PUBLIC

Detailed Design

Market Renewal Program: Energy

Offers, Bids and Data Inputs

Detailed Design

Issue 2.0

This document provides a detailed overview of the processes related to the Offers, Bids, and Data Inputs that will be implemented for the Energy work stream of the Market Renewal Program, including related market rules and procedural requirements.

DES-21

Disclaimer

This document provides an overview of the proposed detailed design for the Ontario Market Renewal Program (MRP) and must be read in the context of the related MRP detailed design documents. As such, the narratives included in this document are subject to on-going revision. The posting of this design document is made exclusively for the convenience of *market participants* and other interested parties.

The information contained in this design document and related detailed design documents shall not be relied upon as a basis for any commitment, expectation, interpretation and/or design decision made by any *market participant* or other interested party.

The *market rules*, *market manuals*, *applicable laws*, and other related documents will govern the future market.

Document Change History

Issue	Reason for Issue	Date
1.0	First publication for external stakeholder review.	May 5, 2020
2.0	Second publication after consideration of external stakeholder feedback.	January 28, 2021

Related Documents

Document ID	Document Title
DES-13	MRP High-level Design Single Schedule Market
DES-14	MRP High-level Design Day-Ahead Market
DES-15	MRP High-level Design Enhanced Real-Time Unit Commitment
DES-16	MRP Detailed Design: Overview
DES-17	MRP Detailed Design: Authorization and Participation
DES-18	MRP Detailed Design: Prudential Security
DES-19	MRP Detailed Design: Facility Registration
DES-20	MRP Detailed Design: Revenue Meter Registration
DES-21	MRP Detailed Design: Offers, Bids and Data Inputs
DES-22	MRP Detailed Design: Grid and Market Operations Integration
DES-23	MRP Detailed Design: Day-Ahead Market Calculation Engine
DES-24	MRP Detailed Design: Pre-Dispatch Calculation Engine
DES-25	MRP Detailed Design: Real-Time Calculation Engine
DES-26	MRP Detailed Design: Market Power Mitigation
DES-27	MRP Detailed Design: Publishing and Reporting Market Information
DES-28	MRP Detailed Design: Market Settlement
DES-29	MRP Detailed Design: Market Billing and Funds Administration

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Table of Changes

This detailed design document has been updated since version 1. For more detailed information about these changes, refer to the “MRP Energy Detailed Design - Version 2.0 Updates” document.

1. Introduction

1.1. Purpose

This document is a section of the Market Renewal Program (MRP) Detailed Design document series specific to the Energy work stream. This document is meant to provide details of the business design and the requirements for *market rules*, market-facing and internal procedures, and the data flow required to support the Offer, Bids and Data Inputs processes as related to the introduction of the future day-ahead market and *real-time market*. This design document will aid the development of user requirements, business processes, *market rules* and supporting systems.

As illustrated in Figure 1–1, this document is part of the MRP detailed design document series and will provide the design basis for the development of the governing documents and the design documents.

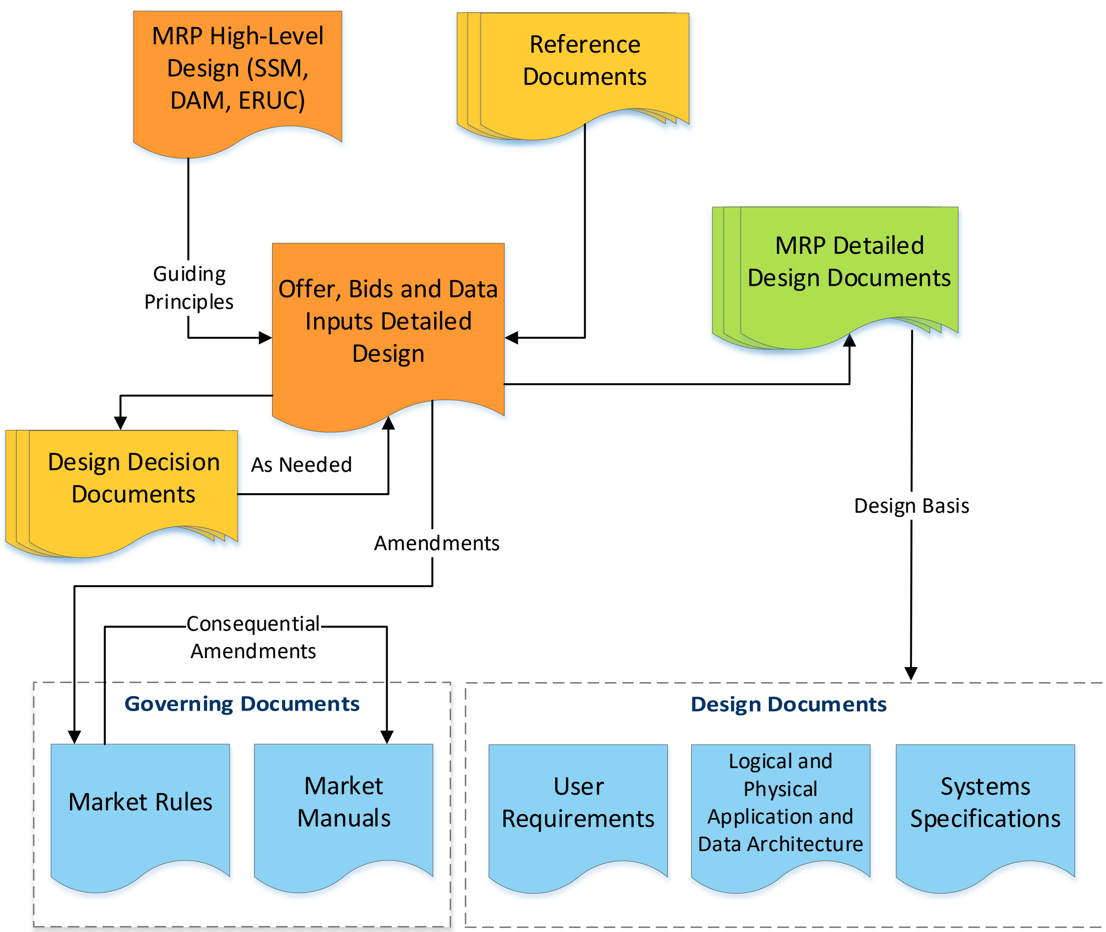

Figure 1-1: Detailed Design Document Relationships

1.2. Scope

This document describes the Offer, Bids and Data Inputs process for the future day-ahead market and *real-time market*, in terms of:

- detailed functional design;
- supporting market rule requirements;
- supporting procedural requirements; and
- business process and information flow requirements.

Various portions of this document make reference to current business practices, rules and procedures of the Offer, Bids and Data Inputs processes. However, this document is not meant as a restatement of the existing design of the *Independent Electricity System Operator* (*IESO)* process. Rather, this document focuses on existing components only to the extent that they might be used in the current or amended form in support of the future day-ahead market and *real-time market*.

1.3. Who Should Use This Document

This document is a public document for use by the MRP project team, pertinent *IESO* departments, and external stakeholders. Portions of this document that are only pertinent to *IESO* internal processes and procedures may not be incorporated into the public version.

1.4. Assumptions and Limitations

Assumptions

While this document makes references to specific parameters that might be used in the Offer, Bids and Data Inputs process, this document may not determine what the value of all those parameters might ultimately be. The value of such parameters will be determined through the development of the *market rules* and *market manuals*.

Limitations

The business process design presented in Sections 2 and 6 of this document provides a logical breakdown of the various sub-processes described in the detailed business design presented in Section 3. However, factors such as existing and future system boundaries and system capabilities may alter the ultimate design of these sub-processes.

1.5. Conventions

The standard conventions followed for this document are as follows:

- Title case is used to highlight process or component names; and
- Italics are used to highlight *market rule* terms that are defined in Chapter 11 of the *market rules*.

1.6. Roles and Responsibilities

This document does not impart any specific roles or responsibilities. This document provides the design basis for development of the documentation associated with the *IESO* Project Lifecycle that will be produced in conjunction with the MRP.

1.7. How This Document Is Organized

This document is organized as follows:

- **Section 2** of this document briefly describes the current context of the *IESO* Offer, Bids and Data Inputs processes, and its future context for the day-ahead market and *real-time market*;
- **Section 3** of this document provides a detailed description of the future Offer, Bids and Data Inputs processes;
- **Section 4** of this document describes how the Offer, Bids and Data Inputs processes will be enabled under the authority of the *market rules* in terms of existing rule provisions, amended rule provisions and additional rule provisions that will need to be developed;
- **Section 5** of this document describes how the requirements of the Offer, Bids and Data Inputs processes are expected to impact the market-facing manuals and internal procedures in terms of existing procedures, amended procedures and additional procedures that will need to be developed; and
- **Section 6** of this document provides an overview of the arrangement of *IESO* processes supporting the overall Offer, Bids and Data Inputs processes described in Section 3. This section also outlines the logical boundaries and interfaces of the various sub-processes related to the Offer, Bids and Data Inputs process in terms of existing processes, amended processes and additional processes that will need to be developed.

– End of Section –

2. Summary of Current and Future State

2.1. Offers, Bids and Data Inputs in Today's Market

Information gathered from *market participants* and the *IESO* is currently used by the *IESO's* calculation engines in the day-ahead, pre-dispatch and real-time processes to *dispatch* or schedule *generation facilities, load facilities* and *boundary entities* to meet the system needs for a given *dispatch day.*

2.1.1. Market Participant Offers, Bids and Data Inputs

Market participants must submit a variety of data in order to participate in the current day-ahead commitment process (DACP) and *real-time market*. This data includes *dispatch data, outage* data, data to provide *ancillary services* and *physical bilateral contract data*.

Registered market participants authorized to submit *dispatch data* for resources registered as dispatchable *generation facilities, dispatchable loads,* and *hourly demand response* (HDR) resources[1] must submit their *dispatch data* into the day-ahead commitment process (DACP) if they wish to be available for *dispatch* in the *real-time market*. Submitting *dispatch data* into the DACP establishes an availability declaration envelope (ADE) that defines the maximum amount of *energy* for which those resources can receive *dispatch instructions* in the *real-time market*.

Self-scheduling generation facilities, *intermittent generators* and *transitional scheduling generators* are non-dispatchable *generation facilities* that are not subject to the ADE requirement. Instead, *registered market participants* authorized to submit *dispatch data* for these *facilities* must submit into the DACP and *real-time market* the amount of *energy* they reasonably expect their *facility* to provide in each *dispatch hour*.

Market participants authorized to submit *dispatch data* for *boundary entity* resources are not required to submit *dispatch data* into the DACP. They may wait to submit their *dispatch data* in the *real-time market.*

Dispatch data includes different parameters for different types of *registered facilities* depending on their operating characteristics. For example, a *quick start*

[1] The *IESO* has replaced the *demand response auction* with a *capacity auction* to enable competition between additional resource types. All references to the *demand response auction* in this document should be read as reference to the *capacity auction*. Conforming changes required to align with the current or future *capacity auction* will be made during implementation via *market rules* and/or *market manuals*.

facility does not have all the same *dispatch data* parameters as a non-quick start (NQS) *generation facility*. The value for a specific parameter could also vary for each *dispatch hour* of a particular *dispatch day* and such parameters are known as hourly *dispatch data.* Alternatively, some parameter values could apply to all *dispatch hours* of a *dispatch day* and are known as daily *generator* data (DGD). The *IESO* uses this *dispatch data* to schedule and *dispatch* the *registered facilities* in the DACP, *pre-dispatch scheduling* and *real-time market* processes*.*

If *market participants* expect their *dispatch data* to remain the same from day to day or week to week, they can reduce the frequency of submitting this data by submitting standing *dispatch data* with an expiry date*.* Standing *dispatch data* is converted into active *dispatch data* and used by the various market processes unless the *market participants* revise their *dispatch data* after the standing *dispatch data* is converted to active *offers* or *bids* by the *IESO* market systems.

2.1.1.1. Dispatch Data Constructs

The *offer* and *bid* components of *dispatch data* consist of the price and quantity of *energy*. While all *facility* types submit their own *offers* or *bids* for *energy* that are used by the calculation engines, not all quantities of *energy* submitted for certain *facility* types are used in the DACP, *pre-dispatch scheduling* and *real-time market* processes. Each of these are discussed below.

Registered market participants submit the financial portion of their *dispatch data* into the DACP as start-up cost, speed no-load cost, and *energy offers* for eligible NQS *generation facilities* and only *energy offers* for all other *registered facilities*, including *boundary entities*. Three-part *offers* are comprised of *start-up cost*, *speed no-load cost*, and *energy offer*. *Start-up costs*, *speed no-load costs*, and *energy offers* allow NQS *generation facilities* to separate the fixed and variable costs associated with the supply of *energy* and *operating reserve* while respecting the physical limitations of a resource. They are currently evaluated in the DACP but are not considered by the calculation engine in the pre-dispatch hours or the *dispatch hour*.

For *variable generation, registered market participants* submit *offer* quantities equal to their available *generation capacity* into the DACP and the *real-time market*. The *IESO* then uses a forecast quantity provided by the *IESO's* centralized forecasting service to determine how much of their available *generation capacity* to schedule as *energy*.

2.1.1.2. Other Data Inputs

Market participants are also required to submit *planned outages* and *forced outages* to the *IESO* that reflect *facility* testing, a partial or full reduction in the capability of a *facility* or the removal of a *facility* from service. *Planned outages* require *IESO* approval.

Market participants may also submit their *physical bilateral contract data* (PBC data) to the *IESO* to adjust their *settlement* of the *real-time market*.

2.1.2. IESO Data Inputs

The *IESO* is responsible for providing a number of inputs into the calculation engines to use when scheduling and *dispatching registered facilities*. These inputs include *reliability* requirements, approved *outages, demand* forecasts, centralized *variable generation* forecasts and the network model. An overview of these inputs is provided below.

2.1.2.1. Reliability Requirements and Approved Outages

Reliability requirements encompass a number of inputs from the *IESO.* These include *operating reserve* (OR) and minimum/maximum area OR requirements, *security limits,* maximum import/export limits, Lake Erie Circulation (LEC) forecast, net interchange scheduling limit (NISL) and *regulation* capacity requirements. The *IESO* updates this information to reflect anticipated conditions for every *dispatch hour* of the *dispatch day.*

The *IESO* also assesses the impact of all *planned outages* and *forced outages* submitted by *market participants. Planned outages* are approved by the *IESO* if the *outage* has no adverse impact to the *reliability* of the *IESO-controlled grid*.

Reliability requirements and *outages* are used by the day-ahead calculation engine (DACE) and by the calculation engines in the pre-dispatch hours and the *dispatch hour* to schedule and *dispatch registered facilities*. *Reliability* requirements and *outages* are also *published* through the *IESO*'s *adequacy* reports.

2.1.2.2. Demand Forecasts

The *IESO* currently produces a single, province-wide *demand* forecast that is used to support scheduling and *dispatch* decisions in the DACP, *pre-dispatch scheduling* and *real-time market* processes. Hourly *demand* forecasts are used in DACP and *pre-dispatch scheduling*, while five-minute forecasts are used in the *real-time market*. The province-wide forecast is generated using historical *demand* data and expectations of future load consumption are based on a number of factors, including weather forecasts.

The hourly *demand* forecasts for a particular *dispatch day* can be manually adjusted by the *IESO* before they are used by the DACE and by the calculation engines in the pre-dispatch hours and the *dispatch hour*. Manual adjustments are typically required when expected ambient weather conditions suddenly change.

2.1.2.3. Centralized Variable Generation Forecasts

The *IESO* currently gathers *variable generation* (VG) forecasts from a *forecasting entity* for every registered *variable generation* resource and any non-registered embedded *variable generation* resource with a capacity greater than or equal to 5 MW. Forecasts for registered *variable generation* resources are used to determine schedules and *dispatch instructions* in the DACP, the *pre-dispatch schedule* and the *real-time market*. Forecasts for non-registered embedded *variable generation* resources are only used by the *IESO* in determining the province-wide *demand* forecast.

2.1.2.4. Network Model

The *IESO* is responsible for maintaining a network model that reflects the topology and operating characteristics of the various *transmission systems*, *distribution systems*, *generation facilities* and *load facilities* that make up the *IESO-controlled grid*. The network model also includes a simplified representation of power systems in neighboring jurisdictions.

The network model is maintained and updated every four to six weeks through the Network Model Build process. This process is typically used to incorporate new *facility* registrations or update existing *facility* registrations. During each Network Model Build cycle, the *IESO* develops and tests changes to the network model in a test environment before deploying the model into the production environment.

The network model is also used to determine other critical inputs for the *IESO's* calculation engines such as anticipated transmission losses, load distribution factors (LDFs), locational shadow prices and the assignment of virtual HDR resources. These inputs are maintained as data files used in the Network Model Build process.

- Transmission losses: The calculation engines use static marginal loss factors to approximate transmission losses in the scheduling and *dispatch* of *generation facilities*, *dispatchable loads* and *boundary entities*. Static marginal loss factors are calculated on a yearly basis for the upcoming year;
- Daily *dispatch* order for *variable generators:* The *IESO* determines a random daily *dispatch* order for *variable generation* resources that the real-time calculation engine uses to tie-break when two or more *variable generators* have the same *offer* price;
- Load Distribution Factors: LDFs are a set of values that define what percentage of the *demand* forecast the calculation engines should assign to each *non-dispatchable load* (NDL) in the network model. The DACE and pre-dispatch calculation engines currently use hourly LDFs that are based on the load patterns from the same day in previous weeks;

- Shadow prices: The network model includes a list of resources where shadow prices are calculated and *published*. The only resources excluded from this list are those registered as *non-dispatchable loads*. The list changes when any resource other than a *non-dispatchable load* is registered or de-registered with the *IESO;* and
- Assignment of virtual and physical HDR resources: The network model assigns a virtual HDR resource to a single bus in each of the *IESO's* ten electrical zones. This bus allows *registered market participants* to submit *dispatch data* for virtual HDR resources. For physical HDR resources, the network model assigns a resource at the physical location of the *non-disaptchable load* associated with the physical *hourly demand response capacity obligation*.

Figure 2–1 summarizes the overall context for *market participant* and *IESO* data submissions to the existing DACE, pre-dispatch and *real-time market* calculation engines. This context includes information flows between the *dispatch algorithms* and *market participants*, as well as information flows between the *offer*, *bid* and data input processes and other internal *IESO* processes.

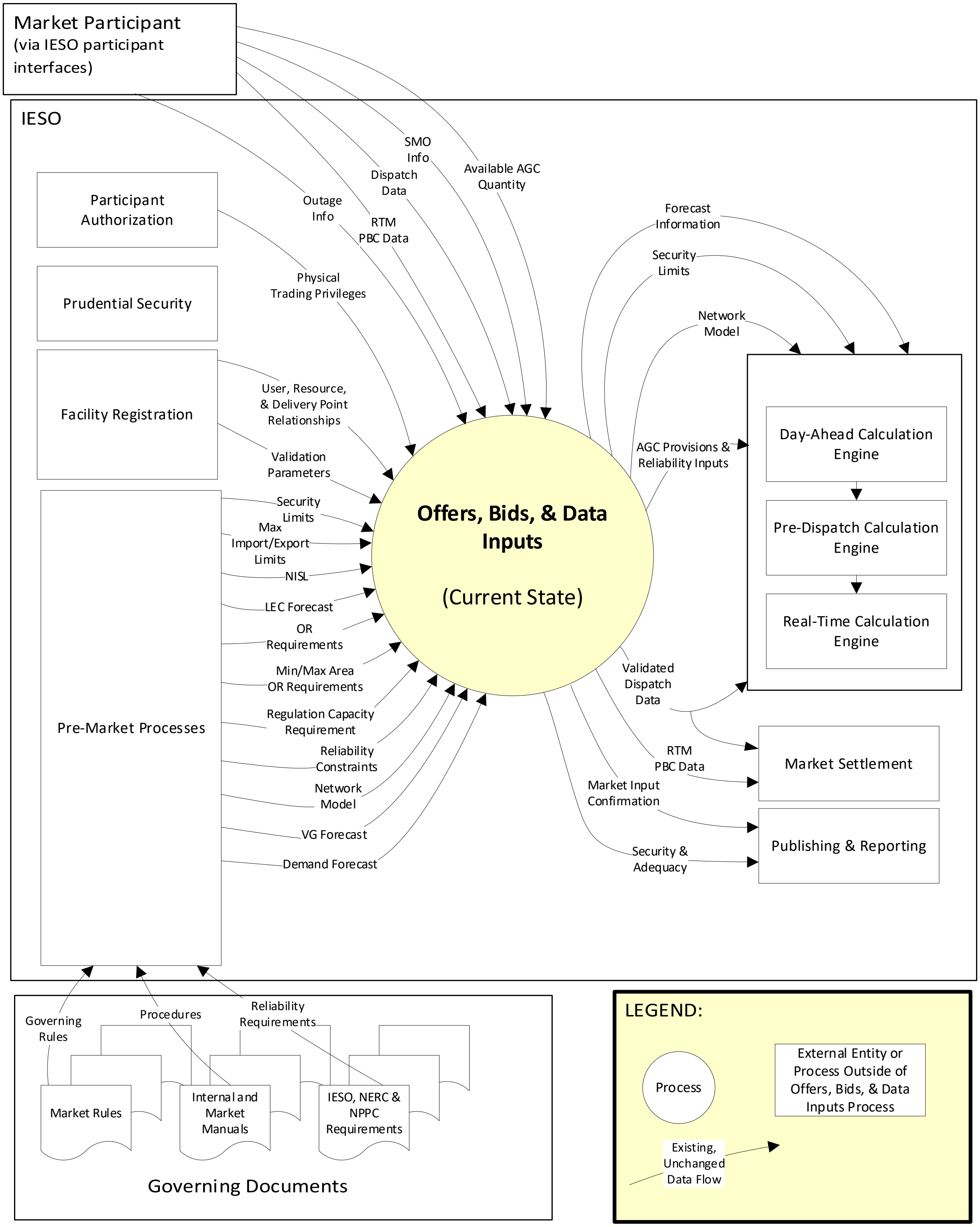

Figure 2-1: Current Offer, Bid and Data Input Processes

2.2. Offers, Bids and Data Inputs in the Future Market

In the future, the day-ahead market (DAM), pre-dispatch (PD) and real-time (RT) calculation engines will require inputs from *market participants* and the *IESO* in order to *dispatch* or schedule *generation facilities, load facilities* and *boundary entities*.

This section is organized into the data inputs that will be required from *market participants* and the *IESO* in the future day-ahead market and *real-time market.*

Some of the changes to data input requirements from *market participants* are required due to the introduction of price responsive loads (PRL) and *market participant* trading privileges for virtual transactions. These new features will only be enabled in the day-ahead market for *energy* but not for *operating reserve.*

Market participants with virtual transaction trading privileges will be authorized to submit virtual transaction *offers* to sell *energy* and virtual transaction *bids* to buy *energy* in the future day-ahead market at *IESO*-defined locations, known as virtual transaction zonal trading entities, without the expectation that they will physically supply or consume *energy* in real-time. Virtual transaction *offers* and *bids* will be validated against *trading limit* information provided by the Prudential Security process.

For PRLs, *registered market participants* will be authorized to submit *bids* to purchase *energy* in the day-ahead market.

Some of the changes to data input requirements by the *IESO* are required due to the move from a two-schedule market to a single schedule market and the introduction of a financially binding day-ahead market.

The data input requirements for both the *IESO* and *market participants* are further described in the sections below.

2.2.1. Market Participant Offers, Bids and Data Inputs

Market participants will continue to submit *dispatch data, physical bilateral contract data* and *outage* requests in order to participate in the day-ahead market and *real-time market.* The ability to submit standing *dispatch data* will also be retained.

The *dispatch data* construct will continue to represent the financial and non-financial parameters that are submitted by *market participants*. New *dispatch data* parameters will also be introduced that will result in more efficient scheduling and an enhanced ability to reflect additional physical operating constraints for specific *generation facilities.*

Dispatch data for supplying *energy* from *generation facilities* will continue to be submitted as hourly and daily parameters. Hourly *dispatch data* will continue to be referred to as hourly whereas daily *generator* data, known as DGD, will be referred to as a daily *dispatch data.* The DGD term will be effectively retired. The three-part *offer* construct used by DACE will also be effectively retired. The construct of the availability declaration envelope (ADE) currently used for the DACP will be retained for the future day-ahead market until the *IESO* determines that is no longer required.

Changes have also been made to the *offer* and *bid* constructs. The following section provides an overview of the changes to the existing *dispatch data* construct.

2.2.1.1. Dispatch Data Constructs

New hourly and daily *dispatch data* parameters will be introduced or existing parameters will be updated for *generation facilities*. These additional parameters will be required particularly for dispatchable NQS *generation facilities*, hydroelectric *generation facilities* and *variable generation*.

For NQS *generation facilities, registered market participants* will submit new daily *dispatch data* parameters to express lead time data associated with their specific thermal states. This data will be submitted as daily *dispatch data* prior to the first calculation engine run of the day-ahead market and will represent a lead time curve for hot, warm and cold states of the *generation unit*. Existing parameters, such as *minimum generation block down time* will also need to be updated to include multiple values for hot, warm and cold in order to properly evaluate lead time data.

New parameters for NQS *generation facilities* will also include speed no-load *offer* and start-up *offer dispatch data* parameters. These two new *dispatch data* parameters will replace the speed no-load cost and start-up cost parameters included in the existing three-part *offer* construct.

For eligible combined cycle *facilities*, *registered market participants* will continue to be able to elect to submit *dispatch data* using *pseudo-units*. However, the requirements for the *dispatch data* parameters that must be submitted for the *pseudo-unit* and the *dispatch data* parameters that must be submitted for the associated physical units has changed. Combined cycle *facilities* that have elected and are eligible to be represented as a *pseudo-unit* resource will now be evaluated in the DAM, PD and RT calculation engines as a *pseudo-unit*. The purpose of these changes is to obtain more feasible and consistent scheduling.

Eligible hydroelectric *generation facilities* will be able to submit additional, new *dispatch data* parameters to better reflect their physical operating constraints. Several new features will be introduced for use in the day-ahead market and *pre-dispatch scheduling* timeframes:

- Minimum hourly output, hourly must-run and minimum daily *energy* limit *dispatch data* parameters will be made available for *registered market participants* to specify minimum *energy* requirements in the day-ahead market and *pre-dispatch scheduling* timeframes;

- Linked resources, time lags and MWh ratios will be made available for *registered market participants* to specify intertemporal dependencies between adjacent upstream and downstream *generation facilities* on the same cascade river system owned by the same *market participant*;
- The *maximum number of starts per day* parameter currently available for dispatchable NQS *generation facilities* will be extended for use to dispatchable hydroelectric *generation facilit*ies; and
- *Forbidden regions* that are currently available for dispatchable hydroelectric *facilities* in the real-time market will also be used in the future day-ahead market and *pre-dispatch scheduling* timeframes.

Variable generators will now have the option to *offer* either the *IESO's* centralized *variable generation* forecast quantity or *offer* their own forecast quantity. This new *dispatch data* parameter for *variable generation* will be strictly used in the DAM calculation engine.

2.2.1.2. Other Data Inputs

Market participants will continue to be required to submit *planned outages* and *forced outages* to the *IESO* in the same manner they do today. Changes to how *market participants* submit *physical bilateral contract data* are expected to be minor.

2.2.2. IESO Data Inputs

The *IESO* will continue to be responsible for inputs of approved *outage* events, *reliability* requirements, *demand* forecasts, *variable generation* forecasts, and the network model into the DAM, PD, and RT calculation engines. To operate the future day-ahead market and *real-time market*, a number of changes will be required for these existing input parameters. Moreover, the move from a two-schedule market to a single schedule market necessitates the addition of two new *IESO* inputs related to constraint violations and market power mitigation. The existing and new inputs are described below.

2.2.2.1. Constraint Violation Penalty Curves

The new single schedule pricing and scheduling logic will require a new set of violation variables for constraint violation treatment in the pricing pass of the calculation engines. The scheduling pass will retain the existing violation variables.

2.2.2.2. Market Power Mitigation

The *IESO*'s new market power mitigation framework will require several new inputs including, but not limited to reference levels, conduct and impact thresholds and constrained area designations.

2.2.2.3. Reliability Requirements and Approved Outages

The current *reliability* inputs are expected to be retained with the exception of the control action *operating reserve*. The functionality that control action *operating reserve* currently serves will be replaced using the constraint violation penalty curve that applies to the constraints for *operating reserve.*

The *IESO* will continue to assess *planned outages* and *forced outages,* and approve *planned outages* as it does today.

2.2.2.4. Demand Forecasts

The current *demand* forecast process will continue to be used as an input for the expected load in the DAM, PD and RT calculation engines. However, with a shift to a day-ahead market and *real-time market* with locational pricing, the *demand* forecast will be generated with greater granularity to drive more accurate load forecasts and *settlement*. As a result, the *IESO* will produce the existing province-wide *demand* forecast as the sum of separate *demand* forecasts for four *demand* forecast areas.

2.2.2.5. Centralized Variable Generation Forecast

For registered *variable generation* resources, the *IESO's* centralized *variable generation* forecast will continue its representation of expected *variable generation* output within the pre-dispatch hours and the *dispatch hour*. In the day-ahead timeframe, registered *variable generators* will have the option to submit an alternative forecast with their *offers*. The centralized forecast will be used in the day-ahead timeframe if no alternative forecast is provided. Forecasts for non-registered embedded *variable generation* will also continue to be used to adjust *demand* forecast quantities.

2.2.2.6. Network Model

The network model is a key input for the *security* assessment function of the DAM, PD and RT calculation engines. The Network Model Build process will require new or updated activities to enable new features of the future day-ahead market and *real-time market.* The following list describes some of the activities in the Network Model Build process that are either new or will require revision to enable the day-ahead market and *real-time market*:

- Definitions for the virtual transaction zonal trading entities. These are required to allow *market participants* to submit virtual transactions in the day-ahead market;
- Maintaining static marginal loss factors will no longer be required as they will be replaced with dynamic marginal loss factors that are automatically

calculated by the calculation engines and reflect prevailing system conditions;

- The *IESO* will continue to determine a daily *dispatch* order for *variable generation* resources that will be used by all calculation engines to tie-break when two or more *variable generation* resources have the same *offer* price;
- New mappings of existing *load facilities* to virtual transaction zonal trading entities and the four new *demand* forecast areas;
- New assignment of physical HDR resources for price responsive load *facilities* used to fulfill a *demand response capacity obligation*; and
- New definitions for pricing locations (previously known as shadow price locations): To enable locational pricing, zonal virtual transaction pricing, and Ontario zonal pricing, the current list of pricing locations will be expanded to include all *registered facilities*.

Figure 2–2 summarizes the modified context for *market participant* and *IESO* data submissions to the future DAM, pre-dispatch and *real-time market* calculation engines. Details associated with these processes are described more fully in Section 3 of this document.

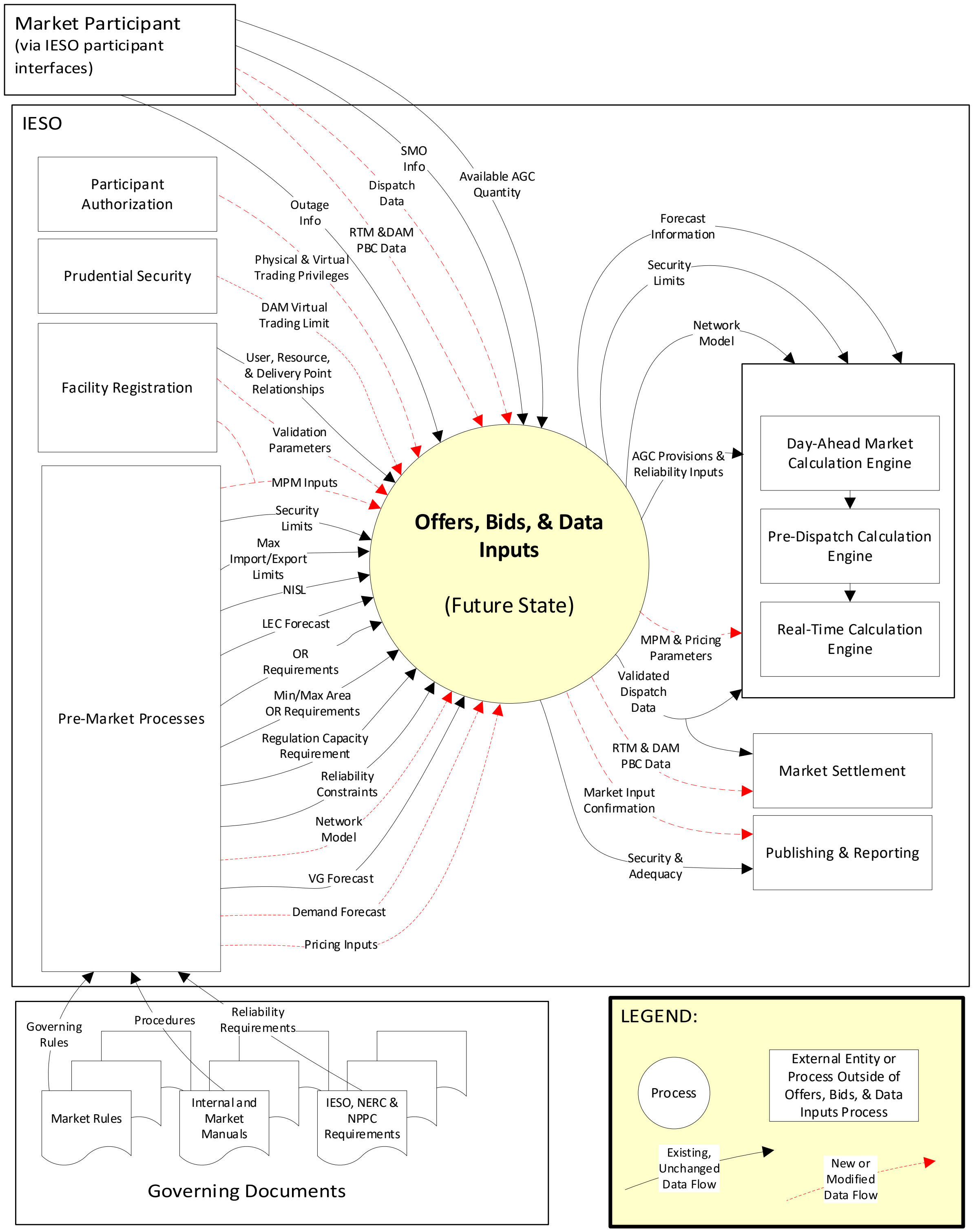

Figure 2-2: Future Offer, Bid and Data Input Processes

– End of Section –

3. Detailed Functional Design

The Offer, Bids and Data Inputs detailed design document specifies the *dispatch data* needed from *market participants* to participate in the day-ahead market or the *real-time market* and also specifies any applicable validation rules. Similarly, this document also specifies the data inputs required from the *IESO* that reflect anticipated system conditions for a particular *dispatch day*. This design document outlines the data inputs that are required to ultimately produce schedules, commitments, *dispatch instructions* and prices. It also identifies the data inputs that are new as a result of the design decisions for the future day-ahead market and *real-time market* and the data inputs that are not changing.

Information about the use of these inputs in other market processes is available in other detailed design documents. For information on specific submission timelines of this data and treatment of this data once it is submitted, refer to the Grid and Market Operations Integration detailed design document. For technical details on how the inputs are evaluated to produce schedules, commitments and prices, refer to the Calculation Engine detailed design documents.

3.1. Structure of this Section

The design of the processes related to Offers, Bids and Data Inputs in the future day-ahead market and *real-time market* will be described in terms of:

- Objectives;
- Day-Ahead Market and Real-Time Market Participation;
- Market Participant Data Inputs; and
- IESO Data Inputs.

To realize the benefits of the future day-ahead market and *real-time market*, changes are required to the data that *market participant*s and the *IESO* need to provide. To identify these changes, this section is divided into inputs submitted by *market participant*s and inputs submitted by the *IESO*.

For *market participant* inputs, the detailed functional design describes the submission requirements for physical *dispatch data* and virtual *dispatch data*. The design will also describe the input parameters that are being retained from the current practices and the input parameters that require changes to enable the future day-ahead market and *real-time market*.

The *IESO* data inputs section provides details of the inputs that will be retained from the current process and the new or modified input parameters that will be required for the future market. The new inputs include parameters associated with market power mitigation, *demand* forecasts, constraint violation penalty curves, and the network model.

3.2. Objectives

The submission of data by *market participants* and the *IESO* is a critical step in ensuring the *security* and *adequacy* of the *IESO-controlled grid*. This data is then processed by the day-ahead market (DAM), pre-dispatch (PD) and real-time (RT) calculation engines to produce schedules, *dispatch instructions* and prices. The objective for this section is to identify the changes to data requirements for both *market participant*s and the *IESO* that are necessary to operate the future day-ahead market and the *real-time market*.

