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Detailed Design

Connecting Today. Powering Tomorrow.

Market Renewal Program: Energy

Real-Time Calculation Engine

Detailed Design

Issue 2.0

This document provides a detailed overview of the processes related to the Real-Time Calculation Engine that will be implemented for the Energy work stream of the Market Renewal Program, including related market rules and procedural requirements.

DES-25

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.	August 31, 2021
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 Settlements
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 provides the details of the business design and the requirements for *market rules*, market facing and internal procedures, and the data flow required to support the Real-Time (RT) Calculation Engine processes as related to the introduction of the future day-ahead market and *real-time market*. This design document will aid in the coordinated development of business processes, *market rules* and supporting systems.

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

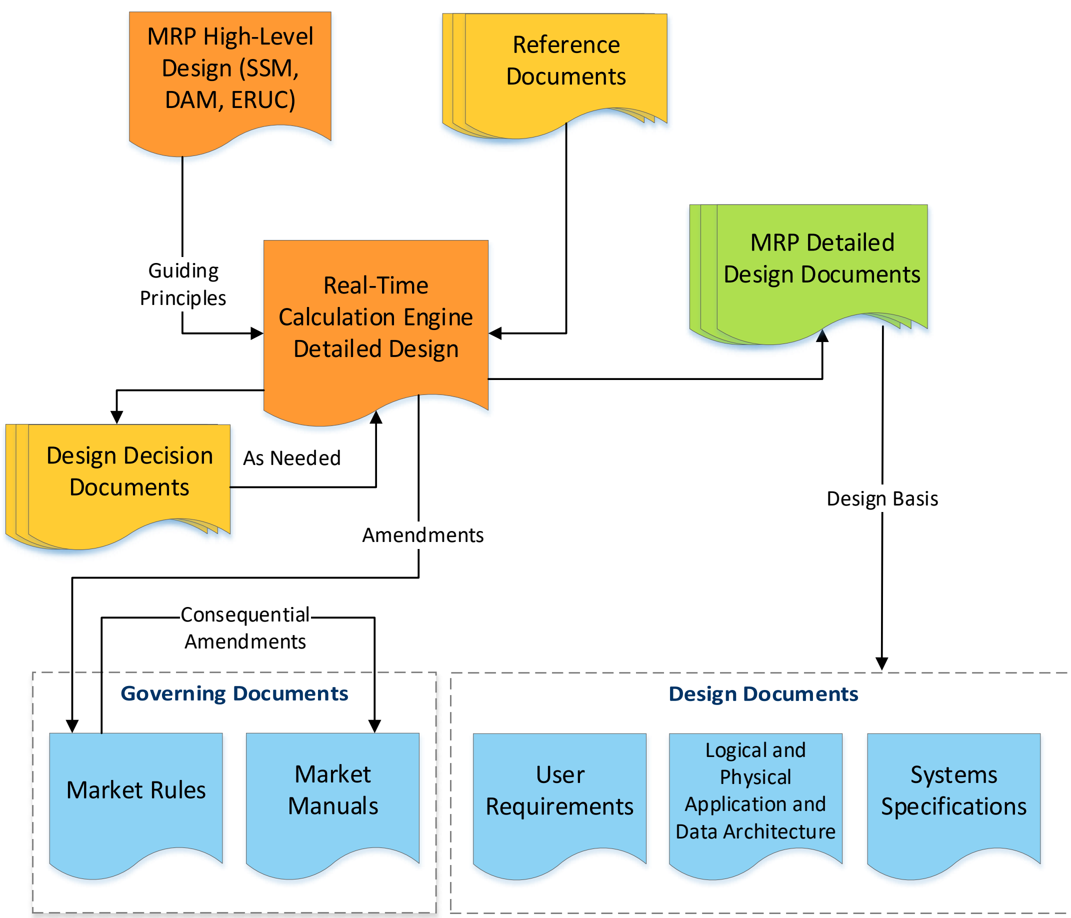

Figure 1-1: Detailed Design Document Relationships

1.2. Scope

This document describes the RT Calculation Engine process requirements, in terms of:

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

Various portions of this document make reference to current business practices, rules, procedures and processes of the RT calculation engine. 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 Real-Time (RT) Calculation Engine processes, this document does not impart any assumptions as to what the value of those parameters might ultimately be. The setting of such parameters will be a matter of *IESO* policy to be determined at a later date under the amended authority of the *market rules*.

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 set 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 *IESO's* current Dispatch Scheduler and Optimizer (DSO) calculation engine as used for *dispatch* and for determining *market prices* and the difference between the current engine and the future Real-Time (RT) calculation engine.
- **Section 3** of this document provides a detailed description of the functional design inferred from sections relevant to the RT Calculation Engine in the high-level designs for Single Schedule Market (SSM), Day-Ahead Market (DAM) and Enhanced Real-time Unit Commitment (ERUC).
- **Section 4** of this document describes how the RT Calculation Engine 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 the requirements of the RT Calculation Engine processes for a system of internal and market-facing procedures in terms of existing procedures, amended procedures and additional procedures that will need to be developed.
- **Section 6** of this document provides an overview of the arrangement of *IESO* processes supporting the overall RT Calculation Engine processes described in Section **3**. This section also outlines the logical boundaries and interfaces of the various sub-processes related to the RT Calculation Engine in terms of existing processes, amended processes and additional processes that will need to be developed.

– End of Section –

2. Summary of the Current and Future State

2.1. The Calculation Engine for Today's Real-Time Dispatch

When the province's wholesale electricity markets were introduced in 2002, the Market Design Committee recommended a two-schedule market as a way to simplify the transition from a regulated system to a competitive electricity market by providing a uniform price for both the supply and consumption of *energy* in real time. This decision has endured and Ontario is now the only jurisdiction in North America with a two-schedule market for *energy* and *operating reserve*.

The core component of the current *real-time market* is a calculation engine referred to as the Dispatch Scheduler and Optimizer (DSO). The DSO implements the *dispatch algorithm* as defined in the *market rules* to formulate *dispatch instructions* for dispatchable *generation facilities* and *dispatchable loads* and to calculate market clearing prices (MCPs). Within the real-time timeframe, the DSO finds an optimal outcome every five minutes by integrating market and *reliability* priorities.

In the current market, the DSO conducts two independent and simultaneous passes to produce two schedules. These schedules are referred to as the constrained *dispatch* schedule and the unconstrained *market schedule*.

2.1.1. The Constrained Dispatch Schedule

To maintain the *reliability* of the *IESO-controlled grid*, a constrained *dispatch* schedule that takes into account the resource and system constraints is required. DSO constrained *dispatch* scheduling considers the detailed network model of the *IESO-controlled grid*, allowing it to account for losses associated with moving electricity through the system and *security* constraints. DSO constrained *dispatch* scheduling looks forward in time to determine what resources need to be *dispatched* to meet the *demand* for the next five-minute *dispatch interval* and requirements that might arise in the next 60 minutes.

DSO constrained *dispatch* scheduling provides five-minute *dispatch* schedules used as the basis for *dispatch instructions* that are communicated to dispatchable *generation facilities* and *dispatchable loads*. Along with the constrained *dispatch* schedules, the DSO produces informational nodal prices – commonly referred to in Ontario as shadow prices – for these dispatchable resources. These nodal prices are not used for *settlement* of *energy* and *operating reserve*.

2.1.2. The Unconstrained Market Schedule

The DSO unconstrained *market schedule* is used to determine a uniform price across the province every five minutes. This price ignores most resource and system constraints. Therefore, this uniform price does not reflect the real cost of generating or consuming electricity at different locations.

The unconstrained *market schedule* of the DSO is determined ex-post. That is, *energy* and *operating reserve* prices for a given interval are determined using the actual *demand* observed in that interval.

Along with the unconstrained *market schedules*, the DSO produces single five-minute MCPs, which are then averaged to establish the province-wide *hourly Ontario energy price* (HOEP). Both the MCP and HOEP are used for the *settlement* of electricity supply and consumption in real time.

2.1.3. Congestion Management Settlement Credits

The differences between constrained *dispatch* schedules and unconstrained *market schedules* require out-of-market payments known as congestion management settlement credits (CMSC). CMSC payments are necessary to maintain the *reliability* of the *IESO-controlled grid.*

CMSC is necessary under the existing two-schedule market because the *dispatch instructions* provided by the constrained *dispatch* schedule may not make financial sense to *market participants* based on the prices produced from the unconstrained *market schedule*. The larger the divergences between these two schedules, the higher the amount of out-of-market payments that the *IESO* might need to provide in the form of CMSC payments to reconcile the difference.

In certain circumstances, the actual *dispatch instructions* are different from the outputs of the DSO runs. These circumstances can arise when the *IESO* needs to intervene with the outcome of the *dispatch algorithm* by modifying or overriding the *dispatch instructions* for reasons related to system *reliability.* In such cases, prices and *dispatch* might not be aligned and may result in CMSC payments.

2.1.4. Inputs to the Real-Time DSO

The DSO requires data inputs from both *market participants* and the *IESO* to calculate the constrained *dispatch* schedules and unconstrained *market schedules*.

2.1.4.1. Market Participant Inputs

Market participant inputs used by the DSO include:

- *Offers* to supply *energy* and/or *operating reserve* from dispatchable resources;

- *Bids* for the withdrawal of *energy* by *dispatchable loads*;
- *Bids* to reduce *energy* withdrawals by *hourly demand response* resources[1];
- Ramp rates;
- Self-schedules from non-dispatchable generation resources;
- Technical data; and
- *Outage* information from all resources.

2.1.4.2. IESO Inputs

The *IESO* provides data inputs to the real-time DSO that include:

- *Demand* forecasts;
- *Operating reserve* requirements;
- *Variable generation* forecasts;
- *Intertie* schedules;
- *Hourly demand response* resource schedules; and
- Network information such as transmission line data and constraints.

The *IESO* currently produces a single, province-wide *demand* forecast that is used to support scheduling and *dispatch* decisions in the real-time scheduling processes. Five-minute forecasts are used in the DSO to calculate *dispatch* schedules for the RT *dispatch hour*. The province-wide forecast is generated using historical *demand* data and expectations of future load consumption that are based on several factors, including weather forecasts.

For each *registered facility* supplying *variable generation,* the *IESO* produces production forecasts for all intervals of the multi-interval optimization (MIO) look-ahead period.[2]

Interchange schedules for imports and exports are based on the schedules calculated by the DSO in the pre-dispatch timeframe. *Dispatch* schedules for those transactions are then established as per the *intertie* check-out procedure. Those *interchange schedules* are then fixed for each *dispatch hour* in the constrained *dispatch*. Import and export schedules for the real-time unconstrained *market*

[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*.

[2] The multi-interval optimization look ahead period is for the next 11 five-minute intervals.

schedule are determined by the unconstrained *market schedule* in the *pre-dispatch scheduling* process.

Non-quick start commitments from the Day-Ahead Commitment Process (DACP) and the Real-Time Generation Cost Guarantee (RT-GCG) program are provided to both schedules of the real-time DSO. All other dispatchable *generation facilities* and *load facilities* are available for five-minute *dispatch* in the constrained *dispatch* schedule without constraints imposed by the DACP or *pre-dispatch scheduling* processes.

2.1.5. The Dispatch Algorithm

The constrained *dispatch* schedule and unconstrained *market schedule* are both calculated by a joint optimization in which the *bids* and *offers* in the *energy market* and *offers* in the *operating reserve market* are evaluated at the same time. This satisfies both the total electricity *demand* and the *operating reserve* requirements in such a way that maximizes the gains from trade.

The constrained *dispatch* schedule is calculated using multi-interval optimization that produces a five-minute schedule for the next *dispatch interval* and advisory schedules for the following ten five-minute intervals. With multi-interval optimization, the DSO software considers a number of future intervals to determine optimal *dispatch instructions* for the current interval, rather than considering just a single interval.

The constrained *dispatch* schedule takes into account static marginal loss factors when establishing the economic *dispatch* merit order of resources. The static marginal loss factors used are determined offline by the *IESO*.

The unconstrained *market schedule* does not perform multi-interval optimization, but calculates prices from a single interval ex-post. The primary *demand* target for the unconstrained *dispatch* schedule includes losses, as it does for the constrained *market schedule*. However, marginal loss factors are not used when establishing the unconstrained merit order of resources.

2.1.6. Outputs from the Real-Time DSO

2.1.6.1. Dispatch Instructions

The DSO determines the real-time constrained *dispatch* schedule for the next *dispatch interval*. The constrained *dispatch* schedule is the basis for *dispatch instructions* that are sent to all dispatchable resources. *Dispatch instructions* for all dispatchable resources are sent to the *dispatch workstations* for *market participants* operating dispatchable resources.

2.1.6.2. Real-Time Prices

The two-schedule system of the current *real-time market* produces a uniform price from the unconstrained *market schedule,* which is used for *settlement*, and nodal prices from the constrained *dispatch* schedule, which are produced for informational purposes only.

DSO unconstrained *market scheduling* produces the uniform five-minute *energy* price, a uniform five-minute *operating reserve* price for each reserve class and a five-minute *intertie* zonal price for each *intertie* zone. How the *intertie* zonal price is determined is described below.

To calculate uniform MCPs, DSO unconstrained *market scheduling* ignores transmission system constraints, including regional *operating reserve* constraints. It assumes that all loads and generation resources are located at the same point on the grid. This allows the calculation of MCPs that are the same for all load and generation resources throughout the province ignoring the losses or other restrictions that can cause prices to differ from location to location on the *IESO-controlled grid*.

The *energy* reference price in Ontario is currently established at the Richview Transformer Station (TS) located in the Greater Toronto Area. Richview TS is used as the reference location for calculating nodal prices. *Energy* and *operating reserve* reference prices are established through the co-optimization of *energy* and *operating reserve*.

The current DSO determines the real-time physical *dispatch* in advance (ex-ante) of each five-minute *dispatch interval* and calculates the prices for *energy* and *operating reserve* following the *dispatch interval* (ex-post).

