IESO internal procedures</td><td></td><td></td><td>Y</td><td></td></tr>
<tr><td>40</td><td>Disregard High-Risk Limits</td><td>This action will allow the IESO to make additional bottled energy available at the expense of increased risk to system security.<br>The IESO will open the offer / bidding window and issue an advisory notice.</td><td>IESO internal procedures</td><td></td><td></td><td>Y</td><td></td></tr>
<tr><td>41</td><td>Purchase emergency energy and request emergency assistance</td><td>The IESO will purchase resources not made available through market mechanisms. The source of the purchases should be the seller’s surplus energy or 30-minute operating reserve made available by Step 38: Disregard High Risk Limits.<br>The IESO will issue an advisory notice.</td><td>Market Rules – Chapter 5 Section 2.3.3A</td><td></td><td></td><td>Y</td><td></td></tr>
<tr><td colspan="8">The IESO is no longer operating to respect the 10-minute synchronized operating reserve requirement and has only enough resources available to meet the minimum regulation requirements.</td></tr>
</table>

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| **42** | Issue *NERC* Energy Emergency Alert 3 (EEA-3) | This *publishes* to all that either:<br>• Firm load interruption is imminent or in process, or<br>• The *IESO* is short of 10-minute *operating reserve*.<br>These alerts are posted on the *NERC* public website.<br>The *IESO* will issue a RCIS message and an advisory notice. | *NERC Reliability Standard* – EOP-011, Attachment 1 | | | Y | |
| **43** | Implement 3% voltage reductions | The *IESO* has reduced voltage by 3% at the distribution level. Power quality affected but no “real” load cut.<br>The *IESO* will issue an advisory notice and RCIS message. | *Market Rules* – Chapter 5 Section 10.3 | | | | Y |
| **44** | Implement 5% voltage reductions | The *IESO* has reduced voltage by 5% at the distribution level. Power quality affected but no “real” load cut. Expect significant customer complaints and requests for *exemption.*<br>The *IESO* will issue an advisory notice and RCIS message. | *Market Rules* – Chapter 5 Section 10.3 | | | | Y |
| **45** | Give warning to the Ministry of Natural Resources and Forestry (MNRF) (1-866-898-7372) that the *IESO* is about to request *market participants* to implement environmental variances | This will allow MNRF to alert their Regional Offices that the *market participants* are about to be requested by the *IESO* to implement their hydroelectric environmental variances. | *IESO* internal procedures | | | | Y |
| **46** | Implement all necessary remaining approved environmental variances. | The *IESO* will request *market participants* to implement all remaining approved environmental variances.<br>The *IESO* will open the *bidding / offer* window and issue an advisory notice. | *IESO* internal procedures | | | | Y |

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| **47** | Operate to Emergency Condition Limits | This action will allow the *IESO* to make additional bottled *energy* available at the expense of increased risk to system *security*.<br>The *IESO* will open the *bidding/offer* window, issue a RCIS message and an advisory notice. | *IESO* internal procedures | | | | Y |
| **48** | Purchase *emergency energy* and request *emergency* assistance | The *IESO* will purchase resources not made available through market mechanisms. The source of the purchases should be the seller's surplus *energy* or *operating reserve* including 10-minute *operating reserve* made available by Step 46: Operate to Emergency Condition Limits.<br>The *IESO* will issue an advisory notice. | *Market Rules* – Chapter 5 Section 2.3.3A | | | | Y |
| **49** | Curtail *non-dispatchable load* | *Curtailment* achieved through *emergency* block or rotational load shedding.<br>The *IESO* will issue a RCIS message and an advisory notice. | *Market Rules* – Chapter 5 Section 10.3 | | | | Y |

## B.2 Emergency Operating State Actions (IESO and External Control Area Deficiency)

Legend applied to the last four columns of the table, indicating the status of the *IESO-controlled grid* associated with each control action:

**A** 30-minute operating reserve, 10-minute operating reserve and regulation reserve maintained

**B** 10-minute *operating reserve* and *regulation* reserve maintained

**C** 10-minute synchronized *operating reserve* and *regulation* reserve maintained

**D** *Regulation* reserve maintained

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| **<u>Initial actions</u>**<br>The *IESO* will:<br>• Utilize all *dispatchable* resources including Ontario *dispatchable load/generation* and electricity storage, *bid* at +MMCP to satisfy *demand* and reserve requirements.<br>• Provide notices of expected supply shortfall, reject, revoke, and recall *outages*, cancel commissioning test and take all other acceptable control actions as articulated in the section B.1 to minimize the deficiency.<br>• Include voltage reduction as sources of *operating reserve.*<br>***At this point all remaining exports would be supplying non-dispatchable load in the deficient jurisdiction and it would be in a state comparable to the Ontario "Emergency Operating State". The following actions will be taken as long as the deficient area remains in a comparable or more severe state:*** | | | | | | | |
| **1** | Curtail exports[21] to jurisdictions not purchasing *emergency energy* or taking equivalent action. | | *Market Rules* – Chapter 5 Section 2.3<br>*IESO* internal procedures | | | Y | |
| **2** | Purchase *Emergency Energy* and request *emergency* assistance. | Purchase resources not made available through market mechanisms.<br>The *IESO* will issue an advisory notice. | *Market Rules* – Chapter 5 Section 2.3.3A | | | Y | |
| **3** | Curtail exports[19] to jurisdictions not implementing 3% voltage reduction or taking equivalent action. | | *Market Rules* – Chapter 5 Section 2.3<br>*IESO* internal procedures | | | Y | |

[21] With the exception of capacity exports **unless the backing resource that has committed its capacity has not been scheduled or is not outputting to the full amount of the capacity export**, at which point the capacity export may be curtailed to the lower of the resource's schedule or output.

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| **4** | Implement 3% voltage reductions in Ontario. | The *IESO* has reduced voltage by 3% at the distribution level. Power quality affected but no "real" load cut.<br>The *IESO* will adjust the real time unconstrained demand and will issue a RCIS message and an advisory notice. | *Market Rules* – Chapter 5 Section 10.3 | | | Y | |
| **5** | Curtail exports[19] to jurisdictions not implementing 5% voltage reduction or taking equivalent action. | | *Market Rules* – Chapter 5 Section 2.3<br>*IESO* internal procedures | | | Y | |
| **6** | Implement 5% voltage reductions in Ontario. | The *IESO* has reduced voltage by 5% at the distribution level. Power quality affected but no "real" load cut. Expect significant customer complaints and requests for *exemption*.<br>The *IESO* will adjust the real time unconstrained demand and will issue a RCIS message and advisory notice. | *Market Rules* – Chapter 5 Section 10.3 | | | | Y |
| **7** | Curtail exports[19] to jurisdictions not operating to emergency condition limits (or disregarding high-risk limits). | | *Market Rules* – Chapter 5 Section 2.3<br>*IESO* internal procedures | | | | Y |
| **8** | Operate to *emergency* condition limits (or disregard high-risk limits) in Ontario. | This action will allow the *IESO* to make additional bottled *energy* available at the expense of increased risk to system *security*.<br>The *IESO* will open the bidding/offer window, issue a RCIS message and an advisory notice. | *IESO* internal procedures | | | | |
| **9** | Curtail remaining exports[19]. | | *Market Rules* – Chapter 5 Section 2.3 | | | | Y |

| No. | Action | Description | References | A | B | C | D |
|---|---|---|---|---|---|---|---|
| **10** | If Hydro Quebec has issued a reliability declaration to the *IESO*, curtail Ontario *non-dispatchable loads* to support firm *energy* export to Hydro Quebec (pro-rata with Hydro Quebec to equalize load shedding in both *control area*, up to the *IESO* capacity quantity) | To be applied only when *IESO* has committed capacity to Hydro Quebec via the IESO/Hydro Quebec 2024 Capacity Sharing Agreement. | *IESO* internal procedures | | | | Y |
| **11** | Curtail Ontario *non-dispatchable loads*. | *Curtailment* achieved through *emergency* block or rotational load shedding.<br>The *IESO* will adjust the real time unconstrained demand and will issue a RCIS message and an advisory notice. | *Market Rules* – Chapter 5 Section 10.3 | | | | Y |

**– End of Section –**

# Appendix C: Cyber Security Incident Reporting

The *market participant* is expected to:

- notify the *IESO* Shift Control Specialist (SCS), by telephone, and provide the required minimum information; and
- submit the applicable reporting form (C.4 or C.5) to the *IESO* SCS at scs@ieso.ca.