Under the *market rules*, the *IESO* is obligated to establish a process for submission of *dispatch data* for participation in the *real-time market*. Similarly, the *IESO* will be obligated to establish a means for submission of *offers*, *bids*, and other data in the day-ahead market. The process for submission of *dispatch data* in the day-ahead market will be integrated with the process for submission of *dispatch data* in the *real-time market*.

As a result, the future day-ahead market and *real-time market* design incorporates additional *offer*, *bid* and data submission requirements that will be addressed in this detailed design document.

3.3. DAM and Real-Time Market Participation

The *IESO* currently requires *registered market participants* to submit *dispatch data* into the day-ahead commitment process (DACP) as follows:

- For a dispatchable *generation facility*, a *dispatchable load* or a *hourly demand response* resource, each *registered market participant* must submit *dispatch data* into the DACP for the *dispatch hours* that they intend to be eligible for *dispatch* by the *IESO* in the *real-time market*. The maximum *offer* and *bid* quantity submitted into the DACP for each *dispatch hour* establishes an availability declaration envelope (ADE) for that *dispatch hour*. The ADE restricts the ability of a *registered market participant* to increase their *offer* or *bid* quantity after the DACP without *IESO* approval; and
- For *self-scheduling generation facilities*, *intermittent generators* and *transitional scheduling generators*, *registered market participants* must submit *dispatch data* into the DACP that indicates the amount of *energy* the *facility* reasonably expects to provide in each *dispatch hour*.

Similar to today, *registered market participants* will be required to submit *dispatch data* into the future day-ahead market as follows:

- *Registered market participants* that intend for their dispatchable *generation facility*, *dispatchable load* or *hourly demand response* resource to be eligible for *dispatch* in the *real-time market* for a given *dispatch hour* of a *dispatch day* must submit *dispatch data* into the day-ahead market for those hours;
- *Registered market participants* must submit *dispatch data* into the day-ahead market for the amount of *energy* they reasonably expect their *self-scheduling generation facility*, *intermittent generator* or *transitional scheduling generator* to provide in each *dispatch hour* of the *real-time market*; and
- *Registered market participants* that intend for their price responsive loads to consume *energy* in the real-time market for a given *dispatch hour* of a *dispatch day* must submit *dispatch data* into the day-ahead market for those hours.

The maximum *offer* quantity of *energy* for a dispatchable *generation facility* and maximum *bid* quantity of *energy* for a *dispatchable load* or *hourly demand response* resource in each hour of the day-ahead market will continue to establish the hourly ADE MW quantity for that hour. Hours for which an *offer* or *bid* is not submitted will continue to establish an ADE of 0 MW for that hour. S*elf-scheduling generation facilities, intermittent generators, transitional scheduling generators* and price responsive loads are exempt from establishing ADE quantities*.*

In the hours that a *registered market participant* submits the entire portion of its *bid* for a *dispatchable load* as non-dispatchable, the hourly ADE MW quantity will continue to be 0 MW for that hour. Where one portion of the *bid* is submitted as non-dispatchable and the remaining portion is submitted as dispatchable, the hourly ADE MW quantity will be established by the dispatchable portion of the *bid* for that hour.

A *registered market participant* that submits *dispatch data* for a dispatchable *generation facility*, *dispatchable load* or *hourly demand response* resource will continue to be permitted to increase its hourly ADE MW quantity for the following reasons:

- If the *facility* returns from *outage* earlier than planned;
- To prevent the *facility* from operating in a manner that would endanger the safety of any person, damage equipment or violate any *applicable law*; or
- If the *IESO* has solicited additional *offers* and *bids*.

The existing ADE deadband that allows for increases of up to the lesser of 2% of the ADE or 10 MW will be expanded to allow for increases of up to lesser of 15% of the ADE or 10 MW.

Hourly *dispatch data* and daily *dispatch data* (including standing *dispatch data* converted into active *dispatch data*) submitted into the day-ahead market will also be used as inputs into *pre-dispatch scheduling* and the *real-time market* if revised *dispatch data* is not submitted. Refer to the Grid and Market Operations Integration detailed design document for more information about the integration of this data between the day-ahead market and *real-time market.*

3.4. Market Participant Data Inputs

This section discusses *dispatch data* and other inputs for each type of *registered facility* to supply or consume *energy,* provide *operating reserve* or provide *ancillary services* into the future day-ahead market and *real-time market.* Additionally, this section provides details on the *outage* information and *physical bilateral contract data* that is required.

This section is structured as follows:

- Standing Dispatch Data;
- Generation Facility Dispatch Data to Supply Energy;
- Generation Facility Ancillary Services;
- Load Facility Dispatch Data to Consume Energy;
- Boundary Entities Dispatch Data for Energy;
- Dispatch Data to Supply Operating Reserve;
- Virtual Transaction Offer and Bids for Energy;
- Outage Information; and
- Physical Bilateral Contract Data.

3.4.1. Standing Dispatch Data

Market participants will continue to have the ability to submit standing *dispatch data* to provide or purchase *energy* or provide *operating reserve* into the day-ahead market and *real-time market*. Standing *dispatch data* will also continue to remain in effect until the *market participant* user-specified end date and time occurs or the standing *dispatch data* is withdrawn.

Standing *offers* to supply *energy* and *operating reserve* will provide for the submission of all current and new hourly and daily *dispatch data* parameters that are applicable to the generation resource type for which the *dispatch data* is submitted.

For *load facilities*, standing *bids* to withdraw *energy* and supply *operating reserve* will provide for the submission of the same *dispatch data* parameters used in the existing day-ahead, pre-dispatch, and real-time *dispatch* processes.

The ability to submit standing *dispatch data* will be extended to price-responsive loads (PRL) and virtual transactions in the day-ahead market only.

For more information on how standing *dispatch data* can be converted to active *dispatch data* on a daily basis, including restrictions for revisions to standing *dispatch data,* refer to the Grid and Market Operations Integration detailed design document.

3.4.2. Generation Facility Dispatch Data to Supply Energy

For the purposes of this section, a *generation facility* can either be a dispatchable *generation facility* or a non-dispatchable *generation facility.* Dispatchable *generation facilities* refer to *quick-start facilities* or non-quick-start (NQS) *generation facilities* that respond to *dispatch instructions*. *Quick-start facilities* are more specifically referred to in this section as either hydroelectric *generation facilities* or *variable generation*. NQS *generation facilities* are more specifically referred to as single cycle *generation facilities* or combined cycle *generation facilities*.

Non-dispatchable *generation facilities* refer to *generation units* that have their *energy* output scheduled by the *registered market participant* and do not respond to *dispatch instructions*. Non-dispatchable *generation facilities* will continue to be defined as either a *self-scheduling generation facility*, a *transitional scheduling generator* or an *intermittent generator*.

In the future day-ahead market and *real-time market*, several enhancements will be made to the existing *dispatch data* construct for the following dispatchable *generation facilities* to include new and modified *dispatch data* parameters:

- Dispatchable hydroelectric *generation facilities*;
- Dispatchable NQS *generation facilities*; and
- *Variable generation*.

All other dispatchable and non-dispatchable *generation facilities* will continue to submit the same *dispatch data* they are currently eligible to submit. *Dispatch data* associated with a *generation facility* will continue to be grouped into three main categories:

- Identification data – identifies the entities authorized to submit *dispatch data* and the *generation facilities* the *dispatch data* will apply to;
- Hourly *dispatch data* – where *dispatch data* values can vary from one *dispatch hour* to the next for a given *dispatch data* parameter; and

- Daily *dispatch data* – where a *dispatch data* value applies to all remaining *dispatch hours* on a given *dispatch day.*

Table 3-1 summarizes the applicability of *dispatch data* parameters to each of the *generation facility* types. An 'x' indicates that the *dispatch data* parameter can be submitted for that *facility* type. This table also identifies the parameter type and whether it is existing or new.

Table 3-1: Applicability of Dispatch Data Parameters to Generation Facility Type

Dispatch Data Type	Dispatch Data Parameter	Existing or New	Generation Facility Type					
			Dispatchable					Non-Dispatchable (Self-scheduling, Transitional, Intermittent)
			NQS (Nuclear)	NQS (Other)	Quick Start (Variable Generator)	Quick Start (Hydro-electric)	Quick Start (Other)	
Id	Registered market participant name	Existing	x	x	x	x	x	x
Id	Resource type	Existing	x	x	x	x	x	x
Id	Resource name	Existing	x	x	x	x	x	x
Hourly	Energy *offer*	Existing	x	x	x	x	x	x
Hourly	Start-up *offer*	New		x				
Hourly	Speed no-load *offer*	New		x				
Hourly	*Energy* ramp rate	Existing	x	x	x	x	x	
Hourly	Minimum hourly output	New				x		
Hourly	Hourly must-run	New				x		
Hourly	*Variable generation* forecast quantity	New			x			
Daily	Linked resources, time lag and MWh ratio	New				x		
Daily	*Forbidden regions*	New				x		
Daily	Maximum daily *energy* limit	Existing		x	x	x	x	

Dispatch Data Type	Dispatch Data Parameter	Existing or New	Generation Facility Type					
			Dispatchable					Non-Dispatchable (Self-scheduling, Transitional, Intermittent)
			NQS (Nuclear)	NQS (Other)	Quick Start (Variable Generator)	Quick Start (Hydro-electric)	Quick Start (Other)	
Daily	Minimum daily *energy* limit	New				x		
Daily	Minimum loading point	Existing		x				
Daily	Minimum generation block run-time	Existing		x				
Daily	Minimum generation block down time	Existing		x				
Daily	Maximum number of starts per day	Existing		x		x		
Daily	Single cycle mode	Existing		x				
Daily	Lead time	New		x				
Daily	Ramp up *energy* to MLP (Ramp hours to MLP and *Energy* per ramp hour)	New		x				

The *IESO* will continue to validate some *dispatch data* against the corresponding *facility* registration data for the *registered facility* and *market participant*. *Registered market participants* will continue to receive a notification if the *dispatch data* is accepted or rejected. It is the responsibility of the *registered market participant* to submit *dispatch data* with sufficient time to allow for correction of the rejected *dispatch data*.

Dispatch data revisions may be subject to restrictions. Refer to the Grid and Market Operations Integration design document for additional information on revising *dispatch data* and the associated timelines.

The following sections define each *dispatch data* parameter, its purpose, submission requirements and the validation process.

3.4.2.1. Identification Data

The following information must continue to be provided to identify the entity authorized to submit *dispatch data* and the *generation facility* for which the *dispatch data* will apply.

Registered Market Participant

*Registered market participant*s will continue to be associated with a specific physical *registered facility* for the purpose of authorizing submission of *dispatch data* for the *facility* for both the *real-time market* and day-ahead market. The *registered market participant* will continue to designate individual users with authority to submit *dispatch data* for specific resources. This establishes the user-resource relationship.

The *registered market participant* will continue to be validated such that the resource name being submitted is the same resource for which the *registered market participant* was authorized to submit *dispatch data* for during the Facility Registration process.

The *registered market participant* will be required to be the same in the day-ahead market and *real-time market* for the same *registered facility*, however the user-resource relationships in the day-ahead market may differ from the user-resource relationships used for the same resource in the *real-time market*.

Resource Type

The resource type will continue to be used to identify the type of resource associated with a *registered facility,* which will be used for submission of *dispatch data* and to validate that the *registered market participant* is submitting the appropriate *dispatch data* parameters for the resource type.

For dispatchable *generation facilities,* the resource types will be:

- *Generation unit*; or
- *Pseudo-unit*.

Registered market participants that have registered *generation unit*s associated with a dispatchable NQS *generation facility* that is a *combined cycle facility* and have not registered for *generation unit* aggregation will continue to be able to submit some of their *dispatch data* for *pseudo-units* and their remaining *dispatch data* for *generation units* to receive schedules on a *pseudo-unit*. *Dispatch data for pseudo-units* are currently only submitted into the DACP. In the future, *dispatch data* for *pseudo-units* will be submitted into the day-ahead market, *pre-dispatch scheduling* and *real-time market. Dispatch data* and registration data for *pseudo-units* and *generation units* will continue to be used to calculate *pseudo-unit* technical parameters for scheduling and *settlement* purposes. *Pseudo-unit* technical parameters and their calculations are described in the DAM, PD and RT calculation engine detailed design documents. The *pseudo-unit* technical parameters that represent the MLP, dispatchable and duct firing regions of a steam turbine are described as the ST Portion of the lower, middle and upper operating region amounts (ST_OR_1, ST_OR_2 and ST_OR_3) in the Calculation Engine detailed design documents. The Market Settlement detailed design document describes these technical parameters as ST_Portion d1, d2 and d3.

The requirements for some of the *dispatch data* parameters that must be submitted for the *pseudo-unit* and for the physical *generation units* will change. Table 3-2 provides a summary of required *dispatch data* parameters for *pseudo-units* and associated *generation units*.

Table 3-2: Combined Cycle Facility Dispatch Data for Pseudo-Units and Generation Units

Dispatch Data Type	Dispatch Data Parameter	New or Existing	Pseudo - Unit	Combustion Turbine Generation Unit	Steam Turbine Generation Unit
Id	Registered market participant name	Existing	x	x	x
Id	Resource type	Existing	x	x	x
Id	Resource name	Existing	x	x	x
Hourly	Energy *offer*	Existing	x		
Hourly	Start-up *offer*	New	x		
Hourly	Speed no-load *offer*	New	x		
Hourly	*Energy* ramp rate	Existing	x		
Daily	Maximum Daily Energy Limit	Existing	x		
Daily	Minimum loading point	Existing		x	x
Daily	Minimum generation block run-time	Existing		x	
Daily	Minimum generation block down time	Existing		x	
Daily	Maximum number of starts per day	Existing		x	

Dispatch Data Type	Dispatch Data Parameter	New or Existing	Pseudo - Unit	Combustion Turbine Generation Unit	Steam Turbine Generation Unit
Daily	Single cycle mode	Existing		x	
Daily	Lead time	New		x	
Daily	Ramp up energy to MLP (Ramp hours to MLP & Energy per ramp hour)	New		x	x

*Registered market participant*s authorized to submit *dispatch data* for *generation units* associated with a *pseudo-unit* will continue to be expected to understand the impact of the value of each of the *dispatch data* parameters submitted for the *generation units* and its effect on *pseudo-unit* schedules and *dispatch instructions.*

For non-dispatchable *generation facilities* the resource types will continue to be:

- *Self-scheduling generation facilities*;
- *Intermittent generator*; or
- *Transitional scheduling generator*.

Resource Name

The resource name will continue to be used to uniquely identify a resource associated with a *registered facility* in the *IESO-administered markets*. The resource name will continue to be validated such that the *registered market participant* submitting the *dispatch data* for the resource is the same *registered market participant* authorized to do so during the Facility Registration process.

3.4.2.2. Hourly Dispatch Data

Hourly *dispatch data* will continue to be defined as a set of parameters that can be submitted for every hour and can vary from one *dispatch hour* to the next for a given *dispatch day.*

Registered market participants will be able to submit different values for the following existing and new *dispatch data* parameters for each *dispatch hour* of a particular *dispatch day*:

- Energy *offer*;
- Start-up *offer*;
- Speed no-load *offer*;

- *Energy* ramp rate;
- Minimum hourly output;
- Hourly must-run; and
- *Variable generator* forecast quantity.

Energy Offer

The *energy offer* will continue to reflect a range of incremental *price-quantity pairs* that can differ from hour to hour.

The DAM, PD and RT calculation engines will use the *energy offer* for *generation unit* resources associated with dispatchable *generation facilities* and non-dispatchable *generation facilities.*

Registered market participants currently submit *energy offers* for *generation units* that are evaluated in the DACE, PD and RT calculation engines for all *registered facilities* with the exception of dispatchable NQS *generation facilities* with registered *pseudo-units*. For dispatchable NQS *generation facilities* with registered *pseudo-units, energy offers* are submitted for *pseudo-units* for evaluation in the DACE whereas *energy offers* are submitted for *generation units* for evaluation in the PD and RT calculation engines.

In the future day-ahead market and *real-time market, registered market participants* will submit *energy offers* for *generation units* that are evaluated in the DAM, PD and RT calculation engines for all *registered facilities* with the exception of dispatchable NQS *generation facilities* with registered *pseudo-units.*

For NQS *generation facilities* with registered *pseudo-units, energy offers* will be submitted for the *pseudo-units* for evaluation in the DAM, PD and RT calculation engines.

The *energy offer* will continue to include the following inputs:

- applicable time (date/time field); and
- a minimum of two and maximum of twenty *price-quantity pairs* representing nineteen *energy* laminations.

Registered market participants will no longer be required to align their *energy offer* with the registered *forbidden regions* of a dispatchable hydroelectric *generation unit* such that the *energy offer* includes *price-quantity pairs* with quantities equal to the higher and lower limits of each registered *forbidden region.* Instead, the *forbidden regions* of a *generation unit* will be submitted as *dispatch data* and is described in the *forbidden regions* section of daily *dispatch data* described below.

The following restrictions and validations will continue to apply to the *energy offer*:

- There must always be at least two *price-quantity pairs*;

- The first quantity must equal 0.0 MW;
- Quantities must be monotonically increasing, expressed in MW or MWh per hour to one decimal place;
- Prices must be non-decreasing and not exceed two decimal places;
- Prices on the first and second *price-quantity pairs* must be the same;
- For non-dispatchable *generation facilities*, a single price will be submitted that represents the price below which the resource is expected to reduce its *energy* output to zero;
- Each price must be greater than or equal to the minimum market clearing price (negative *MMCP*) and less than or equal to the *maximum market clearing price* (*MMCP*). For resources associated with a wind *generation facility*, the price corresponding to the first 10% of the resource's available capacity must be no less than -$15/MWh, and the remaining available capacity must be priced no less than -$3/MWh. For solar factilities, the resource's entire available capacity must be priced no less than -$3/MWh. For resources associated with a nuclear *generation facility*, the price corresponding to the resource's flexible capacity, when available, must be no less than -$5/MWh;
- The quantity for any *dispatch hour* may not exceed the lesser of the registered *generation capacity,* the *maximum continuous rating*, or other maximum allowable injection associated with the *registered facility*;
- For non-dispatchable *generation facilities*, the *energy* quantity submitted should be equal to the *energy* the resource is expected to inject in each *dispatch hour*;
- If more than one *energy offer* is submitted for a specific resource in any *dispatch hour*, only the most recent valid *energy offer* is evaluated; and
- The number of *price-quantity pairs* submitted for a *pseudo-unit* must not exceed twenty divided by the number of combustion turbine *generation units* registered with a combined cycle *generation facility*.

The following new restrictions and validations will apply:

- The *energy* quantity in the second *price-quantity pair* must be greater than or equal to the minimum hourly output submitted as *dispatch data* for a generating unit resource associated with a dispatchable hydroelectric *generation facility*.

Start-Up Offer

In the future day-ahead market and *real-time market*, start-up *offers* will replace *start-up costs* and represent the dollar amount to bring an off-line resource through all the *generation unit* specific startup procedures to *minimum loading point* as *offered* by the *registered market participant.*

Currently, *start-up costs* are submitted as a single value for every *dispatch hour* of a *dispatch day*, can vary from hour to hour, and are only used as inputs to the DACE. In the future day-ahead market and *real-time market*, *registered market participants* will submit three start-up *offer* values for every *dispatch hour* of a *dispatch day* that can vary from hour to hour. The three values will represent the *offers* associated with starting a *generation unit* when it is hot, warm or cold.

Start-up *offers* will be used by both the DAM and PD calculation engines. The DAM calculation engine will use the start-up *offer* that corresponds to the hot, warm or cold operating state which will be selected by the *registered market participant* for the purposes of DAM scheduling. The PD calculation engine will evaluate each of the three start-up *offers* of hot, warm and cold submitted by the *registered market participant* based on how many hours the resource has been offline as determined by the MGBDT submitted as *dispatch data*.

Registered market participants will be eligible to submit a start-up *offer* for *generation units* and *pseudo-units* associated with a dispatchable NQS *generation facility*, excluding those with a registered primary fuel type of uranium. Start-up *offers* will be either submitted for a *pseudo-unit* if a *pseudo-unit* was registered with the NQS *generation facility*, or submitted for the *generation units* if a *pseudo-unit* was not registered. A default value of zero dollars per start will be used by the DAM and PD calculation engines if a start-up *offer* is not submitted.

NQS *generation facilities* registered with *generator offer* guarantee status will be eligible to receive a day-ahead market or pre-dispatch commitment that requires their *minimum generation block run-time* (MGBRT) to be respected by the DAM, PD and RT calculation engines for the following *dispatch day*. If the MGBRT requires the *generation facility* to run past midnight as the result of an end-of-day commitment, escalating start-up *offers* will be used for a *generation unit* that may receive a commitment for hours at the end of the *dispatch day* 0 which requires the MGBRT to be continued into the following *dispatch day* 1. The treatment of escalating start-up *offers* will be a continuation of escalating *start-up costs* currently required in the DACP. The application of escalating start-up *offers* will be a new requirement for the *pre-dispatch scheduling* process. The escalating start-up *offer* for each end of day hour of that *dispatch day* (day 0) must include the start-up *offer*, speed no-load *offer*, and *energy offer* up to the *minimum loading point* for each possible commitment hour overlapping into the next *dispatch day* (day 1) due to the length of the MGBRT. Such escalating start-up *offers* are used to capture costs for each commitment hour in *dispatch day* (day 0) for the entire MGBRT commitment in the *settlement* of *dispatch day* 0.

The following restrictions and validations will be applied to start-up *offers*:

- Submitted values must be an integer between 0 and 999999. A default value of 0 will be used if no value is submitted.

Speed-No-Load Offer

In the future day-ahead market and *real-time market*, speed-no-load *offers* will replace *speed-no-load costs* and represent the hourly dollar amount to operate a *generation unit* in a synchronized status while injecting no *energy* to the *IESO-controlled grid* as *offered* by the *registered market participant.*

Registered market participants will be able to submit speed-no-load *offers* as a single value for each *dispatch hour* of a *dispatch day* that varies from hour to hour. Speed-no-load *offers* will be used by both the DAM and PD calculation engines.

Registered market participants will only be eligible to submit a speed no-load *offer* for *generation units* and *pseudo-units* associated with a dispatchable NQS *generation facility*, excluding those with a registered primary fuel type of uranium. Speed no-load *offers* will be either submitted for a *pseudo-unit* if a *pseudo-unit* was registered with the NQS *generation facility* or submitted for the *generation units* if a *pseudo-unit* was not registered. A default value of zero dollars per hour will be used in the DAM calculation engine and will also be used in the PD calculation engine if a speed no-load *offer* is not submitted.

The following validations will be applied to speed no-load *offers*:

- Submitted values must be an integer between 0 and 99999. A default value of 0 will be used if no value is submitted.

Energy Ramp Rate

Energy ramp rate will continue to be used to specify the speed, in megawatts per minute (MW/min), at which a *generation unit* can increase or decrease its output. Similar to today's DACE, the DAM and PD calculation engines will use the *energy* ramp rate submitted for the first hour of the DAM and PD look-ahead period in determining schedules for dispatchable *generation facilities*. The RT calculation engine will continue to use the *energy* ramp rate submitted for a particular *dispatch hour* in determining *dispatch instructions*. Refer to Section 3.4.1.3 and 3.6.1.4 in the DAM, Section 3.4.1.4 and 3.6.1.4 in PD and section 3.4.1.4 and 3.6.1.4 in the RT calculation engine detailed design documents for more information.

Registered market participants will continue to be eligible to submit *energy* ramp rates for all *generation units* associated with all dispatchable *generation facilities* and *pseudo-units* associated with dispatchable combined cycle *generation facilities*. *Energy* ramp rates submitted for *generation units* will be evaluated by the DAM, PD and RT calculation engines. *Energy* ramp rates submitted for *pseudo-units* are currently only evaluated in the DACE. In the future day-ahead market and *real-time* *market, energy* ramp rates submitted for *pseudo-units* will be evaluated in the DAM, PD and RT calculation engines.

Two separate *energy* ramp rates are defined, one for increasing output (i.e. ramp up rate) and one for decreasing output (i.e. ramp down rate).

Up to five ramp MW quantity, ramp up rate, and ramp down rate value sets may be submitted for each *dispatch hour*. The ramp quantity in each set shall continue to be the maximum MW quantity at which the corresponding ramp rate values apply. The ramp quantities provided as *dispatch data* may continue to differ from the MW quantities used in the *price-quantity pairs* submitted in the *energy offer* for a particular *generation unit*.

Each ramp rate output range is defined as follows:

- Applicable time for the output range(s) (Date/Time field); and
- Ramp quantity (MW), ramp up rate (MW/min), ramp down rate (MW/min).

The following restrictions and validations will continue to apply:

- There must be at least one ramp MW quantity greater than 0.0 MW, and no more than five MW ramp quantity, ramp rate up or ramp rate down sets;
- Each ramp up rate must be less than or equal to the maximum *offer* ramp rate specified for the *generation unit* within the *generation facility* during the Facility Registration process;
- Each ramp down rate must be less than or equal to the maximum *offer* ramp rate specified for the *generation units* within the *generation facility* during the Facility Registration process;
- The ramp quantity shall be expressed in MW to one decimal place and shall be greater than 0.0MW;
- The ramp quantity must increase monotonically;
- The ramp up/ramp down values shall be expressed in MW/min to one decimal place and shall be greater than 0.0 MW/min; and
- The last MW ramp quantity for the *energy* ramp rate must be greater than or equal to the maximum quantity of the *energy offer*.

The following new validation will apply for market power mitigation:

- The *energy* ramp rate submitted as *dispatch data* must be greater than or equal to half the registered reference level for *energy* ramp rate.

Minimum Hourly Output

Minimum hourly output will be a new hourly *dispatch data* parameter used in the DAM and PD calculation engines to represent the minimum amount of *energy*, in

MWh, that a *generation unit* associated with a dispatchable hydroelectric *generation facility* must, if economic, produce in any one hour to prevent the *registered facility* from operating in a manner that, as a *dispatch instruction,* reasonably could be expected to endanger the safety of any person, damage equipment, or violate any *applicable law*.

Registered market participants will only be eligible to submit minimum hourly output quantities for *generation units* associated with a dispatchable hydroelectric *generation facility*. A minimum hourly output value can only be submitted if:

- spill restrictions are anticipated to prevent the *generation unit* from responding to *dispatch instructions* between 0 MW and the minimum hourly output value; and
- it reasonably could be expected that following a *dispatch instruction* between 0 MW and the minimum hourly output value would require the *registered facility* to operate in a manner that endangers the safety of any person, damage equipment, or violate any *applicable law*.

The *IESO* may review the submission of minimum hourly output values to confirm the *registered market participant* is in compliance with this requirement.

Minimum hourly output will be used as an input to the DAM and PD calculation engines to schedule a *generation unit* registered with a dispatchable hydroelectric *generation facility*, if economic, to no less than its minimum hourly output value for every hour a *dispatch data* value is submitted. The *generation unit* will remain fully dispatchable above the minimum hourly output value. A default value of 0 MWh will be used if a minimum hourly output is not submitted.

The following validations will apply:

- Minimum hourly output quantities submitted as *dispatch data* shall not exceed the maximum quantity of the *energy offer* for the *generation unit*; and
- Sum of all minimum hourly output quantities submitted as *dispatch data* must be less than or equal to the maximum daily *energy* limit submitted as *dispatch data* for the *generation unit*.

Hourly Must-Run

Hourly must-run will be a new hourly *dispatch data* parameter used to represent the minimum amount of *energy*, in MWh, that a *generation unit* associated with a dispatchable hydroelectric *generation facility* must produce in any one hour to prevent the *registered facility* from operating in a manner that, as a *dispatch instruction,* reasonably could be expected to endanger the safety of any person, damage equipment, or violate any *applicable law.*

Registered market participants will only be eligible to submit hourly must-run quantities for *generation units* associated with a dispatchable hydroelectric *generation facility* if the *IESO* permits the hourly must-run flag to be registered for the *generation facility* during the Facility Registration process.

An hourly must-run value can only be submitted for anticipated must-run conditions that are required to prevent the *registered facility* from operating in a manner that, as a *dispatch instruction,* reasonably could be expected to endanger the safety of any person, damage equipment, or violate any applicable law. The *IESO* may review the submission of hourly must-run values to confirm the *registered market participant* is in compliance with this requirement.

Hourly must run will be used as an input to the DAM and PD calculation engines to schedule a *generation unit* registered with a dispatchable hydroelectric *generation facility* to no less than the hourly must-run value for every hour that the value is submitted by the *registered market participant*. Hourly must-run quantities will also be respected in the RT calculation engine through the application of minimum generation constraints received as an output from the PD calculation engine. Refer to section 3.4.1.4 of the RT calculation engine detailed design document for details.

Unlike the minimum hourly output parameter, the hourly must-run value cannot result in a schedule of 0MW if the *generation unit* is considered uneconomic. Similar to the minimum hourly output parameter, the *generation unit* will remain fully dispatchable above the hourly must-run value. A default value of 0MWh will be used for hours that an hourly must-run quantity is not submitted as *dispatch data*.

The following validations will apply:

- Hourly must-run quantities submitted as *dispatch data* must be less than or equal to the maximum quantity of the *energy offer* for the *generation unit*; and
- Sum of all hourly must-run quantities submitted as *dispatch data* must be less than or equal to the maximum daily energy limit submitted as *dispatch data* for the *generation unit*.

Variable Generator Forecast Quantity

The *variable generator* forecast quantity is a new *dispatch data* parameter that will only be used by the DAM calculation engine. This parameter will allow *registered market participants* that submit *dispatch data* for *variable generation* resources to receive financially binding DAM schedules based on a forecast quantity of their choice instead of a quantity provided by the *IESO's* centralized *variable generation* forecast.

Registered market participants can choose to be scheduled to no more than the *IESO's* centralized *variable generation* forecast by leaving each hour of the *variable generator* forecast quantity blank.

If a *registered market participant* chooses to submit a forecast quantity of their choice in any *dispatch hour*, it will replace the *IESO's* centralized *variable generation* forecast and will be used by the DAM calculation engine to determine a *variable generator's* financially binding DAM schedule for that *dispatch hour*. Refer to the DAM Calculation Engine detailed design document for additional information about the evaluation of the *variable generator* forecast quantity.

Registered market participants submitting *dispatch data* for a *variable generation* resource will still be required to submit *offers* in the form of *price-quantity pairs* with the last quantity being their total installed capacity net any de-rates or *outages* in each *dispatch hour*. As described in the *energy offer* section of hourly *dispatch data*, the *offer* price in the *price-quantity pair* (excluding the first 10% of the available capacity of a wind *generation facility*) must still be no less than -$3/MWh. The *offer* price in the *price-quantity pair* corresponding to the first 10% of the available capacity of a wind *generation facility* must still be no less than -$15/MWh.

3.4.2.3. Daily Dispatch Data

Daily *dispatch data* will be defined as a set of parameters that are each submitted as a single value and are applied to all *dispatch hours* of a specified *dispatch day*. This type of *dispatch data* is currently only used by the DACE. However, in the future day-ahead market and *real-time market*, both the DAM and PD calculation engines will use these *dispatch data* parameters. The following existing and new parameters will be available for submission as daily *dispatch data:*

- Linked resources, time lag and MWh ratio;
- *Forbidden regions*;
- Maximum daily *energy* limit (Max DEL);
- Minimum daily *energy* limit (Min DEL);
- Single cycle mode;
- *Maximum number of starts per day*;
- *Minimum loading point* (MLP) ;
- *Minimum generation block run-time* (MGBRT) ;
- *Minimum generation block down time* (MGBDT) ;
- Lead time; and
- Ramp up *energy* to MLP.

The following sections describe each daily *dispatch data* parameter, its purpose and the restrictions and validations that are required for the future day-ahead market and *real-time market*.

Linked Resources, Time Lag and MWh Ratio

Linked resources, time lag and MWh ratio will be three new daily *dispatch data* parameters used to represent the *energy* production and time lag relationship between generation resources on a hydroelectric cascade river system. The *energy* produced by upstream resources require a proportional amount of *energy* to be produced by downstream resources after a period of time to prevent downstream resources from operating in a manner that, as a *dispatch instruction*, reasonably could be expected to endanger the safety of any person, damage equipment, or violate any *applicable law*.

These parameters will only be available to *registered market participants* submitting *dispatch data* for dispatchable generation resources that are registered with a minimum hydraulic time lag of less than 24 hours to downstream dispatchable generation resources. The upstream and downstream generation resources must also be owned by the same *market participant*. Refer to time lag parameter in the Facility Registration detailed design document for eligibility requirements.

Registered market participants will have the ability to link eligible resources such that all of the hourly *energy offers* for the upstream resource will be evaluated with all of the hourly *energy offers* for the linked downstream resource

Upstream and downstream resources that have been registered with shared daily *energy* limits can also be linked as an upstream or downstream set. The set of one or more upstream resources that share a daily *energy* limit may be linked to a set of one or more downstream resources that share a daily *energy* limit.

Time lag represents the amount of time it takes for the water discharged from the upstream resource to reach a linked downstream resource*. Registered market participants* would submit a time lag value of zero to indicate that the *energy offers* for the linked resources must be scheduled in the same *dispatch hour.* A time lag value of greater than zero would indicate the linked resources must be scheduled with a delay between them.

MWh ratio represents a proportional amount of *energy* that must be scheduled at a linked downstream resource for every MWh of *energy* scheduled at the upstream resource.

Linked resource, time lag and MWh ratio values can only be submitted for anticipated intertemporal dependencies that are required to prevent downstream resources from operating in a manner that, as a *dispatch instruction*, reasonably could be expected to endanger the safety of any person, damage equipment, or violate any applicable law. The *IESO* may review the submission of these parameter values to confirm the *registered market participant* is in compliance with this requirement.

The DAM and PD calculation engines will evaluate the *energy offers* for linked resources, and if optimal to do so, schedule linked resources in respect of the time lag and MWh ratios submitted as *dispatch data*. A scheduling example is illustrated in Table 3-3 below.

Table 3-3: Scheduling Example for Linked Resources

Generation Resource	Linked to Generation Resource	Time Lag	MWh Ratio	Generation Resource Hourly Energy Schedules (MWh)										
				HE01 to HE06	HE07	HE08	HE09	HE10	HE11 to HE18	HE18	HE19	HE20	HE21	HE22 to HE24
A	B	1 hour	1.0 : 1.5		50					50				
B	C	2 hour	1.0 : 0.8			75					75			
C	D	0 hour	1 : 1					60					60	
D	n/a	n/a	n/a					60					60	

The following *dispatch data* validations and restrictions will apply:

- Unless two or more resources are registered to share daily *energy* limits, only one upstream resource can be linked to one of the downstream resources that it is registered to have a time lag with;
- Where two or more upstream resources are registered to share daily *energy* limits, those upstream resources can only be linked to either:
    - one of the downstream resources they are registered to have a time lag with; or
    - two or more downstream resources they are registered to have a time lag with, as long as the downstream resources are also registered to share daily *energy* limits;
- The time lag value must be a whole number that is greater than or equal to 0 hours and less than or equal to the registered time lag between the linked resources;
- The time lag and MWh ratio values must be identical for upstream resources that are registered as having shared daily *energy* limits; and

- The MWh ratio values must be greater than 0 and up to two decimal places.

Forbidden Regions

Forbidden regions will be a new daily *dispatch data* parameter used to represent one or more operating ranges, in MW, within which a hydroelectric *generation unit* cannot maintain steady state operation without causing equipment damage.

Registered market participants will only be permitted to submit *forbidden region* quantities for *generation units* associated with a dispatchable hydroelectric *generation facility* that have been registered to submit this *dispatch data* parameter during the Facility Registration process.

Forbidden regions are currently registered during the Facility Registration process and used only by the RT calculation engine to prevent a hydroelectric *generating unit* from receiving sustained *dispatch instructions* within the registered *forbidden regions*. *Registered market participants* are also required to align their *energy offer* quantities with the registered *forbidden region* quantities for the RT calculation engine to respect those regions. In the future day-ahead market and *real-time market*, *forbidden regions* will continue to be registered and used to validate the submission of *forbidden regions* as daily *dispatch data.*

Forbidden regions submitted as *dispatch data* will consist of upper and lower limit values that the DAM and PD calculation engines will use to schedule a *generation unit* such that the *generation unit* will not receive hourly schedules within the *forbidden regions.* The RT calculation engine will continue to prevent a sustained *dispatch instruction* within the submitted *forbidden regions* by ramping the resource through the *forbidden region* at its maximum *ramp rate*. *Registered market participants* will not be required to align their *energy offer* quantities with the *forbidden region* quantities submitted as registration data or *dispatch data*.