Under the current two-schedule market, all dispatchable suppliers receive a uniform five-minute MCP determined by the DSO unconstrained *market schedule.* Suppliers that are *dispatched* when their short-run marginal cost is higher than the MCP are compensated via CMSC payments.

Dispatchable loads and exports currently pay the uniform five-minute MCP, and *non-dispatchable loads* including local distribution companies (LDCs) and *non-dispatchable loads* that provide *hourly demand response* pay the uniform HOEP.

Intertie congestion prices (*ICP*) represent the price difference between the MCP and the price on an *intertie.* These price differences stem from physical *intertie* transmission limits. In the current market, the *IESO* calculates a static *ICP* in the pre-dispatch hour ahead of the *dispatch hour* to add to the real-time MCP to obtain the real-time *intertie* zonal price for both import and export transactions.

Figure 2-1 provides a high-level overview of the current calculation engine for the real-time process.

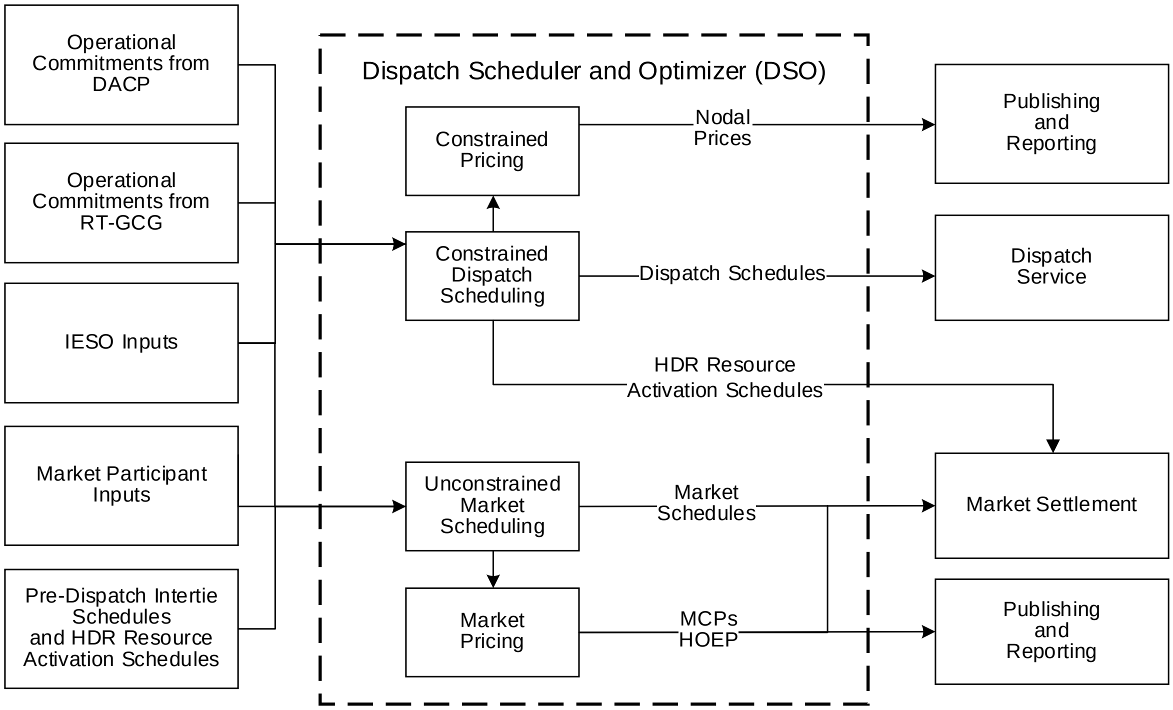

Figure 2-1: Current RT Calculation Engine Process

2.2. The Calculation Engine in the Future Real-Time Market

The core component of the future *real-time market* will be the RT calculation engine. This engine will include a single pass: Real-Time Scheduling and Pricing. This pass will take into account resource and system constraints to determine *dispatch* schedules, locational marginal prices (LMPs) and zonal prices.

The RT calculation engine will perform multi-interval optimization that plans real-time *dispatch* for the *dispatch interval* and the subsequent ten five-minute *intervals*, together comprising the MIO look-ahead period. The schedules for the intervals following the *dispatch interval* are advisory.

2.2.1. Inputs to the RT Calculation Engine

Inputs to the RT calculation engine will include *dispatch data* containing *bids* and *offers* in addition to any *dispatch data* parameter reference levels that were applied as a result of a failure of the market power mitigation price impact test in pre-dispatch. This *dispatch data* will continue to include *price-quantity pairs* and ramp rates for dispatchable resources. In addition to the common set of *dispatch* data parameters, non-quick start (NQS) and hydroelectric resources will have more parameters specific to their operational characteristics. For combined cycle *facilities* that are eligible and have elected to be represented as a *pseudo-unit* (PSU) resource, additional inputs will be used to relate the physical unit and PSU schedules. Refer to the Offer, Bids and Dispatch Data detailed design document for details.

For NQS resources, the RT calculation engine will respect the operational commitments determined by the DAM and PD calculation engines.

Five-minute *demand* forecasts will continue to be used as an input for the expected load in the RT calculation engine. However, the *IESO* will now produce the existing province-wide *demand* forecast as the sum of four separate *demand* forecast areas.

2.2.2. The Dispatch Algorithm

Many future processes for RT scheduling and *dispatch* will stay consistent with the current process. For example, *energy* and *operating reserve* resources will continue to be scheduled using joint optimization.

Some enhancements will be made to enable:

- PSU scheduling and *dispatch*; and
- incorporation of new *dispatch data* parameters.

The following provides a description of the steps included in the Real-Time Scheduling and Pricing pass:

- Real-Time Scheduling: Determines *dispatch* and advisory schedules for all resources. This is accomplished by performing an economic *dispatch* that considers resource and system constraints to maximize the gains from trade. It uses the *dispatch data* set consistent with the previous hour's pre-dispatch. This set will include *market participant bids* and *offers*, in addition to any reference levels that were applied as a result of a failure of the market power mitigation price impact test in pre-dispatch. *IESO* inputs, including the constraint violation penalty curves for meeting the *IESO's reliability* requirements, are also used.
- Real-Time Pricing: Uses the same *dispatch data* and the set of *IESO* inputs from Real-Time Scheduling with one exception. Real-Time Pricing uses the constraint violation penalty curves that are relevant for pricing, instead of the constraint violation penalty curves for *reliability*. Real-Time Pricing also uses the principle for price-setting eligibility[3] to determine *settlement*-ready LMPs again accounting for resource and system constraints.

Marginal loss factors for each *dispatch hour* will be calculated in the hour preceding the *dispatch hour.* These marginal loss factors will then be held fixed for each

[3] The marginal price at each location is set by the *offer* or *bid* that is able to supply the next increment of *demand* at that locale. Resources are able to meet that *demand* when they can be scheduled without restriction due to a system constraint or an operational constraint of a resource.

interval in that *dispatch hour.* The same set of fixed marginal loss factors will be used for calculating schedules and prices.

2.2.3. Outputs from the RT Calculation Engine

2.2.3.1. Dispatch Instructions

The RT calculation engine will continue to determine the real-time constrained *dispatch* schedule for the next five-minute interval. This is the basis of *dispatch instructions* that will continue to be sent to all dispatchable resources.

For combined cycle *facilities* electing to be modelled as PSUs, the PSU *dispatch* will be translated into physical unit *dispatch instructions* based on the proportional relationship between the combustion turbine (CT) and steam turbine (ST). *Market participants* will continue to receive the *dispatch instruction* for the CT and the ST on their *dispatch workstation*. The PSU *dispatch* will be provided for informational purposes to assess scheduling outcomes.

2.2.3.2. Real-Time Prices

The RT calculation engine will determine *energy* and *operating reserve* LMPs, which will account for resource and system constraints. Real-time prices will continue to be no greater than $2,000/MWh for *energy* and $2,000/MW for *operating reserve*. *Energy* and *operating reserve* prices will be no less than -$100/MWh and $0/MW respectively.

The LMPs calculated for the *dispatch interval* will be used for the *settlement* of the *energy market* and the *operating reserve market* while the LMPs calculated for advisory intervals will be informational.

The RT calculation engine will determine prices ex-ante. Under ex-ante pricing, both the *dispatch* scheduling and the pricing algorithms will run prior to the *dispatch interval* and will use the same set of inputs, including the Ontario *demand* forecast. The *IESO* will continue to use Richview TS as the *energy* reference location.

The schedules and LMPs produced by the RT calculation engine are utilized by the *settlement* process to determine *settlement* outcomes for suppliers, *dispatchable loads*, price responsive loads (LMPs only) and exports. Real-time LMPs from all load types are used in the calculation of zonal prices for the *settlement* of virtual transactions.

Real-time LMPs for *non-dispatchable loads* are used in the calculation of the Load Forecast Deviation Charge (LFDC)of the hourly DAM Ontario Zonal Price. The RT Ontario Zonal Price will be produced for informational purposes.

The future market will introduce dynamic *intertie settlement* pricing in real time. *Intertie settlement* in real time will depend on the whether the *intertie* was export-congested, import-congested, or congestion-free in the final run of pre-dispatch.

If an *intertie* is export-congested, the *intertie settlement* price will be the sum of the real-time *intertie* border price and the pre-dispatch *intertie congestion price*. If an *intertie* is import-congested, the *intertie settlement* price will be the lesser of the pre-dispatch *intertie* price and the real-time *intertie* border price. In instances where the *intertie* is congestion free, the *intertie settlement* price will be equal to the real-time *intertie* border price.

For more information on how the RT schedules and RT LMPs pertain to *settlement* outcomes, refer to the Market Settlement detailed design document.

Finally, the Publishing and Reporting Market Information process will produce a number of public, *market participant* confidential and internal *IESO* reports on the *dispatch day* resulting from the RT calculation engine. Refer to the Publishing and Reporting Market Information detailed design document for details.

Figure 2-2 provides a high-level overview of the future RT Calculation Engine process.

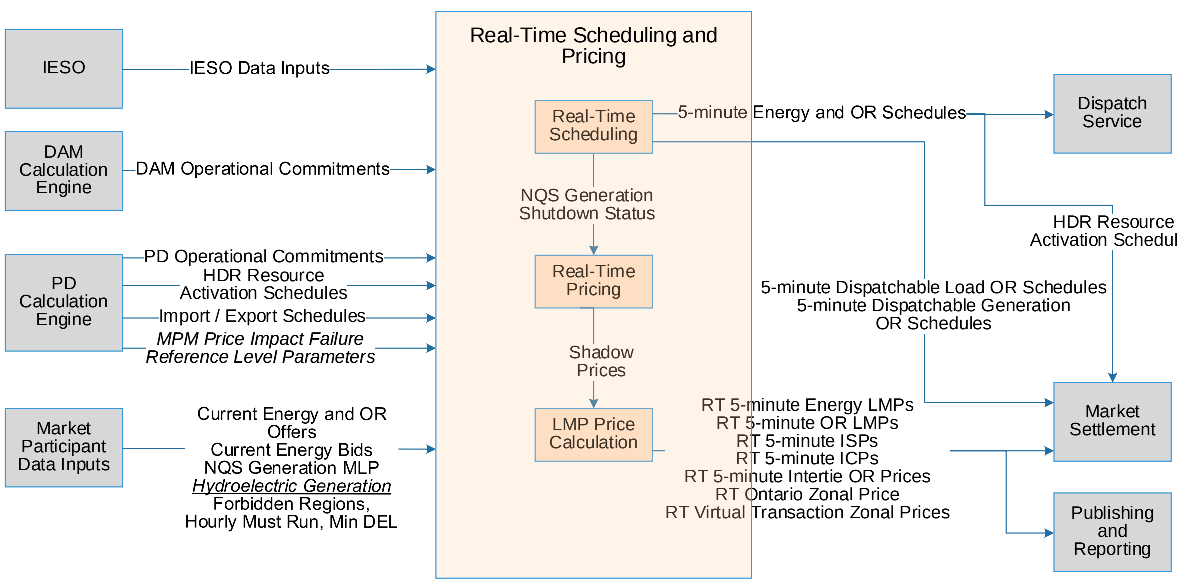

Figure 2-2: Future RT Calculation Engine Process

– End of Section –

3. Detailed Functional Design

3.1. Structure of this Section

For the purposes of this document, schedules and prices for a 'resource' refer to schedules and prices for a resource within a *generation* or *dispatchable load facility* for a *registered market participant*.

The design of the RT calculation engine will be described in terms of:

- Objectives
- RT Calculation Engine Functions
- Inputs into the RT Calculation Engine
- Initialization
- Pass 1: Real-Time Scheduling and Pricing
    - Real-Time Scheduling
    - Real-Time Pricing
- Security Assessment Function
- Pricing Formulas
- Data Generation for Settlement Mitigation
- The Pseudo-Unit Model
- Determination of the Non-Dispatchable Load Forecast

3.2. Objectives

The objective of this detailed functional design is to define the RT calculation engine functions in terms of the scheduling and pricing algorithms used to maximize the gains from trade for *energy* and *operating reserve* while providing for the necessary *reliability* and *security* of the *IESO-controlled grid*.

The high-level designs for MRP identify several objectives for the Ontario *real-time market* for *energy* and *operating reserve*. These objectives, when achieved, will provide improvements to the overall *IESO-administered markets* including providing nodal and zonal prices that are closely aligned to the *demand*, system conditions and *dispatch* in real time. These locational prices will provide more accurate pricing signals and result in improved incentives for *market participants* to submit *offers* at marginal cost.

3.3. RT Calculation Engine Functions

Real-time *dispatch* and pricing in the future *real-time market* will be driven by a RT calculation engine composed of a single pass, Real-Time Scheduling and Pricing, that calculates both *dispatch* schedules and LMPs.

The RT calculation engine will perform multi-interval optimization to plan real-time *dispatch* for the next 11 five-minute intervals. In each set of 11 five-minute intervals, the first interval is the *dispatch interval* and the remaining intervals are advisory intervals.