For information that is unknown, *market participants* are requested to make an interim report and then subsequently update the interim report of any new or changed information.

<u>*Security*-sensitive information must not be included in the emailed report. Such information should be protected and provided in a manner deemed appropriate by the *market participant*.</u>

## C.1 Reporting Timelines

Reporting timelines for *market participants* who are subject to CIP-008,

- within 60 minutes of determining that a Cyber Security Incident is a Reportable Cyber Security Incident; or
- by the end of the next calendar day of determining that a Cyber Security Incident was an attempt to compromise an BES Cyber System, Electronic Security Perimeter (ESP), or an Electronic Access Control or Monitoring System (EACMS); or
- within seven calendar days of determination of any new or any changed information that was previously reported.

Reporting timelines for *market participants* who are subject to CIP-003, are as per the *market participant* own Cyber Security Incident response plan.

## C.2 When Email is Unavailable

If a market participant is unable to reach the *IESO* SCS via email due to system unavailability or other reasons, telephone the *IESO* SCS at 905-855-6200, and dictate the information for the applicable reporting form (C.4 or C.5) to the *IESO* SCS.

## C.3 Minimum Information to Report

At a minimum, the following information must be provided when first notifying the *IESO* SCS of a Reportable Cyber Security Incident:

- Information about the reporting entity, including:
    - Company name; and
    - Company contact name, email, and phone number
- Date and time of recognized event.

- If the recognized event was a Reportable Cyber Security Incident, refer to form C.4 (CIP-003 or CIP-008)
    - Date and time recognized event was determined to be a Reportable Cyber Security Incident.
    - Whether the event originated in the reporting entity's system.
    - BES Assets that were compromised or disrupted.
    - BES Cyber Systems/Cyber Assets that were compromised or disrupted.
    - Reliability tasks that were compromised or disrupted by the Cyber Security Incident and how this was determined (the functional impact).
    - Status of the BES Cyber Systems/Assets (functional or non-functional).
    - Whether the event was deemed to be malicious, suspicious, or unknown.
    - Whether the BES Cyber System or BES Cyber Asset was compromised and an explanation (the attack vector used and the level of intrusion that was achieved / attempted, and the action taken to contain, eradicate, and recover from the incident).
- If the recognized event was an attempt to compromise a BES Cyber System, Electronic Security Perimeter (ESP), or Electronic Access Control or Monitoring System (EACMS), refer to form C.5 (CIP-008);
    - Date and time recognized event was determined to be an attempt to compromise a BES Cyber System, ESP, or EACMS
    - Whether the event originated in the reporting entity's system.
    - BES Assets that were associated with the attempted compromise of the BES Cyber System, ESP, or EACMS
    - BES Cyber System, ESP, or EACMS that the attempt to compromise was targeted.
    - Reliability tasks that were associated with the attempted compromise and how this was determined (the functional impact)
    - Status of the BES Cyber System, ESP, or EACMS targeted by the attempt to compromise (functional or non-functional).
    - Whether the event was deemed to be malicious, suspicious, or unknown.
    - Explanation of the event (the attack vector used and the level of intrusion that was achieved / attempted and action taken to recover)