If null values are submitted for the upper and lower limits of a given *forbidden region,* that *forbidden region* will not be respected by the DAM, PD and RT calculation engines. The following validations and restrictions will apply:

- A maximum of five *forbidden regions* may be submitted as *dispatch data* for each generation resource;
- The number of *forbidden regions* submitted as *dispatch data* must equal the number of *forbidden regions* provided as registration data;
- A lower limit and an upper limit must be submitted for each *forbidden region*; and
- A null value submitted for the upper or lower limit of given a *forbidden region* must be accompanied by a null value for the corresponding lower and upper limit in the same *forbidden region*.

Where null values are not submitted, the following validations and restrictions will apply:

- The upper limit submitted as *dispatch data* must be greater than the lower limit submitted as *dispatch data* for each *forbidden region*;
- The upper limit submitted as *dispatch data* for each *forbidden region* must be less than or equal to the registered upper limit;
- The lower limit submitted as *dispatch data* for each *forbidden region* must be greater than or equal to the registered lower limit; and
- If more than one *forbidden region* is submitted, the lower limit for each successive *forbidden region* must be greater than the upper limit from the previous *forbidden region*.

Maximum Daily Energy Limit (Max DEL)

Max DEL will continue to be defined as the maximum amount of *energy*, in MWh, that a *generation unit* can be scheduled to supply in a *dispatch day*. Max DEL is currently used by the DACE and the PD calculation engine to schedule a *generation facility* until the Max DEL has been reached.

In the future day-ahead market and *real-time market*, Max DEL will be used by both the DAM and PD calculation engines to schedule *generation units* and *pseudo-units* that have limited amounts of *energy* they are able to supply within a *dispatch day.*

Registered market participants will continue to be able to submit Max DEL for *generation unit*s associated with all dispatchable *generation facilities* unless *pseudo-units* are registered with a dispatchable combined cycle *generation facility*. Where *pseudo-units* are registered, the *registered market participant* will submit Max DEL for the *pseudo-unit*, not the *generation unit.*

The *price quantity pairs* submitted for a *generation unit* or *pseudo-unit* will be scheduled up to the Max DEL value for that *price quantity pairing* such that if the *price-quantity pair* is economic in a particular *dispatch hour* for more than is available on the Max DEL, the schedule will be limited to respect the Max DEL.

Registered market participants will also be able to submit a single Max DEL value for two or more dispatchable hydroelectric *generation unit* resource types that are registered as sharing the same forebay. The DAM and PD calculation engines will use the single Max DEL to evaluate the *energy offers* for those *generation units* such that the sum of their hourly schedules across a *dispatch day* do not exceed the Max DEL*.* Refer to the DAM and PD Calculation Engine detailed design documents for more information on how the Max DEL will be evaluated.

The following validations and restrictions will continue to apply:

- Max DEL must be between 0.0 and 999999.9 and the precision must not exceed 1 decimal place; and
- Max DEL must be greater than or equal to the *energy* required to operate a resource at MLP.

Submission of Max DEL is optional and if left blank, null is assumed to be infinite. The following new validations and restrictions will apply:

- For dispatchable hydroelectric *generation facilities*, Max DEL must be greater than or equal to the submitted minimum daily energy limit (Min DEL) value.

Minimum Daily Energy Limit (Min DEL)

Min DEL will be a new *dispatch data* parameter that represents the minimum amount of *energy*, in MWh, that a *generation unit* must be scheduled to supply within a *dispatch day* to prevent the *registered facility* from operating in a manner that would endanger the safety of any person, damage equipment, or violate any *applicable law*. This parameter will be used by both the DAM and PD calculation engines. Min DEL will also be respected in the RT calculation engines as described in the Grid and Market Operations Integration detailed design Section 3.7.2.2.

This parameter will only be available to *registered market participants* submitting *dispatch data* for *generation units* registered with a dispatchable hydroelectric *generation facility*. A Min DEL value can only be submitted for anticipated daily must-run conditions that are required to prevent the *registered facility* from operating in a manner that, as a *dispatch instruction*, reasonably could be expected to endanger the safety of any person, damage equipment, or violate any applicable law. The *IESO* may review the submission of Min DEL values to confirm the *registered market participant* is in compliance with this requirement.

Registered market participants will also be able to submit a single Min DEL value for two or more dispatchable hydroelectric *generation unit* resource types that are registered as sharing the same forebay. The DAM and PD calculation engines will use the single Min DEL to evaluate the *energy offers* for those *generation units* such that the sum of their hourly schedules are greater than or equal to the Min DEL. If this parameter is left blank, it will default to 0 MWh.

The following validations and restrictions will apply:

- Min DEL must be less than or equal to the sum of all hourly *energy* quantities submitted with the *energy offer* for a given *dispatch day*; and
- Min DEL must be less than or equal to the maximum daily *energy* limit (Max DEL) submitted as *dispatch data* for a given *dispatch day*.

Single Cycle Mode

Single cycle mode will continue to be defined as the mode of operating a combined cycle *generation facility*'s combustion turbine *generation unit* without the associated steam turbine *generation unit(s)*. This parameter is currently only used by the DACE. In the future day-ahead market and *real-time market*, the DAM, PD and RT calculation engines will use this parameter.

A *registered market participant* will continue to be able to select single cycle mode for the combustion turbine *generating unit* associated with the *pseudo-unit* registered with the combined cycle *generation facility*. If selected, the steam turbine *generation unit* contribution to the *pseudo-unit* will not be used by the DAM, PD and RT calculation engines. If not selected, the DAM, PD and RT calculation engines will continue to use the steam turbine contribution to evaluate the *pseudo-unit* as a combined cycle *generation facility* based on the registered *generation capacity* of both the combustion turbine *generation unit* and steam turbine *generation unit*, the registered steam turbine *generation unit* contribution to the *pseudo-unit*, and the submitted *dispatch data* associated with the *generation unit* or *pseudo-unit* as presented in this chapter.

Maximum Number of Starts Per Day

The *maximum number of starts per day* (MNSPD) parameter will continue to be defined as the maximum number of times a *generation unit(s)* associated with a resource can be started within a *dispatch day*.

This parameter will continue to be available to *registered market participants* submitting *dispatch data* for a dispatchable NQS *generation facility*, excluding those with a registered primary fuel type of uranium. MNSPD will be extended to *registered market participants* submitting *dispatch data* for generation resources registered as dispatchable hydroelectric *generation facilities*.

MNSPD is currently only used by the DACE. In the future day-ahead market and *real-time market,* both the DAM and PD calculation engines will use this parameter.

For dispatchable NQS *generation facilities* with or without a registered *pseudo-unit,* MNSPD will continue to only be submitted for the combustion turbine *generation unit* and not for the *pseudo-unit*. The MNSPD submitted for the combustion turbine *generation unit* will be used as the MNSPD for the *pseudo-unit* by the DAM and PD calculation engines.

For dispatchable hydroelectric resources registered as single *generation unit* or an aggregate of *generation units,* MNSPD will be submitted for the resource. The DAM and PD calculation engines will evaluate the MNSPD using the new start indication value registration parameter. Registered start indication values will be used to represent scheduling quantities that, when surpassed, indicate additional starts on units within an aggregated resource. Refer to the Facility Registration detailed design document for more information about how the start indication value will be used to count the *maximum number of starts per day* for dispatchable hydroelectric generation resources.

The following validations and restrictions will continue to apply for dispatchable NQS *generation facilities*:

- MNSPD submitted as *dispatch data* must be a number between 1 and 24 starts per day. If MNSPD is not submitted, a default value of 24 starts per day will be used by the DAM calculation engine. The PD calculation engine will be enhanced to use the same default value the DAM calculation engine uses.

The following new validations will apply for dispatchable hydroelectric resources registered as an aggregate of *generation units*:

- MNSPD must be less than or equal to 24 times the number of gen*eration units* registered within the aggregate.

The following new validations will apply for market power mitigation:

- MNSPD submitted as *dispatch data* must be greater than or equal to 50% of the MNSPD reference level registered for the *generation* resource during the Facility Registration process or greater than or equal to 1.

Minimum Loading Point

Minimum loading point (MLP) will continue to represent the minimum MW output that a *generation unit* must maintain to remain stable without the support of ignition. MLP is currently only used by the DACE. In the future day-ahead market and *real-time market*, both the DAM and PD calculation engines will use the MLP to schedule a *generation unit*, if economic, to no less than its MLP value.

Registered market participants will be required to submit MLP values for a dispatchable NQS *generation facility*, excluding those with a registered primary fuel type of uranium. For dispatchable NQS *generation facilities* with a registered *pseudo-unit,* MLP will continue to only be submitted for the combustion turbine *generation unit* and the steam turbine *generation unit*, and not for the *pseudo-unit.* The DAM and PD calculation engines will use the MLP for the *pseudo-unit* that is equal to the sum of the MLPs submitted for the combustion turbine *generation unit* and the 1-on-1 MLP submitted for the steam turbine *generation unit*. If the *pseudo-unit* is operating in single cycle mode, then the MLP for the *pseudo-unit* will be equal to the MLP submitted for the combustion turbine *generation unit*.

A steam turbine *generation unit* that is registered with a combined cycle *generation facility* and not registered for resource aggregation (regardless of whether or not the *registered market participant* has elected to use the *pseudo-unit* model) will continue to be able to submit each of their n-on-1 MLPs where applicable. The number of n-on-1 MLPs submitted for a steam turbine *generation unit* will continue to be dependent on the number of combustion turbine *generation unit*s registered with the combined cycle *generation facility*.

Today in DACP, MLP values submitted above a threshold percentage of the registered MLP are subject to *IESO* approval based on a tolerance value determined by the *IESO*. The tolerance value is currently set to 110%. The limit is calculated as the registered value for MLP multiplied by the *IESO*-determined MLP tolerance. In the future, MLPs submitted for use in the DAM and PD calculation engines will not use this validation. A new validation for market power mitigation described below will be used instead.

The following additional restrictions and validations will continue to apply:

- Submitted MLP values must be between 0.0 MW and 9999.9 and not exceed one decimal place;
- A minimum of 1 and a maximum of 4 MLP values must be entered as *dispatch data;*
- The number of n-on-1 MLP values submitted as *dispatch data* for a combined cycle *generation facility* cannot exceed the number of combustion turbine *generation units* registered for the *generation facility*; and
- MLP values must be increasing.

The following new validation will apply for market power mitigation:

- MLP submitted as d*ispatch data* must be less than or equal to two times the registered MLP reference level.

Minimum Generation Block Run-Time

The *minimum generation block run-time* (MGBRT) parameter will continue to represent the minimum number of consecutive hours a *generation unit* must be scheduled to its MLP. MGBRT is currently only used by the DACE. In the future day-ahead market and *real-time market*, both the DAM and PD calculation engines will use this parameter to schedule a *generation unit*, if economic, to no less than its MLP for no less than the duration of the MGBRT value.

Registered market participants will be required to submit a MGBRT value for a dispatchable NQS *generation facility*, excluding those with a registered primary fuel type of uranium. For dispatchable NQS *generation facilities* with a registered *pseudo-unit,* MGBRT will continue to only be submitted on the combustion turbine *generation unit* and not on the *pseudo-unit*. The MGBRT used to evaluate the *pseudo-unit* by the DAM and PD calculation engines will be equal to the MGBRT submitted for the combustion turbine *generation unit* registered with the *pseudo-unit*.

The following restrictions and validations will continue to apply:

- MGBRT submitted as *dispatch data* must be a positive whole number, greater than 0 and less than or equal to 24.

The following new validation will apply for market power mitigation:

- MGBRT submitted as *dispatch data* must be less than or equal to the lesser of two times the registered MGBRT reference level registered for the *generation unit* or the registered MGBRT reference level plus 3 hours.

Minimum Generation Block Down Time

The *minimum generation block down time* (MGBDT) parameter will continue to be defined as the minimum number of hours between the time when a *generation unit* was last at its MLP before de-synchronization and the time the *generation unit* can be scheduled back to its MLP after re-synchronizing. MGBDT is currently only used by the DACE as a single parameter.

Similar to the current DACE, the DAM calculation engine will use a single MGBDT value in the future day-ahead market. The PD calculation engine will use one of three MGBDT values that represent the thermal operating state of the *generation unit* as either hot, warm or cold.

The DAM calculation engine will evaluate only one MGBDT value and will use hot as the minimum amount of hours a resource must remain offline before it may be scheduled again within the same *dispatch day.*

The PD calculation engine will determine which one of the three MGDBT values to use based on the number of hours the *generation unit* has been offline. A NQS *generation unit* will be considered offline by the PD calculation engine if it is scheduled below its MLP value by the PD calculation engine. Based on the example in Figure 3-1, once the *generation unit* has been offline for four hours, it may then be evaluated by the PD calculation engine using all of the associated hot *dispatch data* values as submitted by the *registered market participant*. The PD calculation engine will use all corresponding hot *dispatch data* submitted for the *generation unit* until the warm MGBDT has been reached. At which time, the corresponding warm *dispatch data* will be used to determine a schedule or operational commitment for the *generation unit*.

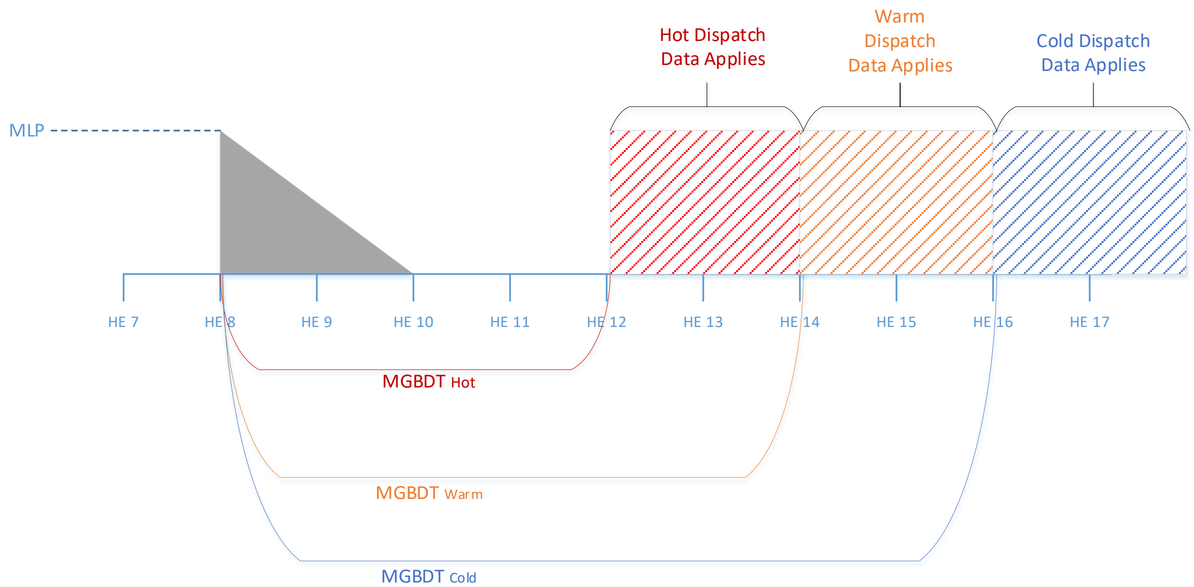

Figure 3-1: MGBDT and Thermal State Dispatch Data Relationship

The PD calculation engine will evaluate a MGBDT value of hot as the minimum amount of hours a resource must remain offline before it may be scheduled again within the same PD look-ahead period.

Corresponding hot, warm or cold *dispatch data* values will be submitted for lead time, ramp up energy to MLP, and start-up *offers*. Submission of hot, warm and cold start-up *offers* were discussed earlier in the hourly *dispatch data* section. Submission of hot, warm and cold values for lead time and ramp up energy to MLP are discussed in the sections that follow.

Hot, warm and cold thermal operating states are required for the PD calculation engine to know how long it will take a *generation unit* to reach its MLP from an offline state. The longer a *generation unit* has been offline, the longer it may take to reach MLP as follows:

- MGBDT (hot) will represent the minimum number of hours a *generation unit* must remain offline before it may be scheduled to generate at or above its MLP when the *generation unit* is considered to be in a hot operating state. The *generation unit* can no longer be scheduled in the hot operating state after it has been offline greater than or equal to the number of hours submitted for MGBDT (warm);
- MGBDT(warm) will represent the minimum number of hours a *generation unit* must remain offline before it may be scheduled to generate at or above its MLP when the *generation unit* is considered to be in a warm operating state. The *generation unit* can no longer be scheduled in the warm operating

state after it has been offline greater than or equal to the number of hours submitted for MGBDT (cold); or

- MGBDT(cold) will represent the minimum number of hours a *generation unit* must remain offline before it may be scheduled to generate at or above its MLP when the *generation unit* is considered to be in a cold operating state.

Registered market participants will be required to submit MGBDT values if they registered to do so for *generation units* registered with a dispatchable NQS *generation facility*, excluding those with a registered primary fuel type of uranium. For dispatchable NQS *generation facilities* with a registered *pseudo-unit,* MGBDT values will continue to only be submitted for the combustion turbine *generation unit* and not for the *pseudo-unit*. The DAM and PD calculation engines will use a MGBDT for the *pseudo-unit* that is equal to the MGBDT value submitted as *dispatch data* for the associated combustion turbine *generation unit.* The MGBDT (hot, warm and cold) submitted as *dispatch data* must be a positive integer between 0 and 24.

The following new validations will apply for market power mitigation:

- The MGBDT (hot) value submitted as *dispatch data* must be less than or equal to MGBDT (warm) value submitted as *dispatch data,* and less than or equal to the lesser of two times the registered MGBDT reference level (hot) or the registered MGBDT reference level (hot) plus 3 hours;
- The MGBDT (warm) value submitted as *dispatch data* must be greater than or equal to the MGBDT (hot) value submitted as *dispatch data,* less than or equal to the MGBDT (cold) value submitted as *dispatch data,* and less than or equal to the lesser of two time the registered MGBDT reference level for (warm) or the registered MGBDT reference level (warm) plus 3 hours;
- The MGBDT (cold) value submitted as *dispatch data* must be greater than or equal to the submitted MGBDT (warm) value submitted as *dispatch data*, and less than or equal to lesser of two times the registered MGBDT reference level (cold) or the registered MGBDT reference level (cold) plus 3 hours; and
- The sum of the MGBDT values for hot, warm and cold submitted as *dispatch data* must be less than or equal to the sum of the registered reference level values for MGBDT hot, warm and cold, plus 6 hours.

Lead Time

Lead time is a new *dispatch data* parameter that represents the amount of time, in hours, needed for a NQS *generation unit* to start-up and reach its MLP from an offline state. The length of the lead time will depend on the thermal operating state of the *generation unit* as either hot, warm or cold. When the resource is hot, it is expected to require less lead time hours to start-up, synchronize and reach MLP than if the resource is cold.

Lead time data will be used by the PD calculation engine for the purposes of issuing a start-up notification to the *registered market participant* to meet an operational commitment. The PD calculation engine will determine the appropriate lead time to apply based on the submitted MGBDT of hot, warm or cold value selected by the PD calculation engine.

The DAM calculation engine will not use the lead time *dispatch data* parameter.

Registered market participants will be required to submit lead time values with their *dispatch data* for a *generation unit* registered as a dispatchable NQS *generation facility* with *generator offer* guarantee status during the Facility Registration process. For dispatchable NQS *generation facilities* with a registered *pseudo-unit,* lead time will be equal to the submitted lead time for the combustion turbine *generation unit* and not on the *pseudo-unit*.

The lead time parameters will be as follows:

- Lead time (hot) expressed in hours, to reach MLP from start-up initiation when the dispatchable NQS *generation facility* has satisfied its MGBDT (hot) and is below its MGBDT (warm) and MGBDT (cold);
- Lead time (warm) expressed in hours, to reach MLP from start-up initiation when the dispatchable NQS *generation facility* has satisfied its MGBDT (warm) and is below its MGBDT (cold); and
- Lead time (cold) expressed in hours, to reach MLP from start-up initiation when the dispatchable NQS *generation facility* has satisfied its MGBDT (cold).

The following new validations will apply for market power mitigation:

- Each lead time value (hot, warm and cold) submitted as *dispatch data* must be a whole number that is greater than or equal to zero value and less than or equal to 24;
- Lead time (hot) value submitted as *dispatch data* must be less than or equal to the MGBDT (hot) value submitted as *dispatch data,* and less than or equal to the lesser of two times the registered lead time reference level (hot) or the registered lead time reference level (hot) plus 3 hours;
- Lead time (warm) value submitted as *dispatch data* must be less than or equal to the MGBDT (warm) value submitted as *dispatch data,* and less than or equal to the lesser of two times the registered lead time reference level (warm) or the registered lead time reference level (wamer) plus 3 hours;
- Lead time (cold) must be less than or equal to the MGBDT (cold) value submitted as *dispatch data,* and less than or equal the lesser of two times the registered lead time reference level (cold) or the registered lead time reference level (cold) plus 3 hours; and

- The sum of the lead time values (hot, warm and cold) must be less than or equal to the sum of the registered reference level values for lead time (hot, warm and cold) plus 6 hours.

Ramp Up Energy to MLP

Ramp up *energy* to MLP is a new set of *dispatch data* parameters used to represent the *energy*, in MWh, a *generation unit* is expected to produce from the time of synchronization to the time it reaches its MLP.

Ramp up *energy* to MLP will be required for the hot, warm and cold thermal operating states of the *generation unit*. Ramp up *energy* to MLP will consist of the following two *dispatch data* parameters:

- Ramp hours to MLP – used to submit the number of hours required for the resource to ramp from synchronization to its MLP; and
- *Energy* per ramp hour – used to submit the average quantity of *energy* in MWh that the resource is expected to produce in each ramp hour, up to one decimal place.

The DAM and PD calculation engines will use the ramp up *energy* to MLP parameters to schedule a dispatchable NQS *generation facility* in the hour(s) prior to its first scheduled *dispatch hour* at or above its MLP, based on the submitted MGBDT of hot, warm or cold by the *registered market participant* in the DAM and the MGBDT of hot, warm or cold that is selected by the PD calculation engine.

Registered market participants will be required to submit ramp up *energy* to MLP values with their *dispatch data* for a dispatchable NQS *generation facility*, excluding those with a registered primary fuel type of uranium. For dispatchable NQS *generation facilities* with registered *pseudo-units,* ramp up *energy* to MLP will be submitted for each combustion turbine *generation unit* and the steam turbine *generation unit* to represent the expected ramp *energy* for each resource in a 1-on-1 configuration. The DAM and PD calculation engines will sum the ramp up *energy* to MLP submitted for the combustion and steam turbine *generation units* as the ramp up *energy* to MLP values for the *pseudo-unit*.

The following new validations will apply for market power mitigation:

- Ramp hours to MLP:
    - o The number of hours for the resource to ramp from synchronization to its MLP submitted as *dispatch data* must be a positive integer between the values of 0 and 24 and be less than or equal to the number of hours submitted as *dispatch data* for lead time; and
    - o The ramp hours to MLP (hot, warm and cold) submitted as *dispatch data* must be less than or equal to the lesser of two times the registered reference level for ramp hours to MLP (hot, warm and cold)

or the registered reference level for ramp hours to MLP (hot, warm and cold) plus 3 hours.

- *Energy* per ramp hour:
  - o *Energy* per ramp hour submitted as *dispatch data* must be more than 50% above the upper bound reference level or 50% below the lower bound reference level for any thermal state; and
  - o The average quantity of *energy* per ramp hour for each subsequent ramp hour to MLP must be greater than or equal to the quantity of *energy* per ramp hour submitted for the previous ramp hour to MLP.

3.4.3. Ancillary Services

The *IESO* will continue to contract for the following *ancillary services*:

- *regulation* service;
- *reactive support service* and *voltage control services*;
- *reliability must-run resources* ; and
- certified *facilities* with *black start capability*;

Certified *facilities* with *black start capability* do not require additional *dispatch data* to be submitted by the *market participant*. *Dispatch data* requirements to support *regulation* services, *reactive support service* and *voltage control services* and *reliability must-run resources* are discussed below.

3.4.3.1. Regulation Services: Available Quantity

Regulation services will continue to be one of the *ancillary* services provided by *market participant*s to the *IESO* in the day-ahead and *real-time markets*. *Ancillary service providers* within the *IESO-controlled grid* will continue to be eligible to provide *regulation* services under the terms of *Automatic Generation Control (AGC)* contracts. However, over the hours of any particular *dispatch day*, an *ancillary service provider* that is eligible to provide *regulation* may or may not actually be selected to provide this service.

The *IESO* will continue to determine which *ancillary service provider* resources are selected to provide *AGC regulation* in each *dispatch hour* of the *dispatch day* and communicate the accepted nominations to the *market participants* before the day-ahead market submission window closes.

Ancillary service providers who wish to provide *regulation* services will continue to submit schedules that reflect the MWs available for any given *dispatch day* as they currently do to satisfy their contract obligations, prior to the closing of the day-ahead market submission window on the *pre-dispatch day*.

The contracted *regulation* will be used as inputs into the DAM calculation engine and will continue to be used as inputs into the PD and RT calculation engines. *Regulation* services will continue to have to be supported by a valid *energy offer* and, as required, other supporting *dispatch data* as specified in their contract and specific to their resource type.

3.4.3.2. Reactive Support and Voltage Control Services and Reliability Must-Run Resources

Reactive support services, *voltage control services* and *reliability must-run resources* will continue to be *ancillary services* provided by *market participants* in the future day-ahead market and *real-time market*. More specifically:

- *Reactive support service* is initiated by the *IESO* and is provided by a *market participant* to allow the *IESO* to maintain the reactive power levels around the *IESO-controlled grid;*
- *Voltage control service* is initiated by the *IESO* and is provided by a *market participant* to allow the *IESO* to maintain the voltage around the *IESO-controlled grid*; and
- *Reliability must-run resources* are provided by a contract between the *IESO* and a *market participant* or a prospective *market participant* for a *registered facility* that is or will be a *generation facility*, a *dispatchable load facility* or a *boundary entity*. The contract allows the *IESO* to call on that *market participant's* or prospective *market participant's facility* in order to maintain *reliability* of the *IESO-controlled grid*.

When a *facility* is called on by the *IESO* as a *reliability must-run, reactive support* or *voltage control* resource, the *IESO* will apply a manual constraint for the *facility* as an input into the DAM, PD and RT calculation engines. The manual constraint identifies that the *facility* must be scheduled to at least the value of the manual constraint.

Reactive support and voltage control services as well as *reliability must-run resources* will continue to have to be supported by a valid *energy offer* and, as required, other supporting *dispatch data* as specified in their contract to provide the *ancillary* service.

3.4.4. Load Facility Dispatch Data to Consume Energy

The *dispatch data* construct currently used for *dispatchable load* and *hourly demand response* resources will continue to be used in the future day-ahead market and *real-time market*. This *dispatch data* construct will also be expanded to allow *registered market participants* to submit *dispatch data* for price responsive loads (PRL) into the day-ahead market. A *registered market participant* will not be authorized to submit *dispatch data* for PRLs into the *pre-dispatch scheduling* and *real-time market* processes since PRLs are considered to be non-dispatchable in these timeframes. *Registered market participants* will also continue to be able to submit *dispatch data* for *dispatchable loads* into the day-ahead market, *pre-dispatch scheduling* and *real-time market* processes .

Similar to the current DACP and *pre-dispatch scheduling* processes, *demand response market participants* will be able to submit *dispatch data* into the day-ahead market and *pre-dispatch scheduling* processes for *hourly demand response* resources registered with a *non-dispatchable load* (NDL) to meet their *demand response capacity obligation* for the hours of their availability window. Demand response *market participants* will also be able to submit *dispatch data* for *hourly demand response* resources registered with a PRL to meet their *demand response capacity obligation.* Refer to the Facility Registration detailed design document for new *demand response market participant* registration requirements associated with PRLs*.*

The following *dispatch data* must continue to be specified by the registered *market participant* or demand response *market participant* :

- *Registered market participant* ;
- Resource type;
- Resource name;
- *Bid* to consume *energy* ; and
- *Energy* ramp rates.

Table 3-4 summarizes the *dispatch data* parameters that can be submitted for each *load facility* and resource type.

Table 3-4: Dispatch Data for Load Facility and Load Resource Types

Dispatch Data	Load Facility or Load Resource Type		
	Dispatchable Load	Price Responsive Load	Hourly Demand Response
Registered Market Participant	x	x	x
Resource Type	x	x	x
Resource Name	x	x	x
Bid to Consume *Energy*	x	x	**x**
Energy Ramp Rate	x	x	x

The following sections describe each *dispatch data* parameter, its purpose, and if required the restrictions and validations that will be applied.

Revision of dispatch data for *load facilities* may be subject to restrictions. Refer to the Grid and Market Operations Integration design document for additional information on revising *dispatch data* and the associated timelines.

3.4.4.1. Registered Market Participant

*Registered market participant*s will continue to be associated with specific *registered facilities* for the purpose of authorizing submission of *dispatch data* in the future day-ahead market and *real-time market*.

Demand response market participants delivering *demand response capacity* with transmission connected *load facilities* or with *embedded load facilities* will continue to identify a *registered market participant* authorized to submit *dispatch data* for each *dispatchable load* resource, physical *hourly demand response* resource, or virtual *hourly demand response resource*.

Market participants electing to change the *facility* registration of an NDL to a designation as a PRL will designate a *registered market participant* and specific user-resource relationships with the authority to submit *dispatch data* for the resource into the day-ahead market.

The *registered market participant* will designate individual users with authority to submit *dispatch data* for each specific *registered facility*. The *registered market participant* and user-resource relationship will continue to be validated such that the resource name being submitted is the same resource for which the *registered market participant* was authorized for during the Facility Registration process for submission of *dispatch data*.

3.4.4.2. Resource Type

The resource type will continue to be used to identify which type of resource associated with a *registered facility* will be used to submit *dispatch data* in the *IESO-administered markets*. The ‘load’ resource type will be the only available resource type for *registered market participants* submitting *dispatch data* for *dispatchable loads*, *hourly demand response* resources, and PRLs.

The resource type will continue to be used to validate that the *registered market participant* is submitting the appropriate *dispatch data* parameters.

3.4.4.3. Resource Name

The resource name will continue to be used to uniquely identify a resource associated with a *registered facility* in the *IESO-administered markets*. The resource name will continue to be validated such that the *registered market participant* submitting *dispatch data* for the resource is the same *registered market participant* authorized to do so during the Facility Registration process.

Registered market participants submitting *dispatch data* to fulfill an *hourly demand response capacity obligation* will use the *hourly demand response resource* name to submit *dispatch data* into the day-ahead market.

PRLs will be assigned a resource name during the re-registration of an NDL as a PRL to be used for submission of *dispatch data* into the day-ahead market only. PRLs registered to fulfill a *demand response capacity obligation* will have a separate physical *hourly demand response* resource name assigned to be used for the submission of *dispatch data* to satisfy such obligation.

3.4.4.4. Bid to Consume Energy

The *bid* to consume *energy* will continue to represent a range of decreasing *price-quantity pairs* that specify a *market price* of *energy*, in $/MWh, at and above which the *IESO* may schedule or *dispatch* a *load facility* to reduce consumption or be taken off the *electricity system*. The DAM, PD, and RT calculation engines will continue to use the *bid* to consume *energy* for *dispatchable loads.*

Registered market participants will submit *bids* to consume *energy* for *hourly demand response* resources into the day-ahead market to fulfill their *demand response capacity obligation*. The *bid* for *hourly demand response* resources will be used by the DAM and PD calculation engines to produce a Demand Response Standby Notice, and the PD Calculation engine will produce a Demand Response Activation notice. Refer to the Grid and Market Operations Integration detailed design document for information on how a Demand Response Activation notice for *hourly demand response* resources will be reflected in the RT calculation engine.

Bids for *energy* submitted into the day-ahead market for PRLs will be processed by the DAM calculation engine only.

Registered market participants will continue to have the ability to designate all or a portion of a *bid* to consume *energy* for a *dispatchable load* as non-dispatchable by submitting the *maximum market clearing price* (*MMCP*) with the quantity intended to be non-dispatchable. *Registered market participants* may also continue to indicate the non-dispatchable status of the entire *dispatchable load* capacity for any hour of the *dispatch day* by not submitting a *bid* (i.e. the 'no-bid' option). Refer to the Grid and Market Operations Integration detailed design document Section 3.3.7.5 for information about a *registered market participant's* ability to change the *bid* status of a *dispatchable load* to and from non-dispatchable status.

Bids can differ from hour to hour and will continue to include the following inputs:

- Applicable time (Date/Time field); and

- A minimum of two and maximum of twenty *price-quantity pairs* representing nineteen *energy* laminations with quantities represented by MW or MW/hour up to one decimal place.

The *energy* quantity must be submitted from 0MW at one price down to the maximum potential desired *energy* at a lower price. Therefore, the *bid* to consume for any resource associated with a *load facility* is a downward sloping *demand* curve.

The following restrictions and validations will continue to be applied:

- The first quantity must equal 0.0 MW;
- Quantities must be monotonically increasing, expressed in MW or MWh per hour to one decimal place;
- Prices must be non-increasing and must not exceed two decimal places;
- There must be at least two *price-quantity pairs*;
- Each price must be greater than or equal to the minimum *market clearing price* (negative *MMCP*) and less than or equal to the *maximum market clearing price* (*MMCP*). For *demand response energy bids,* the *bid* price for the quantity associated with *demand response capacity obligation* must be greater than the *demand response bid price threshold*;
- Prices on the first and second *price-quantity pairs* must be the same; and
- If more than one *bid* is submitted for a specific resource in any *dispatch hour*, only the most recent valid *bid* will be the *bid* that is evaluated.

The following new restrictions and validations will be applied:

- For PRLs and *dispatchable loads*, the last quantity in the *price-quantity pair* must be less than or equal to the maximum registered PRL or *dispatchable load* quantity;
- For *hourly demand response* resources*,* the last quantity in the *price-quantity pair* must be less than or equal to the registered *demand response* capability for the *hourly demand response* resource; and
- For an *hourly demand response* resource registered as a PRL, the sum of the last quantities in the *price-quantity pairs* of the *hourly demand response bid* and the PRL *bid* must be less than or equal to the maximum registered PRL quantity.

3.4.4.5. Energy Ramp Rate

The *energy* ramp rate will continue to be used to specify the speed, in MW/min, at which a resource associated with a *load facility* or *hourly demand response* resource can increase or decrease its consumption.

Registered market participants will continue to be eligible to submit *energy* ramp rates for *dispatchable load* and *hourly demand response* resources. *Energy* ramp rates will not be available for submission for PRLs.

Two separate *energy* ramp rates are defined, one for increasing output (i.e. ramp up rate) and one for decreasing output (i.e. ramp down rate).

Up to five ramp MW quantities, ramp up rate, and ramp down rate sets may be submitted each *dispatch hour*. The ramp quantity in each such set shall continue to be the maximum MW quantity at which the corresponding ramp rate values apply. The ramp quantities provided as *dispatch data* may continue to differ from the *energy* quantities provided in the *price-quantity pairs* for a particular *dispatchable load* or *hourly demand response resource*.

Each ramp rate output range is defined as follows:

- Applicable time for the output range(s) (Date/Time field); and
- Ramp quantities (MW), ramp rate up (MW/min), ramp rate down (MW/min).

The DAM, PD and RT calculation engines will use ramp rates as inputs. The following restrictions and validations used for the current market will be applied:

- There must be at least one ramp quantity with a MW quantity greater than 0.0 MW, and no more than five MW ramp quantiles, ramp up rate and ramp down rate sets;
- Each ramp rate up must be less than or equal to the maximum ramp rate specified for the particular resource within the *load facility* or *hourly demand response* resource during the Facility Registration process;
- Each ramp rate down must be less than or equal to the maximum ramp rate specified for the that resource within the *load facility* or *hourly demand response* resource during the Facility Registration process;
- The ramp quantity shall be expressed in MW to one decimal place and shall be greater than 0.0MW;
- The ramp up/ramp down values shall be expressed in MW/min to one decimal place and shall be greater than 0.0MW/min;
- The ramp quantities must be monotonically increasing;
- The last ramp quantity for the *energy* ramp rate must be greater than or equal to the maximum quantity of the *bid* for *energy* for the resource; and
- For *hourly demand response* resources, the MW break point quantity, ramp up rate and ramp down rate values must be equal to the *demand response capacity obligation* of the *hourly demand response* resource.

3.4.5. Boundary Entity Dispatch Data to Import and Export Energy

Authorized *market participants* will continue to have the ability to submit *dispatch data* for physical *offers* to supply *energy* (imports) and physical *bids* to consume *energy* (exports) associated with a *boundary entity* in the future day-ahead market and *real-time market*.