The optimization will be performed over multiple intervals so resources can be scheduled in advance of actual requirements. For example, ramp capability can be used to solve for anticipated changes in operating conditions and therefore help prevent unresolvable *security* violations from manifesting in real time. Multi-interval optimization provides the *IESO* and *market participants* an indication of the expected operations throughout the next hour. The schedules calculated for the *dispatch interval* will be used to form the *dispatch instructions* issued to *market participants*.

The RT calculation engine will respect the operational commitments determined by the DAM and PD calculation engines for NQS resources. When an operational commitment expires, the RT calculation engine will evaluate the resource according to the economics of its *energy* offers to determine if the resource is to be shut down. *Intertie* schedules will be fixed for each interval of the multi-interval optimization according to the schedules calculated by the *pre-dispatch scheduling* processes and established as per the *intertie* check-out procedure. These schedules will be fixed within an hour and ramping between these schedules will be performed in the interval preceding and interval succeeding the top of the hour. *Dispatch* schedules for *hourly demand response* resources are also determined during the *pre-dispatch scheduling* processes and are fixed within an hour.

A scheduling algorithm will calculate resource schedules to meet *demand*. It will perform a *security*-constrained economic *dispatch* of available resources. This will be achieved by performing multiple iterations between an optimization function and a *security* assessment function. The multiple iterations will be carried out as follows:

1. The optimization function will determine the optimal economic scheduling of available resources. To do this, the optimization function will consider inputs from *market participants* and the *IESO* taking into account resource and system constraints.
2. Each time the optimization function determines resource schedules, the *security* assessment function will assess the *security* of the resulting constrained *dispatch* by considering transmission and operating limits. If the

security assessment function identifies limit violations, an updated *security* constraint set will be provided to the optimization function, and another iteration will be performed.

3. The scheduling algorithm will conclude when the *security* assessment function does not identify any additional *security* limits for the optimization function to enforce.

A pricing algorithm will calculate location marginal prices (LMPs). It will primarily use the same set of *market participant* inputs, *IESO* inputs and resource and system constraints as the scheduling algorithm. It will determine *settlement*-ready LMPs by performing a *security*-constrained economic *dispatch* allowing an *offer* or *bid* lamination to set price in accordance with the principle for price-setting eligibility.

Similar to the scheduling algorithm, the pricing algorithm will perform multiple iterations between an optimization function and a *security* assessment function. The pricing algorithm will use the same *security* assessment function that is used in the scheduling algorithm. However, the optimization function will be modified to:

- use the constraint violation penalty curves for determining *market prices*;
- schedule an NQS resource at or above its *minimum loading point* only in intervals the scheduling algorithm scheduled the NQS resource at or above its *minimum loading point*;
- use resource initial schedules that account for the scheduling algorithm initial schedules as well as the pricing algorithm results from the preceding RT calculation engine run so as to facilitate calculating *settlement*-ready prices under constraint violations and certain control actions;
- use fixed *intertie* schedules that reflect the pricing algorithm results from the preceding PD calculation engine run; and
- use adjusted *demand* to produce prices when load shedding or voltage reduction have been implemented.

The adjusted *demand* or *intertie* schedules will also be reflected in the *security* assessment function.

The RT calculation engine will use the *security* assessment function in the scheduling and pricing algorithms to perform the following calculations and analyses, and provide inputs to the subsequent iteration of the optimization function.

1. Base case power flow: A base case (also known as pre-contingency) power flow will be prepared and solved for each interval. The base case solution will use the resource schedules produced by the optimization function along with network model data supplemented with data determined by the *IESO's*

energy management system (EMS) based on RT telemetry, planned transmission *outages*, and confirmed breaker synchronization time of NQS resources.

2. Pre-contingency security assessment: Continuous thermal limits for all monitored equipment and operating *security* limits (OSLs) will be assessed using the base case solution for pre-contingency limit violations. Violated limits will be linearized and incorporated as constraints for use by the subsequent iteration of the optimization function.
3. Loss calculation: The base case solution will calculate the loss adjustment used in the *energy* balance constraint of the optimization function. Unlike in the DAM and PD calculation engines, the marginal loss factors will not be updated by the security assessment function. Rather, fixed marginal loss factors will be used for all intervals within the same *dispatch hour*.
4. Contingency analysis: A linear power flow will be used to simulate all valid contingencies, calculate post-contingency flows and check for limited-time (i.e. emergency) thermal limit violations. Violated limits will be linearized and incorporated as constraints for use by the subsequent iteration of the optimization function.

The inputs to the RT calculation engine are described in Section 3.4. Section 3.5 describes the initialization processes that the RT calculation engine will perform before the execution of its pass. Section 3.5.4 provides mathematical formulations of the optimization function for the scheduling and pricing algorithms. A description of the *security* assessment function common to the scheduling and pricing algorithms is provided in Section 3.7.

3.4. Inputs into the RT Calculation Engine

The RT calculation engine requires inputs into the optimization function and the *security* assessment function. The inputs for each function and their notations are described in the following sections.

For more information on the nomenclature used for the variables and the mathematical symbols used in the notations, refer to Appendix D.

3.4.1. Inputs into the Optimization Function

The optimization function requires:

- *Market participant* inputs: This set will include *market participant bids* and *offers*, in addition to reference levels that were applied as a result of a failure of the market power mitigation price impact test in pre-dispatch;
- Inputs provided by the *IESO*; and
- The *security* constraint sets and loss adjustment provided by the *security* assessment function.

The optimization function for the pricing algorithm requires the results of the scheduling algorithm execution. These inputs will be specified at the outset of the pricing algorithm optimization function formulation.

3.4.1.1. Multi-Interval Optimization Look-Ahead Period

The RT calculation engine determines resource schedules for the *dispatch interval* and advisory intervals as described in Section 3.3. The intervals considered within one run of the RT calculation engine will be together referred to as the MIO look-ahead period. The MIO look-ahead period will typically be comprised of one *dispatch interval* and 10 advisory intervals, where:

- n_I shall designate the number of five-minute intervals considered within the multi-interval optimization; and
- $I = \{1,..,n_I\}$ shall designate the set of all intervals.

3.4.1.2. Fundamental Sets and Location Identifiers

For the purpose of describing the RT Calculation Engine processes and the constraints used by these processes, each internal resource scheduled by the optimization function will be identified by a unique bus, where:

- B shall designate the set of buses within Ontario, corresponding to internal resources scheduled at locations on the *IESO-controlled grid*.

If more than one internal resource is connected to the *IESO-controlled grid* at the same electrical location, they will be considered to be at separate buses for the purposes of the optimization function.

Imports scheduled from and exports scheduled to each of the *IESO intertie zones* will be fixed in the RT calculation engine and will be modelled as though they are occurring at a proxy location. Imports shall be modelled as though they are generation emanating from sources at the proxy location. Exports shall be modelled as though they are loads occurring at sinks at the proxy location. The *IESO* shall define a number of source and sink buses in the *intertie zones* to be used by imports and exports. The electrical location of these source and sink buses will be identical for all *intertie* transactions at the same proxy location. However, transactions at the same proxy location but specified as occurring at different *intertie zones*, subject to phase shifter operation, will be modelled as flowing across independent paths.

Each import will be identified by a unique *intertie zone* source bus and each export will be identified by a unique *intertie zone* sink bus, where:

- A shall designate the set of all *intertie zones*;
- D shall designate the set of buses outside Ontario, corresponding to imports and exports at *intertie zones*;
- $DX \subseteq D$ shall designate the subset of buses outside Ontario that correspond to exports;
- $DI \subseteq D$ shall designate the subset of buses outside Ontario that correspond to imports;
- $D_a \subseteq D$ shall designate the set of all buses outside Ontario in *intertie zone* $a \in A$;
- $DX_a \subseteq D_a$ shall designate the subset of buses outside Ontario that correspond to exports in *intertie zone* $a \in A$; and
- $DI_a \subseteq D_a$ shall designate the subset of buses outside Ontario that correspond to imports in *intertie zone* $a \in A$.

3.4.1.3. Load Inputs

Load inputs can belong to one of the following categories:

- *Demand* forecasts prepared by the *IESO*;
- *Dispatch data* for *dispatchable loads*;
- Schedules for *hourly demand response* resources. This includes both physical *hourly demand response* resources for which a *registered wholesale meter*

and *delivery point* has been defined and virtual *hourly demand response* resources aggregated within various zones in the *distribution system*;

- Schedules for *dispatchable loads* without an active *bid* currently withdrawing from the *IESO-controlled grid*, known as no-bid load; and
- Schedules for exports of *energy* and *operating reserve* provided by exporters.

Internal load buses of a specific resource type will be denoted as follows:

- $B^{DL} \subseteq B$ shall designate the set of buses identifying *dispatchable loads*;
- $B^{HDR} \subseteq B$ shall designate the set of buses identifying *hourly demand response* resources; and
- $B^{NoBid} \subseteq B$ shall designate the set of buses identifying no-bid load.

Bid for *energy* laminations and *offer* for *operating reserve* laminations at a *dispatchable load* bus will be denoted as follows:

- $J^{E}_{i,b}$ shall designate the set of *bid* for *energy* laminations at bus $b \in B^{DL}$ for interval $i \in I$;
- $J^{10S}_{i,b}$ shall designate the set of synchronized *ten-minute operating reserve offer* laminations at bus $b \in B^{DL}$ for interval $i \in I$;
- $J^{10N}_{i,b}$ shall designate the set of non-synchronized *ten-minute operating reserve offer* laminations at bus $b \in B^{DL}$ for interval $i \in I$; and
- $J^{30R}_{i,b}$ shall designate the set of *thirty-minute operating reserve offer* laminations at bus $b \in B^{DL}$ for interval $i \in I$.

Demand Forecasts

The *IESO* shall prepare five-minute *demand* forecasts that are representative of transmission losses and forecast consumption of all *load facilities* and *hourly demand response* resources. These *demand* forecasts will be produced for each of the *IESO demand* forecast areas[4] and for each interval in the MIO look-ahead period. Before the optimization function uses these forecasts, they will be adjusted as described in Section 3.11 to arrive at a quantity that is representative of load that is considered non-dispatchable and inclusive of losses where:

- FL_i shall designate the five-minute province-wide non-dispatchable *demand* forecast for interval $i \in I$.

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[4] In the future *real-time market,* the *IESO* will produce the province-wide *demand* forecast as the sum of separate *demand* forecasts for four *demand* forecast areas. For more information on *demand* forecasts, refer to the Offers, Bids and Data Inputs detailed design document.

The distribution of forecast *demand* to load locations within each forecast area is performed in the *security* assessment function. See Section 3.7.1.3 for more detail.

When the *IESO* receives or provides Simultaneous Activation of Reserve (SAR) *energy*, the *demand* forecast will be adjusted in the same way for both determining schedules in the scheduling algorithm and calculating *market prices* in the pricing algorithm. See the Grid and Market Operations Integration detailed design document for more information about SAR.

Dispatch Data for Dispatchable Loads

Registered market participants representing *dispatchable loads* may submit a *bid* to consume *energy*, *offers* to provide *operating reserve* and affiliated ramp rates. At most 20 *price-quantity pairs* corresponding to 19 laminations may be submitted in the *bid* to consume *energy*. At most five *price-quantity pairs* corresponding to four laminations may be submitted for each class of *operating reserve* the *dispatchable load* is qualified to provide. The non-dispatchable portion of a *dispatchable load*, i.e. the quantity of *energy* that is *bid* at $MMCP$, must always be scheduled.

Table 3-1 lists the parameters for *dispatch data* submitted for a *dispatchable load* identified by bus $b \in B^{DL}$.

Table 3-1: Parameters for Dispatch Data Submitted for Dispatchable Loads

Parameter	Description
$QDL_{i,b,j}$	shall designate an incremental quantity of *energy* consumption that may be scheduled in interval $i \in I$ in association with bid lamination $j \in J^{E}_{i,b}$.
$PDL_{i,b,j}$	shall designate the *bid* price to consume an incremental quantity of *energy* in interval $i \in I$ in association with *bid* lamination $j \in J^{E}_{i,b}$. The *bid* price indicates the lowest *energy* price at which the *dispatchable load* prefers to forgo *energy* consumption.
$Q10SDL_{i,b,j}$	shall designate the synchronized *ten-minute operating reserve* quantity that may be scheduled in interval $i \in I$ in association with *offer* lamination $j \in J^{10S}_{i,b}$.
$P10SDL_{i,b,j}$	shall designate the price of being scheduled to provide synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $j \in J^{10S}_{i,b}$.
$Q10NDL_{i,b,j}$	shall designate the non-synchronized *ten-minute operating reserve* quantity that may be scheduled in interval $i \in I$ in association with *offer* lamination $j \in J^{10N}_{i,b}$.

Parameter	Description
$P10NDL_{i,b,j}$	shall designate the price of being scheduled to provide non-synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{10N}$.
$Q30RDL_{i,b,j}$	shall designate the *thirty-minute operating reserve* quantity that may be scheduled in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{30R}$.
$P30RDL_{i,b,j}$	shall designate the price of being scheduled to provide *thirty-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $j \in J_{i,b}^{30R}$.
$ORRDL_b$	shall designate the *operating reserve* ramp rate in MW per minute for reductions in load consumption.
$NumRRDL_{i,b}$	shall designate the number of ramp rates provided for interval $i \in I$.
$RmpRngMaxDL_{i,b,w}$ for $w \in \{1,..,NumRRDL_{i,b}\}$	shall designate the wth ramp rate break point for interval $i \in I$. For notational convenience, $RmpRngMaxDL_{i,b,0}$ shall also be defined and will be equal to zero.
$URRDL_{i,b,w}$ for $w \in \{1,..,NumRRDL_{i,b}\}$	shall designate the maximum rate in MW per minute at which the *dispatchable load* can increase its amount of *energy* consumption in interval $i \in I$ while operating in the range between $RmpRngMaxDL_{i,b,w-1}$ and $RmpRngMaxDL_{i,b,w}$.
$DRRDL_{i,b,w}$ for $w \in \{1,..,NumRRDL_{i,b}\}$	shall designate the maximum rate in MW per minute at which the *dispatchable load* can decrease its amount of *energy* consumption in interval $i \in I$ while operating in the range between $RmpRngMaxDL_{i,b,w-1}$ and $RmpRngMaxDL_{i,b,w}$.
$QDLFIRM_{i,b}$	shall designate the quantity of *energy* that is *bid* at *MMCP* in interval $i \in I$.