## C.4 Reportable Cyber Security Incident Reporting Form

<table>
<tr><th colspan="5">REPORTABLE CYBER SECURITY INCIDENT REPORTING FORM</th></tr>
<tr><th colspan="2">Task</th><th colspan="3">Comments</th></tr>
<tr><td rowspan="5">1</td><td>Company Name:</td><td colspan="3"></td></tr>
<tr><td>Contact Person (Name):</td><td colspan="3"></td></tr>
<tr><td>Contact Person (Email):</td><td colspan="3"></td></tr>
<tr><td>Contact Person (Phone):</td><td colspan="3"></td></tr>
<tr><td>Submitted By (Name):</td><td colspan="3"></td></tr>
<tr><td rowspan="3">2</td><td>Date of Recognized Event (yyyy/mm/dd):</td><td colspan="3"></td></tr>
<tr><td>Time of Recognized Event (hh:mm):</td><td colspan="3"></td></tr>
<tr><td>Time Zone:</td><td colspan="3"></td></tr>
<tr><td>3</td><td>Did the event originate in your system?</td><td>☐ Yes</td><td>☐ No</td><td>☐ Unknown</td></tr>
<tr><td>4</td><td>Is this a CIP-003 or CIP-008 Reportable Cyber Security Incident?</td><td>☐ CIP-003</td><td colspan="2">☐ CIP-008</td></tr>
<tr><td>5</td><td>What BES Assets are compromised or disrupted?</td><td colspan="3"></td></tr>
<tr><td>6</td><td>What BES Cyber System or Asset is compromised or disrupted?</td><td colspan="3"></td></tr>
<tr><td rowspan="2">7</td><td>What reliability tasks were compromised or disrupted by the Cyber Security Incident and how was this determined? (functional impact)</td><td colspan="3"></td></tr>
<tr><td>How was this determined?</td><td colspan="3"></td></tr>
<tr><td>8</td><td>What is the status of the BES Cyber System or Asset following the disturbance?</td><td>☐ Functioning</td><td colspan="2">☐ Non-Functioning</td></tr>
<tr><td>9</td><td>Was the incident determined to be malicious, suspicious, or unknown?</td><td>☐ Malicious</td><td>☐ Suspicious</td><td>☐ Unknown</td></tr>
<tr><td rowspan="2">10</td><td>Was the BES Cyber System or Asset compromised?</td><td>☐ Yes</td><td colspan="2">☐ No</td></tr>
<tr><td>If yes, please provide details of the attack, what vector used and the level of intrusion that was achieved or attempted, the steps your entity has taken to contain, eradicate and recover from the incident.</td><td colspan="3"></td></tr>
</table>

## C.5 Reportable Attempted Compromise Incident Reporting Form (CIP-008)

| ATTEMPTED COMPROMISE INCIDENT REPORTING FORM | | | | |
|---|---|---|---|---|
| Task | | Comments | | |
| 1 | Company Name: | | | |
| | Contact Person (Name): | | | |
| | Contact Person (Email): | | | |
| | Contact Person (Phone): | | | |
| | Submitted By (Name): | | | |
| 2 | Date of Recognized Event (yyyy/mm/dd): | | | |
| | Time of Recognized Event (hh:mm): | | | |
| | Time Zone: | | | |
| 3 | Did the event originate in your system? | ☐ Yes | ☐ No | ☐ Unknown |
| 5 | What BES Assets associated with the attempt compromise? | | | |
| 6 | What are the BES Cyber System, ESP, or EACMS that were targeted by the attempt to compromise? | | | |
| 7 | What reliability tasks were associated with the attempted compromise? (functional impact) | | | |
| | How was this determined? | | | |
| 8 | What is the status of the BES Cyber System, ESP, or EACMS following the attempt to compromise? | ☐ Functioning | ☐ Non-Functioning | |
| 9 | Was the incident determined to be malicious, suspicious, or unknown? | ☐ Malicious | ☐ Suspicious | ☐ Unknown |
| 10 | Provide details of the attempted compromise details of the attack, what vector used and the level of intrusion that was attempted, the steps your entity has taken to contain, eradicate and recover from the incident. | | | |

**– End of Section –**

# References

| Document ID | Document Title |
|---|---|
| MDP_RUL_0002 | Market Rules for the Ontario Electricity Market |
| MDP_PRO_0022 | Market Manual 2.6: Treatment of Compliance Issues |
| MDP_PRO_0023 | Market Manual 2.7: Treatment of Market Surveillance Issues |
| MDP_PRO_0048 | Market Manual 1.4: Connection Assessment and Approval |
| IMP_PRO_0035 | Market Manual 7.3: Outage Management |
| IMO_PLAN_0001 | Market Manual 7.8: Ontario Power System Restoration Plan (OPSRP) |
| IMO_PLAN_0002 | Market Manual 7.10: Ontario Electricity Emergency Plan |
| NERC Standard CIP-003 | Cyber Security – Security Management Controls |
| NERC Standard CIP-008 | Cyber Security – Incident Reporting and Response Planning |
| NERC Standard EOP-004 | Event Reporting |
| NERC Standard EOP-011 | Emergency Operations |

**– End of Document –**