Similar to the current DACP and PD processes, *market participants* will be able to submit import and export *dispatch data* into the future DAM and PD processes. The DAM calculation engine will use this *dispatch data* to economically schedule imports and exports for any given *dispatch hour* in a *dispatch day*. However, the PD calculation engine will be modified to only use *dispatch data* for imports and exports with day-ahead *market schedules* until the pre-dispatch run three-hours ahead of each *dispatch hour*. During the three-hour ahead run, the PD calculation engine will evaluate imports and exports with day-ahead *market schedules*, including any new import and export *dispatch data* submitted after the close of the day-ahead market submission window. For additional information about how imports and exports will be evaluated and scheduled, refer to the DAM and PD Calculation Engine and the Grid and Market Operations Integration detailed design documents respectively.

Dispatch data revisions for import and export *energy* may be subject to restrictions. Refer to the Grid and Market Operations Integration detailed design document for additional information on revising *dispatch data* and the associated timelines.

3.4.5.1. Dispatch Data Parameters Common to Imports and Exports

Market participants will continue to be required to provide information for the following *dispatch data* parameters for a *boundary entity*:

- *Market participant* name;
- Resource type;
- Tie point ID;
- *Boundary entity* resource name;
- e-Tag ID;
- *Offer* to import *energy*; and
- *Bid* to export *energy*

Market participants will also be able to submit a new capacity transaction parameter as *dispatch data. Energy* ramp rate will continue to not apply to *boundary entity* import *offers* or export *bids* for *energy*. The following sections describe the existing and new *dispatch data* parameters stated above.

Market Participant Name

The *market participant* name will continue to be a *dispatch data* parameter that identifies the corporate person that is authorized by the *market rules* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*. The *market participant* name must continue to match one of the *market participant* names that has been authorized to submit *dispatch data* as a *boundary entity* during the Facility Registration process.

Resource Type

The resource type will continue to be used to identify the resource as either an import or an export.

Tie Point ID

The tie point ID will continue to be used to identify the *intertie zone* with which the transaction will be associated. This is also referred to as the market scheduling point. The existing four-letter market scheduling point name or tie point ID for each *intertie zone* will be used by the DAM and PD calculation engines.

For validation purposes, the *boundary entity* resource tie point ID must continue to be equal to the registered tie point ID values provided by the *IESO* during the Facility Registration process in order for the *offer* or *bid* for *energy* to be passed to the DAM and PD calculation engines.

Boundary Entity Resource Name

The *boundary entity* resource name identifies the import source or export sink resource associated with the *intertie zone* that the participant is electing to inject *energy* into or withdraw *energy* from the *IESO-controlled grid*. Import *offers* for *energy* will continue to use *boundary entities* identified as a source. Export *bids* for *energy* will continue to use *boundary entities* identified as a sink.

All *market participants* who have registered the capability to import or export can associate an *offer* or *bid* to import or export against any *boundary entity* source or sink. The combination of *market participant* name, market scheduling point name, and *boundary entity* resource name will continue to uniquely identify the *intertie interchange schedules* that use the same *boundary entity*.

For validation purposes, the *boundary entity* resource name must continue to be equal to the registered *boundary entity* resource name values provided by the *IESO* during the Facility Registration process in order for the *offer* or *bid* for *energy* to be passed to the DAM and PD calculation engines.

e-Tag ID

The e-Tag ID will continue to be used to facilitate the checkout of the transaction (*interchange schedule*) for the expected real-time exchange of *energy* with an external *control area*. See the Grid and Market Operations Integration detailed design document for deadlines to submit the e-Tag ID.

Based on the timing of the DAM calculation engine run, an e-Tag ID may not necessarily be secured in the day ahead by a *market participant* for a potential *intertie* transaction. This does not preclude the scheduling of the transaction day ahead. The e-Tag ID may be submitted as a change to *dispatch data* for *intertie* transactions scheduled by the DAM calculation engine at such time as the e-Tag ID is secured but no later than the short notice cut-off time prior to the *dispatch hour*.

Offer to Import Energy

The *offer* to import *energy* will continue to represent the prices and associated quantities of *energy* a *market participant* intends to sell into the *IESO control area* at a particular *intertie zone*. The information must include:

- Applicable time (Date/Time field); and
- A minimum of two and maximum of twenty *price-quantity pairs* representing nineteen *energy* laminations with quantities represented by MW or MWh/hour in whole numbers with no decimals.

The *offer* for *energy* is an upward sloping supply curve. The *offer* can continue to be different for any given *dispatch hour* in a *dispatch day*. The following restrictions and validations will continue to apply:

- First quantity must equal 0 MW;
- Quantities must be monotonically increasing and expressed in whole MW or MWh per hour;
- Prices must be non-decreasing and not exceed two decimal places;
- Each price must be greater than or equal to the minimum *market clearing price* (negative *MMCP*) and less than or equal to the *maximum market clearing price* (*MMCP*);
- Prices on the first and second pairs must be the same; and
- There must always be at least two *price-quantity pairs*.

Bid to Export Energy

The *bid* to export *energy* will continue to allow the *market participant* to submit the prices and associated quantities of *energy* they desire to consume at a particular *intertie zone*. The information required for this parameter is identical to the information required for an *offer* for *energy* at a *boundary entity* as described in the previous section.

The *bid* quantity must be submitted from 0 MW at the maximum potential desired *energy* purchase price, up to the maximum consumption of MWs at the minimum desired *energy* purchase price. The *bid* for *energy* is therefore a downward sloping demand curve.

The same validations that apply to *energy offers* at a *boundary entity* will also continue to be applied to *energy bids* at a *boundary entity,* except that prices must continue to be non-increasing for the *bid* for *energy*.

Capacity Transaction

Capacity transaction will be a new hourly *dispatch data* parameter that *market participants* will use to identify an export *bid* as a *called capacity export*. It will also be used to identify an import *offer* or export *bid* that supports the *IESO*/Hydro-Quebec capacity sharing agreement. Refer to the Called Capacity Export and *IESO*/Hydro-Quebec Capacity Sharing Agreement sections below for a description of the *dispatch data* submission requirements.

The capacity transaction parameter will replace the current requirement for a *market participant* to designate a *called capacity export* by including the term “ICAP” within the comments field of the E-tag ID *dispatch data* parameter. Today, the *IESO* uses the “ICAP” to identify these transactions should not be curtailed ahead of regular transactions.

The capacity transaction parameter will also be used to inform the PD Calculation Engine to include *called capacity exports,* including import *offers* and export *bids* that support the *IESO*/Hydro-Quebec capacity sharing agreement, in all *dispatch hours* beyond the T+2 PD scheduling horizon for which the capacity transaction has been called.

3.4.5.2. Wheeling Through Transactions

Wheeling through transactions will continue to be evaluated as an individual *offer* for a *boundary entity* importing *energy* into the *IESO-controlled grid* and an individual *bid* for a *boundary entity* exporting *energy* from the *IESO-controlled grid. Market participants* will continue to have the option of identifying an import *offer* at one *boundary entity* and an export *bid* at a different *boundary entity* as wheeling through transactions. This identification effectively links the wheeling through transactions so that they are scheduled together.

Market participants will no longer be required to identify that an import and an export are linked *interchange schedules* of the same wheeling through *interchange schedule* by submitting the export *bid* at *MMCP*, and the import *offer* between -$50 and negative *MMCP*.

If the *market participant* chooses to submit a wheeling through transaction, the *market participant* will only be required to edit the E-tag IDs submitted with their *dispatch data* to have the following naming convention:

- For the import: WI_SourceCA...SinkCA; and
- For the export: WX_SourceCA...SinkCA.

The *market participant* must also submit the same e-tag ID with the *dispatch data* for both the import *offer* and the export *bid* to indicate that the two transactions are linked and part of the same wheeling through transaction.

Currently, the DACE assesses the export *bid* and import *offer* together as linked transactions, whereas the current PD calculation engine assesses both the export *bid* and the import *offer* as separate transactions. In the future, both DAM and PD calculation engines will assess the export *bid* and the import *offer* as linked transactions. The linked *bid* and *offer* will be scheduled to equal quantities if both are economic. Wheeling through transactions will remain ineligible to supply *operating reserve*. It is not feasible to have *offers* to supply *operating reserve* associated with wheeling through transactions since the physical *energy* in a wheeling through transaction does not remain within Ontario.

3.4.5.3. Called Capacity Exports

Called capacity exports will continue to represent an *energy* export that is supported by the capacity of a *generation unit* within the *IESO control area* that has committed all or a portion of its capacity to an external *control area*. When a capacity export is called by an external *control area operator* to deliver its capacity, the *market participant* will continue to be required to submit an export *bid* for *energy* at the corresponding *boundary entity.*

The following restrictions and validations will continue to apply to the *bid* submission for a *called capacity export*:

- Export must be *bid* at *MMCP* for the duration of the capacity call;
- Must contain two *price-quantity pairs*. The first quantity must continue to be 0 MW and the second quantity must not exceed the called export MW quantity;
- The six-digit resource ID must be identified for the *generation unit* resource that has committed the capacity;
- Tie point ID must be selected in the direction of the calling external *control area*; and
- The delivery date and delivery hour shall span the period of the call as stipulated by the calling jurisdiction.

The following new restrictions and validations will apply:

- The capacity transaction parameter must be selected for each *dispatch hour* the capacity export was called for by the external control area; and
- The *market participant* submitting the *bid* for the called capacity export must be the *registered market participant* for the *generation facility* that has received approval from the *IESO* to export capacity.

Market participants with *generation units* exporting capacity may continue to submit *offers* for *operating reserve* into the *IESO-administered markets*. The *market participant* is responsible for ensuring that they manage the *offers* for *operating reserve* for their *generation unit* for the duration of the capacity call such that enough capacity remains available for *operating reserve* activations.

3.4.5.4. IESO/Hydro-Quebec Capacity Sharing Agreement

The *IESO* and Hydro-Quebec have a capacity sharing agreement that allows either balancing authority to call upon the other balancing authority's capacity when it experiences an *adequacy* shortfall. Hydro-Quebec Energy Marketing Inc. (HQEM) will continue to submit import *offers* in response to *reliability* declarations made by the *IESO* and export *bids* in response to *reliability* declarations made by Hydro-Quebec.

Under the capacity sharing agreement, the following restrictions and validations will continue to apply to the *bid* submission:

- Tie point ID must be selected as PQ.Outaouais and in the direction of the calling *control area*; and
- The delivery date and delivery hour shall span the period of the call as stipulated by the calling jurisdiction.

The following new restrictions and validations will apply:

- The capacity transaction parameter must be selected for each *dispatch hour* the capacity was called for.

3.4.6. Dispatch Data to Supply Operating Reserve

The three classes of *operating reserve* that will continue to be *offered* into the future day-ahead market and *real-time market* are:

- 10-minute synchronized *operating reserve* (also known as 10-minute spinning reserve);
- 10-minute non-synchronized *operating reserve*; and
- 30-minute *operating reserve*.

Resources associated with a dispatchable *generation facility* or a *dispatchable load* within Ontario will continue to be eligible to provide all three classes of *operating reserve* in the future day-ahead market and the *real-time market,* subject to performance criteria evaluated during the Facility Registration process. Refer to the Facility Registration detailed design document for more information about the performance criteria evaluation for providing *operating reserve.*

Imports and exports associated with a *boundary entity* will continue to only be eligible to *offer* 30-minute and 10-minute non-synchronized *operating reserve* subject to performance criteria evaluated during the Facility Registration process. *Boundary entities* are not permitted to provide 10-minute spinning *operating reserve*.

Non-dispatchable *generation facilities* will continue to be ineligible to provide *operating reserve.* PRL *facilities* and virtual entities will also be ineligible to provide *operating reserve*.

Table 3-5 lists the existing parameters that will be required when submitting *offers* for *operating reserve* from dispatchable *generation facilities* and *dispatchable loads* within Ontario and *boundary entities* outside of Ontario.

Table 3-5: Dispatch Data Parameters for Operating Reserve

Dispatchable Generation Facility and Dispatchable Load	Boundary Entity Import and Export
• *Registered market participant*	• *Market participant*
• Resource name	• *Boundary entity* resource name
• *Offer* to supply *operating reserve*	• *Offer* to supply *operating reserve*
• Reserve Class	• Reserve Class
• *Operating reserve* ramp rate	• Tie point ID
• Reserve loading point	• e-Tag ID

Participant and resource name parameters are common to *offers* and *bids* for *energy* that must accompany each *offer* to supply *operating reserve*. These parameters are defined in earlier sections of this document.

The *boundary entity* resource name and tie point ID must continue to be equal to the registered values provided during the Facility Registration process in order for the *offer* to provide *operating reserve* to be accepted as valid for *boundary entities*.

The *offer* per reserve class parameter is common to both internal resources as well as for *boundary entities*. This parameter is discussed in the following section, followed by the other internal resource *dispatch data* parameters. For the *boundary entity dispatch data* parameters, refer to Section 3.4.5 Boundary Entity Dispatch Data to Import and Export for Energy above.

Dispatch data revisions for *operating reserve* may be subject to restrictions. Refer to the Grid and Market Operations Integration detailed design document for additional information on revising *dispatch data* and the associated timelines.

3.4.6.1. Offer to Provide Operating Reserve

The *offer* to provide *operating reserve* is an *ancillary service* provided by *market participants*[2] as part of the *energy market*. *Offers* for o*perating reserve* will continue to consist of a range of *price-quantity pairs* (prices and associated *energy* quantities) that can differ for every *dispatch hour*. *Registered market participants* will continue to be eligible to submit *offers* for *operating reserve* for dispatchable *generation facilities, dispatchable loads* and *boundary entities.*

For dispatchable NQS *generation facilities* registered as a combined cycle *generation facility, registered market participants* currently have the ability to choose to submit *offers* to provide *operating reserve* into the DACE for the *pseudo-unit* resource type or the *generation unit* resource type. The PD and RT calculation engines currently use *offers* to provide *operating reserve* that are submitted on the *generation units*, and not on the *pseudo-unit*.

In the future day-ahead market and *real-time market*, *registered market participants* submitting *dispatch data* for a dispatchable NQS *generation facility* that is a combined cycle *generation facility* and registered to have *dispatch data* submitted for a *pseudo-unit* will only submit *offers* for *operating reserve* for the *pseudo-unit* resource type into the DAM, PD and RT calculation engines.

Offers for *operating reserve* for dispatchable *generation facilities*, *dispatchable loads* and *boundary entities* will continue to include the following information:

- Applicable time (date/time field); and
- A minimum of two and up to five *price-quantity pairs* ($/MW) pairs for each class of *operating reserve* for each *dispatch hour*. The final quantity will represent the maximum quantity of the *offer*.

The following restrictions and validations will be retained:

- Each *offer* to supply *operating reserve* must be accompanied by a corresponding *offer* or *bid* for *energy* the covers the same MW range;
- The quantity in the first *price-quantity pair* must be set to 0.0 MW for internal resources or 0 MW for *boundary entity* resources;

[2] See section 3.4.3 for other *ancillary services* that are contracted.

- The quantity for each *price-quantity pair* will be expressed in MW to one decimal place for internal resources, or expressed in whole MW for *boundary entity* resources;
- The price in each *price-quantity pair* must not decrease as the quantity increases;
- The price in each *price-quantity pair* will be expressed in dollars and whole cents ($0.00) per MW and each price must be greater than or equal to zero (the minimum operating reserve price, -MORP) and less than or equal to $2000 (the *maximum operating reserve price, +MORP)*;
- The first *price-quantity pair* is submitted with a zero quantity with an associated price. The second *price-quantity pair* must be submitted with a new quantity associated with the same price as the first *price-quantity pair*;
- Quantity of *operating reserve offered* by hourly imports and exports must be less than or equal to the quantity of *energy offered* by that import or *bid* by that export; and
- *Offers* for *operating reserve* are limited by the registered maximum generation capability of the *generation facility* and the quantity of *energy bid* or *offered* at the *boundary entity*.

The following new validation will be introduced:

- *Offers* for *operating reserve* are limited by the registered maximum *dispatchable load* quantity.

3.4.6.2. Reserve Class

*Market participant*s must continue to enter one of the following predefined reserve class types for each *offer* to supply *operating reserve*:

- 10-minute synchronized *operating reserve*;
- 10-minute non-synchronized *operating reserve*; or
- *30-minute operating reserve*.

Eligible dispatchable *generation facilities* and *dispatchable loads* will continue to be able to *offer* all three classes of *operating reserve*. Importers and exporters will continue to only be able to *offer* 10-minute non-synchronized *operating reserve* and 30-minute *operating reserve*.

3.4.6.3. Operating Reserve Ramp Rate

Similar to the current DACE, PD and RT calculation engines, the *operating reserve* ramp rate will be used by the DAM, PD, and RT calculation engines to limit the amount by which a resource can be scheduled or dispatched to provide any class of *operating reserve*. The *operating reserve* ramp rate will continue to be used to specify the rate, in megawatts per minute (MW/min) that a dispatchable resource associated with a *generation facility* or *load facility* can respond to an *operating reserve* activation.

Operating reserve ramp rate will continue to not apply to *boundary entity* import or export *offers* to supply *operating reserve*.

For each resource qualified to provide *operating reserve* a separate *operating reserve* ramp rate must be submitted. The *operating reserve* ramp rate is different from the ramp rate up and ramp rate down associated with *offers* and *bids* for *energy*.

Currently the DACE, PD and RT calculation engines use the same single *operating reserve* ramp rate for every *dispatch hour* an *offer* to provide *operating reserve* is submitted by the *registered market participant*. In the future market, the DAM and PD calculation engines will continue to use a single *operating reserve* ramp rate for all hours of the DAM and PD look-ahead periods. For DAM, the *operating reserve* ramp rate used will always be the rate submitted in the first hour of the *dispatch day.* For PD, the *operating reserve* ramp rate used will always be the rate submitted in the first hour of the PD look-ahead period.

The future RT calculation engine will be capable of using different *operating reserve* ramp rates submitted for different *dispatch hours*.

Refer to Section 3.4.1.3 and 3.6.1.4 of the DAM, Section 3.2.1.4 and 3.6.1.4 PD, and Section 3.4.1.4 and 3.6.1.4 of the RT calculation engine design documents for more information on the application of *operating reserve* ramp rates. The following restrictions and validations will continue to apply:

- For resources registered as a dispatchable *generation facility*, *operating reserve* ramp rate must be less than or equal to the maximum *offer* ramp rate specified for the resource at registration; and
- For resources registered as a *dispatchable load*, *operating reserve* ramp rate must be less than or equal to the maximum *bid* ramp rate specified for the resource at registration.

The following new validation will apply for market power mitigation:

- The *operating reserve* ramp rate submitted as *dispatch data* must be greater than or equal to half the registered reference level for *operating reserve* ramp rate.

3.4.6.4. Reserve Loading Point

Reserve loading point will continue to specify the minimum generation level in megawatts (MW) at which a resource associated with a dispatchable *generation facility* can provide the maximum *operating reserve* of the class of *operating reserve* being *offered*. The reserve loading point is not currently used by the DACE however it will be used by the DAM calculation engine. The PD and RT calculation engines will continue to use reserve loading point to simultaneously schedule *energy* and *operating reserve*.

Registered market participants submitting *offers* for a dispatchable *generation facility* to supply *operating reserve* will continue to be required to submit a reserve loading point. For *dispatchable loads* and *boundary entities* this value must be left null and will default to 0.0 MW.

The following restrictions and validations will continue to be performed:

- For 10-minute spinning *operating reserve,* reserve loading point must be greater than 0 MW and less than or equal to the registered maximum *generation capacity* of the resource;
- For 10-minute non-spinning *operating reserve,* reserve loading point must be set to 0.0 MW; and
- For 30-minute *operating reserve*, reserve loading point must be greater than or equal to 0.0 MW and less than or equal to the registered maximum *generation capacity* of the resource.

Additionally, if the *registered market participant* anticipates that a *generation unit* will be operating below its reserve loading point for the entire duration of a given *dispatch hour,* an *offer* to supply *operating reserve* shall not be submitted for that *dispatch hour*.

3.4.6.5. e-Tag ID

For *boundary entities* the *offer* to provide *operating reserve* must continue to include the e-Tag ID to facilitate the checkout of the transaction (*interchange schedule*) for the expected real-time exchange of *energy* with an external *control area* should an *operating reserve* activation occur. See the Grid and Market Operations Integration detailed design document for deadlines to submit the e-Tag ID.

3.4.7. Virtual Transaction Offers and Bids for Energy

Dispatch data for virtual transaction *offers* or *bids* for *energy* are new and will only be processed in the day-ahead market. Authorized *market participants* can use virtual transactions to buy or sell *energy* in the day-ahead market with no expectation to physically consume or supply that *energy* in the *real-time market* during the corresponding real-time *settlement hour*. *Dispatch data* for virtual transactions to supply *operating reserve* will not be permitted in the future day-ahead or *real-time market*.

Market participants submitting *dispatch data* for virtual transactions into the day-ahead market for a particular *dispatch day* must specify the following *dispatch data* parameters:

- *Market participant* name;
- Virtual transaction type;
- Virtual transaction zonal trading entity; and
- Virtual transaction *price-quantity pairs* for *energy*.

The following sections describe each virtual *dispatch data* parameter, its purpose and the validations that are required for the future day-ahead market.

3.4.7.1. Market Participant Name

The *market participant* name is a registration parameter that identifies a person who has been authorized for virtual transaction trading. The *market participant* name designated in the virtual transaction *dispatch data* submission must match one of the authorized *market participant* names.

3.4.7.2. Virtual Transaction Type

Market participants will use the virtual transaction type to identify their virtual transaction *dispatch data* submission as either a virtual transaction *offer* to sell *energy,* or a virtual transaction *bid* to buy *energy* in the day-ahead market.

3.4.7.3. Virtual Transaction Zonal Trading Entity

Market participants will be required to specify which of the following nine virtual transaction zonal trading entities their submitted virtual transaction type will apply to:

- Northwest virtual transaction trading zone, representing all *load facilities* within the Northwest electrical zone;
- Northeast virtual transaction trading zone, representing all *load facilities* within the Northeast electrical zone;
- Essa virtual transaction trading zone, representing all *load facilities* within the Essa electrical zone;
- Ottawa virtual transaction trading zone, representing all *load facilities* within the Ottawa electrical zone;
- East virtual transaction trading zone, representing all *load facilities* within the East electrical zone;

- Toronto virtual transaction trading zone, representing all *load facilities* within the Toronto electrical zone;
- Southwest virtual transaction trading zone, representing all *load facilities* within the Bruce and Southwest electrical zones;
- Niagara virtual transaction trading zone, representing all *load facilities* within the Niagara electrical zone; and
- West virtual transaction trading zone, representing all *load facilities* within the West electrical zone.

The *IESO* may temporarily remove certain *load facilities* from the virtual zonal trading entity definitions described above if the *IESO* determines that the distribution of virtual transaction *offers* and *bids* for *energy* to specific *load facilities* within the trading zones lead to persistent AC load flow divergences in the DAM calculation engine that cannot otherwise be prevented.

3.4.7.4. Virtual Transaction Price-Quantity Pairs for Energy

Virtual transaction *price-quantity pairs* will allow *market participants* to submit different hourly prices and associated quantities of *energy* they desire to sell or buy at a particular virtual transaction zonal trading entity. The inputs for this parameter will include:

- Applicable time (Date/Time field); and

A minimum of two and maximum of twenty *price-quantity pairs* representing nineteen *energy* laminations with quantities represented by MW or MW/hour to one decimal place.

The following restrictions or validations will apply:

- There must always be at least two *price-quantity pairs*;
- Quantities in the *price-quantity pairs* must be monotonically increasing;
- The first quantity in the *price-quantity pairs* must be equal to 0.0. MW;
- The second quantity in the *price-quantity pairs* must be at least 1.0 MW;
- There must be at least a 1.0 MW difference between any two consecutive quantities of the *price-quantity pairs*;
- Prices in the first and second *price-quantity pairs* must be the same;
- Prices in the *price-quantity pairs* must be increasing for virtual transaction *offers* and non-increasing for virtual transactions *bids*;
- Prices in the *price-quantity pairs* must be greater than or equal to the minimum market clearing price (negative *MMCP*) and less than or equal to the *maximum market clearing price* (*MMCP*);

- Virtual transaction *bids* and *offers* at submission will be validated as follows:
    1. The absolute value of the sum of the MWh quantity of virtual *bids* and *offers* submitted by the *market participant* but not yet cleared by the DAM calculation engine will be screened daily to ensure that they are lower than the *market participant*-supplied absolute value of the maximum daily *trading limit* (in MWh).
    2. The *IESO*-estimated cumulative dollar exposure will be screened daily to ensure that it is lower than the *IESO*-determined virtual transaction *minimum trading limit* (in dollars).
- The total number of *price-quantity pairs* submitted by the same *market participant* must be less than or equal to an *IESO*-determined virtual transaction *energy* lamination volume limit; and
- The total *energy* quantity of a virtual *offer* or *bid* submitted at any virtual transaction zonal trading entity must be less than or equal to the *IESO*-determined virtual transaction *offer* or *bid* cap for each virtual transaction zonal trading entity.

Refer to the Prudential Security detailed design document for more information about the daily screening of virtual transactions and the conditions under which virtual transaction *offers* or *bids* for *energy* will be rejected.

3.4.8. Outage Information

Outage information will continue to represent the planned or unplanned removal of equipment from service, unavailability for connection of equipment or temporary derating, restriction of use, or reduction in performance of equipment for any reason.

All *outage* information will continue to be submitted by *market participants* and assessed by the *IESO* in accordance with the existing Market Rules Chapter 5 section 6: Outage Coordination and Market Manual 7.3: Outage Management.

Outage information is currently used by DACE, and the PD and RT calculations. *Outage* information as currently submitted and assessed will be used by the DAM, PD and RT calculation engines to schedule resources based on the system configuration and connectivity for the period of the *outage*.

3.4.8.1. Segregated Mode of Operation (SMO)

Segregated mode of operation (SMO) will continue to be defined as an electrical configuration where a portion of the *IESO-controlled grid* is used to connect one or more *generation facilities* to a neighbouring *control area* using a *radial intertie* for the purposes of delivering electricity or *physical services* to such *control area*.

In the future day-ahead market and *real-time market*, *market participants* with *generation facilities* eligible for SMO will be required to submit the same *outage* information they submit in the current DACP and *real-time market* to facilitate their request for SMO*.* Submission and cancellation timelines for SMO requests will be revised in the future market. Refer to the Grid and Market Operations Integration detailed design document for a description of these changes.

3.4.9. Physical Bilateral Contract Data

Physical bilateral contracts (PBC) will continue to be defined as an agreement between two parties for the transfer of *energy* for a specified quantity and price determined by the parties in agreement. The *IESO* will continue to be neither of these parties.

Currently, the *selling market participant* may choose to submit the *physical bilateral contract data* they are associated with to the *IESO* to facilitate the *settlement* of their PBC based on their activity in *real-time market*.

In the future day-ahead market and *real-time market*, the *selling market participant* will have the ability to specify the *physical bilateral contract data* associated with their PBC as applying to their activity in the day-ahead market or the *real-time market*. The parties may submit either or both of their *physical bilateral contract data* for the *real-time market* and the day-ahead market.

DAM PBC quantities will allow for the transfer of DAM uplift *settlement amounts* from the *buying market participant* to the *selling market participant* in proportion to the size of the PBC contract. Specifically, the *selling market participant* will assume a portion of the DAM uplift amounts.

Physical bilateral contract data must continue to be submitted no earlier than seven calendar days prior to the *dispatch day* and within six business days after the *dispatch day* to allow time for *preliminary settlement statements* to be created. Revisions and cancellations may continue to be made anytime within the timelines described above.

Unless otherwise specified, for *selling market participants* electing to provide the *IESO* with *physical bilateral contract data*, the following data must continue to be submitted:

- Identity of the selling *market participant* and the buying *market participants*;
- Applicable date and hours;
- Location of transaction which will be associated with a specific *delivery point* or *intertie* metering point;

- For real-time market PBCs, a quantity in MWh or 100% of the adjusted metered quantity at the transaction point where one of the two parties is the metered *market participant* for that meter;
- New for the day-ahead market PBCs, a quantity in MWh or 100% of the day-ahead market scheduled quantity of the selling *market participant* or the buying *market participant* produced by the DAM calculation engine where the transaction location is the *delivery point* of one of the two parties; and
- Assignment of hourly uplift components. The selling *market participant* will be able to assume a portion of uplift amounts in the future day-ahead market and real-time market. Refer to the Market Settlement detailed design document for the specific hourly uplifts that may be assigned.

3.4.9.1. Standing Physical Bilateral Contract Data

For *physical bilateral contract data* that will not change from *trading week* to *trading week*, standing *physical bilateral contract data* for the day-ahead market and *real-time market* may be submitted. Standing *physical bilateral contract data* comes into effect on the second *dispatch day* after submission and remains in effect until the expiration date unless withdrawn or revised prior to the expiration date.

See the Market Settlement detailed design document for more information on how *physical bilateral contract data* for the day-ahead market and *real-time market* will be used.

3.5. IESO Data Inputs

Consistent with the current DACP, many of the *IESO* data inputs for a particular *dispatch day* will initially be prepared for use in the day-ahead market. These data inputs will continue to be updated to reflect anticipated system conditions for the *dispatch day* in the *pre-dispatch scheduling* and *real-time market* as the *dispatch hour* approaches. Many of the *IESO* data inputs are not expected to change from the current practice. With the exception of new inputs related to constraint violation penalty curves and market power mitigation, modified *IESO* inputs include those associated with the Network Model Build process and the *IESO's demand* forecast. These modifications are discussed further in sections 3.5.4 and 3.5.6 respectively.

For details on timing and management of these input parameters, see the Grid and Market Operations Integration detailed design document.

The following sections describe *IESO* inputs that will be used for the future day-ahead market and *real-time market.*

3.5.1. Reliability Requirements

Consistent with the current processes, *reliability* requirements for a particular *dispatch day* will initially be prepared for use in the day-ahead market and will continue to be updated to reflect anticipated system conditions for the same *dispatch day* in the *pre-dispatch scheduling* and *real-time market*. Refer to the Grid and Market Operations Integration detailed design document for information on the management of *reliability* requirements.

The *IESO* will continue to prepare the following *reliability* requirements prior to the day-ahead market and as real-time approaches:

- Security Limits;
- Maximum Import/Export Limits;
- Net Interchange Scheduling Limit (NISL);
- Lake Erie Circulation Forecast;
- Operating Reserve Requirements;
- Minimum/Maximum Area Operating Reserve;
- Regulation Capacity Requirements; and
- Reliability Constraints.

For information on the *reliability* requirements that will be published by the *IESO* in the future day-ahead market and *real-time market,* refer to the Publishing and Reporting Market Information detailed design document.

The following sections describe each *reliability* requirement and its purpose for the future day-ahead market and *real-time market*.

3.5.1.1. Security Limits

Security limit inputs are Operating Security Limits (OSLs) and thermal ratings that will continue to be used by the *security* assessment function of all calculation engines to schedule and *dispatch* resources within the maximum transfer capabilities of the *IESO-controlled grid*.

OSLs used by the DAM, PD and RT calculation engines will continue to be activated and updated by the *IESO* based on the latest forecast conditions and the expected configuration of the *IESO-controlled grid*.

Thermal ratings used by the DAM and PD calculation engines will continue to be based on lookup limits provided by *transmitters* and forecasted weather data. Thermal ratings used by the RT calculation engine will continue to be received from *transmitters.*

3.5.1.2. Maximum Import/Export Limits

Maximum import/export limit inputs will continue to define the maximum amount of *energy* and *operating reserve* that can be scheduled for import and export for each *intertie zone* and, as required, over two or more *intertie zones*. Maximum import/export limits will be specified for every hour of the *dispatch day.* These inputs will be used by all calculation engines in the future and communicated to *market participants*. The *IESO* will continue to update maximum import/export limits based on expected system conditions and *outage* configurations.

3.5.1.3. Net Interchange Scheduling Limit

The Net Interchange Scheduling Limit (NISL) will be used by the DAM and PD calculation engines to limit the maximum hour-to-hour change in net schedules between Ontario and other jurisdictions. The default value will continue to be set by the *IESO* and the *IESO* will continue to have the authority to adjust it for *reliability* reasons, including the issuance of Energy Emergency Alerts (EEA).

3.5.1.4. Lake Erie Circulation Forecast

The Lake Erie circulation forecast will be used by the DAM, PD and RT calculation engines to account for any hourly unscheduled *energy* that is expected to flow through the *IESO-controlled grid* in either direction between the Michigan and New York Frontier interfaces. This hourly forecast value is normally set to 0 MW because unscheduled *energy* can be regulated by the *transmitters* adjusting the Phase Angle Regulators (PARs). However, if it is anticipated that the PARs are unable to regulate the flow, the hourly forecast values will continue to be updated based on historical Lake Erie circulation observed during recent similar days and any other relevant information.

3.5.1.5. Operating Reserve Requirements

Operating reserve requirements are specified by the regulating bodies *NERC* and *NPCC*. *NERC* requires that each balancing authority carry enough *operating reserve* to account for the most severe single contingency. *NPCC* further refines this to specify reserve classes and their associated requirements. *NPCC* states that 10-minute *operating reserve* must be available that is at least equal to a balancing authority's first contingency loss. A portion of the 10-minute reserve must be spinning (synchronized). 30-minute reserve must be available equivalent to at least one-half its second contingency loss. Due to the dynamic nature of the operating system, changes to configuration, flows and *outage* conditions may impact how much *operating reserve* must be scheduled for each *dispatch hour* in a *dispatch day*.

Operating reserve requirements[3] will continue to be initially set for the day-ahead market and will also be used as inputs into PD and RT calculation engines. Updates to the *operating reserve* requirement will continue to be used by the PD and RT calculation engines.

3.5.1.6. Minimum / Maximum Area Operating Reserve

Minimum area *operating reserve* requirements will continue to be used to schedule a minimum amount of *operating reserve* in areas of the *IESO-controlled grid* and maximum area *operating reserve* will continue to be used to prevent over-scheduling of *operating reserve* in areas of the *IESO-controlled grid.* These areas represent locations within the grid where scheduling of *operating reserves* on resources may be restricted due to constraints on the transmission system.

Maximum area *operating reserve* in MW will continue to be applied by the *IESO* to prevent scheduling *operating reserve* where resources are expected to be unable to comply with *dispatch instructions* when activated. This maximum limit will restrict the cumulative amount that resources within this specified area can be scheduled for all classes of *operating reserve*.

Minimum area *operating reserve* may continue to be required for any class of *operating reserve* in an electrical area to identify a specific quantity of *operating reserve* that must be scheduled in the area to support *reliability* requirements in the specified area.

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[3] May include flexibility *operating reserve* requirements and other adjustments for reliability purposes. Refer to the Grid and Market Operations Integration detailed design document for details.

Both minimum and maximum area *operating reserve* limitations will continue to be applied hourly and adjusted by the *IESO* based on expected system conditions and *outage* configurations. These inputs will be used by all calculation engines.

3.5.1.7. Regulation Capacity Requirement

The *regulation* capacity requirement will continue to be defined as the minimum amount of service required to control power system frequency and maintain the balance between load and generation. *Automatic generation control* or *AGC* will continue to be the primary means by which the *IESO* meets the *regulation* capacity requirement in the future day-ahead and *real-time market.*

The *IESO* will continue to determine on the *pre-dispatch day* the minimum quantity of *regulation* capacity needed for each hour of the *dispatch day*. Similar to the current practice for the DACP, the *AGC* nomination data will continue to be specified by the *IESO* prior to the day-ahead market. This will allow *generators* that are eligible to provide *regulation* to nominate the *generation units* that will be placed on *AGC* to meet the required *regulation* capacity.

Regulation capacity requirements for *AGC* will continue to be updated throughout the *pre-dispatch day* and *dispatch day* as required. The amount of *regulation* capacity required for *AGC* will be used as inputs by all calculation engines.

3.5.1.8. Reliability Constraints

Reliability constraints may be applied to specific *registered facilities* as scheduling constraints within all calculation engines to support *reliability must-run contracts*, *reactive support service* contracts or other *reliability* needs where the *IESO* anticipates the calculation engines will be unable to resolve *reliability* issues via the normal *offer* and *bid* mechanisms consistent with all other resources.

The *registered facilities* specified through these constraints and identified in advance of the day-ahead market will continue to be designated as “must commit” resources in the targeted hours for the unit commitment passes of the DAM and PD calculation engines for the appropriate *dispatch day*.