The RT calculation engine will respect the *energy* ramping constraints determined by the submitted MW quantity (up to five), ramp up rate and ramp down rate value sets described above. The optimization function formulations provided in this document assume one ramp up rate ($URRDL_b$ for $b \in B^{DL}$) and one ramp down rate ($DRRDL_b$ for $b \in B^{DL}$) apply across the entire operating range of a *dispatchable load*. For more information, see the *energy* ramping constraints in Section 3.6.1.5.

Schedules for Hourly Demand Response Resources

Schedules for physical and virtual *hourly demand response* resources with active *bids* will be fixed within the RT calculation engine. These fixed schedules are calculated by the *pre-dispatch scheduling* run three hours prior to the *dispatch hour*. Virtual *hourly demand response* resource schedules will be identified with a proxy bus. The electrical location of this proxy bus depends only on the zone in which the virtual *hourly demand response* resource has submitted a *bid*. For a physical or virtual *hourly demand response* resource with an active *bid* identified by bus $b \in {}^{HDR}$:

- $FHDR_{i,b}$ shall designate the fixed schedule of *energy* consumption for interval $i \in I$.

A physical or virtual *hourly demand response* resource without an active *bid* is accounted for in the *demand* forecast.

No-Bid Dispatchable Load Schedules

In circumstances when a *dispatchable load* without an active *bid* is observed through the EMS to be withdrawing *energy* from the *IESO-controlled grid*, the optimization function will assign a fixed schedule to this resource as determined by the EMS based on telemetry. This treatment will support the ability of a *dispatchable load* to designate its entire consumption as non-dispatchable by not submitting an active *bid*. For a no-bid load identified by bus $b \in B^{NoBid}$:

- $FNBL_{i,b}$ shall designate the fixed quantity of *energy* scheduled for withdrawal at bus b for interval $i \in I$.

Export Schedules

The schedules for export transactions will be fixed within the scheduling algorithm. The fixed schedules used are first calculated by the *pre-dispatch scheduling* processes and established as per the *intertie* check-out procedure. Ramping between the hourly *pre-dispatch schedules* is performed in the interval preceding and interval succeeding the top of the hour. These established schedules may be modified in real time to reflect *intertie* curtailment performed for adequacy or *security* reasons and unplanned *intertie* outages. For an *intertie zone* sink bus $d \in DX$:

- $FXLSch_{i,d}$ shall designate the fixed quantity of *energy* scheduled for export to bus d for interval $i \in I$ used for determining schedules;
- $F10NXLSch_{i,d}$ shall designate the fixed quantity of non-synchronized *ten-minute operating reserve* scheduled from the exporter at bus d in interval $i \in I$ used for determining schedules; and

- $F30RXLSch_{i,d}$ shall designate the fixed quantity of *thirty-minute operating reserve* scheduled from the exporter at bus d in interval $i \in I$ used for determining schedules.

These fixed schedules may include but are not limited to emergency sales or inadvertent payback transactions.

The schedules for export transactions will also be fixed within the pricing algorithm. They will be derived from the pricing algorithm results of the PD calculation engine run determining binding *intertie* schedules for the *dispatch hour*. For an *intertie zone* sink bus $d \in DX$:

- $FXLPrc_{i,d}$ shall designate the fixed quantity of *energy* scheduled for export to bus d for interval $i \in I$ used for calculating *market prices*;
- $F10NXLPrc_{i,d}$ shall designate the fixed quantity of non-synchronized *ten-minute operating reserve* scheduled from the exporter at bus d in interval $i \in I$ used for calculating *market prices*; and
- $F30RXLPrc_{i,d}$ shall designate the fixed quantity of *thirty-minute operating reserve* scheduled from the exporter at bus d in interval $i \in I$ used for calculating *market prices*.

3.4.1.4. Supply Inputs

Supply inputs can belong to one of the following categories:

- *Dispatch data* for *self-scheduling generation facilities*, *transitional scheduling generators* and *intermittent generators*, known as non-dispatchable *generation facilities*;
- *Dispatch data* for dispatchable *generation facilities*;
- Schedules for generation without an active *offer* currently injecting into the *IESO-controlled grid*, known as no-offer generation; and
- Schedules for *energy* and *operating reserve* provided by importers.

Internal supply buses of a specific type will be denoted as follows:

- $B^{NDG} \subseteq B$ shall designate the set of buses identifying non-dispatchable generation resources;
- $B^{DG} \subseteq B$ shall designate the set of buses identifying dispatchable generation resources. Dispatchable generation resources can be further categorized by resource type as described in the Dispatch Data for Dispatchable Generation Facilities sub-section in this section; and
- $B^{NoOffer} \subseteq B$ shall designate the set of buses identifying no-offer generation.

Offer for *energy* laminations and *offer* for *operating reserve* laminations at a supply bus will be denoted as follows:

- $K^{E}_{i,b}$ shall designate the set of *offer* for *energy* laminations for $b \in B^{NDG} \cup B^{DG}$ for interval $i \in I$;
- $K^{10S}_{i,b}$ shall designate the set of synchronized *ten-minute operating reserve offer* laminations at bus $b \in B^{DG}$ for interval $i \in I$;
- $K^{10N}_{i,b}$ shall designate the set of non-synchronized *ten-minute operating reserve offer* laminations at bus $b \in B^{DG}$ for interval $i \in I$; and
- $K^{30R}_{i,b}$ shall designate the set of *thirty-minute operating reserve offer* laminations at bus $b \in B^{DG}$ for interval $i \in I$.

Dispatch Data for Non-Dispatchable Generation Facilities

The RT calculation engine takes into account the forecast output from non-dispatchable generation resources. The *registered market participants* of *self-scheduling generation facilities*, *transitional scheduling generators* and *intermittent generators* will provide *dispatch data* on forecast production and the lowest price at which they wish to be scheduled. The forecast production and price will be treated as an offer for *energy* with a single lamination. For a non-dispatchable generation resource identified by bus $b \in B^{NDG}$:

- $QNDG_{i,b,k}$ shall designate the incremental quantity of *energy* generation that may be scheduled in interval $i \in I$ in association with *offer* lamination $k \in K^{E}_{i,b}$; and
- $PNDG_{i,b,k}$ shall designate the *offered energy* price for incremental generation in interval $i \in I$ in association with *offer* lamination $k \in K^{E}_{i,b}$. The *offered* price indicates the lowest price at which the non-dispatchable generation resource is willing to be scheduled.

The observed output of a *self-scheduling generation facility* as determined by the EMS based on telemetry will be used to determine a fixed schedule across the MIO look-ahead period in respect of the *offer* quantity provided by the *facility*, where:

- $FNDG_{i,b}$ shall designate the fixed schedule for the non-dispatchable generation resource at bus $b \in B^{NDG}$ for interval $i \in I$.

Dispatch Data for Dispatchable Generation Facilities

Registered market participants representing dispatchable *generation facilities* may submit *offers* to supply *energy*, *offers* to provide *operating reserve* and other affiliated *dispatch data*. A maximum of 20 *price-quantity pairs* corresponding to 19 laminations may be submitted in the *offer* to produce *energy*. A maximum of five *price-quantity pairs* corresponding to four laminations may be submitted for each class of *operating reserve* a resource is qualified to provide. Depending on the *facility* type, *market participants* may submit additional *dispatch data*. The RT calculation engine evaluates the additional *dispatch data* submitted differently than the DAM and PD calculation engines because the RT calculation engine considers a rolling 60-minute look-ahead period.

Table 3-2 lists the parameters for *dispatch data* submitted for a dispatchable generation resource identified by bus $b \in B^{DG}$. These inputs are common to all dispatchable *generation facilities.*

Table 3-2: Parameters for Dispatch Data Submitted for Dispatchable Generation

Parameter	Description
$QDG_{i,b,k}$	shall designate an incremental quantity of *energy* that may be scheduled in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{E}$.
$PDG_{i,b,k}$	shall designate the *offered energy* price for incremental generation in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{E}$. The *offered* price indicates the lowest *energy* price at which the resource is willing to be scheduled.
$Q10SDG_{i,b,k}$	shall designate the *offered* quantity of synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10S}$.
$P10SDG_{i,b,k}$	shall designate the *offered* price of being scheduled to provide synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10S}$.
$Q10NDG_{i,b,k}$	shall designate the *offered* quantity of non-synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10N}$.
$P10\mathrm{N}DG_{i,b,k}$	shall designate the *offered* price of being scheduled to provide non-synchronized *ten-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{10N}$.
$Q30RDG_{i,b,k}$	shall designate the *offered* quantity of *thirty-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{30R}$.
$P30RDG_{i,b,k}$	shall designate the *offered* price of being scheduled to provide *thirty-minute operating reserve* in interval $i \in I$ in association with *offer* lamination $k \in K_{i,b}^{30R}$.
$ORRDG_b$	shall designate the maximum *operating reserve* ramp rate in MW per minute.

Parameter	Description
$NumRRDG_{i,b}$	shall designate the number of ramp rates provided for interval $i \in I$.
$RmpRngMaxDG_{i,b,w}$ for w $\in$ $\{1,..,NumRRDG_{i,b}\}$	shall designate the w[th] ramp rate break point for interval $i \in I$. For notational convenience, $RmpRngMaxDG_{i,b,0}$ shall also be defined and will be equal to zero.
$URRDG_{i,b,w}$ for $w \in$ $\{1,..,NumRRDG_{i,b}\}$	shall designate the maximum rate in MW per minute at which the resource can increase the amount of *energy* it supplies in interval $i \in I$ while operating in the range between $RmpRngMaxDG_{i,b,w\text{-}1}$ and $RmpRngMaxDG_{i,b,w}$.
$DRRDG_{i,b,w}$ for $w \in$ $\{1,..,NumRRDG_{i,b}\}$	shall designate the maximum rate in MW per minute at which the resource can decrease the amount of *energy* it supplies in interval $i \in I$ while operating in the range between $RmpRngMaxDG_{i,b,w\text{-}1}$ and $RmpRngMaxDG_{i,b,w}$.
$RLP30R_{i,b}$	shall designate the reserve loading point for *thirty-minute operating reserve* in interval $i \in I$ indicating the minimum output level at which the resource can provide its full *thirty-minute operating reserve* amount.
$RLP10S_{i,b}$	shall designate the reserve loading point for synchronized *ten-minute operating reserve* in interval $i \in I$ indicating the minimum output level at which the resource can provide its full synchronized *ten-minute operating reserve* amount.

The RT calculation engine will respect the *energy* ramping constraints determined by the submitted MW quantity (up to five), ramp up rate and ramp down rate value sets described above. The optimization function formulations provided in this document assume one ramp up rate ($URRDG_b$ for $b \in B^{DG}$) and one ramp down rate ($DRRDG_b$ for $b \in B^{DG}$) apply across the entire operating range of a *dispatchable* generation resource. For more information, see the *energy* ramping constraints in Section 3.6.1.5.

In addition to the above inputs that are common to all dispatchable generation resources, the RT calculation engine will evaluate additional inputs for the following generation resource types to further enable accurate representation of their operating characteristics:

- NQS resources: *minimum loading point*;
- PSU resources: steam turbine share of MLP region, steam turbine share of dispatchable region, indication of whether the PSU can provide *ten-minute operating reserve* while scheduled in its duct firing region;

- *Variable generation* resources: *IESO's* centralized *variable generation* forecast; and
- Hydroelectric resources: *forbidden regions*, hourly must run and minimum daily *energy* limit.

Buses identifying resources of these types will be denoted as follows:

- $B^{NQS} \subseteq B^{DG}$ shall designate the subset of buses identifying NQS resources;
- $B^{PSU} \subseteq B^{NQS}$ shall designate the subset of buses identifying PSU resources;
- $B^{VG} \subseteq B^{DG}$ shall designate the subset of buses identifying *variable generation* resources; and
- $B^{HE} \subseteq B^{DG}$ shall designate the subset of buses identifying hydroelectric resources.

The following sub-sections provide further detail on the notations that will be used to represent the operational characteristics that are specific to each generation resource type.

NQS Resources

Table 3-3 lists the parameters for *dispatch data* submitted for an NQS resource identified by bus $b \in B^{NQS}$.

Table 3-3: Parameters for Dispatch Data Submitted for NQS Resources

Parameter	Description
$MinQDG_b$	shall designate the *minimum loading point* indicating the minimum output at which the resource must be scheduled except for times when the resource is starting up or shutting down.

PSU Resources

For combined cycle *facilities* that have elected and are eligible to be represented as a PSU resource, additional inputs are required to reflect the physical unit loading as a function of the PSU schedules. For more information about how the PSU model is derived from registration parameters and submitted *dispatch data* parameters, see Section 3.10. Table 3-4 lists the parameters for *dispatch data* submitted for a PSU resource identified by bus $b \in B^{PSU}$.

Table 3-4: Parameters for Dispatch Data Submitted for PSU Resources

Parameter	Description
$K_{i,b}^{MLP} \subseteq K_{i,b}^{E}$	shall designate the *energy offer* laminations corresponding to the MLP region of the *pseudo-unit* in interval $i \in I$.
$K_{i,b}^{DR} \subseteq K_{i,b}^{E}$	shall designate the *energy offer* laminations corresponding to the dispatchable region of the *pseudo-unit* in interval $i \in I$.
$K_{i,b}^{DF} \subseteq K_{i,b}^{E}$	shall designate the *energy offer* laminations corresponding to the duct firing region of the *pseudo-unit* in interval $i \in I$.
$STShareMLP_b$	shall designate the steam turbine share of the MLP region.
$STShareDR_b$	shall designate the steam turbine share of the dispatchable region.

To calculate the loading on a specific steam turbine, the combined cycle *facility* must identify the PSU resources sharing a steam turbine, where:

- PST shall designate the set of steam turbines being *offered* as part of a PSU; and
- $B_p^{ST} \subseteq B^{PSU}$ shall designate the subset of buses identifying PSU resources with a share of steam turbine $p \in PST$.

At the time of registration, a combined cycle *facility* will indicate using a flag that a PSU resource may not provide *ten-minute operating reserve* from its duct firing region, where:

- $B^{NO10DF} \subseteq B^{PSU}$ shall designate the subset of buses identifying a PSU resource that cannot provide *ten-minute operating reserve* from its duct firing region.

Variable Generation Resources

For each *registered facility* supplying *variable generation*, the *IESO* will continue to provide production forecasts for all intervals of the MIO look-ahead period. For the *variable generation* resource at bus $b \in B^{VG}$:

- $FG_{i,b}$ shall designate the forecast for interval $i \in I$.

Hydroelectric Resources

Table 3-5 lists the parameters for *dispatch data* submitted for a hydroelectric resource identified by bus $b \in B^{HE}$.

Table 3-5: Parameters for Dispatch Data Submitted for Hydroelectric Resources

Parameter	Description
$(ForL_{i,b,w}, ForU_{i,b,w})$ for $w \in \{1,..,NFor_{i,b}\}$	shall designate the lower and upper limits of the resource's *forbidden regions* in interval $i \in I$ indicating that the resource cannot stably operate between $ForL_{i,b,w}$ and $ForU_{i,b,w}$ for all $w \in \{1,..,NFor_{i,b}\}$ and must be ramped through this region at its maximum offered ramp capability.

A resource minimum constraint will be used by the RT calculation engine to enforce the hourly must run *dispatch data* parameter. A resource minimum constraint will also be used to respect the minimum daily *energy* limit *dispatch data* parameter if the preceding PD calculation engine run determines this constraint to be binding for a resource across the *dispatch day*. See Section 3.4.1.5 for more information on resource minimum constraints.

No-Offer Generation Schedules

In circumstances when a generation resource without an active *offer* is observed through the EMS to be injecting into the *IESO-controlled grid*, the RT calculation engine will schedule this resource as required by the *IESO* to enable system *reliability*. For no-offer generation identified by bus $b \in B^{NoOffer}$:

- $FNOG_{i,b}$ shall designate the fixed quantity of *energy* scheduled for injection at bus b for interval $i \in I$.

Import Schedules

The schedules for import transactions will be fixed within the scheduling algorithm. The fixed schedules used are first calculated by the *pre-dispatch scheduling* processes and established as per the *intertie* check-out procedure. Ramping between the hourly *pre-dispatch schedules* is performed in the interval preceding and interval succeeding the top of the hour. These established schedules may be modified in real time to reflect *intertie* curtailment performed for adequacy or *security* reasons and unplanned *intertie* outages. For an *intertie zone* source bus $d \in DI$:

- $FIGSch_{i,d}$ shall designate the fixed quantity of *energy* scheduled for import from bus d for interval $i \in I$ used for determining schedules;
- $F10NIGSch_{i,d}$ shall designate the fixed quantity of non-synchronized *ten-minute operating reserve* scheduled from the importer at bus d in interval $i \in I$ used for determining schedules; and

- $F30RIGSch_{i,d}$ shall designate the fixed quantity of *thirty-minute operating reserve* scheduled from the importer at bus d in interval $i \in I$ used for determining schedules.

These fixed schedules may include *emergency* purchases or inadvertent payback transactions.

The schedules for import transactions will also be fixed within the pricing algorithm. They will be derived from the pricing algorithm results of the PD calculation engine run determining binding *intertie* schedules for the *dispatch hour*. For an *intertie zone* source bus $d \in DI$:

- $FIGPrc_{i,d}$ shall designate the fixed quantity of *energy* scheduled for import from bus d for interval $i \in I$ used for calculating *market prices*;
- $F10NIGPrc_{i,d}$ shall designate the fixed quantity of non-synchronized *ten-minute operating reserve* scheduled from the importer at bus d in interval $i \in I$ used for calculating *market prices*; and
- $F30RIGPrc_{i,d}$ shall designate the fixed quantity of *thirty-minute operating reserve* scheduled from the importer at bus d in interval $i \in I$ used for calculating *market prices*.

Because the PD calculation engine import schedules from the scheduling and pricing algorithms are carried forward, the adjustments for *emergency* purchases that do not support a sale will persist in real time. Therefore, transactions corresponding to *emergency* purchases that do not support a sale will not be scheduled in the pricing algorithm of the RT calculation engine even though they are scheduled in the scheduling algorithm.

3.4.1.5. Additional IESO Data Inputs

This sub-section describes the additional inputs that the *IESO* will provide to the RT calculation engine to enable system *reliability* when a solution is determined.

Marginal Loss Factors

Losses will be modelled in the RT calculation engine using marginal loss factors and a loss adjustment. The marginal loss factors for each interval in a given *dispatch* hour will be fixed at the same value. As described in Section 3.7.2.3, the marginal loss factors used will coincide for all intervals within the same *dispatch hour*, where:

- $MglLoss_{i,b}$ shall designate a marginal loss factor and shall reflect the marginal impact on transmission losses resulting from transmitting *energy* from the reference bus to serve an increment of additional load at resource bus $b \in B \cup D$ in interval $i \in I$. When determining marginal loss factors, the impact of local branches (e.g. load step-down transformers) between the resource bus and the resource connection point to the *IESO-controlled grid* will be excluded.

Operating Reserve Requirements

The *IESO* will input minimum *operating reserve* requirements for each interval of the MIO look-ahead period. *Operating reserve* requirements will include minimum requirements for the total amount of synchronized *ten-minute operating reserve*, the total amount of *ten-minute operating reserve* and the total amount of *thirty-minute operating reserve*. For each interval $i \in I$:

- $TOT10S_i$ shall designate the synchronized *ten-minute operating reserve* requirement;
- $TOT10R_i$ shall designate the *ten-minute operating reserve* requirement; and
- $TOT30R_i$ shall designate the *thirty-minute operating reserve* requirement, which may also include an increase to account for the flexibility *operating reserve* requirement.

In addition, the *IESO* will define several regions within Ontario that will have their own regional *operating reserve* minimum requirements and maximum restrictions. Each region shall consist of a set of buses at which *operating reserve* scheduled may be used to satisfy the minimum requirement for that region and is limited by the maximum restriction for that region, where:

- $ORREG$ shall designate the set of regions for which regional *operating reserve* limits have been defined;
- $B_r^{REG} \subseteq B$ shall designate the set of internal buses in *operating reserve* region $r \in ORREG$;
- $D_r^{REG} \subseteq D$ shall designate the set of *intertie zone* buses in *operating reserve* region $r \in ORREG$;
- $REGMin10R_{i,r}$ shall designate the minimum requirement for total *ten-minute operating reserve* in region $r \in ORREG$ in interval $i \in I$[5];
- $REGMin30R_{i,r}$ shall designate the minimum requirement for *thirty-minute* operating reserve in region $r \in ORREG$ in interval $i \in I$[6];
- $REGMax10R_{i,r}$ shall designate the maximum amount of total *ten-minute operating reserve* that may be provided in region $r \in ORREG$ in interval $i \in I$; and

[5] These minimum limits could be set at zero.

[6] These minimum limits could be set at zero.

- $REGMax30R_{i,r}$ shall designate the maximum amount of *thirty-minute operating reserve* that may be provided in region $r \in ORREG$ in interval $i \in I$.

Resource Minimum and Maximum Constraints

Dispatchable Load

The minimum and maximum consumption of a *dispatchable load* may be limited for the following reasons:

- *Operating reserve* activation: an *operating reserve* activation performed on a *dispatchable load* will limit a *dispatchable load*'s consumption for the duration of the activation; or
- *Reliability* constraints: a constraint imposed as a result of a control action may limit the minimum or maximum consumption of a *dispatchable load*.

The RT calculation engine will accordingly enforce minimum and maximum constraints on the consumption of a *dispatchable load*. For interval $i \in I$:

- $MinDL_{i,b}$ shall designate the most restrictive of the above minimum consumption limits for the *dispatchable load* at bus $b \in B^{DL}$; and
- $MaxDL_{i,b}$ shall designate the most restrictive of the above maximum consumption limits for the *dispatchable load* at bus $b \in B^{DL}$.

Dispatchable Generation Resources

The minimum and maximum output of an internal generation resource may be limited for the following reasons:

- *Reliability* constraints: The *IESO* will identify resources that must operate for *reliability* purposes. The *IESO* may, as required, place minimum or maximum constraints on these resources to support *reliability must-run contracts*, *reactive support service* contracts or other *reliability* needs, to enable the reliable operation of the system.
- *Regulation*: The *IESO* will continue to enter into contracts with *market participants* for certain dispatchable generation resources to provide *regulation*. RT *offers* must be submitted for such generation resources. A resource providing *AGC* will be scheduled to at least the more restrictive of its minimum *AGC* limit and its *minimum loading point* plus the designated *AGC* range. It will be scheduled to at most the more restrictive of its maximum *AGC* limit and its maximum offered *energy* quantity minus the designated *AGC* range. Generation resources are not allowed to supply *operating reserve* into the *real-time market* in hours where *AGC* is being provided. Therefore, the RT calculation engine will not schedule *operating reserve* from a resource in these hours. Although the RT calculation engine

will schedule *energy* from an *AGC* provider within the range described above, this schedule will not be issued as a *dispatch instruction* for *energy*. It will be used by the *AGC* function as the economic basepoint around which to raise and lower signals in response to *area control error* (*ACE*).

- DAM and PD commitments: Operational commitments for NQS resources will lead to a minimum constraint forcing the resource to its *minimum loading point* in the intervals of the commitment. See Section 3.6.1.5 for more information about how a committed resource is scheduled to ramp to its *minimum loading point* after start-up has been confirmed.
- *Outages* and De-rates: *Outages* or de-rates from the *IESO's* Outage Coordination and Scheduling System (OCSS) limit a generation resource's maximum output.
- *Operating reserve* activation: an *operating reserve* activation performed on a dispatchable generation resource will constrain the resource's output above a minimum limit for the duration of the activation.
- Hydroelectric minimum constraints: a minimum constraint will be imposed to respect hydroelectric hourly must run and minimum daily *energy* limit *dispatch data* parameters when applicable as described in the Grid and Market Operations Integration detailed design document.

The RT calculation engine will accordingly enforce minimum and maximum constraints on the output of a dispatchable internal generation resource. For interval $i \in I$:

- $MinDG_{i,b}$ shall designate the most restrictive of the above minimum output limits for the dispatchable generation resource at bus $b \in B^{DG}$; and
- $MaxDG_{i,b}$ shall designate the most restrictive of the above maximum output limits for the dispatchable generation resource at bus $b \in B^{DG}$.

PSU Resources

Within the optimization function of the RT calculation engine, most minimum and maximum limits on the output of a *pseudo-unit* (PSU) resource will be enforced in the same way minimum and maximum limits on the output of other dispatchable generation resources are enforced. However, the minimum and maximum limits may be input to the RT calculation engine on a physical unit basis and then converted to a constraint on the corresponding PSU resources before the execution of the RT calculation engine pass. Such minimum and maximum limits for the PSU resource at bus $b \in B^{PSU}$ for interval $i \in I$ will be represented by $MinDG_{i,b}$ and $MaxDG_{i,b}$ as described above. The logic to perform the conversion of physical unit limitations to PSU limitations is described in Section 3.10.3.

Special logic will apply when a de-rate is submitted on the combustion turbine. To model this logic, the dispatchable and duct firing capacity of the PSU resource will be calculated as described in Section 3.10.2.1. For interval $i \in I$ and for the PSU resource at $b \in B^{PSU}$:

- $MaxDR_{i,b}$ shall designate the maximum output limit in interval i for the dispatchable region; and
- $MaxDF_{i,b}$ shall designate the maximum output limit in interval i for the duct firing region.

Control Action Adjustments for Pricing

The RT calculation engine will require additional inputs to calculate *market prices* appropriately when control actions have been implemented.

In the case of voltage reduction or load shedding, an adjustment must be made to the *demand* scheduled by the optimization function and subsequently the *security* assessment function, where:

- $CAAdj_i$ shall designate the *demand* adjustment required to calculate *market prices* appropriately when voltage reduction or load shedding has been implemented.

For the purposes of the optimization function formulation, the convention will be that a positive value for the *demand* adjustment term reflects an increase in *demand*. For more information about control action handling, see the Grid and Market Operations detailed design document.

Constraint Violation Penalties

In some situations, the RT calculation engine might be unable to resolve all system constraints. For example, the RT calculation engine would fail to produce a solution when insufficient generation is offered to meet the forecast *demand* unless the engine is permitted to serve only a portion of the forecast *demand*. To ensure the RT calculation engine can always find a feasible solution, it will be allowed to violate certain system constraints at a cost.[7] This will be achieved via constraint violation penalty curves, which establish the value placed on satisfying a constraint and indicate the relative priority of satisfying a certain constraint compared to other constraints. The constraint violation penalty curves used by the scheduling algorithm to produce constrained schedules may differ from the constraint violation penalty curves used by the pricing algorithm to calculate *market prices* in order to produce *settlement*-ready prices.

[7] Under such conditions, system *reliability* will be maintained by *IESO* control actions.

The constraints described below will include constraint violation variables with affiliated penalty price terms appearing in the objective function. The number of violation variables required for the scheduling algorithm and pricing algorithm may differ depending on the number of segments in the applicable constraint violation penalty curve. For notational purposes, the scheduling and pricing penalty curves for each constraint will be assumed to have the same number of segments and any unneeded segments will be assigned a quantity of zero. The notation for the affiliated prices and quantities is described below.