3.5.2. Pricing Inputs

3.5.2.1. Maximum Market Clearing Price

The *maximum market clearing price* (*MMCP*) will continue to define the maximum allowable price for *energy*. Negative *maximum market clearing price* will continue to be the minimum allowable price for *energy* (negative *MMCP*). *MMCP* and negative *MMCP* will be used in the day-ahead market and the *real-time market* and will continue to be specified from time-to-time by the *IESO Board.*

3.5.2.2. Maximum Operating Reserve Price

The *maximum operating reserve price* will continue to define the maximum allowable price for any class of *operating reserve*. It will be used in the day-ahead market and the *real-time market* and will continue to be specified from time to time by the *IESO Board.*

3.5.2.3. Constraint Violation Penalty Curves

Constraint violation penalty curves will continue to be defined as the penalty functions for the violation of constraints in the *dispatch algorithm.* They will be used in the day-ahead market and the *real-time market* and will continue to be specified from time to time by the *IESO Board*.

The *dispatch algorithms* currently used by DACE, and the PD and RT calculation engines produce schedules and prices by optimizing all *dispatch data* submitted by *market participants* to most efficiently meet *energy* and *operating reserve* requirements. Because the calculation engines may at times be unable to resolve all modelled constraints, the *dispatch algorithm* can attempt to achieve a solution by allowing constraints to be violated by using a violation variable. This violation variable, currently defined through a penalty price, adds a penalty cost to the *dispatch algorithm* that allows a violated constraint to be relaxed and allows the calculation engines to find a solution. The constraint violation penalty curves set prices and determine the scheduling priority of managing one constraint violation over another.

In the future day-ahead market and *real-time market,* constraint violation penalty curves will continue to be used by the *dispatch algorithm* in all three calculation engines. However, the form of the constraint violation penalty curves will be different between the scheduling passes and the pricing passes of the *dispatch algorithm.* The scheduling pass will continue to use a single *price-quantity pair* while the pricing passes will be updated to use multiple *price-quantity pairs*. Multiple *price-quantity pairs* will be used in the pricing pass to increase the penalty cost as the magnitude of the constraint violation increases. The following constraints have been described in Section 3.5.1 of this document (with the exception of *energy* balance constraints) and will continue to have corresponding constraint violation penalty curves applied:

- All three classes of *operating reserve;*
- Minimum and maximum area *operating reserve;*
- *Energy* balance (over or under generation);
- *Security Limits*;
- Net Interchange Scheduling Limit (NISL); and
- Maximum Import and Export Limits.

Penalty price curves applied to each of these constraints in the scheduling and pricing passes of the DAM, PD and RT calculation engines are described in next two sections.

Penalty Price Curves in the Scheduling Passes

Penalty price curves specific to the scheduling passes will be used by the calculation engines to ensure they continue to produce schedules when constraint violations occur. The scheduling pass will continue to use a single *price-quantity pair* penalty price curve*.* With respect to the pricing of the penalty curves for the scheduling pass, most will be unchanged in the future day-ahead market and *real-time market* while one will be modified.

A new single *price-quantity* price curve will be introduced in the DAM and PD calculation engines scheduling passes that apply to dispatchable hydroelectric resources that have Linked Resources, Time Lag and MWh Ratios submitted as *dispatch data* so that the calculation engines are able to produce a solution when constraints are in conflict.

Table 3-6 summarizes the penalty price curves and corresponding penalty prices that will be used for each constraint violation in the future day-ahead market and *real-time market*

Table 3-6: Penalty Curves in the Scheduling Pass

Penalty Curve Name	Penalty Price	Calculation Engine(s)	Description
Operating Reserve – system wide (10-min synchronized Reserve Requirement)	Current: $12,000/MW Future: $12,000/MW	Current: All Future: DAM, PD, RT	Penalty prices will remain unchanged and set to current levels in the future day-ahead market and *real-time market*. The penalty price for total *thirty-minute operating reserve* will continue to be high enough to allow the calculation engine to consider all valid combinations of *offers* and *bids* for *energy* and *offers* for *operating reserve* before it allows an *operating reserve* constraint to be violated. The total *ten-minute operating reserve* penalty price will continue to allow the *thirty-minute operating reserve* constraint to be violated before the *ten-minute operating reserve* constraint is violated. Similarly, the penalty price for the synchronized *ten-minute operating reserve* ensures that 10-minute synchronized reserve is given higher priority than the total 10-
Operating Reserve – system wide (Total 10-min Reserve Requirement)	Current: $10,000/MW Future: $10,000/MW	Current: All Future: DAM, PD, RT	
Operating Reserve – system wide (Total 30-min Requirement)	Current: $6,000/MW Future: $6,000/MW	Current: All Future: DAM, PD, RT	

Penalty Curve Name	Penalty Price	Calculation Engine(s)	Description
Operating Reserve - flexibility	Current: $6,000/MW Future: $6,000/MW	Current: All Future: DAM, PD, RT	minute requirement. The penalty prices used for flexibility *operating reserve* will continue to be the same as those used for the system-wide total 30-minute constraint. However, the *IESO* will introduce the ability to specify a separate penalty price for the portion of the total 30-minute constraint that is designated as flexibility *operating reserve*. The *IESO* will have the authority to set penalty prices for the flexibility *operating reserve* constraint that are different from the penalty prices used for the total *thirty-minute operating reserve* constraint in the scheduling pass.
Operating Reserve - Area	Maximum Current: $60,000/MW Future: $60,000/MW Minimum Current: $4,000/MW Future: $4,000/MW	Current: All Future: DAM, PD, RT	The DAM, PD and RT calculation engines will continue to use a penalty price of $60,000 for maximum area *operating reserve* constraints. These penalty prices will prevent transmission constraint violations that may otherwise occur when *operating reserve* is activated from *facilities* within the area. The DAM, PD and RT calculation engines will continue to use a penalty price of $4,000/MW for the minimum area *operating reserve* constraint.
Energy Balance	Current and future under generation: $30,000/MWh Current and future over generation: negative $30,000/MWh	Current: All Future: DAM, PD, RT	The *IESO* will continue to use a penalty price of $30,000/MWh for under generation violations and negative penalty price of $30,000/MWh for over generation violations.
Transmission Security	Current: $60,000/MW Future: $60,000/MW	Current: All Future: DAM, PD, RT	The penalty price shall continue to be set at $60,000 and the constraint exceedance percentage shall be for all possible security limit violations ranging from 0% to infinity.

Penalty Curve Name	Penalty Price	Calculation Engine(s)	Description
NISL	Current: $40,000/MW Future: $35,000/MW	Current: DACP, PD Future: DAM, PD	The current DACP and PD calculation engines use a $40,000/MW penalty price. In the future day-ahead market and *real-time market*, this penalty price will change and be set at $35,000 for all magnitudes of NISL violations in the PD and DAM calculation engines.
Downstream under or over generation[4]	Current: None Future: $37,000	Current: None Future: DAM, PD	There will be one penalty price for all magnitudes of downstream over or under generation. This new price curve has been introduced to the design so that the DAM and PD calculation engines are able to solve when hydroelectric constraints are in conflict. The single price will be $37,000.
Intertie	Current: $40,000/MW Future: $40,000/MW	Current: DACP, PD Future: DAM, PD	There will be one penalty price for all magnitudes of *intertie* limit violations. The penalty price shall continue to be set at $40,000.
Daily Energy Limits	Current: $100,000/MW Future: $100,000/MW	Current: DACP, PD Future: DAM, PD	There will be one penalty price for all magnitudes of DEL violations. The penalty price shall continue to be set at $100,000

Penalty Price Curves in the Pricing Passes

Penalty price curves specific to the pricing passes will be used by the calculation engines to ensure they continue to produce prices when constraint violations occur. Multiple *price-quantity pair* penalty curves are new inputs that will be used in the pricing passes of the future day-ahead market and *real-time market* to provide the *IESO* and *market participants* with price signals for scarcity conditions. The penalty price curves will be comprised of up to 20 *price-quantity pairs* or price-percentage pairs where:

- prices are defined in dollars ($ per MW);
- breakpoint quantities are defined in megawatts (MW); and

[4] During implementation the IESO will consider separate penalty prices for downstream under generation and downstream over generation, with input from participants.

- breakpoint percentages (%) are defined in constraint exceedance amounts, which is the measurable amount of units that exceed a transmission limit.

The constraint violation penalty curves will be represented as either a *demand* or a supply curve, depending on the type of constraint. The DAM and PD calculation engines will use constraint violation penalty curves that can vary from hour to hour. The RT calculation engine will use constraint violation penalty curves that can vary from five-minute interval to five-minute interval.

The *IESO* will use the methodologies described in Table 3-7 below to set the pricing for each of the constraint violation penalty curves.

The penalty prices used may be adjusted from time to time by the *IESO Board* where the *IESO* determines that constraint violation price signals may either overstate or understate the cost of managing the constraint violation given prevailing market conditions. The *IESO* shall advise *market participants* of such changes.

Table 3-7 summarizes the penalty curve inputs for each of the constraints in relation to the pricing pass and provides a brief description.

Table 3-7: Penalty Curves in the Pricing Pass

Penalty Curve Name	Description
Operating Reserve – system wide	The pricing passes for all calculation engines will use separate penalty price *demand* curves for the three *operating reserve* constraints. The MW quantity ranges of the *price-quantity pairs* used for each *operating reserve* constraint will be based on the *operating reserve* requirement for each class of *operating reserve*. When the requirement is changed, the relative proportion of each MW quantity range will be scaled to maintain the relative proportions of each MW range. The central price point of the *price-quantity pairs* used for the total *30-minute operating reserve* constraint will be based on the 99th percentile of historical *30-minute operating reserve* prices. The price points above and below the central price point will be priced in a graduated fashion with respect to the central price point. The central price point of the *price-quantity pairs* used for the total 10-minute *operating reserve* constraint will be based on the 99th percentile of historical 10-minute *operating reserve* prices. Price points above and below the central price point will be priced in a graduated fashion with respect to the central price point. The lowest price point of the *price-quantity pairs* used must be no less than the highest price point of the *price-quantity pairs*

Penalty Curve Name	Description
	used for the 30-minute *operating reserve* constraint. The penalty prices used for the 10-minute synchronized *operating reserve* constraint will be higher than the prices used for the total 10-minute constraint such that the cumulative prices in the *operating reserve* constraint violation price curve rise in a graduated fashion as the *operating reserve* shortage progresses from a shortage in total 30-minute *operating reserve* to a shortage in total 10-minute *operating reserve* and then finally to a shortage in 10-minute synchronized *operating reserve*.
Operating Reserve - area	The DAM, PD and RT calculation engines will use penalty prices for the maximum area *operating reserve* constraint that are equal to the penalty prices used for the second price-percentage pair in the transmission security limit constraint violation penalty curve described further below. The DAM, PD and RT calculation engines will use a penalty price for the minimum area *operating reserve* constraint that is equal to the lowest penalty price used for the system-wide total *ten-minute operating reserve* constraint violation penalty curve.
Operating Reserve - flexibility	The DAM, PD and RT calculation engines will use the constraint violation penalty curve for the system-wide total *thirty-minute operating reserve* to set penalty prices for the flexibility *operating reserve* constraint. The *IESO* will have the authority to set penalty prices for the flexibility *operating reserve* constraint that are different from the penalty prices used for the total *thirty-minute operating reserve* constraint in the pricing pass.
Energy Balance	The DAM, PD and RT calculation engines will use different constraint violation penalty curves for the under-generation and over-generation constraints. The penalty prices used for the under-generation constraint will be set high enough to ensure that valid *offers* of *energy* for *registered facilities* will be evaluated first. The penalty prices will be set high enough so that it does not displace an *offer* of *energy* at up to *MMCP* while taking into account transmission losses and the impact of *operating reserve* joint optimization. For over-generation constraints, the DAM, PD and RT calculation engines will use penalty prices that will be low enough so that the calculation engines do not use the violation price before using a *dispatchable load bid* at negative *MMCP* with high transmission losses.
Transmission Security	The DAM, PD and RT calculation engines will use two price ($) / percentage (%) pairs for all transmission *security limit* constraints. The constraint exceedance percentage for the first price-percentage pair shall be for any

Penalty Curve Name	Description
	constraint exceedance at or below 2% of the applicable transmission *security limit*. The second price-percentage pair shall represent any constraint exceedance above 2%. The *IESO* will determine the penalty prices used based on historical shadow prices for binding and violated transmission security constraints. The price of the first price-percentage pair shall be based on the price that best minimizes the differences between the surplus during violations and the uplift occurring during both violations and when there are binding constraints for historical occurrences. The price of the second price-percentage pair shall be greater than *MMCP* and based on the division of the *MMCP* by a shift factor coefficient of less than 1. The shift factor will be a measure of the relative electrical proximity and directness of a pricing node to a constraint, derived through the historical review of transmission security constraints.
NISL	The DAM, PD and RT calculation engines will use a single penalty price for all magnitudes of NISL constraint violations. The penalty price used for the NISL constraint will be based on the 99^{th} percentile of historical NISL congestion prices.
Intertie	The DAM and PD calculation engines will use a single penalty price for all magnitudes of *intertie* constraint violations. In order to maintain the scheduling hierarchy for constraints in the pricing pass that were used in the scheduling pass, the penalty price used for the *intertie* constraint will be based on the mid-point between the penalty price for the over-generation *energy* balance constraints and the second *price-quantity pair* of the transmission security constraint violation price curve.
Daily Energy Limits	The DAM, PD and RT calculation engines will use a single penalty price for all magnitudes of daily *energy* limit violations. The penalty price used will be set above all other penalty prices in order to minimize the daily *energy* limit violations, while still providing a feasible region for the calculation engine to be solved.

3.5.3. Market Power Mitigation Inputs

The Market Power Mitigation process will require new inputs that will be used in the future day-ahead market and the *real-time market* to prevent *market participants* from exercising the market power they may have when competition in the *IESO-administered markets* is restricted.

The *IESO* will assess when competition is restricted and will employ the conduct and impact test methodology in those cases to determine if mitigation is necessary. Each type of mitigation uses different sets of inputs, evaluates based on different criteria and applies different decision-making logic to determine which, if any, *registered facilities* should be subject to market power mitigation. The *IESO* will then apply the appropriate mitigation process to *dispatch data* submitted for affected *registered facilities*.

Market power mitigation inputs include reference levels for financial and non-financial *dispatch data* parameters. Financial *dispatch data* parameters include *energy offer*, start-up *offer*, speed no-load *offer*, *offer* for *operating reserve*, and *energy offer* for the range of production up to MLP. Reference levels for financial *dispatch data* parameters will be used by the ex-ante mitigation functions of the DAM, and PD calculation engines to test for economic withholding. Ex-ante mitigation of financial *dispatch data* will result in modifying schedules and *dispatch instructions* for *registered facilities* and their corresponding LMPs in the day-ahead market and in pre-dispatch, and based on any persisting mitigated *dispatch data* from the *pre-dispatch scheduling* process in the *real-time market*.

Non-financial *dispatch data* parameters include MGBRT, MGBDT, MLP, *energy* ramp rate, *operating reserve* ramp rate, lead time, ramp hours to MLP, *energy* per ramp hour and *maximum number of starts per day.* Reference levels and pre-defined conduct thresholds for non-financial *dispatch data* will be used by the *dispatch data* validation process to validate the submission of non-financial *dispatch data* parameters. If the value submitted for the applicable non-financial *dispatch data* parameters exceeds the reference value and the conduct threshold, the *dispatch data* submission will be rejected.

Some of the market power mitigation inputs will also be used in settlement mitigation processes that test for impacts to make-whole payments that can result in *settlement* adjustments after the DAM and *real-time markets* have been cleared.

The following sections describe the market power mitigation inputs that the *IESO* will use to carry out the conduct and impact tests. For specific details about each type of input, the various types of mitigation tests that will be applied in the future market and the set of steps required for each mitigation test, refer to the Market Power Mitigation detailed design document.

3.5.3.1. Constrained Area Designations

Constrained area designations will define areas of the *IESO-controlled grid* where competition may be restricted with varying degrees of duration and frequency. Constrained area designations will be determined by the *IESO* and used to test for both economic withholding within the DAM, PD and RT calculation engines, and for physical withholding after-the-fact. Constrained area designations will also be used to identify the conduct and impact thresholds to apply to each *registered facility*.

3.5.3.2. Reliability Constraints

Reliability constraints manually applied to *registered facilities* by the *IESO* will be flagged for a *settlement* mitigation assessment for economic withholding during *settlement*.

3.5.3.3. Uncompetitive Interties

The *IESO* will designate *interties* where competition is restricted as uncompetitive *interties*. The *IESO* will perform an ex-post assessment for economic withholding on uncompetitive *interties*. The *IESO* will apply the conduct and impact tests on *market participant bids* and *offers* to test for economic withholding on those *interties*. If the conduct and impact tests are failed, the *IESO* will apply a *settlement* charge.

3.5.3.4. Reference Levels

The *IESO* in consultation with *market participants* will determine the reference levels for financial and non-financial *dispatch data* parameters for each *registered facility* for different timeframes and for both on-peak and off-peak *dispatch hours*. Financial *dispatch data* parameters are a subset of *dispatch data* that are represented as financial values. Non-financial *dispatch data* parameters are a subset of the *dispatch data* that are not represented as financial values.

Reference levels for financial *dispatch data parameters* will be based on the short-run marginal costs of a *registered facility.* Reference levels for non-financial *dispatch data* parameters will be based on the operating characteristics of a *registered facility.* The DAM, PD and RT calculation engines will mitigate a *market participant's* financial *dispatch data* for *energy* and *operating reserve* to its respective reference level when a *registered facility* fails the conduct and impact tests for economic withholding. Reference levels will also be used in determining make-whole payment adjustments as part of *settlement* of the day-ahead market and *real-time market.*

3.5.3.5. Conduct Thresholds

The *IESO* will determine conduct thresholds that will be used in conjunction with reference levels and impact thresholds when assessing mitigation for economic withholding. There will be conduct thresholds for *dispatch data* parameters for which there exists a reference level.

Conduct thresholds are used in conjunction with reference quantities and impact thresholds when assessing mitigation for physical withholding.

3.5.3.6. Impact Thresholds

Impact thresholds represent the margin that is used to determine whether prices in the as-*offered* results are significantly higher than prices in the reference level results. Impact thresholds will be determined by the *IESO* and will be used in conjunction with reference levels and conduct thresholds when assessing mitigation for economic withholding.

When assessing mitigation for physical withholding, impact thresholds will be used in conjunction with reference quantities and conduct thresholds.

3.5.4. Network Model

The network model is integral in planning and managing the *reliability* of the *IESO-controlled grid*. It contains a detailed topology representation of the *IESO-controlled grid* and a simplified representation of power systems in neighboring jurisdictions. It is used as input to the *IESO's* real-time *energy* management system (EMS) and all calculation engines. The topology of the network model is determined through normal equipment statuses, *outages* and/or telemetry as applicable to each of the calculation engines.

This section first discusses the changes required to the Network Model Build process and to the network model itself in order to maintain the *reliability* of the *IESO-controlled grid* in the future day-ahead market and *real-time market*.

3.5.4.1. Network Model Build Process

The Network Model Build process will continue to coordinate updates to the network model when *market participant* information is updated, new *facilities* are registered, and when existing *facilities* are modified or retired. This will assure the effective dates used by other *IESO* market systems are reflected in the network model updates.

The following new activities will be added to the Network Model Build process to support the future day-ahead and *real-time market*:

- Create and maintain virtual transaction zonal trading entities: As described in Section 3.4.7 Virtual Transaction Offers and Bids for Energy, virtual transaction zonal trading entities will enable *market participants* to submit virtual transactions into the day-ahead market. Virtual transactions that clear the day-ahead market will be distributed to all *load facilities* using the LDFs, which are described in a following sub-section. The list of *load facilities* will exclude those where the addition of virtual MWs leads to AC load flow divergence in the future DAM calculation engine. Refer to the DAM

Calculation Engine detailed design document for information about the evaluation and scheduling of virtual transactions; and

- Create and maintain mappings of the *IESO*'s existing ten electrical zones to the nine new virtual transaction zonal trading entities described earlier in this document and the four new demand forecasts areas described later in this document. These mappings will be used to provide the calculation engines with re-normalized LDFs so that virtual transactions that clear the DAM and the *demand* forecasts for the four new *demand* forecast areas can be distributed to *load facilities*.

3.5.4.2. Marginal Loss Factors

Marginal loss factors represent the increase or reduction in system losses when injections or withdrawals occur at locations other than the *reference bus*. System losses and marginal loss factors vary due to changes in prevailing system conditions such as transmission flows and topology. The marginal loss factors are used in the calculation engines to capture the impact of load and generation schedules on system losses.

Currently, the calculation engines use static marginal loss factors that the *IESO* calculates off-line and updates on a yearly basis as part of the Network Model Build process. In the future day-ahead market and *real-time market*, the *IESO* will no longer calculate static marginal loss factors offline. Instead, all calculation engines will dynamically calculate and use marginal loss factors that reflect prevailing system conditions. Refer to the DAM, PD and RT calculation engine detailed design documents for more information on how dynamic loss factors will be calculated and used.

3.5.4.3. Daily Dispatch Order for Variable Generators

Currently, the *IESO* randomly determines on a monthly basis, a daily *dispatch* order for *variable generation* resources for each day of the month. The RT calculation engine uses the daily *dispatch* order in a tie-breaking logic to determine which *variable generation* resource will be dispatched when two or more *variable generation* resources have the same *offer* price.

In the future day-ahead market and *real-time market*, the *IESO* will determine a daily *dispatch* order for *variable generation* in the same manner as today. The daily *dispatch* order will be used by the DAM, PD and RT calculation engines. Refer to the DAM, PD and RT calculation engine detailed design documents for more information on tie-breaking logic for *variable generation*.

3.5.4.4. Pricing Locations

Pricing locations will continue to be defined as locations in the network model that define where prices will be calculated by the DAM, PD and RT calculation engines.

Currently, shadow price locations are defined in the network model and are used for informational purposes since a uniform price is used for *settlement* purposes. In the future day-ahead and *real-time market,* locational marginal prices (LMPs) will be used for *settlement* and informational purposes. LMPs will replace the current uniform price for *settlement* of all *dispatchable generation facilities,* non-dispatchable *generation facilities, dispatchable loads* and price responsive loads. A new Ontario zonal price will be applied for *settlement* of *non-dispatchable loads*.

The following pricing location definitions will continue to be maintained as part of the Network Model Build process:

- All *delivery points* associated with dispatchable *generation facilities* , *dispatchable loads* , and non-dispatchable *generation facilities* ;
- All *boundary entities* ; and
- All *hourly demand response* resources ;

The following pricing locations will need to be added as part of the Network Model Build process:

- All *delivery points* associated with *non-dispatchable loads* and price responsive loads;
- *Pseudo-unit* resources;
- A new single Ontario zone; and
- All new virtual transaction zonal trading entities.

Refer to the DAM, PD and RT calculation engine detailed design documents for information on the calculation of prices at these pricing locations.

3.5.4.5. Load Distribution Factors (LDFs)

LDFs are a set of values that define what percentage of the *demand* forecast should be assigned to each *load facility* in the network model. LDFs define the load pattern the calculation engines use to distribute the *demand* forecast to individual *load facilities* to determine hourly schedules for *registered facilities* in the day-ahead and pre-dispatch timeframes, and five-minute *dispatch instructions* for dispatchable *registered facilities* in the *dispatch hour*. LDFs are currently determined based on historical and updated load patterns.

The DACE currently uses hourly LDFs that are based on the load patterns from the same day in previous weeks. For example, if tomorrow’s *dispatch day* is a Monday, the LDFs used are based on the load patterns observed on previous Mondays. In the future *energy market*, the DAM and PD calculation engines will also use LDFs that are based on load patterns from the same day in previous weeks, for all hours except the first two hours of the PD calculation engine's look-ahead period. The first two hours of the PD calculation engine look-ahead period will continue to use LDFs that are based on the load pattern observed in the current *dispatch hour*.

The RT calculation engine will continue to use LDFs that are based on the load pattern observed in the current and last *dispatch hours*.

3.5.5. Centralized Variable Generation Forecast

The centralized *variable generation* forecast will continue to be used as an input into the day-ahead and pre-dispatch timeframes and the *dispatch hour*, and a *forecasting entity* will continue to provide the *IESO* with the centralized *variable generation* forecast in the future day-ahead market and *real-time market*.

The PD and RT calculation engines will continue to use the centralized *variable generation* forecast to determine the maximum amount of *energy* that a *registered facility* supplying *variable generation* can be scheduled and *dispatched*.

The DAM calculation engine will use the centralized *variable generation* differently than the manner in which it is currently used by the DACP. Although the centralized *variable generation* forecast will continue to be used to schedule for *reliability* purposes, it will no longer be used as the *offer* quantity for *variable generators*. As described in Section 3.4.2 under the sub-section: Variable Generator Forecast Quantity, *registered market participants* submitting *offers* on behalf of *variable generation* will have the ability to submit their own forecast quantity or to use the centralized *variable generation* forecast as part of their hourly *dispatch data*. Additional details on the use of the centralized *variable generation* forecast in each respective timeframe can be found in the DAM, PD and RT Calculation Engine detailed design documents.

The centralized *variable generation* forecast will continue to be used as an input into the *IESO's demand* forecasting process. The *demand* forecast process currently relies on the centralized *variable generation* forecast to account for the impact that embedded *variable generation* may have on the demand.

The *IESO* will continue to have the authority to adjust the centralized *variable generation* forecast in order to minimize forecast deviations from expected actual production. Refer to the Grid and Market Operations Integration detailed design document for adjustment procedures.

3.5.6. Demand Forecasts

The *IESO* currently produces *demand* forecasts using a province-wide approach. Forecasts are generated using historical load consumption as well as expectations of future load consumption which are based on a number of factors, including weather forecasts.

In the future day-ahead and *real-time market*, the *IESO* will produce four separate area *demand* forecasts. A *demand* forecast at the province-wide level will continue to be published but now as the sum of the four separate area *demand* forecasts. The *demand* forecasts will better reflect localized weather conditions and consumption patterns for each area. The following section describes in greater detail the changes the *IESO* will be making to its *demand* forecast process.

3.5.6.1. Demand Forecast Areas

As described above, the *IESO* will produce four separate area *demand* forecasts that sum to the total *demand* forecast for the entire province. *Demand* forecasts for each *demand* forecast area will be generated on a continuous basis for every *dispatch hour* of the current *dispatch day* and ten consecutive future *dispatch days*. The four *demand* forecast areas will be defined as one or more of the *IESO's* existing 10 electrical zones as follows:

- Northeast: comprised of all *load facilities* in the existing Northeast electrical zone;
- Northwest: comprised of all *load facilities* in the existing Northwest electrical zone;
- Southeast: comprised of all *load facilities* in the existing East, Essa, Ottawa and Toronto electrical zones; and
- Southwest: comprised of all *load facilities* in the existing Bruce, Niagara, Southwest and West electrical zones.

Demand forecasts for each *demand* forecast area will consist of a five-minute *demand* forecast, an hourly average *demand* forecast and an hourly peak *demand* forecast. The hourly average *demand* forecast will continue to be the average of the five-minute *demand* forecasts for each *dispatch hour* while the hourly peak *demand* forecast will continue to be the peak five-minute forecast for each *dispatch hour*. *Demand* forecasts for each *demand* forecast area will be reflective of anticipated *demand* at all *load facilities* inclusive of transmission losses, as they currently are for the single province-wide *demand* forecast.

Before the *demand* forecasts for each *demand* forecast area can be used by the optimization functions of the DAM, PD and RT calculation engines, they will be automatically adjusted by removing the forecast consumption of all *load facilities* for which *registered market participants* are submitting *dispatch data*. Transmission losses are removed before the non-dispatchable *demand* forecast is used by the security assessment function.

Load facilities for which *registered market participants* submit *dispatch data* in all timeframes include *dispatchable loads* and *hourly demand response* resources, whereas *dispatch data* for PRLs is only submitted in the DAM. The purpose of removing forecast consumption of participating *load facilities* is to arrive at a *demand* forecast quantity that is solely reflective of loads considered to be non-dispatchable. For ease of reference, the *demand* forecast for all *load facilities* within a *demand* forecast area is referred to as the total *demand* forecast and the *demand* forecast that is solely reflective of loads considered to be non-dispatchable is referred to as the non-dispatchable *demand* forecast.

The high-level methodology that will be used to arrive at the non-dispatchable *demand* forecast for each *demand* forecast area is further described in the non-dispatchable *demand* forecasts section below.

Moving to *demand* forecast areas will require changes to the *demand* forecast information currently published by the *IESO*. Refer to the Publishing and Reporting Market Information detailed design document for more information.

The *IESO* will continue to have the authority to adjust *demand* forecasts in order to minimize forecast deviations from expected actual consumption. Refer to the Grid and Market Operations Integration detailed design document for adjustment procedures.

3.5.6.2. Total Demand Forecast Inputs

Total *demand* forecasts will be supported by additional meteorological data as follows:

- The *IESO* will increase the total number of weather stations that provide a primary source of meteorological data; and
- A secondary source of meteorological data may also be collected by the *IESO* to use as back-up input data in the event that unforeseen circumstances reduce the quality of primary meteorological data.

3.5.6.3. Non-Dispatchable Demand Forecasts

The forecast consumption of all *load facilities* for which *registered market participants* submit *dispatch data* will be removed from the total *demand* forecasts of each *demand* forecast area to arrive at the non-dispatchable *demand* forecast for each area. The non-dispatchable *demand* forecast for each *demand* forecast area will then be evaluated by the optimization function of the calculation engines.

Transmission losses will also be removed from the non-dispatchable *demand forecasts* for each *demand* forecast area to avoid double counting the losses since the *security* assessment function of the DAM, PD and RT calculation engines determine losses during its execution. Refer to the DAM, PD and RT Calculation

Engine detailed design documents for how transmission losses will be determined by each of the engines.

Each calculation engine will use slightly different non-dispatchable *demand* forecasts as described below.

Day-Ahead Market Calculation Engine

The DAM calculation engine will use the hourly average non-dispatchable *demand* forecast as well as the hourly peak non-dispatchable *demand* forecast for each *demand* forecast area.

The hourly average non-dispatchable *demand* forecast used by Pass 1 and Pass 3 of the DAM calculation engine will be determined by removing the forecast consumption for the following *load facilities* from the average hourly total *demand* forecast:

- Forecast consumption of all *dispatchable loads*;
- Forecast consumption of all PRLs;
- *Bid* demand response capability of virtual *hourly demand response* resources; and
- *Bid* demand response capability of physical *hourly demand response* resources associated with NDLs and PRLs.

The hourly peak non-dispatchable *demand* forecast of each area used by Pass 2 of the DAM calculation engine will be determined by removing the forecast consumption for the following *load facilities* from the peak hourly total *demand* forecast:

- Forecast consumption of all *dispatchable loads* except *dispatchable loads* for which there is no *bid*;
- *Bid* demand response capability *of virtual hourly demand response* resources*;* and
- *Bid* demand response capability of physical *hourly demand response* resources associated with NDLs and PRLs.

Refer to the DAM Calculation Engine detailed design document for more information about the determination of the non-dispatchable *demand* forecasts used as inputs into the various passes of the DAM calculation engine.

Pre-Dispatch Calculation Engine

The PD calculation engine will use the hourly average non-dispatchable *demand* forecast for each *demand* forecast area unless there is a significant difference between the average and peak total *demand* forecasts. Refer to the Grid and Market Operations Integration detailed design document for the criteria the *IESO* will use to determine the total *demand* forecast that will be used to arrive at the non-dispatchable *demand* forecast for each *demand* forecast area.

The hourly average and hourly peak non-dispatchable *demand* forecast for each *demand* forecast area will be determined by removing the forecast consumption for the following *load facilities* from the average and peak hourly total *demand* forecast:

- Forecast consumption of all *dispatchable loads* except *dispatchable loads* for which there is no *bid*;
- *Bid* demand response capability *of virtual hourly demand response* resources; and
- *Bid* demand response capability of physical *hourly demand response* resources associated with NDLs and PRLs.

Refer to the PD Calculation Engine detailed design document for more information about the determination of the non-dispatchable *demand* forecast inputs into the PD calculation engine.

Real-Time Calculation Engine

The RT calculation engine will use an up-to-date five minute non-dispatchable *demand* forecast for each forecast area. This forecast will be generated using the latest telemetry values from the six most recent intervals. Additional details can be found in the RT Calculation Engine detailed design document.

– End of Section –

4. Market Rule Requirements

The *market rules* govern the *IESO-controlled grid* and establish and govern the *IESO-administered markets*. The *market rules* codify obligations, rights and authorities for both the *IESO* and *market participants*, and the conditions under which those rights and authorities may be exercised and those obligations met.

This section is intended to provide an inventory of the changes to *market rule* provisions required to support the Offers, Bids and Data Inputs detailed design, and is intended to guide the development of *market rule* amendments.

This inventory is not meant to be an exhaustive list of required rule changes, but is a "snapshot" in time based on the current state of design development of this specific design document. Resulting *market rule* amendments will incorporate the integration of the individual design documents.

New and amended Chapter 11 defined terms: These terms will be consolidated in a single document at a later time as part of the *market rule amendment* process, and will support multiple design documents.

The inventory is developed in the following tables, which describe the impacts to the *market rules* and classifies them into the following three types:

- Existing – no change: Identifies those provisions of the existing *market rules* that are not impacted by the design requirements;
- Existing – requires amendment: Identifies those provisions of the existing *market rules* that will need to be amended to support the design requirements; and
- New: Identifies new *market rules* that will likely need to be added to support the design requirements.

Table 4-1: Market Rules Chapter 4 Impacts

Market Rule Section	Type	Topic	Requirement
Section 7.3.5 and 7.3.6	Existing - no change	Centralized Forecast for Variable Generation Facilities	Sections 7.3.5 and 7.3.6: • These sections specify *IESO* obligations in providing confidential centralized forecasts prepared by the *forecasting entity* to each *registered market participant* for each of their *variable generation facilities.*

Market Rule Section	Type	Topic	Requirement
			• Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration

Table 4-2: Market Rules Chapter 5 Impacts

Market Rule Section	Type	Topic	Requirement
Section 1	Existing - no change	Purposes, Interpretation and General Principles	Section 1: • Chapter 5 of the *market rules* describes the scope and operation of the *IESO-controlled grid*, and the various responsibilities, obligations and authorities of the *IESO* and each *market participant* in order to maintain the *reliability* of the *IESO-controlled grid*. Section 1 describes the purpose, interpretation and general principles of Chapter 5. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 2	Existing - no change	IESO-Controlled Grid and Operating States	Section 2: • This section specifies the scope of the *IESO-controlled grid* including normal operating state, emergency operating state and high-risk operating state. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 3	Existing - no change	Obligations and Responsibilities	Section 3: • This section specifies the responsibilities, obligations and authorities placed on the *IESO* and each *market participant* to assist in supporting power system *reliability.* • Provisions unaffected by the design changes

Market Rule Section	Type	Topic	Requirement
			specified in the Offers, Bids and Data Inputs design document. • For the MRP project, not related to Offers, Bids and Data Inputs, *amendments* may be required to sections 3.3.1 and 3.3.2 pending decisions on staging of the *market rules* for MRP and pending decisions as to when *reliability* related information must be *published* by the *IESO* following the coming into force of MRP *market rule amendments*. OVERLAP: Grid and Market Operations Integration
Section 4.1	Existing - no change	System Reliability: Objectives	Section 4.1: • This section specifies the requirements to ensure availability of sufficient *generation capacity* and *ancillary services* to the *IESO-administered markets.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 4.2	Existing - no change	System Reliability: Standards for Ancillary Services	Section 4.2: • This section specifies *IESO* obligations to ensure *ancillary services* are available to maintain *reliability* of the *IESO-controlled grid.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 4.3	Existing - no change	System Reliability: Generic Performance Requirements for Ancillary Services	Section 4.3: • This section specifies the generic requirements for provision of *ancillary services* by *registered facilities.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration

Market Rule Section	Type	Topic	Requirement
Section 4.4	Existing - no change	System Reliability: Regulation	Section 4.4: • This section specifies the *IESO* obligation to define AGC requirements in order to maintain *reliability* of the *IESO-controlled grid.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 4.5, 4.5.1 to 4.5.5	Existing - no change	System Reliability: Operating Reserve	Sections 4.1.1 to 4.5.5: • These sections specify *IESO* obligations to define *operating reserve* requirements to maintain the *reliability* of the *IESO-controlled grid* (pre-market inputs). • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 4.5.7 to 4.5.21	Existing – no change	System Reliability: Ten-Minute and Thirty-Minute Operating Reserve	Sections 4.5.7 to 4.5.21: • These sections specify requirements for *ten-minute operating reserve* and *thirty-minute operating reserve*. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 4.6	Existing - no change	System Reliability: Reactive Support and Voltage Control	Section 4.6: • This section specifies *IESO* obligations to ensure sufficient *reactive support service* and *voltage control service* to maintain *reliability* of the *IESO-controlled grid.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.

Market Rule Section	Type	Topic	Requirement
Section 4.7	Existing - no change	System Reliability: Black Start Service	Section 4.7: • This section specifies *IESO* obligations to determine required amounts and locations of black start capability across the *IESO-controlled grid.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 4.8	Existing - no change	System Reliability: Reliability Must-Run Resources	Section 4.8: • This section specifies *IESO* obligations to define *reliability must-run resources* requirements to maintain the *reliability* of the *IESO-controlled grid.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 4.9	Existing - no change	System Reliability: Auditing and Testing of Ancillary Services	Section 4.9: • This section specifies *IESO* obligations to test *facilities* that will or do provide *ancillary services* to the *IESO-controlled grid.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 4.10	Existing - no change	System Reliability: Consequences of Failure to Pass a Test	Section 4.10: • This section specifies consequences of failure to pass a test as prescribed in section 4.9. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 4.11	Existing - no change	System Reliability: Emergency Conditions	Section 4.11: • This section specifies that the *IESO* may acquire *ancillary services* from any *market participant* when the *IESO-controlled grid* is in an emergency operating state. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs

Market Rule Section	Type	Topic	Requirement
			design document.
Section 5.1	Existing - no change	System Security: Objectives and General Obligations	Section 5.1: • This section specifies procedures necessary to enable the *IESO* to ensure the *security* of the *IESO-controlled grid*, including, for example, the establishment of *security limits.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 5.2	Existing - no change	System Security: Security Limits	Section 5.2: • This section specifies *IESO* obligations to establish and *publish security limits* as well as *market participant* obligations regarding thermal ratings. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 5.3	Existing - no change	System Security: The Use of Tie-Lines and Associated Facilities	Section 5.3: • This section specifies *IESO* obligations to establish *security limits* for *interties,* as well as *market participant* obligations to follow *reliability* requirements for imports and exports (requirements for *boundary entity bids* and *offers*). • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 5.4	Existing - no change	System Security: Reliability Policy for Area Supply	Section 5.4: • This section specifies that the *IESO* may develop and apply specific *security* criteria in areas of the *IESO-controlled grid.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.

Market Rule Section	Type	Topic	Requirement
			OVERLAP: Grid and Market Operations Integration
Section 5.6	Existing - no change	System Security: Inadvertent Interchange	Section 5.6: • This section obligates the *IESO* to address *inadvertent interchange* in any agreement relating to *security* between the *IESO* and other *security coordinators.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 6.1	Existing - no change	Outage Coordination: Introduction	Section 6.1: • This section enables the *IESO* to review and assess the impact of *outage* schedules on *reliability*. *Market participants* are obligated to obtain the approval of the *IESO* in respect of *planned outage* schedules. The *IESO* is permitted to reject, revoke *advance approval* of and recall *outages* that may have an impact on the *reliability* of the *IESO-controlled grid* or a material impact on the operation of the *IESO-administered markets*. Section 6.1 specifies *facilities* for which *outages* must be reported to and scheduled with the *IESO*. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Chapter 5 Section 6.2	Existing - no change	Outage Coordination: Outage Planning	Section 6.2: • This section specifies *market participant* and *IESO* obligations related to *planned outages.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 6.3	Existing - no change	Outage Coordination: Outage Scheduling with the IESO	Section 6.3: • This section specifies *market participant* and *IESO* obligations relating to the submission of *planned outages* or *forced outages*. • Provisions unaffected by the design changes

Market Rule Section	Type	Topic	Requirement
			specified in the Offers, Bids and Data Inputs design document.
Section 6.4	Existing - no change	Outage Coordination: Submission of Outage Schedules and IESO Approval of Outage Schedules	Section 6.4: • This section specifies *IESO* and *market participant* obligations and requirements to confirm/approve *outages*, including timing. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 6.5	Existing - no change	Outage Coordination: Information	Section 6.5: • This section specifies *transmitter* and *generator* obligations to provide to the *IESO* information to enable the *IESO* to review and schedule *outages.* It also specifies the *IESO's* obligation to *publish planned outage* information, subject to the confidentiality provisions of Chapter 3. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Publishing and Reporting Market Information
Section 7.1	Existing - no change	Forecasts and Assessments: Forecasts Prepared by the IESO	Section 7.1: • This section specifies the forecasts prepared and *published* by the *IESO*, including demand forecasts. • Ontario zonal demand report (days 0 to 34) will be impacted. Zones will need to be revised as per new forecast zones (greater granularity – existing provides wide demand forecast produced as the sum of four demand forecast areas). However, *amendments* are not required since the *market rules* indicate that the *IESO* prepares the forecasts as specified in the applicable *market manual.* • Changes are not required to the methodology to produce forecasts. Existing methodology indicated

Market Rule Section	Type	Topic	Requirement
			in "Reliability outlook methodology" will not be impacted. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Publishing and Reporting Market Information
Section 7.2	Existing - no change	Forecasts and Assessments: Basis for IESO Forecasts	Section 7.2: • This section obligates the *IESO* to develop forecasts of peak *demand* and *energy demand* by area, that are based on, but potentially differ from the forecasts provided to it by *distributors*, other load-serving entities and *connected wholesale customers.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 7.3	Existing - no change	Forecasts and Assessments: Advance Assessments of System Reliability	Section 7.3: • This section obligates the *IESO* to prepare and *publish* reports of its findings in relation to such *reliability* assessments • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration, Publishing and Reporting Market Information
Section 7.4	Existing - no change	Forecasts and Assessments: Purpose of Assessments	Section 7.4: • This section specifies the purpose of the *IESO* conducting the *reliability* assessments and *forecasts* under Ch5 S7.3. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 7.5	Existing - no change	Forecasts and Assessments: Information Requirements	Section 7.5: • This section specifies *market participant* obligations to provide information for use by the *IESO* in conducting *reliability* assessments, as

Market Rule Section	**Type**	**Topic**	**Requirement**
			described in the applicable *market manual.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 14	Existing - no change	Information and Reporting Requirements	Section 14: • This section specifies information required by the *IESO* that must be reported by *market participants* for *reliability* purposes. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Appendix 5.1 Section 1.1	Existing - no change	Performance Standards for Ancillary Services: Regulation	Section 1.1: • This section specifies performance standards and obligations of *registered facilities* providing *regulation.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Appendix 5.1 Section 1.2	Existing - no change	Performance Standards for Ancillary Services: Operating Reserve	Section 1.2: • This section specifies performance standards and obligations of *ancillary service providers offer*ing *operating reserve.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Appendix 5.1 Section 1.3	Existing - no change	Performance Standards for Ancillary Services: Reactive Support and Voltage Control – Generation Facilities	Section 1.3: • This section specifies performance standards and obligations of registered *facilities* that are *generation facilities* providing reactive support service and voltage control service. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.

Market Rule Section	Type	Topic	Requirement
Appendix 5.1 Section 1.4	Existing - no change	Performance Standards for Ancillary Services: Reactive Support and Voltage Control – Non-Generation Facilities	Section 1.4: • This section specifies performance standards and obligations of each connected wholesale customer, *transmitter* and *distributor* connected to the *IESO-controlled grid* providing reactive support service and voltage control service. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Appendix 5.1 Section 1.5	Existing - no change	Performance Standards for Ancillary Services: Black Start	Section 1.5: • This section specifies performance standards and obligations of *certified black start facilities*, as well as *IESO* testing and assessment of *certified black start facilities.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.

Table 4-3: Market Rules Chapter 7 Impacts

Market Rule Section	Type	Topic	Requirement
Section 1, 1.1.1	Existing - requires amendment	Introductory Rules: Introductory Rules/Purpose	Sections 1/1.1.1: • This section specifies the purpose of Chapter 7 and the scope of the *physical markets*. • *Amendments* are required to integrate the market renewal project and are generic to all design chapters. Section 1.7 is applicable to the Offers, Bids and Data Inputs detailed design. The following required *amendments* are generally required, and not exclusive to the Offers, Bids and Data Inputs design document: • Expand this section to make clear that Chapter 7 of the *market rules* sets forth rules governing the registration of *facilities* and *boundary entities*, and also sets forth rules governing the real-time operations of the *electricity system* and the

Market Rule Section	Type	Topic	Requirement
			market clearing and pricing process in the *physical markets*. Specify the sections in Chapter 7 such as section1 and section 2 (Registration of Physical Operations) which will be common to real-time/pre-dispatch as well as day-ahead market physical operations. • As a consequential amendment a definition is required for the day-ahead market and the definition of *physical market* requires amendment to include the day-ahead market
Section 1.2.1	Existing - no change	Introductory Rules: Application	Section 1.2.1: • This section specifies to whom Chapter 7 of the *market rules* applies to. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 1.2.2	Existing - no change	Introductory Rules: Application	Section 1.2.2: • This section specifies that the rules in Chapter 7 currently apply to both the 60Hz and the 25Hz portions of the *electricity system*. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 1.2.3	Existing - no change	Introductory Rules: Application	Section 1.2.3: • This section specifies generic terminology for "area" in regards to *operating reserve.* • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 1.3	Existing - requires amendment	Introductory Rules: Scope of the Physical Markets	Section 1.3.1: • This section specifies that the *IESO* shall administer two types of *physical markets* – the real-time market and the procurement markets. • Amend to specify that the *IESO* is obligated to operate a third type of *physical market* – the day-ahead market. Section 1.3.4 (new):

Market Rule Section	**Type**	**Topic**	**Requirement**
			• Add new section 1.3.4 to administer the day-ahead market, similar to existing section 1.3.2 on the administration of the *real-time markets*. Section 1.3.4 should reference the applicable day-ahead market sections in the new Chapter 7A of the *market rules*.
Section 1.4	Existing – no change	Co-ordination with Control Areas Outside the IESO Control Area	Section 1.4: • This section obligates the *IESO*, where required or appropriate under regional *reliability* agreements with other *control areas*, and subject to confidentiality agreements, to share with other *control area operators* all relevant information concerning physical system operations in relation to the *electricity system*. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 1.5	Existing – no change	Delivery in Respect of Extra-provincial Intertie Transactions	Section 1.5: • This section specifies that where *energy* or *ancillary service* is being conveyed into or out of the *IESO-controlled grid* from an *intertie zone* outside Ontario, that such delivery will be deemed to occur on the Ontario portion of the applicable *intertie*. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.
Section 1.6	Existing - no change	Introductory Rules: Planned Outages for IESO Systems	Section 1.6: • This section obligates the *IESO* to follow process for *planned outages* to its own systems. The generic language is adequate to include day-ahead market systems. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document.

Market Rule Section	Type	Topic	Requirement
Section 1.7	Existing - requires amendment	Introductory Rules: IESO Authorities and Obligations Regarding the Operation of the Day-Ahead Commitment Process Functions	Section 1.7: • This section currently describes the *IESO* authorities and obligations with respect to the day-ahead commitment process. With elimination of the day-ahead commitment process this section will be repurposed to specify overarching *IESO* authorities and obligations related to both the day-ahead market and the *real-time market*. • *Amend* the title to 'IESO Authorities and Obligations Regarding the Day-Ahead Market, the Pre-Dispatch Process and the Real-Time Market.' • *Amend* sections 1.7.1 through 1.7.5, and add additional sections as applicable, to specify overarching *IESO* authorities related to the new day-ahead market and revised *real-time market*. Amendments include: • CEO determination of go live dates for the day-ahead market and new *real-time market*. Sections 1.7.1 through 1.7.3 currently address this authority for the day-ahead commitment process. (generic, not limited to the Offers, Bids and Data Inputs inventory) • *IESO* establishment of floor prices for *variable generators* and *flexible nuclear generation*. This is currently in section 3.5.4A (Offers, Bids and Data Inputs specific) • *IESO* determination of parameters for the calculation engines including *MMCP*, *maximum operating reserve price* and penalty functions for the violation of constraints in the *dispatch algorithm*, and in future in the *pre-dispatch* calculation engine, the *real-time* calculation engine and the day-ahead calculation engine. These *IESO* authorities are currently in section 4.4.6 (Offers, Bids and Data Inputs specific) • *IESO Board* authorities to direct the *IESO* to audit the day-ahead, *pre-dispatch* and *real-time* calculation engines. Currently the audit provisions are in section 4.2.4 of Chapter 7.

Market Rule Section	Type	Topic	Requirement
			• Content in existing sections 1.7.4 and 1.7.5 relates to the cancellation of the existing day-ahead commitment process due to software failures. Cancellation and failure of *IESO-administered markets* will be assessed under the Grid and Market Operations Integration detailed design document. OVERLAP: Grid and Market Operations Integration
Section 2, 2.2.6A – 2.2.6K	Existing - requires amendment	Registration for Physical Operations	Sections 2.2.6A-K: • These sections were introduced to support the 2006 day-ahead commitment process and 2011 enhanced day-ahead commitment process. • The sections include some details that are relevant to the Offers, Bids and Data Inputs design document, while the remaining details are under the Facility Registration and Grid and Market Operations Integration design documents. • The Offers, Bids and Data Inputs design document is consolidating the concepts of daily and hourly *dispatch data* under the holistic umbrella of *dispatch data*. With respect to sections 2.2.6A-K, information relevant to *dispatch data* (the Offers, Bids and Data Inputs design document) will be moved to Section 3 – Data Submissions for the Real-Time Markets. Similar obligations will be specified in new Chapter 7A for the day-ahead market. Under the Offers, Bids and Data Inputs design document, the following *amendments* are required to the content of the existing sections: • S2.2.6A – eliminate the requirement that the *price-quantity pair* hourly *dispatch data* parameter must respect *forbidden regions. Forbidden regions* will be submitted as daily *dispatch data* and respected by the calculation engines. • S2.2.6J – move daily *dispatch data* to section 3 of Chapter 7 and section 2 of Chapter 7A and expand as required to include new daily *dispatch data*

Market Rule Section	Type	Topic	Requirement
			parameters. OVERLAP: Facility Registration
Section 3	Existing - requires amendment	Data Submissions for the Real-Time Markets	Section 3: • This section describes the *dispatch data* submission process and form of *dispatch data* for the real-time market. • Amend to describe new daily and hourly *dispatch data* requirements and make clear that *dispatch data* submission into the day-ahead market shall also be considered as an unchanged *dispatch data* submission into the real-time market (pre-dispatch scheduling and real-time *dispatch hour*), where applicable, unless the *dispatch data* is subsequently re-submitted or revised. • Amend to remove *market rules* obligations related to the day-ahead commitment process. OVERLAP: Grid and Market Operations Integration
Section 3.1	Existing - requires amendment	Data Submissions for the Real-Time Markets: Applicability of this Section	Section 3.1: • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. New section may be required, to specify that a *dispatch data* submission into the day-ahead market in accordance with new Chapter 7A, shall also be considered as an unchanged *dispatch data* submission into the *real-time market* (*pre-dispatch scheduling* and *real-time dispatch*), where applicable, unless the *dispatch data* is subsequently re-submitted or revised. OVERLAP: Grid and Market Operations Integration

Market Rule Section	Type	Topic	Requirement
Section 3.2	Existing - no change	Data Submissions for the Real-Time Markets: The Data Submission Process	Section 3.2: • Existing provisions by which a *registered market participant* submits *dispatch data* into the *real-time market*, and by which the *IESO* confirms receipt of or rejects such *dispatch data* are adequate to support the Offers, Bids and Data Inputs chapter. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Grid and Market Operations Integration
Section 3.3	Existing - requires amendment	Data Submissions: Dispatch Data Submissions	Section 3.3: • The majority of the subject matter in this section requires assessment under the Grid and Market Operations Integration design document, including: timing of submission, revisions, replacement *energy*, *IESO* authorities to direct submissions, and any new limitations on revisions. Subject matter assessed under the Offers, Bids and Data Inputs design document: • Standing data provisions in section 3.3.9 may be adequate to specify standing data provisions. Since standing *dispatch data* provisions will be common to the day-ahead market and *real-time market*, *amendments* may be required to integrate standing *dispatch data* in Chapter 7 section 3.3.9 with Chapter 7A section 2. Standing *dispatch data* construct for *energy* and *operating reserve* will include applicable daily and hourly *dispatch data* parameters; • Amendments may be required to specify that standing *dispatch data* converted to active *dispatch data* in the day-ahead market in accordance with new Chapter 7A shall also be a *dispatch data* submission into the *real-time market* (*pre-dispatch scheduling* and *real-time dispatch*), where applicable, unless the *dispatch data* is subsequently re-submitted, revised or

Market Rule Section	Type	Topic	Requirement
			expired. • Existing provisions in section 3.3.18 are adequate to support the requirement in the Offers, Bids and Data Inputs chapter that a *dispatchable load* may designate all or a portion of a *dispatchable load facility* as *non-dispatchable*. OVERLAP: Grid and Market Operations Integration
Section 3.3A	Existing - requires amendment	Dispatch Data Submissions for the Day-Ahead Commitment Process	Section 3.3A: • Provisions in section 3.3A were introduced to support *dispatch data* submission into the day-ahead commitment process. • New chapter 7A will specify *dispatch data* submission requirements in the day-ahead market. Provisions such as the availability declaration envelope in section 3.3A will be moved into new Chapter 7A. • Section 3.3A may be deleted and remaining relevant provisions will be moved into section 3 for the *real-time market* and section 2 of Chapter 7A for the day-ahead market where applicable. OVERLAP: Grid and Market Operations Integration
Section 3.4	Existing - requires amendment	Data Submissions: The Form of Dispatch Data	Section 3.4: • Existing provisions are generally adequate to describe the form of *dispatch data* for the real-time market. • Amendments may be required to add specifics for the form of *dispatch data* for *generation facilities* registered with *pseudo-units* and physical *generation units*. OVERLAP: Settlements (Impact of *physical bilateral contract quantities* under section 3.4.1)

Market Rule Section	Type	Topic	Requirement
Section 3.5	Existing - requires amendment	Data Submissions: Energy Offers and Energy Bids	Section 3.5: • Existing provisions require *amendment*, and new provisions are required to establish the new daily and hourly *dispatch data* construct. • Existing provisions in section 2.2.6J will be *amended* and moved into section 3.5 and existing provisions in section 3.5 may require *amendment* to address specific *dispatch data* submission for *pseudo-units*. Daily *Dispatch Data* Parameters – values apply to all *dispatch hours* of a given *dispatch day*. • Linked resources, time lag and MWh ratio – a set of three new parameters to represent the *energy* production and time lag relationship between *generation facilities* on a hydroelectric cascade river system. This is an optional set of parameters. Establish in section 3.5 and add validations. • *Forbidden region* – new optional parameter to represent one or more pre-defined operating ranges, in MW, within which a hydroelectric *generation facility* cannot maintain steady state operation without causing equipment damage. Applicable only if a *forbidden region* is registered. Establish in section 3.5 and add validations. • Maximum Daily Energy Limit (Max DEL) – existing optional parameter currently in section 3.5.7 which specifies the maximum amount of *energy*, in MWh, that a *generation unit* can be scheduled in a *dispatch day*. New validations are required. • Minimum Daily Energy Limit (Min DEL) – new optional parameter and validations to represent the minimum amount of *energy*, in MWh, that a *generation unit* must be scheduled to supply within a *dispatch day* under specific conditions. Applicable to dispatchable hydroelectric *generation facilities*. Establish in section 3.5. • Single Cycle Mode – existing optional parameter

Market Rule Section	Type	Topic	Requirement
			from section 2.2.6J which specifies the mode of operating a combined cycle *generation facility*'s combustion turbine *generation unit* without the associated steam turbine *generation unit*. Establish in section 3.5. • *Maximum Number of Starts Per Day* – existing optional parameter from section 2.2.6J which specifies the maximum number of times a *generation unit* is physically able to be started within a *dispatch day*. Establish in section 3.5 and add new validations (including MPM validations). Expand for hydroelectric *generation facilities* (currently applicable to *registered facilities* that are not *quick-start facilities*, excluding those with a registered primary fuel type of uranium.) • *Minimum Loading Point* – existing optional parameter from section 2.2.6J which specifies the minimum output that a *generation unit* must maintain to remain stable without the support of ignition. Establish in section 3.5, *amend* to specify it will be a required parameter, and add validations, including new market power mitigation validations. • *Minimum Generation Block Run-Time* – existing optional parameter from section 2.2.6J which specifies the minimum number of consecutive hours a *generation unit* must be schedule to its *minimum loading point*. Establish in section 3.5, *amend* to specify it will be a required parameter, and add existing validations and new market power mitigation validations. • *Minimum Generation Block Down-Time* – existing optional parameter from section 2.2.6J which specifies the minimum number of hours between the time when a *generation unit* was last at its *minimum loading point* before synchronization and the time the *generation unit* can be schedule back to its *minimum loading point* after synchronization. Establish in section 3.5, *amend*

Market Rule Section	Type	Topic	Requirement
			to specify it will be a required parameter, and revise the parameter to represent three values – hot, warm and cold. Add existing validations and new market power mitigation validations. • Lead Time – new required parameter which specifies the amount of time, in hours, needed for *generation unit* in a *generation facility* that is not a *quick start facility* to start-up and reach its *minimum loading point* from an offline state. The parameter will represent three values – hot, warm and cold. Applicable to *registered facilities* that are not *quick-start facilities*, excluding those with a registered primary fuel type of uranium. Establish in section 3.5 and add new validations, including new market power mitigation validations. • Ramp-Up Energy to MLP - new required set of parameters which represent the *energy*, in MWh, a *generation unit* is expected to produce from the time of synchronization to the time it reaches its *minimum loading point*. Applicable to *registered facilities* that are not *quick-start facilities*, excluding those with a registered primary fuel type of uranium. Establish the two individual parameters Ramp Hours to Minimum Loading Point and Energy Per Ramp Hour in section 3.5 and add new validations including new market power mitigation validations. Hourly *Dispatch Data* Parameters - values may vary from one *dispatch hour* to the next during a given *dispatch day*. • *Price-Quantity Pair*s for *Energy Offer* or *Energy Bid* – no change to the parameters or validations in section 3.5. New validations required for hydroelectric *generation facilities* and *dispatchable loads*. Establish new market power mitigation validations. • Start-Up Offer – new optional parameter to replace existing *start-up cost* and which

Market Rule Section	Type	Topic	Requirement
			represents the dollar amount to bring an off-line *generation facility* through start-up procedures, synchronization to *minimum loading point.* The parameter will represent three values – hot, warm and cold. Applicable to *registered facilities* that are not *quick-start facilities*, excluding those with a registered primary fuel type of uranium. Establish in section 3.5 and add new validations, including market power mitigation validations. Delete corresponding start-up cost definition and reference in section 2.2C. Escalating start-up costs to address over midnight operation are not currently in the market rules (market manual level) • Speed No-Load Offer – new optional parameter to replace existing *speed no-load cost* and which represents the hourly dollar amount to maintain a *generation facility* synchronized while injecting no *energy* to the *IESO-controlled grid.* Applicable to *registered facilities* that are not *quick-start facilities*, excluding those with a registered primary fuel type of uranium. Establish in section 3.5 and add new validations, including market power mitigation validations. Delete corresponding *speed no-load* definition and reference in section 2.2C. • Energy Ramp Rate – no change to provisions in section 3.5.5. Add market power mitigation validations. • Minimum Hourly Output – new optional parameter to represent the minimum amount of *energy*, in MWh, that a *generation unit* associated with a *dispatchable* hydroelectric *generation facility* must, if economic, produce in any one hour under specific scenarios. Establish in section 3.5 and add validations. • Hourly Must-Run – new optional parameter to represent the minimum amount of *energy*, in MWh, that a *generation unit* associated with a

Market Rule Section	Type	Topic	Requirement
			dispatchable hydroelectric *generation facility* must produce in any one hour under specific scenarios. Establish in section 3.5 and add validations. • Capacity Transaction Flag – new optional parameter to identify an export *bid* as a *called capacity export*; or identify an import *offer* or export *bid* that supports the *IESO*/HQ capacity sharing agreement. Impact on existing sub-sections of section 3.5 include: • 3.5.1, 3.5.2, 3.5.4, 3.5.6, 3.5.8 – no change • 3.5.3 – no change to existing validations. A new validation is required for *dispatchable loads* such that the last quantity in the series of *price-quantity pairs* must be less than or equal to the maximum load consumption specified during *facility* registration. A new validation is required for *hourly demand response*. • 3.5.4A – the obligation to establish floor prices is moved to revised section 1.7. There is no change to validation of an *offer* against an existing floor price. • 3.5.5 – see ramp rate above • 3.5.7 – see daily energy limit above. Section may need to be *amended* to use new terminology of maximum daily *energy* limit. • 3.5.9 – to be assessed under Settlements
Section 3.6	Existing - requires amendment	Data Submissions: Operating Reserve Offers	Section 3.6: • Existing provisions are adequate to support the *operating reserve dispatch data* submissions requirements that are unchanged under the Offers, Bids and Data Inputs design document. • *Amendments* are required to add MPM validations for *operating reserve* ramp rate OVERLAP: Market Power Mitigation, Grid and Market Operations Integration
Section 3.7	Existing -	Data	Section 3.7.1:

Market Rule Section	Type	Topic	Requirement
	requires amendment	Submissions: Self-Scheduling Generators	• This section specifies that a *registered market participant* for a *self-scheduling generation facility* shall submit *dispatch data* indicating the amount of *energy* that the *registered market participant* reasonably expects to be provided by the *self-scheduling generation facility* in each *dispatch hour*. • the form of *dispatch data* may require amendment to state that *dispatch data* submission into the day-ahead market will also be used as a submission into the real-time market (pre-dispatch scheduling and real-time *dispatch hour*) if *dispatch data* is not re-submitted or revised. Section 3.7.2: • Assess tolerances under the Grid and Market Operations Integration design document Section 3.7.3: • Amend to refer to the day-ahead market instead of the day-ahead commitment process. Timing of *dispatch data* submission in this section will be assessed under the Grid and Market Operations Integration design document OVERLAP: Grid and Market Operations Integration
Section 3.8	Existing - requires amendment	Data Submissions: interties	Section 3.8.1: • This section states that a *registered market participant* for an *intermittent generator* shall submit *dispatch data* indicating its forecast of the amount of *energy* that the *intermittent generator* will inject in each hour of the *dispatch day*. • the form of *dispatch data* may require *amendment* to state that *dispatch data* submission into the day-ahead market will also be used as a submission into the *real-time market* (*pre-dispatch scheduling* and *real-time dispatch hour*) if *dispatch data* is not re-submitted or revised. Section 3.8.2: • Amend to refer to the day-ahead market instead of the day-ahead commitment process. Timing of

Market Rule Section	Type	Topic	Requirement
			dispatch data submission in this section will be assessed under the Grid and Market Operations Integration design document. OVERLAP: Grid and Market Operations Integration
Section 3.8A	Existing - requires amendment	Data Submissions: Transitional Scheduling Generators	Section 3.8A.1: • This section states that a *registered market participant* for a registered *facility* that is a *transitional scheduling generator* shall submit *dispatch data* indicating its forecast of the amount of *energy* that the *transitional scheduling generator* will inject in each hour of the *dispatch day*. • the form of *dispatch data* may require amendment to state that *dispatch data* submission into the day-ahead market will also be used as a submission into the *real-time market* (*pre-dispatch scheduling* and real-time *dispatch hour*) if *dispatch data* is not re-submitted or revised. The reference to section 3.3.1 of Chapter 7 relates to timing which will be assessed under the Grid and Market Operations Integration design document. Section 3.8A.2: • Amend to refer to the day-ahead market instead of the day-ahead commitment process. Timing of *dispatch data* submission in this section will be assessed under the Grid and Market Operations Integration design document. OVERLAP: Grid and Market Operations Integration
Section 3.9	Existing - no change	Data Submissions: Transmission System Information	Section 3.9: • This section obligates *transmitters* to provide the *IESO* with *transmission system* information. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. • Timing will be assessed under the Grid and Market Operations Integration design document.

Market Rule Section	Type	Topic	Requirement
			OVERLAP: Grid and Market Operations Integration
Section 4	Existing - requires amendment	The Dispatch Algorithm	Section 4 describes the *dispatch algorithm*, which is currently represented by a single engine used for both *pre-dispatch* and *real-time*. The single engine will be replaced with two new engines and section 4 will be replaced with two new sections to reflect the new engines. The new *pre-dispatch* engine will be described under new section 4A and the new *real-time* engine will be described under new section 4D. Subjects of the main sub-sections of 4A (pre-dispatch calculation engine) and 4D (real-time calculation engine) may include: • Purpose • Optimization Objective • Inputs • Description of the Multiple Passes • Outputs The new sections will provide high-level information. Details will be described further in new Appendix 7B for *pre-dispatch* and new Appendix 7C for *real-time*. A comparable section 3 of Chapter 7A and associated appendix will be required for the day-ahead market. Existing section 4.4 is applicable to the Offers, Bids and Data Inputs design document, while the remainder of the sections will be further assessed under the Grid and Market Operations Integration, the Pre-Dispatch Calculation Engine and the Real-Time Calculation Engine design documents. OVERLAP: Grid and Market Operations Integration, Pre-Dispatch Calculation Engine, Real-Time Calculation Engine
Section 4.4	Existing - requires amendment	The Dispatch Algorithm: Inputs to the Dispatch	Section 4.4: • Describes the inputs to the *dispatch algorithm*, which is currently represented by a single engine used for both *pre-dispatch* and *real-time*.

Market Rule Section	Type	Topic	Requirement
		Algorithm	• Section 4.4 will be replaced with two new sections to reflect the new engines. Inputs to the new *pre-dispatch* engine will be described under new section 4A.3 while inputs to the new *real-time* engine will be described under new section 4D.3. • The new sections will provide high-level information about inputs which will be described further in the new Appendix 7B for *pre-dispatch* and new Appendix 7C for *real-time*. Some of the high-level details in current section 4.4 will be moved to new sections 4A.3 and 4D.3 of Chapter 7. Other details will be moved to the appendices, and any information related to overall *IESO Board* authorities will be moved to section 1. • A comparable section 3.3 of Chapter 7A and associated appendix will be required for the day-ahead market. OVERLAP: Grid and Market Operations Integration, Pre-Dispatch Calculation Engine, Real-Time Calculation Engine
Section 4.4.1	Existing - requires amendment	The Dispatch Algorithm: Inputs to the Dispatch Algorithm	Section 4.4.1: • This section specifies that the *IESO* shall use as inputs the data and information outlined in section 4.4 and described in more detail in Appendix 7.5. • This section will be deleted and similar statements may be made in new sections 4A.3 and 4D.3 of Chapter 7 and section 3.3 of Chapter 7A.
Section 4.4.2	Existing - requires amendment	The Dispatch Algorithm: Inputs to the Dispatch Algorithm	Section 4.4.2: • This section states that the cost to suppliers of *energy* and *operating reserves* and the value to *dispatchable loads* of delivered electricity shall be based on *offers* and *bids* (including standing *dispatch data*) submitted by *registered market participants* with respect to dispatchable *generation facilities* and *dispatchable load facilities*. • This section will be deleted and a statement about

Market Rule Section	Type	Topic	Requirement
			market participant dispatch data may be added into each of new sections 4A.3 and 4D.3 of Chapter 7 and section 3.3 of Chapter 7A, or may be added into the applicable appendices. OVERLAP: Grid and Market Operations Integration, Pre-Dispatch Calculation Engine and Real-Time Calculation Engine. Consideration needs to be given to what represents a valid *offer* or *bid* for the purposes of representing the cost to suppliers of *energy* and *operating reserve*.
Section 4.4.3 and 4.4.3A	Existing - requires amendment	The Dispatch Algorithm: Inputs to the Dispatch Algorithm	Section 4.4.3 and 4.4.3A: • These sections relate to tool functionality meant to adjust *demand* in the unconstrained schedule in order to account for the amounts by which *generators* and *loads* deviate from their scheduled quantities. • This functionality was deemed unnecessary in a uniform pricing regime, and was deferred until such time as the *IESO* implements locational pricing. • These sections will be deleted and the information assessed under the Grid and Market Operations Integration, Pre-Dispatch Calculation Engine and Real-Time Calculation Engine design documents. • For the purpose of the Offers, Bids and Data Inputs design document, new sections 4A.3 and 4D.3 of Chapter 7 and section 3.3 of Chapter 7A will need to identify *demand* forecasts as an input to the calculation engines.
Section 4.4.4	Existing - requires amendment	The Dispatch Algorithm: Inputs to the Dispatch Algorithm	Section 4.4.4: • This section describes limits on *intertie* flows, including the net *interchange schedule* limit. • This section will be deleted and new sections 4A.3 and 4D.3 of Chapter 7 and section 3.3 of Chapter 7A will need to identify that data to support the *IESO's* grid model is an input to the calculation engines.

Market Rule Section	Type	Topic	Requirement
Section 4.4.5	Existing - requires amendment	The Dispatch Algorithm: Inputs to the Dispatch Algorithm	Section 4.4.5: • This section describes data used to support the *IESO-controlled grid* model such as *security* constraints, *reliability* constraints, minimum requirements for *operating reserve* and *ancillary services*. • This section will be deleted and new sections 4A.3 and 4D.3 of Chapter 7 and section 3.3 of Chapter 7A will need to identify that data to support the *IESO-controlled grid* model is an input to the calculation engines.
Section 4.4.6	Existing - requires amendment	The Dispatch Algorithm: Inputs to the Dispatch Algorithm	Section 4.4.6: • This section describes basic parameters of the *dispatch* algorithm including *MMCP*, *maximum operating reserve price* and penalty functions for the violation of *dispatch algorithm* constraints. • This section will be deleted. • The *IESO Board* authorities to set these parameters from time to time shall be moved to section 1.7 of Chapter 7 which will re-worked to describe overall *IESO* authorities and obligations for the day-ahead market, the *pre-dispatch* process and *the real-time market*. • New sections 4A.3 and 4D.3 of Chapter 7 and section 3.3 of Chapter 7A will state that the basic parameters are used as inputs to the applicable calculation engines.
Section 4.4.7	Existing - requires amendment	The Dispatch Algorithm: Inputs to the Dispatch Algorithm	Section 4.4.7: • This section specifies that *interchange schedule data* is derived from outputs of iterations of the engines. • This section will be deleted. • A similar statement may be included in the new sections 4A.3 and 4D.3 of Chapter 7 and section 3.3 of Chapter 7A, or may be added into the applicable appendices. OVERLAP: Grid and Market Operations Integration,

Market Rule Section	Type	Topic	Requirement
			Pre-Dispatch Calculation Engine and Real-Time Calculation Engine
Section 5	Existing - requires amendment	The Pre-dispatch Scheduling Process	Section 5: • This section specifies *IESO* obligations and permissions with respect to *pre-dispatch* scheduling. • Delete section 5 and replace with the following new sections: o 4A: The Pre-Dispatch Calculation Engine o 4A.1: Purpose o 4A.2: Optimization Objective o 4A.3: Inputs o 4A.4: Multiple Passes o 4A.5: Outputs o 4B: Pre-Dispatch Schedules and Prices o 4B.1: Timelines o 4B.2: Pre-Dispatch Prices o 4B.3: Pre-Dispatch Schedules o 4C: Releasing and Publishing Pre-Dispatch Information o 4C.1: Publishing Pre-Dispatch Information o 4C.2: Releasing MP Specific Pre-Dispatch Information • Section 5 contains duplication of subject matter with Ch7 S4 and Appendix 7.5. New sections to replace section 5 will provide high-level information only. Some of the details in current section 5 will be moved to new sections 4A, 4B and 4C of Chapter 7, Other details will be moved to new Appendix 7.5B detailing the *pre-dispatch* calculation engine. • Comparable sections will be required for *real-time* (4D, 4E and 4F of Chapter 7) and day-ahead (sections 3, 4 and 5 of Chapter 7A). OVERLAP: Grid and Market Operations Integration, Pre-Dispatch Calculation Engine, Publishing & Reporting Market Information and Settlements

Market Rule Section	Type	Topic	Requirement
Section 5.2	Existing - requires amendment	The Pre-dispatch Scheduling Process: Information Used to Determine Pre-Dispatch Schedules	Section 5.2: • includes information used to determine *pre-dispatch schedules* and duplicates information in existing section 4.4 and Appendix 7.5. This duplication will be eliminated under the new format. • Section 5.2 will be replaced with new section 4A.3 which will consolidate applicable requirements from sections 4.4, 5.2, 5.3 and 5.4 to provide a high-level description of the inputs to the *pre-dispatch* calculation engine. The inputs will be described in detail in new Appendix 7.5B. OVERLAP: Grid and Market Operations Integration and Pre-Dispatch Calculation Engine
Section 5.3	Existing - requires amendment	The Pre-dispatch Scheduling Process: Determining the Pre-Dispatch Schedule	Section 5.3: • Parts of section 5.3 specify additional information used to determine *pre-dispatch schedules*. Information used to determine *pre-dispatch schedules* will be specified in new section 4A.3. See section 5.2 for further detail. OVERLAP: Grid and Market Operations Integration and Pre-Dispatch Calculation Engine
Section 5.4	Existing - requires amendment	The Pre-dispatch Scheduling Process: Projected Market Schedules and Prices	Section 5.4: • Similar to section 5.2 and section 5.3, information used to determine *pre-dispatch schedules* will be specified in new section 4A.3. See section 5.2 for further detail. OVERLAP: Grid and Market Operations Integration and Pre-Dispatch Calculation Engine
Section 6	Existing - requires amendment	The Real-Time Scheduling Process	Section 6: • This section specifies *IESO* obligations and permissions with respect to *real-time* scheduling. • Replace section 6 with the following new sections: o 4D: The Real-Time Calculation Engine o 4D.1: Purpose o 4D.2: Optimization Objective

Market Rule Section	Type	Topic	Requirement
			o 4D.3: Inputs o 4D.4: Multiple Passes o 4D.5: Outputs o 4E: Real-Time Schedules and Prices o 4E.1: Timelines o 4E.2: Real-Time Prices o 4E.3: Real-Time Schedules o 4F: Releasing and Publishing Real-Time Information o 4F.1: Publishing Real-Time Information o 4F.2: Releasing MP Specific Real-Time Information • Section 6 includes duplication of subject matter with Ch7 S4 and Appendix 7.5. Section 6 will be replaced with new sections to provide high-level information. Some of the details in current section 6 will be moved to new sections 4D, 4E and 4F of Chapter 7, Other details will be moved to new Appendix 7.5B detailing the *real-time* calculation engine. • Comparable sections will be required for *pre-dispatch* (4A, 4B and 4C of Chapter 7) and day-ahead (sections 3, 4 and 5 of Chapter 7A). OVERLAP: Grid and Market Operations Integration, Real-Time Calculation Engine, Publishing & Reporting Market Information and Settlements
Section 6.2	Existing - requires amendment	The Real-Time Scheduling Process: Information Used to Determine Real-Time Schedules	Section 6.2: • Includes information used to determine *real-time schedules* and duplicates information in existing section 4.4 and Appendix 7.5. This duplication will be eliminated under the new format. • Section 6.2 will be replaced with new section 4D.3 which will consolidate applicable requirements from section 4.4, 6.2, 6.3 and 6.4 to provide a high-level description of the inputs to the *real-time* calculation engine. The inputs will be described in detail in new Appendix 7.5C.