The *energy* balance constraint may be violated for both reasons of under generation and over generation. For interval $i \in I$:

- $(PLdViolSch_{i,w}, QLdViolSch_{i,w})$ for $w \in \{1,..,N_{LdViol_i}\}$ shall designate the price-quantity segments of the penalty curve for under generation used for scheduling to meet the *IESO*'s *reliability* requirements;
- $(PLdViolPrc_{i,w}, QLdViolPrc_{i,w})$ for $w \in \{1,..,N_{LdViol_i}\}$ shall designate the price-quantity segments of the penalty curve for under generation used for calculating *market prices*;
- $(PGenViolSch_{i,w}, QGenViolSch_{i,w})$ for $w \in \{1,..,N_{GenViol_i}\}$ shall designate the price-quantity segments of the penalty curve for over generation used for scheduling to meet the *IESO*'s *reliability* requirements; and
- $(PGenViolPrc_{i,w}, QGenViolPrc_{i,w})$ for $w \in \{1,..,N_{GenViol_i}\}$ shall designate the price-quantity segments of the penalty curve for over generation used for calculating *market prices*.

The synchronized *ten-minute operating reserve* constraint may be violated to allow a shortfall. For interval $i \in I$:

- $(P10SViolSch_{i,w}, Q10SViolSch_{i,w})$ for $w \in \{1,..,N_{10SViol_i}\}$ shall designate the price-quantity segments of the penalty curve for the synchronized *ten-minute operating reserve* requirement used for scheduling to meet the *IESO*'s *reliability* requirements; and
- $(P10SViolPrc_{i,w}, Q10SViolPrc_{i,w})$ for $w \in \{1,..,N_{10SViol_i}\}$ shall designate the price-quantity segments of the penalty curve for the synchronized *ten-minute operating reserve* requirement used for calculating market prices.

The total *ten-minute operating reserve* constraint may be violated to allow a shortfall.

For interval $i \in I$:

- $(P10RViolSch_{i,w}, Q10RViolSch_{i,w})$ for $w \in \{1,..,N_{10RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for the total *ten-minute operating* *reserve* requirement used for scheduling to meet the *IESO*'s *reliability* requirements; and

- $(P10RViolPrc_{i,w}, Q10RViolPrc_{i,w})$ for $w \in \{1,..,N_{10RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for the total *ten-minute operating reserve* requirement used for calculating market prices.

The *thirty-minute operating reserve* constraint may be violated to allow a shortfall. For interval $i \in I$:

- $(P30RViolSch_{i,w}, Q30RViolSch_{i,w})$ for $w \in \{1,..,N_{30RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for the total *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement used for scheduling to meet the *IESO*'s *reliability* requirements; and
- $(P30RViolPrc_{i,w}, Q30RViolPrc_{i,w})$ for $w \in \{1,..,N_{30RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for the total *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement used for calculating *market prices*.

Area minimum and maximum *operating reserve* requirements may be violated. For interval $i \in I$:

- $(PREG10RViolSch_{i,w}, QREG10RViolSch_{i,w})$ for $w \in \{1,..,N_{REG10RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* minimum requirements used for scheduling to meet the *IESO's reliability* requirements;
- $(PREG10RViolPrc_{i,w}, QREG10RViolPrc_{i,w})$ for $w \in \{1,..,N_{REG10RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* minimum requirements used for calculating *market prices*;
- $(PREG30RViolSch_{i,w}, QREG30RViolSch_{i,w})$ for $w \in \{1,..,N_{REG30RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for area *thirty-minute operating reserve* minimum requirements used for scheduling to meet the *IESO's reliability* requirements;
- $(PREG30RViolPrc_{i,w}, QREG30RViolPrc_{i,w})$ for $w \in \{1,..,N_{REG30RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for area *thirty-minute operating reserve* minimum requirements used for calculating *market prices*;
- $(PXREG10RViolSch_{i,w}, QXREG10RViolSch_{i,w})$ for $w \in \{1,..,N_{XREG10RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* maximum restrictions used for scheduling to meet the *IESO's reliability* requirements;

- $(PXREG10RViolPrc_{i,w}, QXREG10RViolPrc_{i,w})$ for $w \in \{1,..,N_{XREG10RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for area total *ten-minute operating reserve* maximum restrictions used for calculating *market prices*;
- $(PXREG30RViolSch_{i,w}, QXREG30RViolSch_{i,w})$ for $w \in \{1,..,N_{XREG30RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for area total *thirty-minute operating reserve* maximum restrictions used for scheduling to meet the *IESO's reliability requirements*; and
- $(PXREG30RViolPrc_{i,w}, QXREG30RViolPrc_{i,w})$ for $w \in \{1,..,N_{XREG30RViol_i}\}$ shall designate the price-quantity segments of the penalty curve for area total *thirty-minute operating reserve* maximum restrictions used for calculating *market prices*.

Pre-contingency and post-contingency internal transmission limits may be violated. For interval $i \in I$:

- $(PPreITLViolSch_{f,i,w}, QPreITLViolSch_{f,i,w})$ fo $w \in \{1,..,N_{PreITLViol_{f,i}}\}$r shall designate the price-quantity segments of the penalty curve for exceeding the pre-contingency limit of the transmission constraint for *facility* $f \in F$ used for scheduling to meet the *IESO*'s *reliability* requirements;
- $(PPreITLViolPrc_{f,i,w}, QPreITLViolPrc_{f,i,w})$ for $w \in \{1,..,N_{PreITLViol_{f,i}}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the pre-contingency limit of the transmission constraint for *facility* $f \in F$ used for calculating *market prices*. As described in the Offers, Bids and Data Inputs detailed design document, the quantity will be based on a percentage of the applicable transmission *security limit*. As the percentage and limit do not depend on the optimization function decisions, the quantity can be precomputed and treated as fixed within the RT calculation engine optimization function;
- $(PITLViolSch_{c,f,i,w}, QITLViolSch_{c,f,i,w})$ for $w \in \{1,..,N_{ITLViol_{c,f,i}}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the contingency $c \in C$ post-contingency limit of the transmission constraint for *facility* $f \in F$ used for scheduling to meet the *IESO*'s *reliability* requirements; and
- $(PITLViolPrc_{c,f,i,w}, QITLViolPrc_{c,f,i,w})$ for $w \in \{1,..,N_{ITLViol_{c,f,i}}\}$ shall designate the price-quantity segments of the penalty curve for exceeding the contingency $c \in C$ post-contingency limit of the transmission constraint for *facility* $f \in F$ used for calculating *market prices*. Similar to pre-contingency limits, the penalty curve quantities are based on a percentage of the applicable transmission *security limit* and are fixed within the RT calculation engine optimization function.

Tie-Breaking

When there exist two or more equivalent *bids* or *offers* for *energy* or *offers* for *operating reserve* that do not create differences in the optimization, tie-breaking rules will be used by the RT calculation engine. Two tie-breaking methods will be used.

The first tie-breaking method pertains to only *variable generation* resources and its application is facilitated by pre-processing *variable generation offers* within the initialization processes of the RT calculation engine. The intent of this method is to break ties when two or more *energy offers* from *variable generation* resources are such that there is no difference in the cost to the market of using either *offer*. In such instances, the schedules for these *offers* shall be determined using the daily *dispatch* order for *variable generation*, where:

- $NumVG_i$ shall designate the number of *variable generation* resources in the daily *dispatch* order for interval $i \in I$; and
- $TBM_{i,b} \in \{1,..,NumVG_i\}$ shall designate the tie-breaking modifier for the *variable generation* resource at bus $b \in B^{VG}$ for interval $i \in I$.

The second tie-breaking method pertains to all *bids* and *offers* for *energy* and *offers* for *operating reserve* and is applied using a quadratic penalty within the optimization function of the RT calculation engine. The intent of this method is to break ties when two or more *bids* or *offers* are such that there is no difference in the cost to the market of using either *bid/offer*. In such instances, the schedules for these *bids* or *offers* shall be prorated based on the amount of *energy offered* and available at the corresponding price. No additional input to the RT calculation engine is required to perform this pro-rata tie-breaking.

3.4.1.6. Initial Scheduling Assumptions

The RT calculation engine will require data about the current operation of resources submitting *bids* and *offers*, confirmed start-up and shutdown times for NQS resources and other inputs to make initial scheduling assumptions. This data is described in the following sub-sections.

Resource Initial Schedules

Initial schedules represent the initial loading of a resource, the point from which the resource may be scheduled in respect of its ramp rates. The resource initial schedules used in the scheduling algorithm will account for both the EMS MW value determined based on real-time telemetry and the resource schedule from the preceding RT calculation engine run, where:

- $RTDLTel_{-1,b}$ shall designate the EMS MW value for the *dispatchable load* at bus $b \in B^{DL}$;

- $SDLSch^{Prev}_{0,b}$ shall designate the schedule determined for the *dispatchable load* at bus $b \in B^{DL}$ by the scheduling algorithm of the preceding RT calculation engine run;
- $RTDGTel_{-1,b}$ shall designate the EMS MW value for the dispatchable generation resource at bus $b \in B^{DG}$; and
- $SDGSch^{Prev}_{0,b}$ shall designate the schedule determined for the dispatchable generation resource at bus $b \in B^{DG}$ by the scheduling algorithm of the preceding RT calculation engine run.

The resource initial schedules used in the pricing algorithm will additionally account for the resource schedule calculated in the pricing algorithm of the preceding RT calculation engine run, where:

- $SDLPrc^{Prev}_{0,b}$ shall designate the schedule determined for the *dispatchable load* at bus $b \in B^{DL}$ in the pricing algorithm of the preceding RT calculation engine run; and
- $SDGPrc^{Prev}_{0,b}$ shall designate the schedule determined for the dispatchable generation resource at bus $b \in B^{DG}$ in the pricing algorithm of the preceding RT calculation engine run.

Start-up and Shutdown for NQS Resources

To facilitate scheduling the start-up and shutdown for NQS resources (corresponding to times at which a resource operates below its *minimum loading point*), the following inputs determined by observed resource operation as well as confirmed start-up and shutdown times are required. For the NQS resource at bus $b \in B^{NQS}$ and interval $i \in I$:

- $AtZero_{i,b} \in \{0,1\}$ shall designate that the resource is scheduled to be offline;
- $SU_{i,b} \in \{0,1\}$ shall designate that the resource must be scheduled on its start-up trajectory. This input may indicate an upcoming confirmed start-up or that the resource has started ramping up already;
- $AtMLP_{i,b} \in \{0,1\}$ shall designate that the resource is scheduled to operate at or above MLP as per a minimum generation constraint or because resource shutdown has yet to be confirmed by the *IESO*;
- $EvalSD_{i,b} \in \{0,1\}$ shall designate that the resource has been de-committed by the PD calculation engine, such de-commitment has been confirmed by the *IESO* and therefore, the resource can be evaluated for *energy* schedules below MLP; and
- $SD_{i,b} \in \{0,1\}$ shall designate that the resource must be scheduled on its shutdown trajectory. This input may indicate an upcoming mandatory shutdown or that the resource has started ramping down already.

Exactly one of these inputs can be equal to one. That is, for all buses $b \in B^{NQS}$ and intervals $i \in I$:

$$AtZero_{i,b} + SU_{i,b} + AtMLP_{i,b} + EvalSD_{i,b} + SD_{i,b} = 1.$$

See the Grid and Market Operations Integration detailed designed document for more information about NQS start-up and shutdown procedures.

3.4.1.7. Inputs Provided by the Security Assessment Function

Transmission inputs to the optimization function are calculated by the *security* assessment function based on information prepared by the *IESO* to enable the RT calculation engine to evaluate the *security* of the *IESO-controlled grid.*

Transmission Constraints

A set of linearized transmission constraints will be provided by the *security* assessment function. Operating *security limits* and thermal limits for both pre-contingency and post-contingency conditions will be considered, where:

- F shall designate the set of *facilities* (or groups of *facilities*) in Ontario for which transmission constraints may be identified; and
- C shall designate the set of contingency conditions that are considered in the *security* assessment function.

For each interval $i \in I$, if the pre-contingency limit on *facility* $f \in F$ is violated, the *security* assessment function will calculate a linearization of the constraint in the optimization function scheduling variables and provide the affiliated coefficients and limit. Let $F_i \subseteq F$ designate the set of *facilities* whose pre-contingency limit was violated in interval i of a preceding *security* assessment function iteration. For a *facility* $f \in F_i$:

- $PreConSF_{i,f,b}$ shall designate the pre-contingency sensitivity factor for bus $b \in B \cup D$ indicating the fraction of *energy* injected at bus b which flows on *facility* f during interval i under pre-contingency conditions; and
- $AdjNormMaxFlow_{i,f}$ shall designate the corresponding limit indicating the maximum flow allowed on *facility* f in interval i under pre-contingency conditions.

For each interval $i \in I$ and contingency $c \in C$, if the post-contingency limit on *facility* $f \in F$ is violated, the *security* assessment function will calculate a linearization of the constraint in the optimization function scheduling variables and provide the affiliated coefficients and limit. Let $F_{i,c} \subseteq F$ designate the set of *facilities* whose post-contingency limit for contingency c was violated in interval i of a preceding *security* assessment function iteration.

For a facility $f \in F_{i,c}$:

- $SF_{i,c,f,b}$ shall designate the post-contingency sensitivity factor for bus $b \in B \cup D$ indicating the fraction of *energy* injected at bus b which flows on *facility* f during interval i under post- contingency conditions for contingency c; and
- $AdjEmMaxFlow_{i,c,f}$ shall designate the corresponding limit indicating the maximum flow allowed on *facility* f in interval i under post-contingency conditions for contingency c.

Transmission Losses

Losses will be modelled in the RT calculation engine using marginal loss factors as described in Section 3.4.1.5 and a loss adjustment, where:

- $LossAdj_i$ shall designate any adjustment needed for interval $i \in I$ to correct for any discrepancy between Ontario total system losses calculated using a base case power flow from the *security* assessment function and linearized losses that would be calculated using the marginal loss factors.

A discrepancy may arise because a linear equation based on marginal loss factors is used to represent losses, but losses are not a linear function of load. The adjustment required may be positive or negative and depends on the location of the *reference bus.* For the purposes of the optimization function formulation, the convention will be that a positive value for the loss adjustment term reflects the need for less generation to cover losses.

3.4.1.8. Inputs Provided by the Ex-Ante Market Power Mitigation Process

The *offers* for *energy* from a dispatchable generation resource and *offers* for *operating reserve* from a *dispatchable load* or a dispatchable generation resource may be subject to mitigation when such a resource is located in an area of restricted competition. If such *offers* are deemed to have failed the conduct and price impact tests within the pre-dispatch ex-ante Market Power Mitigation process, then the corresponding inputs described in Section 3.4.1.3 and Section 3.4.1.4 will be the reference level *dispatch data*.

3.4.2. Inputs into the Security Assessment Function

Similar to today's DSO, the RT calculation engine *security* assessment function will continue to use the outputs of the optimization function, *security limits* and the network model to perform *security* analysis of the *IESO-controlled grid*. Section 3.7.1 provides further details on how these inputs are used by the *security* assessment function in the RT calculation engine pass.

3.4.2.1. Inputs Provided by the Optimization Function

The optimization function will provide the *security* assessment function with schedules for load and supply resources (withdrawals and injections), which will be represented at their corresponding electrical buses in the network model.

3.4.2.2. Security Limits

The *security* assessment function will continue to apply a set of equations, known as operating *security limits* (OSLs). OSLs help ensure that power flows remain within NERC and NPCC *reliability* criteria both pre-contingency and following contingency events. The *security* assessment function will also continue to use pre-contingency and post-contingency thermal ratings to help ensure that RT *dispatch* results in transmission flows that respect the thermal limits.

3.4.2.3. Network Model

The *security* assessment function will continue to use data related to the power system model, load distribution factors, contingencies and monitored equipment.

3.5. Initialization

Before commencing its pass, the RT calculation engine will perform any necessary initialization processes. These processes include selecting a *reference bus*, determining islanding conditions, applying the *variable generation* resource tie-breaking logic and pre-processing minimum and maximum generation constraints that will apply to *pseudo-units*.

3.5.1. Reference Bus

The optimization function will use a fixed *reference bus* as a starting point to determine all LMPs. By default, this *reference bus* will be the Richview Transformer Station. If the *reference bus* is out of service, then an alternative station will be chosen as per the prevailing system conditions.

3.5.2. Islanding

In the case of a network split, only the island with the largest number of *IESO-controlled grid* buses will be considered, and the following will apply:

- Resources, imports and exports that are not in the largest island will be assumed to neither inject nor withdraw and, therefore, will be disregarded by the optimization function;
- The load forecasts used by the optimization function will only include *demand* forecast areas in the largest island; and

- If necessary, the *reference bus* will be updated to a bus within the largest island.

For any nodes outside the largest island, prices will be determined as per the methodology detailed in Section 3.

3.5.3. Variable Generation Resource Tie-Breaking

As described in the Tie-Breaking sub-section in Section 3.4.1.5, *variable generation* resource *energy offer* prices will be modified prior to the engine pass for the purposes of tie-breaking. For each interval $i \in I$, each *variable generation* resource bus $b \in B^{VG}$ and each *offer* lamination $k \in K^{E}_{i,b}$, the *offer* price $PDG_{i,b,k}$ shall be updated to $PDG_{i,b,k}$-$\left(\frac{TBM_{i,b}}{NumVG_i}\right)\rho$ where ρ is a small nominal value of order 10^{-4}.

3.5.4. PSU Constraints

For a combined cycle *facility* that has elected to be represented as a *pseudo-unit*, any minimum or maximum generation constraint applied to a corresponding physical unit will be pre-processed to determine appropriate constraints for the PSU resources. The logic for determining the appropriate constraints is described in Section 3.10.

3.6. Pass 1: Real-Time Scheduling and Pricing

Pass 1, Real-Time Scheduling and Pricing, will use *market participant* and *IESO* inputs along with resource and system constraints to schedule available resources to meet forecast non-dispatchable *demand* and evaluate *demand* from *dispatchable loads*. The schedules calculated will be used as the basis for *dispatch instructions* and to provide advisory information for the upcoming *dispatch hour*. Pass 1 will also determine LMPs consistent with these scheduling decisions.

3.6.1. Real-Time Scheduling

Real-Time Scheduling will perform a *security*-constrained economic *dispatch* of available resources to meet the *IESO*'s non-dispatchable *demand* forecast and *IESO*-specified *operating reserve* requirements. Real-Time Scheduling will also evaluate *demand* from *dispatchable loads*. However, schedules for imports, exports, *hourly demand response* resources and operational commitments of NQS resources will be held fixed as determined by the *pre-dispatch scheduling* processes.

Real-Time Scheduling will use the *dispatch data* set from the previous hour's pre-dispatch to maximize the gains from trade. This data set will include *market participant bids* and *offers*, along with any reference levels that were applied as a result of a failure of the market power mitigation price impact test in pre-dispatch. The gains from trade is the difference between the total price of *bids* that are scheduled and the total price of *offers* that are scheduled. The optimization is subject to the resource constraints accompanying those *bids* and *offers*, and system constraints imposed by the *IESO* to maintain *reliability*.

The schedules produced by Real-Time Scheduling will comprise the *constrained schedules* that are used for producing real-time *dispatch instructions* and advisory schedules.

The following sections describe the formulation of the optimization function for Real-Time Scheduling.

3.6.1.1. Inputs

All applicable inputs identified in Section 3.4.1 will be evaluated.

3.6.1.2. Variables and Objective Function

The RT calculation engine will solve for the following variables:

- $SDL_{i,b,j}$ shall represent the amount of *dispatchable load* scheduled at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J^{E}_{i,b}$;
- $S10SDL_{i,b,j}$ shall represent the amount of synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J^{10S}_{i,b}$;

- $S10NDL_{i,b,j}$ shall represent the amount of non-synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J_{i,b}^{10N}$;
- $S30RDL_{i,b,j}$ shall represent the amount of *thirty-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J_{i,b}^{30R}$;
- $SNDG_{i,b,k}$ shall represent the amount of non-dispatchable generation scheduled at bus $b \in B^{NDG}$ in interval $i \in I$ in association with lamination $k \in K_{i,b}^{E}$;
- $SDG_{i,b,k}$ shall represent the amount of dispatchable generation scheduled at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K_{i,b}^{E}$;
- $S10SDG_{i,b,k}$ shall represent the amount of synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K_{i,b}^{10S}$;
- $S10NDG_{i,b,k}$ shall represent the amount of non-synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K_{i,b}^{10N}$;
- $S30RDG_{i,b,k}$ shall represent the amount of *thirty-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K_{i,b}^{30R}$;
- $SCT_{i,b}$ shall represent the schedule of the combustion turbine associated with the PSU resource at bus $b \in B^{PSU}$ in interval $i \in I$;
- $SST_{i,p}$ shall represent the schedule of steam turbine $p \in PST$ in interval $i \in I$;
- TB_i shall represent any adjustment to the objective function to facilitate pro-rata tie-breaking in interval $i \in I$, as described in Section 3.4.1.5 and this section; and
- $ViolCost_i$ shall represent the cost incurred in order to avoid having the schedules for interval $i \in I$ violate certain constraints, as described in Section 3.4.1.5 and this section.

To maximize the gains from trade, the objective function in Real-Time Scheduling will maximize the value of the following expression:

$$\sum_{i=1..n_I} (ObjDL_i - ObjNDG_i - ObjDG_i - TB_i - ViolCost_i)$$

where:

$$ObjDL_i = \sum_{b \in B^{DL}} \left(\begin{array}{c} \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} \cdot PDL_{i,b,j} - \sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \cdot P10SDL_{i,b,j} - \\ \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \cdot P10NDL_{i,b,j} - \sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \cdot P30RDL_{i,b,j} \end{array} \right);$$

$$ObjNDG_i = \sum_{b \in B^{NDG}} \left(\sum_{k \in K_{i,b}^{E}} SNDG_{i,b,k} \cdot PNDG_{i,b,k} \right);$$

and

$$ObjDG_i = \sum_{b \in B^{DG}} \left(\begin{array}{c} \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} \cdot PDG_{i,b,k} + \sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \cdot P10SDG_{i,b,k} + \\ \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \cdot P10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \cdot P30RDG_{i,b,k} \end{array} \right).$$

The tie-breaking term - TB_i - is obtained by adding a term for each *bid* or *offer* lamination. For each lamination, this term is the product of a small penalty cost and the quantity of the lamination scheduled. The penalty cost is calculated by multiplying a base penalty cost of $TBPen$ by the amount of the lamination scheduled and then dividing by the maximum amount that could have been scheduled. When this penalty cost is multiplied by the amount scheduled from that lamination, a quadratic function that increases as the amount scheduled increases is obtained. This effectively increases the *bid* or *offer* price by zero if nothing is scheduled from the lamination, but by $TBPen$ if the maximum amount that could have been scheduled is scheduled. This slight price gradient, which is smaller than the minimum step size of *bid* or *offer* prices, will ensure that two otherwise tied laminations will be scheduled to the point where their modified costs are identical, effectively achieving a prorated result. If a lamination quantity is given by Q_{idx}, its available quantity will be given by Q_{idx}^{avail}. The tie-breaking term is computed as follows:

$$TB_i = TBDL_i + TBNDG_i + TBDG_i$$

where:

$$TBDL_i = \sum_{b \in B^{DL}} \left(\begin{array}{c} \sum_{j \in J_{i,b}^{E}} \left(\frac{\left(SDL_{i,b,j}\right)^2 \cdot TBPen}{QDL_{i,b,j}^{avail}} \right) + \sum_{j \in J_{i,b}^{10S}} \left(\frac{\left(S10SDL_{i,b,j}\right)^2 \cdot TBPen}{Q10SDL_{i,b,j}^{avail}} \right) + \\ \sum_{j \in J_{i,b}^{10N}} \left(\frac{\left(S10NDL_{i,b,j}\right)^2 \cdot TBPen}{Q10NDL_{i,b,j}^{avail}} \right) + \sum_{j \in J_{i,b}^{30R}} \left(\frac{\left(S30RDL_{i,b,j}\right)^2 \cdot TBPen}{Q30RDL_{i,b,j}^{avail}} \right) \end{array} \right);$$

$$TBNDG_i = \sum_{b \in B^{NDG}} \left(\sum_{k \in K_{i,b}^{E}} \left(\frac{\left(SNDG_{i,b,k}\right)^2 \cdot TBPen}{QNDG_{i,b,k}^{avail}} \right) \right);$$

and

$$TBDG_i = \sum_{b \in B^{DG}} \left(\begin{array}{l} \sum_{k \in K_{i,b}^{E}} \left(\frac{\left(SDG_{i,b,k}\right)^2 \cdot TBPen}{QDG_{i,b,k}^{avail}} \right) + \sum_{k \in K_{i,b}^{10S}} \left(\frac{\left(S10SDG_{i,b,k}\right)^2 \cdot TBPen}{Q10SDG_{i,b,k}^{avail}} \right) + \\ \sum_{k \in K_{i,b}^{10N}} \left(\frac{\left(S10NDG_{i,b,k}\right)^2 \cdot TBPen}{Q10NDG_{i,b,k}^{avail}} \right) + \sum_{k \in K_{i,b}^{30R}} \left(\frac{\left(S30RDG_{i,b,k}\right)^2 \cdot TBPen}{Q30RDG_{i,b,k}^{avail}} \right) \end{array} \right).$$

$ViolCost_i$ calculates the total constraint violation cost and depends on the constraint violation variables. The constraint violation variables for interval $i \in I$ are:

- $SLdViol_{i,w}$ is the violation variable affiliated with segment $w \in \{1,..,\mathrm{N}_{\mathrm{LdViol_i}}\}$ of the penalty curve for the *energy* balance constraint (allowing under-generation);
- $SGenViol_{i,w}$ is the violation variable affiliated with segment $w \in \{1,..,\mathrm{N}_{\mathrm{GenViol_i}}\}$ of the penalty curve for the *energy* balance constraint (allowing over-generation);
- $S10SViol_{i,w}$ is the violation variable affiliated with segment $w \in \{1,..,\mathrm{N}_{\mathrm{10SViol_i}}\}$ of the penalty curve for the synchronized *ten-minute operating reserve* requirement;
- $S10RViol_{i,w}$ is the violation variable affiliated with segment $w \in \{1,..,\mathrm{N}_{\mathrm{10RViol_i}}\}$ of the penalty curve for the total *ten-minute operating reserve* requirement;
- $S30RViol_{i,w}$ is the violation variable affiliated with segment $w \in \{1,..,\mathrm{N}_{\mathrm{30RViol_i}}\}$ of the penalty curve for the *thirty-minute operating reserve* requirement and, when applicable, the flexibility *operating reserve* requirement;
- $SREG10RViol_{r,i,w}$ is the violation variable affiliated with segment $w \in \{1,..,N_{REG10RViol_i}\}$ of the penalty curve for violating the area total *ten-minute operating reserve* minimum requirement in region $r \in ORREG$;
- $SREG30RViol_{r,i,w}$ is the violation variable affiliated with segment $w \in \{1,..,\mathrm{N}_{\mathrm{REG30RViol_i}}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* minimum requirement in region $r \in ORREG$;
- $SXREG10RViol_{r,i,w}$ is the violation variable affiliated with segment $w \in \{1,..,\mathrm{N}_{\mathrm{XREG10RViol_i}}\}$ of the penalty curve for violating the area total *ten-minute operating reserve* maximum restriction in region $r \in ORREG$;
- $SXREG30RViol_{r,i,w}$ is the violation variable affiliated with segment $w \in \{1,..,\mathrm{N}_{\mathrm{XREG30RViol_i}}\}$ of the penalty curve for violating the area *thirty-minute operating reserve* maximum restriction in region $r \in ORREG$;
- $SPreITLViol_{f,i,w}$ is the violation variable affiliated with segment $w \in \{1,..,\mathrm{N}_{\mathrm{PreITLViol_{f,i}}}\}$ of the penalty curve for violating the pre-contingency transmission limit for *facility* $f \in F$; and

- $SITLViol_{c,f,i,w}$ is the violation variable affiliated with segment $w \in \{1,..,N_{ITLViol_{c,f,i}}\}$ of the penalty curve for violating the post-contingency transmission limit for *facility* $f \in F$ and contingency $c \in C$.