Market Rule Section	Type	Topic	Requirement
			OVERLAP: Grid and Market Operations Integration and Real-Time Calculation Engine
Section 6.3	Existing - requires amendment	The Real-Time Scheduling Process: Determining the Real-Time Schedule	Section 6.3: • Parts of section 6.3 specify additional information used to determine *real-time schedules*. Information used to determine *pre-dispatch* schedules will be specified in new section 4D.3. See section 6.2 for further detail. OVERLAP: Grid and Market Operations Integration and Real-Time Calculation Engine
Section 6.4	Existing - requires amendment	The Real-Time Scheduling Process: Market Schedules and Market Prices	Section 6.4: • Similar to sections 6.2 and 6.3, information used to determine *real-time schedules* will be specified in new section 4D.3. See section 6.2 for further detail. OVERLAP: Grid and Market Operations Integration and Real-Time Calculation Engine
Section 4A	New	The Pre-Dispatch Calculation Engine	Section 4A NEW: • New section to provide an overview of the *pre-dispatch* calculation engine and detail the *IESO's* obligation to determine *pre-dispatch* schedules and prices using the *pre-dispatch* calculation engine as described in this section and in new Appendix 7.5B. Subjects may include: o Purpose o Optimization Objective o Inputs o Description of the passes o Outputs • New section 4A will provide high-level information which will be described in greater detail in new Appendix 7.5B • Existing section 4 of Chapter 7 which is currently applicable to both *pre-dispatch* and *real-time* will be replaced with this new section 4A (*pre-dispatch*), along with new section 4D (*real-time*). New section 3 of Chapter 7A will address the day-

Market Rule Section	Type	Topic	Requirement
			ahead calculation engine. OVERLAP: Grid and Market Operations Integration and Pre-Dispatch Calculation Engine
Section 4A.3	New	The Pre-Dispatch Calculation Engine: Inputs to the Pre-Dispatch Calculation Engine	Section 4A.3 NEW: • New section to consolidate information from existing sections 4.4, 5.2, 5.3 and 5.4 to provide a high-level description of the inputs to the *pre-dispatch* calculation engine. The section will refer to new Appendix 7.5B where the inputs will be described in greater detail. • Inputs may include but are not limited to: o *Dispatch data* in accordance with new section 3 of Chapter 7 o *Demand* forecasts o Data required to support the *IESO-controlled grid* model (network model, *security limits*, etc.) o *Maximum market clearing price*, *maximum operating reserve price* and penalty functions for the violation of constraints o Market power mitigation parameters o Daily *dispatch* order for *variable generators* currently in section 2.8.4 of Appendix 7.5 OVERLAP: Grid and Market Operations Integration and Pre-Dispatch Calculation Engine
Section 4D	New	The Real-Time Calculation Engine	Section 4D New: • New section to provide an overview of the *real-time* calculation engine and detail the *IESO*'s obligation to determine *real-time schedules* and prices using the *real-time* calculation engine as described in this section and in new Appendix 7.5C. Subjects may include: o Purpose o Optimization Objective o Inputs o Description of the passes

Market Rule Section	Type	Topic	Requirement
			o Outputs • New section 4D will provide high-level information which will be described in greater detail in new Appendix 7.5C • Existing section 4 of Chapter 7 which is currently applicable to both *pre-dispatch* and *real-time* will be replaced with this new section 4D (*real-time*) along with new section 4A (*pre-dispatch*). New section 3 of Chapter 7A will address the day-ahead calculation engine. OVERLAP: Grid and Market Operations Integration and Pre-Dispatch Calculation Engine
Section 4D.3	New	The Real-Time Calculation Engine: Inputs to the Real-Time Calculation Engine	Section 4D.3 NEW: • New section to consolidate information from existing sections 4.4, 6.2, 6.3 and 6.4 to provide a high-level description of the inputs to the *real-time* calculation engine. The section will refer to new Appendix 7.5C where the inputs will be described in greater detail. • Inputs may include but are not limited to: o *Dispatch data* in accordance with new section 3 of Chapter 7 o *Demand* forecasts o Data required to support the *IESO-controlled grid* model (network model, *security limits*, etc.) o *Maximum market clearing price*, *maximum operating reserve price* and penalty functions for the violation of constraints o Market power mitigation parameters o Daily *dispatch* order for *variable generators* currently in section 2.8.4 of Appendix 7.5 OVERLAP: Grid and Market Operations Integration and Pre-Dispatch Calculation Engine
Section 9	Existing - requires amendment	IESO Procurement Markets	Section 9: • This section specifies *IESO* obligations to procure *physical services* that are needed to maintain

Market Rule Section	Type	Topic	Requirement
			reliable system operations that are not *offered* in the *real-time markets*. • *Amendments* are required to section 9.1 to make clear that section 9 details the procurement of *physical services* that are not *offered* in the *real-time markets* and day-ahead markets. • *Amendments* may be required in section 9.6 to correct references to revised section 3 of Ch7. OVERLAP: Settlements
Section 19	Existing - requires amendment	Capacity Market Participants with Capacity Obligations	Section 19: • This section specifies delivery of a *demand response capacity obligation*. • *Amendments* may be required in section 19.2 to account for price responsive loads in addition to non *dispatchable loads.* OVERLAP: Grid and Market Operations Integration
Section 20	Existing - requires amendment	Capacity Exports in the IESO-Administered Market	Section 20: • This section specifies *IESO* and *market participant* obligations with respect to capacity exports in the *IESO-administered markets*. • This section of the *market rules* contains high-level language and points to the details in the applicable *market manual*. As such, provisions are generally unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. • Provisions in sections 20.3 and 20.4 may require *amendment* to introduce the new Capacity Transaction Flag hourly *dispatch data* parameter; however, the use of the parameter may instead be included in the *market manuals*. OVERLAP: Grid and Market Operations Integration
Appendix 7.1	Existing - requires amendment	Energy Offer, Schedule or Forecast Information	Appendix 7.1: • This section specifies the required *energy offer*, schedule or forecast information for *generation facilities* and *boundary entities*.

Market Rule Section	Type	Topic	Requirement
			• Amendments are required to: o Specify that the information is relevant to the day-ahead market and the *real-time market*, since the *dispatch data* construct will be common to all timeframes; and o To expand section 1.1 to be inclusive of both hourly and daily *dispatch data*, where applicable, and to amend requirements that may change under sections 3.3, 3.3A, 3.4 and 3.5 of Chapter 7 and under new sections of Chapter 7A. • Alternatively, the appendix may be deleted if the information is duplicated from the body of Chapter 7 of the *market rules*.
Appendix 7.2	Existing - requires amendment	Energy Bid Information	Appendix 7.2: • This section specifies the required e*nergy bid* information for *loads* and *boundary entities*. • *Amendments* are required to specify that the information is relevant to the day-ahead market and the *real-time market*, since the *dispatch data* construct will be common to all timeframes; • Alternatively, the appendix may be deleted if the information is duplicated from the body of Chapter 7 of the *market rules*.
Appendix 7.3	Existing - requires amendment	Operating Reserve Offer Information	Appendix 7.3: • This section specifies the required *operating reserve offer* information for *generation facilities* and *boundary entities*. *Amendments* are required to introduce market power mitigation validations for th*e operating reserve ramp rate.* • Alternatively, the appendix may be deleted if the information is duplicated from the body of Chapter 7 of the market rules. OVERLAP: Grid and Market Operations Integration
Appendix 7.4	Existing - requires	Transmission Information	Appendix 7.4: • This section specifies transmission information

Market Rule Section	Type	Topic	Requirement
	amendment	Required for Scheduling and Dispatching	required to be provided and updated to the *IESO* for scheduling and *dispatch* purposes. • *Amendments* are required to specify that the information is relevant to the day-ahead market and the *real-time market*. Section 1.1.3.1 of Appendix 7.4 refers to the "scheduling *dispatch* and pricing algorithm" which may require *amendment* to reflect the new calculation engines.
Appendix 7.5	Existing - requires amendment	The Market Clearing and Pricing Process	Appendix 7.5: • This section specifies the Market Clearing and Pricing Process details of the calculation engine for the *real-time market*, which is currently comprised of both the pre-dispatch hours (pre-dispatch timeframe) and the *dispatch hour* (known as the *real-time* timeframe). • Going forward, the pre-dispatch and real-time timeframes will be use two engines instead of one. Amendments are required to replace Appendix 7.5 with two new appendices. Refer to Appendices 7.5B and 7.5C for further information. OVERLAP: Appendix 7.5 replacement to be addressed under the Pre-Dispatch Calculation Engine, Real-time Calculation Engine, and Grid and Market Operations Integration design documents.
Appendix 7.5A	Existing - requires amendment	The DACP Calculation Engine Process	Appendix 7.5A: • This section provides detail on the existing day-ahead commitment process calculation engine. • *Amendments* are required to delete this appendix since the day-ahead commitment process is being discontinued and replaced with the day-ahead market. The new day-ahead market calculation engine is described in a new appendix 7A.X under new Chapter 7A. OVERLAP: Appendix 7.5A replacement to be addressed under the Day-Ahead Market Calculation Engine design document and Grid and Market Operations Integration design documents.

Market Rule Section	Type	Topic	Requirement
Appendix 7.5B	New	The Pre-Dispatch Calculation Engine	Appendix 7.5B New: • Refer to notes under Appendix 7.5, which is being replaced with new Appendices 7.5B and 7.5C. • Appendix 7.5B is a new appendix required to provide the details of the pre-dispatch calculation engine. The new appendix will be created under the Pre-Dispatch Calculation Engine design document. The *market participant* and *IESO* inputs described in the Offers, Bids and Data Inputs design document will be included in sections of the new appendix specific to inputs to the *pre-dispatch* calculation engine. New section 4A.3 of Chapter 7 will briefly state that the inputs to the *pre-dispatch* calculation engine will be detailed in new Appendix 7.5B. OVERLAP: Grid and Market Operations Integration and Pre-Dispatch Calculation Engine
Appendix 7.5C	New	The Real-Time Calculation Engine	Appendix 7.5C New: • Refer to notes under Appendix 7.5, which is being replaced with new Appendices 7.5B and 7.5C. • Appendix 7.5C is a new appendix required to provide the details of the *real-time* calculation engine. The new appendix will be created under the Real-Time Calculation Engine design document. The *market participant* and *IESO* inputs described in the Offers, Bids and Data Inputs design document will be included in sections of the new appendix specific to inputs to the *real-time* calculation engine. New section 4D.3 of Chapter 7 will briefly state that the inputs to the *real-time* calculation engine will be detailed in new Appendix 7.5C. OVERLAP: Grid and Market Operations Integration and Real-Time Calculation Engine
Appendix 7.6	Existing - requires amendment	Local Market Power	Appendix 7.6: • This section specifies the *IESO's* existing market power mitigation construct.

Market Rule Section	Type	Topic	Requirement
			• The existing market power mitigation construct will be deleted and replaced by the new market power mitigation design specified in the MPM detailed design document. OVERLAP: Market Power Mitigation detailed design
Appendix 7.7	Existing - no change	Radial Intertie Transactions	Appendix 7.7: • This section specifies *IESO* and *market participant* obligations related to a *generation facility* operating in *segregated mode of operation*. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document; however, cross reference to section 3.3 of Chapter 7 (Dispatch Data Submissions) may require amendment. OVERLAP: Settlements and Grid and Market Operations Integration
Appendix 7.8	New	MPM Inputs	Appendix 7.8 New: • Established under the Market Power Mitigation design chapter market rules inventory. • The Offers, Bids and Data Inputs design document specifies the market power mitigation inputs that will be used in the day-ahead market and *real-time market.* Inputs include: o Constrained area designations o *Reliability* constraints o Uncompetitive *interties* o Reference levels o Conduct thresholds o Impact thresholds • Market power mitigation inputs will be used to validate some *dispatch data* parameters described in section 3 of Chapter 7 and section 2 of Chapter 7A.

Table 4-4: Market Rules Chapter 7A Impacts

New Chapter 7A – Day-Ahead Market Operations

Market Rule Section	Type	Topic	Requirement
Section 1	New	Introduction	Section 1: NEW • Not exclusive to the Offers, Bids and Data Inputs design document. • *Market rules* specifying the purpose and application of the new chapter and the scope of the day-ahead market, including reconciliation with *real-time market* operations, *generator offer* guarantee, adherence to schedules and treatment of *dispatch data*, and virtual transactions.
Section 2	New	Data Submission for the Day-Ahead Market	Section 2 NEW: • New section required to specify the *registered market participant* data submission requirements for the day-ahead market. This section may include some duplication with the *real-time market* data submission requirements in section 3 of Chapter 7. • Changes to the existing *real-time market dispatch data* construct for *energy* include: • New hourly and daily *dispatch data* construct described above in section 3.5 of Chapter 7, including hourly and daily parameters. o Lead Time parameter is not valid in the day-ahead market. o Variable Generator Forecast is a new optional hourly parameter applicable only in the day-ahead market to allow *registered market participants* that submit *dispatch data* for *variable generators* to receive financially binding schedules based on a forecast quantity of their choice instead of a quantity provided in the *IESO's* centralized forecast of *variable generation facilities* prepared by a *forecasting entity*. • New *dispatch data* for price responsive loads

Market Rule Section	Type	Topic	Requirement
			(*energy* only, not *operating reserve*) • New *dispatch data* for virtual transactions (*energy only*, not *operating reserve*, submitted by authorized *market participants*). • New ability for *variable generators* to submit their own forecast into the day-ahead market. Sub-sections of new section 2 may include: • Applicability – new section required to specify that participation in the day-ahead market requires data submission in accordance with this new section 2. • Data submission process – new section to specify the requirement for *dispatch data* to be submitted through the *electronic information system* or such other means as determined by the *IESO*, and specify *IESO* obligations with respect to such data. • *Dispatch data* submissions – new section to specify the timing, use and standing data provisions o Timing and use of *dispatch data* submission to be assessed under the Grid and Market Operations Integration design document and the Day-Ahead Market Calculation Engine design document. o The day-ahead market will include standing *dispatch data* provisions. Standing *dispatch data* for *energy* and *operating reserve* will include all applicable daily and hourly *dispatch data* parameters. Refer to section 3.3 of Chapter 7. Standing *dispatch data* construct for *energy* will be extended for use by new price-responsive loads and virtual transactions in the day-ahead market. o The availability declaration envelope ("must *offer*") provisions in section 3.3Aof Chapter 7 will be moved to new Chapter

Market Rule Section	Type	Topic	Requirement
			7A. • The form of *dispatch data* – new section to specify the form of *dispatch data* for physical transactions and *operating reserve* in the day-ahead market. Refer to section 3.4 of Chapter 7 for discussion of *physical bilateral contract quantities* which will also be required in this section. o *Dispatchable* and *non-dispatchable generation facility* daily and hourly *dispatch data*, including *offers*, forecasts and *self-schedules* for physical transactions. Specifics may be required for the form of *dispatch data* for *generation facilities* registered with *pseudo-units* and physical *generation units*. o *Variable generator* submission of *offers,* including the new feature for submission of own forecast into the day-ahead market instead of the forecast provided by the *forecasting entity*. o *Hourly demand response* resource data, including a *demand response energy bid* to reduce *energy* consumption o *Dispatch data* to fulfill a demand response capacity obligation into the day-ahead market o Dispatchable and *non-dispatchable load facility* hourly *dispatch data*, including *bids* for price responsive loads o *Boundary entity* hourly *dispatch data*, including *offers* and *bids* for physical transactions o *Generation facility*, *load facility* and *boundary entity offers* for *operating reserve*. • The form of virtual transaction data – new section to specify the form of data for virtual transactions in the day-ahead market.

Market Rule Section	Type	Topic	Requirement
			o New *IESO*-determined virtual transaction *energy* lamination volume limit and the *IESO*-determined virtual transaction *bid* or *offer* cap. • *Offers* and *bids* – new section to specify *offers* and *bids* for *energy* in the day-ahead market for both physical and virtual transactions. o This section will apply to both physical and virtual transactions in the day-ahead market. o This section will specify requirements for *price-quantity pairs* and other *dispatch data* included in *offers* and *bids*. It will incorporate *price-quantity pair*, ramp and daily energy limit information from existing Ch7 S3.4.3,3.4.4, 3.4.4A, 3.4.5 and 3.5. It will also discuss ramp rates (not applicable to price response loads), as well as new and existing hourly and daily *dispatch data* parameters and validations of parameters. • *Operating reserve offers* – new section to specify *offers* for *operating reserve* in the day-ahead market. Refer to requirements specified above under section 3.6 of Chapter 7. o *Operating reserve offers* by way of virtual transactions and price responsive loads are not allowed • Update information – new section to specify that *transmitters* shall provide the *IESO* with updates to information in Appendix 7.4 and *generators* shall provide the *IESO* with updates to their *outage* plan (section 6 of Chapter 5). Timing to be assessed under the Grid and Market Operations Integration design document. OVERLAP: Grid and Market Operations Integration
Section 3	New	DAM Calculation Engine	Section 3: NEW • New section to detail the *IESO* obligation to determine day-ahead *market schedules* and

Market Rule Section	Type	Topic	Requirement
			prices using the day-ahead market calculation engine as described in this section and in new appendix 7A.X. This section will also provide high level description of the day-ahead market calculation engine under the following subject matter: o Purpose o Optimization o Inputs o Description of the passes o Outputs • Inputs subject matter is impacted by the Offers, Bids and Data Inputs design document. • This section may be further assessed under the Grid and Market Operations Integration design document, the Day-Ahead Market Calculation Engine design document, the Settlements design document and the Publishing and Reporting Market Information design document. • Existing section 4 of Chapter 7 which is currently applicable to both *pre-dispatch* and *real-time* will be replaced with new section 4A (*pre-dispatch*) and new section 4D (*real-time*), This new section 3 of Ch7A will be similar, and will provide high-level information which will be described in greater detail in new Appendix 7A.X (day-ahead market calculation engine) OVERLAP: Grid and Market Operations Integration and Day-Ahead Market Calculation Engine
Section 3.3	New	DAM Calculation Engine: Inputs to the DAM Calculation Engine	Section 3.3: NEW • New section to provide a summary of the inputs to the day-ahead market calculation engine. The section will refer to new Appendix 7A.X where the inputs will be described in greater detail. • Inputs may include but are not limited to: o *Dispatch data* in accordance with new section 2 of Chapter 7A

Market Rule Section	Type	Topic	Requirement
			o *Demand* forecasts o Data required to support the *IESO-controlled grid* model (network model, *security limits*, etc.) o *Maximum market clearing price*, *maximum operating reserve price* and penalty functions for the violation of constraints o Market power mitigation parameters o Virtual transaction zonal trading entities o Daily *dispatch* order for *variable generators* currently in section 2.8.4 of Appendix 7.5 OVERLAP: Grid and Market Operations Integration
Appendix 7A.X	New	Energy Offer, Schedule or Forecast Information	New appendix may be required for the day-ahead market in parallel with existing Appendix 7.1.
Appendix 7A.X	New	Energy Bid Information	New appendix may be required for the day-ahead market in parallel with existing Appendix 7.2. The day-ahead appendix may need to reflect price responsive loads.
Appendix 7A.X	New	Operating Reserve Offer Information	New appendix may be required for the day-ahead market in parallel with existing Appendix 7.3
Appendix 7A.X	New	Transmission Information Required for Scheduling and Dispatching	New appendix may be required for the day-ahead market in parallel with existing Appendix 7.4
Appendix 7A.X	New	Virtual Transaction Offer and Bid Information	New appendix may be required for the day-ahead market to reflect virtual transactions
Appendix 7A.X	New	Day-Ahead Market Calculation Engine	New appendix required to provide the details of the day-ahead market calculation engine. The new appendix will be created under the Day-Ahead Market Calculation Engine detail design document.

Market Rule Section	Type	Topic	Requirement
			The *market participant* and *IESO* inputs described in the Offers, Bids and Data Inputs design document will be included in sections of the new appendix specific to inputs to the day-ahead market calculation engine. New section 3 of new Chapter 7A will briefly state that the inputs to the day-ahead market calculation engine will be detailed in new Appendix 7A.X. OVERLAP: Grid and Market Operations Integration, Day-Ahead Calculation Engine

Table 4-5: Market Rules Chapter 8 Impacts

Market Rule Section	Type	Topic	Requirement
Section 1	Existing - no change	Introductory Rules	Section 1: • Identifies that Chapter 8 sets forth rules governing the submission of *physical bilateral data* by *market participants* and the use of such *physical bilateral contract data* by the *IESO*. • Provisions unaffected by the design changes specified in the Offers, Bids and Data Inputs design document. OVERLAP: Settlements
Section 2	Existing - requires amendment	Physical Bilateral Contract Data and Quantities	Section 2: • Identifies rights of *market participants* and obligations of the *IESO* with respect to *physical bilateral contract data;* and the content, form and revisions of *physical bilateral contract data*. • Sub-sections may require *amendment* to acknowledge the day-ahead market, with specific timing and data requirements. OVERLAP: Settlements
Section 2.1	Existing - requires amendment	Physical Bilateral Contract Data and Quantities: Overview	Section 2.1: • Identifies rights of *market participants* with respect to *physical bilateral contracts*, and obligations of the *IESO* with respect to *physical*

Market Rule Section	Type	Topic	Requirement
			bilateral contract data. • Section may require amendment to acknowledge the day-ahead market. OVERLAP: Settlements
Section 2.2	Existing - requires amendment	Physical Bilateral Contract Data and Quantities: The Content of Bilateral Contract Data	Section 2.2: • Describes the content of *physical bilateral contract data*. • Section may require amendment to distinguish between *physical bilateral contract data* for the *real-time market* and the day-ahead market. OVERLAP: Settlements
Section 2.3	Existing - requires amendment	Physical Bilateral Contract Data and Quantities: The Form of Bilateral Contract Data	Section 3.3: • Describes the form of *physical bilateral contract* data. • Section may require amendment to distinguish between *physical bilateral contract* data for the *real-time market* and the day-ahead market. OVERLAP: Settlements
Section 2.4	Existing - requires amendment	Physical Bilateral Contract Data and Quantities: Submitting and Revising Physical Bilateral Contract Data	Section 2.4: • Describes requirements with respect to revising *physical bilateral contract data* and effective timing of such data. • Section may require *amendment* to distinguish between the *real-time market* and the day-ahead market with respect to submission timing and coming into effect of *physical bilateral contract data*. OVERLAP: Settlements

– End of Section –

5. Procedural Requirements

5.1. Market-Facing Procedural Impacts

The existing *market manuals* related to the Offers, Bids and Data Inputs process will be retained to the extent possible. The majority of changes result from the introduction of price responsive loads (PRL), virtual transactions and new *dispatch data* constructs for dispatchable hydroelectric and combined cycle *generation facilities.* The documents most directly related to the Offers, Bids and Data Inputs process are:

- Market Manual 1: Connecting to Ontario's Power System;
- Market Manual 4: Market Operations;
- Market Manual 7: System Operations;
- Market Manual 9: Day-Ahead Commitment;
- Market Manual 13: Capacity Exports.

The following tables identify sections within the *market manuals* and training materials that are related but will not require changes, sections that require modification, and new sections that will need to be added to support the Offers, Bids and Data Inputs process in the future market.

Table 5-1: Impacts to Market Manual 1: Connecting to Ontario's Power System

Procedure	Type of change (no change, modification, new)	Section	Description
Part 1.5 – Market Registration Procedures	Modification	3 Register Equipment	• Replace references to DACP with DAM and references to three-part *offers* with daily and hourly *dispatch data.* • Updates required to reflect registration of new resource attributes used to validate the submission of new *dispatch data* parameters by *registered market participants*. For hydroelectric *generation facilities*, new *dispatch data* parameters that require additional registration attributes

Procedure	Type of change (no change, modification, new)	Section	Description
			include hourly must-run, linked resources, time lag, MWh ratio and *maximum number of starts per day*. For non-quick start *generation facilities*, these attributes include lead time.

Table 5-2: Impacts to Market Manual 4: Market Operations

Procedure	Type of change (no change, modification, new)	Section	Description
Part 4.2 - Submission of Dispatch data in the Real-Time Energy and Operating Reserve Markets	Modification	All sections	*Registered market participant* responsibilities for dispatchable *generation facilities* needs to be updated to reflect submission of hourly *dispatch data* and submission of daily *dispatch data*.
	Modification	2.3 Timing of the Real-Time *Energy* and *Operating reserve market*s	Changes to this section are described in the Grid and Market Operations Integration detailed design document.
	Modification	2.3.1 Generating Units with Start-Up Delays	Section to be updated to reflect that the PD calculation engine will use *dispatch data* parameters such as lead time and ramp up to MLP to account for start-up delays associated with combined cycle *generation facilities*. Further changes to this section are described in the Grid and Market Operations Integration detailed design document.

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
Part 4.2 - Submission of Dispatch data in the Real-Time Energy and Operating Reserve Markets	Modification	2.3.2 Replacement *Energy Offers* Program	Changes to this section are described in the Grid and Market Operations Integration detailed design document.
	Modification	2.3.3 and 2.3.4 Procedural Steps for Submitting *Dispatch Data* and Revisions Until/Within Two Hours Prior to the *Dispatch Hour*	Changes to this section are described in the Grid and Market Operations Integration detailed design document.
	Modification	2.4.1 *Energy Offers* and *Bids*	• Single price restriction for *price-quantity pairs* corresponding to *minimum loading point* for all hours of the *minimum generation block run-time* to be eliminated. • *IESO* will no longer require *price-quantity pairs* for *generation facilities* with *forbidden regions* to respect upper and lower limits of each *forbidden region*. • Evaluation of *pseudo-units* will now only require *price-quantity pairs* for each *pseudo-unit*. The *IESO* will no longer require *price-quantity pairs* to also be submitted on the physical unit associated with *pseudo-unit*. • *Energy offered* for dispatchable hydroelectric *generation facilities* must have an *energy* quantity in the

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
			second *price-quantity pair* that is greater than or equal to any minimum hourly output or hourly must-run values submitted as *dispatch data.* • Change references for DEL to Max DEL and include new requirements for *registered market participants* that submit Min DEL.
Part 4.2 - Submission of Dispatch data in the Real-Time Energy and Operating Reserve Markets	Modification	2.4.2 OR *Offers*	Updates required to reflect that *registered market participants* registered to submit *dispatch data* for a *pseudo-unit* resource type will only submit *offers* for *operating reserve* for a *pseudo-unit* resource type.
	No change	2.4.3 *Energy* schedules and forecasts	Existing requirements remain valid for the future *real-time market.*
	No change	2.4.4 Standing *Dispatch Data*	Existing requirements remain valid for the future *real-time market.*
	Modification	2.5 *Dispatch Data* for Importing and Exporting *Energy* and Importing *Operating Reserve*	Updates required to reflect that *registered market participants* will only be required to edit e-tag IDs to indicate an import *offer* and an export *bid* to are part of the same wheeling through transaction.
	Modification	2.6.1 *Dispatch Data* Requirements for Scheduling a *Called Capacity Export*	Updates required to reflect that the capacity transaction *dispatch data* parameter must be submitted for each *dispatch hour* of a capacity export *bid*.

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
Part 4.2 - Submission of Dispatch data in the Real-Time Energy and Operating Reserve Markets	No change	2.6.2 Changes/ Updates to *Called Capacity Exports* or Capacity Resources	Existing requirements remain valid for the future *real-time market.*
	Modification	2.7 Requests for *Segregated Mode of Operation*	Changes to this section are described in the Grid and Market Operations Integration detailed design document.
	Modification	2.8 Publication of *Pre-Dispatch Schedules*	Changes to this section are described in the Grid and Market Operations Integration detailed design document.
	Modification	Appendix A: Content of *Dispatch Data*	A.1 to be updated to include virtual transaction *offers* and *bids* for *energy* for the day-ahead market only.
	No change	Appendix B: Short Notice Change Criteria	Changes to this appendix are described in the Grid and Market Operations Integration detailed design document.
	No change	Appendix C: Contingency Plan	Existing requirements remain valid for the future *real-time market.*
	Modification	Appendix D: Pre-dispatch Schedule Production and Publication	Section D.1 to be updated to reflect that a *demand* forecast for each *demand* forecast area will be used to determine pre-dispatch schedules.
	No change	Appendix E: Boundary Entity Resources	Existing requirements remain valid for the future *real-time market.*
	No change	Appendix F: Ontario Specific E-Tag Requirements	Existing requirements remain valid for the future *real-time market.*

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
Part 4.3 - Real-Time Scheduling of the Physical Markets	Modification	3.0 Determining Real-Time Schedules	• Updates required to reflect that *real-time schedules* for *a facility* will be determined using *dispatch data* instead of registered data for *forbidden regions* and *minimum loading point*. Registered *forbidden regions* for a *facility* will now only be used for validation of *dispatch data* submissions. Registered reference levels for *minimum loading points* will now be used to validate *minimum loading point* submissions as *dispatch data*. • New section may be required to describe inputs used by the PD calculation engine to determine *pre-dispatch* schedules. These inputs include the new and existing *dispatch data* parameters for hydroelectric *generation facilities* and NQS *generation facilities* described in Section 3.4. • Updates required to describe that the PD and RT calculation engines will be capable of evaluating *dispatch data* for *pseudo-units.* • Remaining changes to this section are described in the Grid and Market Operations Integration detailed design document.
	Modification	All other sections	Changes to other sections are described in the Grid and Market Operations Integration detailed design document.

Table 5-3: Impacts to Market Manual 7: System Operations

Procedure	Type of change (no change, modification, new)	Section	Description
Part 7.1 - IESO-Controlled Grid Operating Procedures	Modification	Appendix B - Emergency Operating State Control Actions	Updates required to reflect that CAOR will no longer be used by the *IESO* in assessing control actions to use to alleviate an *emergency operating state*.
	No change	All other sections	Existing requirements remain valid for the future *real-time market.*
Part 7.2 - Near-Term Assessments and Reports	Modification	2.4 Producing and Publishing the Ontario Zonal Demand Forecast Report	Updates required to reflect that the Ontario total demand forecast will be determined as the sum of four demand forecast areas.
	Modification	5.0 Control Action Operating Reserve	Updates required to reflect that CAOR will no longer be used by the *IESO* to represent control actions to meet *operating reserve* requirements.
	Modification	All other sections	Changes to these sections are described in the Publishing and Reporting Market Information detailed design document.
Part 7.4 - IESO-Controlled Grid Operating Policies	No change	All sections	Existing requirements remain valid for the future real-time market.

Table 5-4: Impacts to Market Manual 9: Day-Ahead Commitment

Procedure	Type of change (no change, modification, new)	Section	Description
Part 9.0 - DACP Overview	Modification	2.0 About this Manual	*Market participant* responsibilities to be updated to reflect day-ahead market *dispatch data* submission requirements for virtual transactions, PRLs, *variable*

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
			generation, *dispatchable loads* and dispatchable *generation facilities*.
Part 9.0 - DACP Overview	Modification	3.0 About the Day-Ahead Commitment Process	Changes to this section are described in the Grid and Market Operations Integration detailed design document.
	Modification	4.0 Procedures Summary	Figure 4-1 to be updated to show the interrelationships of the future day-ahead *market manuals* and other *market manuals*.
	Modification	5.0 Applicability of Procedures	Table 5-1 to be updated to reflect mappings between future day-ahead market events and the applicable day-ahead market procedures.
	Modification	Appendix A DACP Background	This appendix may be deleted or updated to provide background for the day-ahead market.
Part 9.2 - Submitting Operational and Market Data for the DACP	Modification	3.0 Introduction	References to daily generation data to be removed and replaced with hourly *dispatch data* and daily *dispatch data*.
	Modification	4.1 *Generation Facilities*, *Dispatchable Loads*, and *Hourly Demand Response* Resources	Section to be updated to include: • *Dispatch data* submission requirements for PRLs. • *Bid* quantities for a *dispatchable load* must have a corresponding *bid* price of *MMCP* for that *bid* quantity to be considered non-dispatchable in the day-ahead market. • Submission requirements for new *dispatch data* parameters for *variable generation,* dispatchable hydroelectric *generation units* and combined cycle

Procedure	Type of change (no change, modification, new)	Section	Description
			generating units.
Part 9.2 - Submitting Operational and Market Data for the DACP	Modification	4.2 Imports and Exports	Updates required to remove references to the day-ahead intertie *offer* guarantee.
	Modification	4.3 Linked Wheel Transactions	Changes to this section are described in the Grid and Market Operations Integration detailed design document.
	New	4.4 Virtual Transactions	New section required to describe *dispatch data* submission requirements for virtual transaction *offers* and *bids* for *energy*.
	Modification	5.0 Submitting Operational and Market Data for DACP	Table 5-1 to be updated to include PRLs and virtual transactions as new resource types. Daily generator data column to be replaced with two new columns for daily and hourly *dispatch data*.
	Modification	5.1 Submit New or Revised Dispatch Data	Section to be updated as follows: • Table 5-2 to reflect new hourly *dispatch data* parameters. • Three-part *offers* will no longer be submitted in DAM. Start-up *offers* will replace start-up costs and allow for *offers* to reflect thermal state of *combined cycle facility*. Speed-no-load *offer* will replace speed-no-load cost. • Updates required to reflect that *offers* for physical *generation units* will no longer be required for *registered market participants* submitting *dispatch data for* a *pseudo-unit.* • Updates to timelines for submission and revision of *dispatch data* for the day-ahead market are described in the

Procedure	**Type of change (no change, modification, new)**	**Section**	**Description**
			Grid and Market Operations Integration detailed design document. • Updates required to reflect new hourly *dispatch data* parameters and submission validations for dispatchable hydroelectric *generation facilities.* • Updates required to reflect new *variable generation* forecast quantity as hourly *dispatch data*.
Part 9.2 - Submitting Operational and Market Data for the DACP	Modification	5.2 Submit Daily Generation Data	Section to be updated to reflect new daily *dispatch data* parameters as follows: • Table 5-6 to be updated to reflect new daily *dispatch data* parameters • Updates required to reflect that three different values to reflect thermal states of hot, warm and cold can be submitted for ramp up to MLP, lead time, and *minimum generation block down time.* • Updates required to reflect new validations for market power mitigation for *minimum loading point*, *minimum generation block run-time*, *minimum generation block down time*, *maximum number of starts per day*, lead time, and ramp up to MLP submissions as daily *dispatch data*. • Updates required to reflect new validations and restrictions for Max DEL, Min DEL and linked resources, time lag and MWh ratio submissions as daily *dispatch data*.

Procedure	Type of change (no change, modification, new)	Section	Description
Part 9.2 - Submitting Operational and Market Data for the DACP	Modification	5.3 Request for *Segregated Mode of Operation*	Updates for SMO submission and cancellation timelines described in the Grid and Market Operations Integration detailed design document.
	No change	5.4 Submit *Regulation Offers*	Existing requirements remain valid for the future day-ahead market.
	Modification	5.5 Procedure for Submitting *Dispatch Data* during Contingencies	Changes to this section are described in the Grid and Market Operations Integration detailed design document.
	Modification	Appendix A: Reason Codes and Valid Reasons for Change	Changes to this section are described in the Grid and Market Operations Integration detailed design document.
Part 9.3 - Operation of the DACP	Modification	All sections	Changes to this market manual are described in the Grid and Market Operations Integration detailed design document.
Part 9.4 - Real-Time Integration of the DACP	Modification	All sections	Changes to this market manual are described in the Grid and Market Operations Integration detailed design document.
Part 9.5 - Settlement of the DACP	Modification	All sections	Changes to this market manual are described in the Market Settlement detailed design document.

Table 5-5: Impacts to Market Manual 13: Capacity Export Requests

Procedure	Type of change (no change, modification, new)	Section	Description
Part 13.1 - Capacity Export Requests	No change	All sections	Existing requirements remain valid for the future day-ahead and real-time market.

5.2. Internal Procedural Impacts

Most of the internal procedures currently used by the Bids, Offers and Input Data process will continue to be used to support the future *real-time market* and the day-ahead market. Many of the internal *IESO* procedures will be updated to account for submission and validation of new *dispatch data* parameters for virtual transactions, price-responsive loads and dispatchable *generation facilities.* Updates are also required to produce a province-wide *demand* forecast as the sum of four separate area demand forecasts and add new mapping activities to the Network Model Build process.

Applicable *market rules* and supporting tools will undergo changes as a result of the new day-ahead market implementation and other solution enhancements. The existing procedures will be updated to account for the corresponding changes in the *market rules* and tools.

Changes or additions to internal *IESO* procedures are for internal *IESO* use as documented in Appendix B and are not included in the public version of this document. Appendix B details the impacts to internal procedures in terms of existing procedures that support the new market requirements, existing procedures that need to be updated, and new internal procedures that need to be created to support the future day-ahead market and *real-time market*.

– End of Section –

6. Business Process and Information Flow Overview

6.1. Market Facing Process Impacts

This section provides an overview to the arrangement of processes required in order to support the overall Offers, Bids and Data Inputs process and the critical information flows between them.

The context diagrams presented in Section 2 of this document are considered as level 0 data flow diagrams and represent the major flows of information into and out of the Offers, Bids and Data Inputs process. This section now presents the Offers, Bids and Data Inputs process at the next level of detail (Level 1). A further break-down of the processes presented in this section (i.e. levels 2,3,4…) falls into the realm of systems design and is beyond the scope of this document.

The data flow diagram does not illustrate:

- flow of time or sequence of events (as might be illustrated in a timeline diagram);
- decision rules (as might be illustrated in Flowchart); and
- logical architecture and systems architecture (as might be illustrated in a Logical Application and Data Architecture, and/or Physical Application and Data Architecture).

What it does illustrate however, is a logical breakdown of the sub-processes that constitute a large and complex system such as the Offers, Bids and Data Inputs process. Specifically, the data flow diagram presented below illustrates:

- the Offers, Bids and Data Inputs process as a grouping of several major and tightly coupled sub-processes;
- the key information flows between each of the processes;
- external sources of key information required by the Offers, Bids and Data Inputs process;
- external destinations of key information from the Offers, Bids and Data Inputs process; and
- the same logical boundary of the Offers, Bids and Data Inputs process as illustrated in the Level 0 context diagram presented in Section 2 of this document.

This section is not meant to impart information systems or technology architecture, but rather to capture the entire Offers, Bids and Data Inputs process as a series of interrelated sub-processes.

The functional design outlined in Section 3 of this document maps to the business process overview presented in this section. In any areas where there are inconsistencies between this section and the description of the business process provided in Section 3, the business process described in Section 3 will take precedence.

The data flow diagram illustrated in Figure 6-1 presents the Offers, Bids and Data Inputs process for physical and virtual transactions in the future day-ahead market and *real-time market*. The following sections of this document will provide an overview to each of the main sub-processes of the Offers, Bids and Data Inputs process.

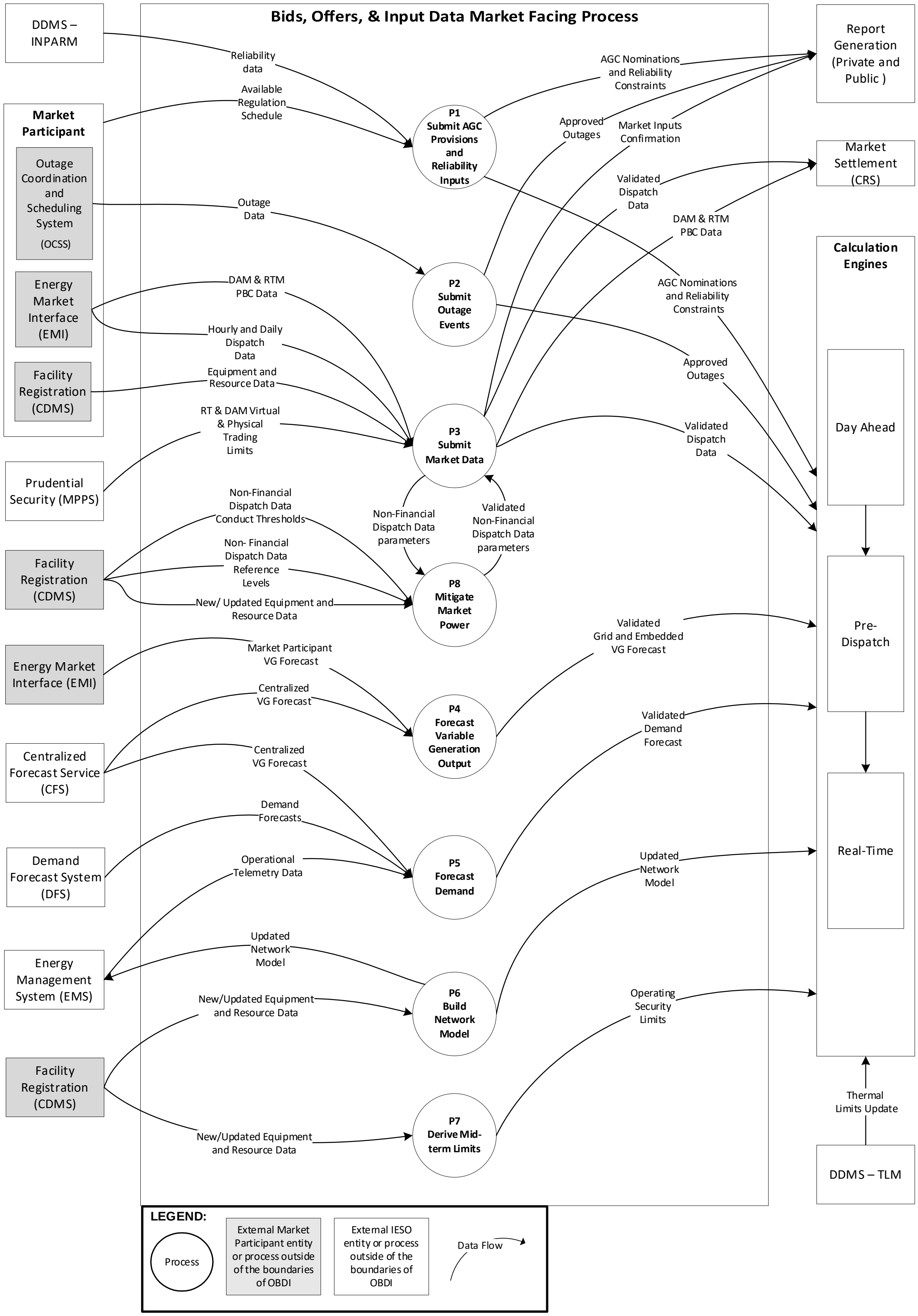

Figure 6-1: High Level Process and Information Flow

6.1.1. Process P1 – Submit AGC Provisions and Reliability Inputs

Description

The Submit AGC Provisions and *Reliability* Inputs (P1) process determines the AGC and *reliability* requirements for the next *dispatch day* based on submissions from *market participants* and system conditions.

The key processing steps are to receive the available AGC quantity from *market participants* through the Energy Market Interface (EMI), validate the AGC submissions (based on timing of submission, status of *market participants* and the availability and suitability of required data), selects the AGC provision for the *dispatch day* and communicates the results to the *registered market participant.*

Input and Output Data Flows

Table 6-1: Process P1 Input and Output Data Flows

Flow	Source	Target	Frequency
Available *Regulation* Schedule	*Market participant*	Process P1	Daily

Description:

- These are schedules submitted by *registered market participants* which reflect the MWs available for any given *dispatch day* to satisfy their AGC contract obligations, prior to the closing of the day-ahead market submission window; and
- *Regulation* services will continue to be supported by a valid *energy offer* and, as required, other supporting *dispatch data* as specified in their contract and specific to their resource type.

Flow	Source	Target	Frequency
Reliability data	DDMS INPARM	Process P1	Daily

Description:

- These are a set of *IESO* inputs used by the calculation engines to schedule and *dispatch* resources in respect of *reliability* requirements; and
- These inputs include but is not limited to *intertie* scheduling limits, *operating reserve* requirements, operating security limits, Lake Erie circulation forecast, NISL.

Flow	Source	Target	Frequency
AGC Nominations and Reliability constraints	Process P1	Report Generation (Private and Public) Calculation Engines	As required by the Calculation Engines

Description:

AGC Nominations

- The *IESO* will determine which *ancillary service provider* resources are selected to provide *AGC regulation* in each *dispatch hour* of the *dispatch day* and communicate the accepted nominations to the *market participants* before the day-ahead market submission window closes.

Reliability Constraints

- These nominations are implemented as an input constraints into the day-ahead, pre-dispatch and real time calculation engines for the *dispatch day.*

6.1.2. Process P2 – Submit Outage Events

Description

The Submit Outage Events (P2) process outlines the tasks related to *reliability* assessment, *outage* assessment, and *security limit* derivation in the planning timeframe for *outage* management. The *reliability* of the *IESO-controlled grid* requires *outage* assessments for all relevant equipment and *security limits* under all *outage* conditions.

No process changes are required for the future market.

Input and Output Data Flows

Table 6-2: Process P2 Input and Output Data Flows

Flow	Source	Target	Frequency
Outage data	*Market participant* via OCSS	Process P2	As required
Description: • *Outage* data will continue to represent the planned or unplanned removal of equipment from service, unavailability for connection of equipment or temporary derating, restriction of use, or reduction in performance of equipment for any reason; and • The *market participant* requesting an *outage* will need to submit their request using the OCSS. If the OCSS is unavailable, then the *market participant* would have to submit their request via telephone or email.			
Flow	**Source**	**Target**	**Frequency**
Approved Outages	Process P2	Calculation Engine Report Generation (Private and Public)	As required by the Calculation Engines

Description:

- Following the assessment of an *outage* request, where an *outage* has been assessed as not adversely impacting *reliability* of the *IESO-controlled grid*, the request is approved by the *IESO* and communicated to the *market participant;*
- The *IESO* may reject an outage request if there is insufficient time to assess the impact of the *outage* or the *outage* request does not meet the acceptable criteria or raises *reliability* concerns; and
- For forces outages, *IESO* does not assess for approval or rejection.

6.1.3. Process P3 – Submit Market Data

Description

The Submit Market Data (P3) process accepts and, where required, validates *dispatch data* from *market participants* for the *IESO*'s scheduling and optimization algorithms. This process also includes the interaction with the Mitigate Market Power process (P8) for the validation of non-financial *dispatch data* parameters.

Input and Output Data Flows

Table 6-3: Process P3 Input and Output Data Flows

Flow	Source	Target	Frequency
Hourly and daily *dispatch data*	*Market participant* (via EMI)	Process P3	As required

Description:

Energy

- *Dispatch data* for supplying *energy* from *generation facilities* will continue to be submitted either as hourly or daily parameters. Hourly *dispatch data* will continue to be referred to as hourly whereas daily generator data, currently known as DGD, will be referred to as a daily *dispatch data.* The DGD term will become obsolete;
- New hourly and daily *dispatch data* parameters will be introduced or existing parameters will be updated. These additional parameters will be required for dispatchable NQS *generation facilities*, hydroelectric *generation facilities* and *variable generation* resources;
- The *dispatch data* construct will continue to represent financial and non-financial parameters that are submitted by *market participants*;
- Standing *dispatch data* and regular *dispatch data* will be validated against information provided during the Facility Registration process;
- *Dispatch data* is also validated to ensure it is correctly formatted, has acceptable

numeric values, and has the necessary information. In addition, *dispatch data* must be received from the valid *registered market participant* for the resource; and

- If a *dispatch data* parameter is approved, it is stored and applied for the appropriate day.

Operating Reserves:

- Dispatchable *generation facilities* and *dispatchable loads* will continue to be eligible to provide all three classes of *operating reserve* in the future day-ahead market and the *real-time market*, subject to performance criteria evaluated during the Facility Registration process; and
- The three classes of *operating reserve* that will continue to be *offered* into the future day-ahead market and *real-time market* are:
  - o 10-minute synchronized *operating reserve* (also known as 10-minute spinning reserve);
  - o 10-minute non-synchronized *operating reserve*; and
  - o *30-minute operating reserve*.
- Imports associated with a *boundary entity* will continue to only be eligible to *offer* 30-minute and 10-minute non-synchronized *operating reserve* subject to performance criteria evaluated during the Facility Registration process. *Boundary entities* are not permitted to provide 10-minute spinning *operating reserve.*

Flow	**Source**	**Target**	**Frequency**
DAM and RTM PBC Data	*Market participant* (via EMI)	Process P3	As *offers*/ *bids* are received

Description:

- *Physical bilateral contract data* will be submitted by *market participants* to facilitate the settlement of their agreement based on their activity in the DAM or *real-time market*;
- The parties may submit one or both of the *real-time market* PBC data and DAM *physical bilateral contract* data;
- DAM *physical bilateral contract* quantities will allow for the transfer of DAM uplift settlement amounts from the buying *market participant* to the selling *market participant* in proportion to the size of the *physical bilateral contract*. Specifically, the selling *market participant* will assume a portion of the DAM uplift amounts; and
- *Physical bilateral contract data* must continue to be submitted no earlier than seven calendar days prior to the *dispatch day* and within six business days after the *dispatch day* to allow time for *preliminary settlement statements* to be created. Revisions and cancellations may continue to be made anytime within the timelines described above.

Flow	**Source**	**Target**	**Frequency**

<table>
<tr><td>Equipment and Resource data</td><td>Market participant (via Facility Registration)</td><td>Process P3</td><td>As required</td></tr>
<tr><td colspan="4">Description:
The market participant submits facility equipment information via Online IESO. This includes information obtained via the following processes: Record Equipment, Register Revenue Meter Installation; Prepare for Operations and Commission Equipment processes;
This includes new or updated information with respect to market resources, power system equipment models and data, topology, connection points, operational characteristics (e.g. impedances, normal statuses) and operational meters for system monitoring and control; and
As offers and bids are received from market participants, they are validated against the equipment and resource data. Resource characteristics include the nameplate rating of the facility, ramp rates, etc. This data will be used to validate the identity and capacity of the market participant submitting the bids and offers.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>RT & DAM Virtual & Physical Trading Limits</td><td>Prudential Security (MPPS)</td><td>Process P3</td><td>Daily</td></tr>
<tr><td colspan="4">Description:
The Prudential Security process will provide information to the Energy Market Interface regarding the maximum megawatt hours and trading limit in dollars that a market participant can transact on a given day;
Physical transactions and virtual transactions actual exposure will be calculated separately as they accrue through the various stages of the daily financial exposure calculation; and
On a continuous basis, virtual transaction bids and offers will be screened against a virtual transaction trading limit (in dollars) established by the IESO and an absolute value of the maximum daily trading limit (in MWh) provided by the market participant.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Market Input Confirmation</td><td>Process P3</td><td>Reports Generation (for market participants)</td><td>Daily</td></tr>
</table>

Description: • This activity will send a notification to the *market participant* that their submission has been approved for use as *dispatch data* for the dates and hours indicated in the submission.			
Flow	**Source**	**Target**	**Frequency**
DAM & RTM PBC Data	Process P3	Market Settlement (CRS)	Daily
Description: • *Physical bilateral contract data* (PBC data) will be submitted by *market participants* to facilitate the settlement of their agreement based on their activity in the DAM or *real-time market*; • The parties may submit either or both of the *real-time market* PBC data and day-ahead market PBC data; • DAM *physical bilateral contract* quantities will allow for the transfer of DAM uplift *settlement amounts* from the *buying market participant* to the *selling market participant* in proportion to the size of the PBC contract. Specifically, the *selling market participant* will assume a portion of the DAM uplift amounts; and • PBC data must continue to be submitted no earlier than seven calendar days prior to the *dispatch day* and within six business days after the *dispatch day* to allow time for *preliminary settlement statements* to be created. Revisions and cancellations may continue to be made anytime within the timelines described above.			
Flow	**Source**	**Target**	**Frequency**
Validated Dispatch Data	Process P3	Calculation Engines Market Settlement (CRS)	As *dispatch data* received
Description: • The *dispatch data* submissions will be validated against registered data values according to a set of business rules to ensure that they are correctly formatted, have the necessary information and have been received from the valid *registered market participant*; • The *IESO* will also validate the submission of non-financial *dispatch data* parameters against their registered reference levels and a predefined conduct threshold. If the submitted *dispatch data* exceeds the reference level plus the conduct threshold, the *dispatch data* will be rejected; and • The validated *dispatch data* will be continue to act as an input into the market settlement process, day-ahead market, pre-dispatch and real-time calculation engines.			
Flow	**Source**	**Target**	**Frequency**

Non-financial *dispatch data* parameters	Process P3	Process P8	As needed

Description:

- Reference levels for non-financial *dispatch data* parameters will be used by the *dispatch data* validation process to mitigate non-financial *dispatch data* parameters such as *minimum generation block run-time* (MGBRT), *minimum generation block down time* (MGBDT), *minimum loading point* (MLP), *energy* ramp rate, *operating reserve* ramp rate, lead time, ramp up *energy* to MLP and maximum number of starts per day; and
- The *IESO* will validate this *dispatch data* against reference levels and predefined conduct thresholds. If the value submitted for the applicable non-financial *dispatch data* parameter is above the reference value plus the conduct threshold, the *offer* will be rejected.

Flow	**Source**	**Target**	**Frequency**
Validated non-financial *dispatch data* parameters	Process P8	Process P3	As needed

Description:

- To mitigate the exercise of market power, the *IESO* will validate the non-financial *dispatch data* for a resource at the time of *dispatch data* submission. The non-financial *dispatch data* parameter values will be validated against their reference levels. The *IESO* will evaluate whether the non-financial *dispatch data* exceeds the parameter reference level plus a predefined conduct threshold. If the submitted non-financial *dispatch data* parameter value is more than the reference level plus the conduct threshold, the *dispatch data* will be rejected.

6.1.4. Process P4 – Forecast Variable Generation Output

Description

The Forecast Variable Generation (VG) Output (P4) process delivers *energy*, ramp and cut-out forecasts to the *IESO* for all *variable generation* resources. The *IESO publish*es forecasts of expected output for *variable generation* and provides forecast notifications to *market participants* and internally to the *IESO*.

Input and Output Data Flows

Table 6-4: Process P4 Input and Output Data Flows

Flow	Source	Target	Frequency
Centralized VG Forecasts	Centralized Forecast Service (CFS)	Process P4	As required
Description: • The *IESO* will continue to gather *variable generation* forecasts from a *forecasting entity* for every registered *variable generation facility* and any non-registered embedded *variable generation facility* with a capacity greater than or equal to 5 MW; • Forecasts for registered *variable generation facilities* are used to determine schedules and *dispatch instructions* in the DAM, the *pre-dispatch schedule* and the *real-time market*; and • Forecasts for non-registered embedded *variable generation facilities* are only used by the *IESO* in determining the *demand* forecasts.			
Flow	**Source**	**Target**	**Frequency**
Market participant VG Forecast	market participant (via EMI)	Process P4	Daily
Description: • The *market participant* VG forecast quantity is a new *dispatch data* parameter that will only be used by the DAM calculation engine; and • This parameter will allow *registered market participants* that submit *dispatch data* for *variable generators* to receive financially binding DAM schedules based on a forecast quantity of their choice instead of a quantity provided by the *IESO* centralized *variable generation* forecast.			
Flow	**Source**	**Target**	**Frequency**
Validated Grid and Embedded VG forecast	Process P4	Calculation Engine	As required by the Calculation Engines
Description: • This is the forecasted *variable generation* output for each *variable generator* for each hour of the next *dispatch day*. This will be *published* on the *IESO* website and also used to support downstream processes.			

6.1.5. Process P5 – Forecast Demand

Description

The Forecast Demand process (P5) provides Ontario hourly and five-minute *demand* forecasts for Day 0 to Day 10. This process will adjust the *demand* forecast to remove losses and *bid* load, and as needed based on system conditions, to determine the NDL forecast.

Input and Output Data Flows

Table 6-5: Process P5 Input and Output Data Flows

<table>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Operational Telemetry Data</td><td>Energy Management System (EMS)</td><td>Process P5</td><td>Every 5 minutes</td></tr>
<tr><td colspan="4">Description:
• Operational telemetry is used to update demand forecast models and load distribution patterns; and
• IESO operators monitor telemetry and have the ability to correct for telemetry failures to improve the accuracy of information.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Demand Forecasts</td><td>Demand Forecasts Systems (DFS)</td><td>Process P5</td><td>As required by the Calculation Engines</td></tr>
<tr><td colspan="4">Description:
• In the future day-ahead and real-time market, the IESO will continue to produce a demand forecast at the province-wide level but as the sum of four separate area demand forecasts. The area demand forecasts produced by the IESO will be used as an input for the expected load in the DAM, PD and RT calculation engines;
• Hourly area demand forecasts (peak and average) will be used for DAM and PD calculation engines. Five-minute area demand forecasts will be used for the RT calculation engine; and
• In order to have the most up to date area demand forecast input in the DAM, PD and RT scheduling algorithms, IESO operators will continue to be able to assess and adjust the forecast for each timeframe in a timely manner.</td></tr>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
</table>

Centralized VG Forecasts	Centralized Forecasting System (CFS)	Process 5	Hourly

Description:

- The *IESO* currently gathers *variable generation* forecasts from a *forecasting entity* for every registered *variable generation facility* and any non-registered embedded *variable generation facility* with a capacity greater than or equal to 5 MW; and
- Forecasts for registered *variable generation facilities* will be used to determine schedules and *dispatch instructions* in the future DAM, the *pre-dispatch schedule* and the *real-time market*. Forecasts for non-registered embedded *variable generation facilities* will only used by the *IESO* in determining the province-wide *demand* forecast.

Flow	Source	Target	Frequency
Validated Demand Forecast	Process P5	Calculation Engine	Daily

Description:

- Generated *demand* forecasts will be reviewed by *IESO* and where required, updates or adjustments will be made to the forecasts to reflect weather deviations and improve the accuracy of the forecast.

Flow	Source	Target	Frequency
Operating Security Limits	Process P7	Calculation Engines	As required

Description:

- OSLs are one of several *reliability* requirements that the *IESO* updates to reflect anticipated conditions for every *dispatch hour* of the *dispatch day*;
- OSLs used by the DAM, *PD* and RT calculation engines will continue to be activated and updated by the *IESO* based on the latest forecast conditions and the expected configuration of the *IESO-controlled grid*; and
- Only one set of OSLs will continue to be used for all timeframes but the flexibility to change OSLs as we approach different timeframes will be retained.

6.1.6. Process P6 – Build Network Model

Description

This process (P6) provides the network model that represents a detailed topology of the *IESO-controlled grid* and a simplified topology of neighboring jurisdictions. The network model supports a number of applications used by the *IESO* including but not limited to the calculation engines and the real-time energy management system (EMS).

Input and Output Data Flows

Table 6-6: Process P6 Input and Output Data Flows

Flow	Source	Target	Frequency
New/Updated Equipment and Resource Data	*Market participant* (via Facility Registration)	Process P6	As required

Description:

- The *market participant* submits *facility* equipment information via Online IESO. This includes information obtained via the following processes: Record Equipment, Register Revenue Meter Installation; Prepare for Operations and Commission Equipment processes;
- This includes new or updated information with respect to market resources, power system equipment models and data, topology, *connection points*, operational characteristics (e.g. impedances, normal statuses) and operational meters for system monitoring and control; and
- This data is used to map resources to zones and map operational meters to specific points in the network model.

Flow	Source	Target	Frequency
Updated Network Model	Process P6	Energy Management System (EMS) Calculation Engines	Monthly or as required for exceptional cases

Description:

- The updated network model contains a detailed topology representation of the *IESO-controlled grid* and a simplified representation of power systems in neighboring jurisdictions; and
- It is used as a static input to the *IESO's* real-time energy management system (EMS) and all calculation engines. The topology of the network model is determined through normal equipment statuses, *outages* and/or telemetry as applicable to each of the calculation engines.

Flow	Source	Target	Frequency
Thermal Update Limits	Process P6	Calculation Engines	As required

Description:

- Thermal ratings used by the DAM and PD calculation engines will continue to be based on lookup limits provided by *transmitters* and forecasted weather data. Thermal ratings used by the RT calculation engine will continue to be received from *transmitters.*

6.1.7. Process P7 – Derive Mid-term Limits

Description

This process provides system control orders (SCO) which indicate the base case operating security limits (OSL) to facilitate the secure operation of the ICG. The process includes three major activities. Activity Plan Studies delivers study scope, schedules, and assignments. Activity Conduct Studies delivers approved study results. Activity Implement Study Results delivers updated system control orders, solutions and training.

Input and Output Data Flows

Table 6-7: Process P7 Input and Output Data Flows

Flow	Source	Target	Frequency
New/Updated Equipment and Resource Data	*Market participant* (via Facility Registration)	Process P7	As required
Description: • The *market participant* submits *facility* equipment information via Online IESO. This includes information obtained via the following processes: Record Equipment, Register Revenue Meter Installation; Prepare for Operations and Commission Equipment processes; • This includes new or updated information with respect to market resources, power system equipment models and data, topology, *connection points*, operational characteristics (e.g. impedances, normal statuses) and operational meters for system monitoring and control; and • This data item could trigger a new study which will result in an updated System Control Order (SCO).			
Flow	**Source**	**Target**	**Frequency**
Operating Security Limits	Process P7	Calculation Engines	As required

Description:
• OSLs are one of several *reliability* requirements that the *IESO* updates to reflect anticipated conditions for every *dispatch hour* of the *dispatch day*; • OSLs used by the DAM, *PD* and RT calculation engines will continue to be activated and updated by the *IESO* based on the latest forecast conditions and the expected configuration of the *IESO-controlled grid*; and • Only one set of OSLs will continue to be used for all timeframes but the flexibility to change OSLs as we approach different timeframes will be retained.

6.1.8. Process P8 – Mitigate Market Power (Ex-Ante Validation of Non-Financial Dispatch Data)

Description

The new Market Power Mitigation framework seeks to identify exercises of market power that can potentially impact *market prices* or affect compensation payments to *market participants*. The *IESO* will implement a new market power mitigation framework in the future market. The *IESO* will implement an ex-ante validation of non-financial *dispatch data* process to, where possible, identify and mitigate the exercise of market power before schedules and prices are finalized in the future day-ahead market and the *real-time market*.

The *IESO* will test market conditions for the potential exercise of local and global market power in the *energy* market and apply the ex-ante mitigation process to test the relevant resources for price impact.

Input and Output Data Flows

Table 6-8: Process P8 Input and Output Data Flows

Flow	Source	Target	Frequency
New/Updated Equipment and Resource Data	*Market participant* (via Facility Registration)	Process P8	On demand
Description: • The *market participant* submits *facility* equipment information via Online IESO. This includes information obtained via the following processes: Record Equipment, Register Revenue Meter Installation; Prepare for Operations and Commission Equipment processes; • This includes new or updated information with respect to market resources, power system equipment models and data, topology, *connection points*, operational characteristics (e.g. impedances, normal statuses) and operational meters for system			

monitoring and control; and

- For Market Power Mitigation, this data will be used to verify resource identity and retrieve applicable reference levels and predefined conduct thresholds for MPM validation

Flow	Source	Target	Frequency
Non-Financial Dispatch Data Reference Levels	Process P8	Calculation Engines	On demand

Description:

- Reference levels are *IESO* -determined estimates of the *offer* parameters that a resource would have submitted if it were operating under competitive conditions. *Market participants* will be able to view their applicable reference levels on a confidential basis;
- The *IESO* will determine reference levels for financial parameters that describe characteristics expressed in monetary terms. Examples of financial parameters include *energy offers* , speed-no-load costs and start-up costs. Reference levels for financial parameters will be established in consultation with *market participants* using a cost-based methodology;
- The *IESO* will also determine reference levels for non-financial parameters to reflect the resource's operational capabilities. This will be used to validate that a parameter was not *offered* in error, such as ensuring that certain *dispatch data* parameters are not negative values; and
- The non-financial *dispatch data* reference levels are the following:
  - o *Minimum generation block run-time* (MGBRT) reference level;
  - o *Minimum generation block down time* (MGBDT) reference level (hot, warm, cold);
  - o *Minimum loading point* (MLP) reference level;
  - o *Energy* ramp rate reference level;
  - o *Operating reserve* ramp rate reference level;
  - o Lead time reference level (hot, warm, cold);
  - o Ramp hours to *minimum loading point* reference level;
  - o *Energy* per ramp hour reference level, and
  - o *Maximum number of starts per day* reference level.

Flow	Source	Target	Frequency
Non-Financial Dispatch Data Conduct Thresholds	IESO (via Facility Registration)	Process P8	On demand

Description:

- Conduct thresholds are allowable tolerances above the established reference levels;
- The conduct threshold determines how much a *dispatch data* duration parameter can deviate from its reference level without failing the conduct test; and
- Conduct thresholds will vary based on the extent to which competition is restricted.

The conduct thresholds are listed below:

- Submitted MGBRT is more than the lesser of 100% or 3 hours above the reference level;
- Submitted MGBDT is more than the lesser of 100% or 3 hours above the reference level for any thermal state; or submitted MGBDT across all thermal states is more than 6 hours above the total reference levels across all thermal states;
- Submitted MLP is greater than 100% above reference level;
- Submitted energy ramp rate *offered* is lower than 50% of the reference level;
- Submitted *operating reserve* ramp rate *offered* is lower than 50% of the reference level;
- Submitted lead time is more than the lesser of 100% or 3 hours above the reference level for any thermal state; or submitted lead time across all thermal states is more than 6 hours above the total reference levels across all thermal states;
- Submitted ramp hours to MLP is more than the lesser of 100% or 3 hours above the reference level for any thermal state;
- Submitted *energy* per ramp hour is more than 50% above the upper bound reference level or 50% below the lower bound reference level for any thermal state; and
- Submitted *maximum number of starts per day* 50% is lower than the reference level or lower than 1.

Flow	Source	Target	Frequency
Non-financial *dispatch data* parameters	Process P3	Process P8	As needed

Description:

- Reference levels for non-financial *dispatch data* parameters will be used by the *dispatch data* validation process to mitigate non-financial *dispatch data* parameters such as *minimum generation block run-tim* e (MGBRT), *minimum generation block down time* (MGBDT), *minimum loading point* (MLP), energy ramp rate, *operating reserve* ramp rate, lead time, ramp up *energy* to MLP and *maximum number of starts per day*; and
- The *IESO* will validate this *dispatch data* against reference levels and predefined conduct thresholds. If the value submitted for the applicable non-financial *dispatch data* parameter is above the reference value plus the conduct threshold, the *offer* will be rejected.

Flow	Source	Target	Frequency

Validated Non-financial *dispatch data* parameters	Process P8	Process P3	As needed

Description:

- To mitigate the exercise of market power, the *IESO* will validate the non-financial *dispatch data* for a resource at the time of *dispatch data* submission. The non-financial *dispatch data* parameter values will be validated against their reference levels. The *IESO* will evaluate whether the non-financial *dispatch data* exceeds the parameter reference level plus a predefined conduct threshold. If the submitted non-financial *dispatch data* parameter value is more than the reference level plus the conduct threshold, the *dispatch data* will be rejected.

6.2. Internal Process Impacts

The internal processes currently used for the collection and preparation of Offers, Bids and Data Inputs will continue to be used in the future day-ahead market and *real-time market*.

Internal *IESO* processes related to the Offers, Bids and Data Inputs include:

- Submit AGC Provisions and Reliability Inputs (currently an activity under Plan Operations);
- Submit *Outage* Events (currently an activity under Plan Operations);
- Submit Market Data (currently called Submit Market Transactions);
- Forecast *Variable Generation* Output;
- Forecast *Demand*;
- Derive Violation Curves;
- Derive Mid-term Limits; and
- Network Model Build (formerly Build Online Network Model process under Enroll Customer)

Some of the internal processes interact with various *IESO* processes around the periphery of Offers, Bids and Data Inputs. For the most part, any changes to the Offers, Bids and Data Inputs processes under the MRP do not impact the internal procedures that address these periphery areas. However, in some areas this may be contingent upon the tools impact of the future day-ahead market and *real-time market*.

Changes or additions to internal *IESO* processes are for internal *IESO* use as documented in Appendix C, and are not included in the public version of this document. Appendix C details the impacts to internal processes in terms of existing processes that support the new requirements, existing activities that need to be updated, and process and information models that may need to be updated.

– End of Section –

Appendix A: Market Participant Interfaces

Table A-1 provides a description of the changes to *IESO* technical interfaces with *market participants* that may be required to support the Offers, Bids and Data Input process design of the future day-ahead market and *real-time market*.

Table A-1: Changes to IESO Technical Interfaces

MP Interface Name	Interface Type	Description of Impact
Energy market Interface (EMI)	Web-Client	New hourly *dispatch data* parameters and daily *dispatch data* parameters, removal of daily *generator* data (DGD) designations, new and modified validation rules for hourly and daily *dispatch data*.
Market Information Management Application Programmatic Interface (MIM API)	Application Programmatic Interface	
Online Outage Coordination and Scheduling System (OCSS)	Web-Client	No changes required.

– End of Appendix –

Appendix B: Internal Procedural Requirements *[Internal only]*

This section is confidential to the *IESO*.

Appendix C: Internal Business Process and Information Requirements *[Internal only]*

This section is confidential to the *IESO*.

References

Document Name	Document ID
MRP Detailed Design: Overview	DES-16
MRP Detailed Design: Prudential Security	DES-17
MRP Detailed Design: Facility Registration	DES-19
MRP Detailed Design: Grid and Market Operations Integration	DES-22
MRP Detailed Design: Day-Ahead Market Calculation Engine	DES-23
MRP Detailed Design: Pre-Dispatch Calculation Engine	DES-24
MRP Detailed Design: Real-Time Calculation Engine	DES-25
MRP Detailed Design: Market Power Mitigation	DES-26
MRP Detailed Design: Publishing and Reporting Market Information	DES-27
MRP Detailed Design: Market Settlement	DES-28
Market Manual 1: Connecting to Ontario's Power System, Part 1.5: Market Registration Procedures	PRO-408
Market Manual 4: Market Operations, Part 4.2: Submission of Dispatch data in the Real-time Energy and Operating reserve markets	MDP_PRO_0027
Market Manual 4: Market Operations, Part 4.3: Real-Time Scheduling of the Physical Markets	MDP_PRO_0034
Market Manual 7: System Operations, Part 7.1: IESO-Controlled Grid Operating Procedures	MDP_PRO_0040
Market Manual 7: System Operations, Part 7.2: Near-Term Assessments and Reports	IMP_PRO_0033
Market Manual 7: System Operations, Part 7.4: IESO-Controlled Grid Operating Policies	IMP_POL_0002
Market Manual 9: Day-Ahead Commitment Part 9.0: DACP Overview	IESO_MAN_0041

Document Name	Document ID
Market Manual 9: Day-Ahead Commitment, Part 9.2: Submitting Operational and Market Data for the DACP	IESO_MAN_0077
Market Manual 9: Day-Ahead Commitment, Part 9.3: Operation of the DACP	IESO_MAN_0078
Market Manual 9: Day-Ahead Commitment, Part 9.4: Real-Time Integration of the DACP	IESO_MAN_0079
Market Manual 9: Day-Ahead Commitment, Part 9.5: Settlement of the DACP	IESO_MAN_0080
Market Manual 13: Capacity Exports Part 13.1: Capacity Export Requests	PRO-357
Market Rules for the Ontario Electricity Market (Market Rules)	MDP_RUL_0002

– End of Document –