From these variables, the violation cost is computed as follows:

$$
\begin{aligned}
ViolCost_i = & \sum_{w=1..N_{LdViol_i}} SLdViol_{i,w} \cdot PLdViolSch_{i,w} \\
& - \sum_{w=1..N_{GenViol_i}} SGenViol_{i,w} \cdot PGenViolSch_{i,w} \\
& + \sum_{w=1..N_{10SViol_i}} S10SViol_{i,w} \cdot P10SViolSch_{i,w} \\
& + \sum_{w=1..N_{10RViol_i}} S10RViol_{i,w} \cdot P10RViolSch_{i,w} \\
& + \sum_{w=1..N_{30RViol_i}} S30RViol_{i,w} \cdot P30RViolSch_{i,w} \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{REG10RViol_i}} SREG10RViol_{r,i,w} \right. \\
& \left. \cdot PREG10RViolSch_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{REG30RViol_i}} SREG30RViol_{r,i,w} \right. \\
& \left. \cdot PREG30RViolSch_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{XREG10RViol_i}} SXREG10RViol_{r,i,w} \right. \\
& \left. \cdot PXREG10RViolSch_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{XREG30RViol_i}} SXREG30RViol_{r,i,w} \right. \\
& \left. \cdot PXREG30RViolSch_{i,w} \right)
\end{aligned}
$$

$$+\sum_{f\in F_i}\left(\sum_{w=1..N_{PreITLViol_{f,i}}} SPreITLViol_{f,i,w}\cdot PPreITLViolSch_{f,i,w}\right)$$
$$+\sum_{c\in C}\sum_{f\in F_{i,c}}\left(\sum_{w=1..N_{ITLViol_{c,f,i}}} SITLViol_{c,f,i,w}\cdot PITLViolSch_{c,f,i,w}\right).$$

This maximization will be subject to the constraints described in the next sections.

3.6.1.3. Constraints Overview

The constraints that apply to the optimization can be divided into three categories:

1. Single interval constraints to ensure that the schedules determined in the optimization do not violate the parameters specified in the *dispatch data* submitted by *registered market participants*;
2. Inter-interval and multi-interval constraints to ensure that the schedules determined in the optimization do not violate the parameters specified in the *dispatch data* submitted by *registered market participants*; and
3. Constraints to ensure that those schedules do not violate the *reliability* criteria established by the *IESO*.

3.6.1.4. Bid/Offer Constraints Applying to Single Intervals

Scheduling Variable Bounds

No schedule can be negative, nor can any schedule exceed the quantity *offered* for the respective market (*energy* and *operating reserve*). Therefore, for all intervals $i \in I$:

$0 \le SDL_{i,b,j} \le QDL_{i,b,j}$ for all $b \in B^{DL}$, $j \in J^{E}_{i,b}$;

$0 \le S10SDL_{i,b,j} \le Q10SDL_{i,b,j}$ for all $b \in B^{DL}$, $j \in J^{10S}_{i,b}$;

$0 \le S10NDL_{i,b,j} \le Q10NDL_{i,b,j}$ for all $b \in B^{DL}$, $j \in J^{10N}_{i,b}$;

$0 \le S30RDL_{i,b,j} \le Q30RDL_{i,b,j}$ for all $b \in B^{DL}$, $j \in J^{30R}_{i,b}$;

$0 \le SNDG_{i,b,k} \le QNDG_{i,b,k}$ for all $b \in B^{NDG}$, $k \in K^{E}_{i,b}$;

$0 \le SDG_{i,b,k} \le QDG_{i,b,k}$ for all $b \in B^{DG}$, $k \in K^{E}_{i,b}$;

$0 \le S10SDG_{i,b,k} \le Q10SDG_{i,b,k}$ for all $b \in B^{DG}$, $k \in K^{10S}_{i,b}$;

$0 \le S10NDG_{i,b,k} \le Q10NDG_{i,b,k}$ for all $b \in B^{DG}$, $k \in K^{10N}_{i,b}$; and

$0 \leq S30RDG_{i,b,k} \leq Q30RDG_{i,b,k}$ for all $b \in B^{DG}$, $k \in K_{i,b}^{30R}$.

An NQS resource cannot provide *energy* when it is scheduled to be offline. Therefore, for all intervals $i \in I$, NQS resource buses $b \in B^{NQS}$, and *offer* laminations $k \in K_{i,b}^{E}$:

$$0 \leq SDG_{i,b,k} \leq (1 - AtZero_{i,b}) \cdot QDG_{i,b,k}.$$

An NQS resource cannot provide *operating reserve* unless it is scheduled at or above its *minimum loading point*. Therefore, for all intervals $i \in I$ and NQS resource buses $b \in B^{NQS}$:

$0 \leq S10SDG_{i,b,k} \leq (AtMLP_{i,b} + EvalSD_{i,b}) \cdot Q10SDG_{i,b,k}$ for all $k \in K_{i,b}^{10S}$;

$0 \leq S10NDG_{i,b,k} \leq (AtMLP_{i,b} + EvalSD_{i,b}) \cdot Q10NDG_{i,b,k}$ for all $k \in K_{i,b}^{10N}$; and

$0 \leq S30RDG_{i,b,k} \leq (AtMLP_{i,b} + EvalSD_{i,b}) \cdot Q30RDG_{i,b,k}$ for all $k \in K_{i,b}^{30R}$.

Resource Initial Conditions

Resource initial schedules will be used as the initial loading point for a resource when determining its schedule for the *dispatch interval*. Accordingly, these initial schedules will be determined in respect of the EMS MW value determined based on real-time telemetry and offered ramp rates to verify that the initial schedule is compliant with a resource's physical capabilities.

For notational convenience, the initial resources schedules will be denoted using the scheduling variables in Section 3.6.1.2 with the interval set to 0. For example, $SDG_{0,b,k}$ shall denote the initial schedule of the dispatchable generation resource at bus $b \in B^{DG}$ affiliated with *offer* lamination $k \in K_{0,b}^{E}$.

Dispatchable Load

The initial schedule for the *dispatchable load* at bus $b \in B^{DL}$ will be fixed in the optimization function, where:

- $SDLInitSch_{0,b}$ shall designate the initial schedule for the *dispatchable load* at bus b.

This parameter will be calculated as follows.

1. Calculate $TelUp_{0,b}$ using the submitted up ramp rates and break points to determine the maximum consumption level the *dispatchable load* can achieve in five minutes from $RTDLTel_{-1,b}$.
2. Calculate $TelDown_{0,b}$ using the submitted down ramp rates and break points to determine the minimum consumption level the *dispatchable load* can achieve in five minutes from $RTDLTel_{-1,b}$.
3. If the schedule from the preceding RT calculation engine run is achievable by ramping from the EMS MW value, then set the initial schedule to the

schedule from the preceding RT calculation engine run. Otherwise, set the initial schedule to the nearest boundary.

a. If $TelDown_{0,b} \leq SDLSch_{0,b}^{Prev} \leq TelUp_{0,b}$, then set $SDLInitSch_{0,b} = SDLSch_{0,b}^{Prev}$.

b. Otherwise, if $SDLSch_{0,b}^{Prev} < TelDown_{0,b}$, then set $SDLInitSch_{0,b} = TelDown_{0,b}$.

c. Otherwise, set $SDLInitSch_{0,b} = TelUp_{0,b}$.

The initial scheduling variables will be fixed to the resource initial schedules. For all *dispatchable load* buses $b \in B^{DL}$:

$$\sum_{j \in J_{0,b}^{E}} SDL_{0,b,j} = SDLInitSch_{0,b}.$$

Dispatchable Generation Resources

The initial schedule for the dispatchable generation resource at bus $b \in B^{DG}$ will be fixed in the optimization function, where:

- $SDGInitSch_{0,b}$ shall designate the initial schedule for the dispatchable generation resource at bus b.

This parameter will be calculated as follows.

1. Calculate $TelUp_{0,b}$ using the submitted up ramp rates and break points to determine the maximum production level the resource can achieve in five minutes from $RTDGTel_{-1,b}$.
2. Calculate $TelDown_{0,b}$ using the submitted down ramp rates and break points to determine the minimum production level the resource can achieve in five minutes from $RTDGTel_{-1,b}$.
3. If the schedule from the preceding RT calculation engine run is achievable by ramping from the EMS MW value, then set the initial schedule to the schedule from the preceding RT calculation engine run. Otherwise, set the initial schedule to the nearest boundary.

   a. If $TelDown_{0,b} \leq SDGSch_{0,b}^{Prev} \leq TelUp_{0,b}$ then set $SDGInitSch_{0,b} = SDGSch_{0,b}^{Prev}$.

   b. Otherwise, if $SDGSch_{0,b}^{Prev} < TelDown_{0,b}$ then set $SDGInitSch_{0,b} = TelDown_{0,b}$.

   c. Otherwise, set $SDGInitSch_{0,b} = TelUp_{0,b}$.

The initial scheduling variables will be fixed to the resource initial schedules. For all dispatchable generation resource buses $b \in B^{DG}$:

$$\sum_{k \in K_{0,b}^{E}} SDG_{0,b,k} = SDGInitSch_{0,b}.$$

Resource Minimums and Maximums

The schedule of an internal resource may be limited depending on the impact of the constraints detailed in Resource Minimum and Maximum Constraints within Section 3.4.1.5.

Dispatchable Load

A constraint is required to limit *dispatchable loads* within their minimum and maximum consumption for an interval. Therefore, for all intervals $i \in I$ and all buses $b \in B^{DL}$:

$$MinDL_{i,b} \leq \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} \leq MaxDL_{i,b}.$$

The non-dispatchable portion of a *dispatchable load* must always be scheduled. Therefore, for all intervals $i \in I$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} \geq QDLFIRM_{i,b}.$$

Non-Dispatchable Generation Resources

Non-dispatchable generation resources will be scheduled to the fixed quantity determined by their observed output. Therefore, for all intervals $i \in I$ and all buses $b \in B^{NDG}$:

$$\sum_{k \in K_{i,b}^{E}} SNDG_{i,b,k} = FNDG_{i,b}.$$

Dispatchable Generation Resources

A constraint is required to limit dispatchable generation resources within their minimum and maximum output for an interval. The maximum output of a dispatchable *variable generation* resource will additionally be limited by its forecast. For all intervals $i \in I$ and all buses $b \in B^{DG}$, let

$$AdjMaxDG_{i,b} = \begin{cases} min(MaxDG_{i,b}, FG_{i,b}) & if\ b \in B^{VG} \\ MaxDG_{i,b} & otherwise \end{cases}$$

and

$$AdjMinDG_{i,b} = min(MinDG_{i,b}, AdjMaxDG_{i,b}).$$

Then, for all intervals $i \in I$ and all buses $b \in B^{DG}$:

$$AdjMinDG_{i,b} \leq \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} \leq AdjMaxDG_{i,b}.$$

NQS Resources

A constraint is required to schedule an NQS resource at or above its *minimum loading point* when the resource is committed or when resource shutdown is yet to be confirmed by the *IESO*. For all NQS resource buses $b \in B^{NQS}$ and intervals $i \in I$:

$$\sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} \geq AtMLP_{i,b} \cdot MinQDG_{b}.$$

Operating Reserve Scheduling

Dispatchable Load

The total *operating reserve* (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a *dispatchable load* cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled load less the non-dispatchable portion. Lastly, it cannot exceed the remaining portion of its capacity that is dispatchable after considering minimum load consumption constraints. These conditions can be enforced by the following constraints for all intervals $i \in I$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} + \sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \leq 30 \cdot ORRDL_{b};$$

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} + \sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \leq \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} - QDLFIRM_{i,b};$$

and

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} + \sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \leq \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} - MinDL_{i,b}.$$

The amount of synchronized *ten-minute operating reserve* plus the non-synchronized *ten-minute operating reserve* that a *dispatchable load* is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint for all intervals $i \in I$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \leq 10 \cdot ORRDL_{b}.$$

Dispatchable Generation Resources

The total *operating reserve* (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a dispatchable generation resource cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum *offered* generation minus the *energy* schedule). Lastly, it cannot exceed its unscheduled capacity. These conditions can be enforced by the following constraints for all intervals $i \in I$ and all buses $b \in B^{DG}$:

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq 30 \cdot ORRDG_b;$$

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq \sum_{k \in K_{i,b}^{E}} (QDG_{i,b,k} - SDG_{i,b,k});$$

and

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq AdjMaxDG_{i,b} - \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k}.$$

The amount of *ten-minute operating reserve* (both synchronized and non-synchronized) that a dispatchable generation resource is scheduled to provide cannot exceed the amount by which it can increase its output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint for all intervals $i \in I$ and all buses $b \in B^{DG}$:

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \leq 10 \cdot ORRDG_b.$$

The amount of synchronized *ten-minute operating reserve* that a dispatchable generation resource is scheduled to provide is limited by its synchronized *ten-minute operating reserve* loading point. This condition can be enforced by the following constraint for all intervals $i \in I$ and all buses $b \in B^{DG}$ with $RLP10S_{i,b}>0$:

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \leq \left(\sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} \right) \cdot \left(\frac{1}{RLP10S_{i,b}} \right) \cdot \left(min \left\{ 10 \cdot ORRDG_b, \sum_{k \in K_{i,b}^{10S}} Q10SDG_{i,b,k} \right\} \right).$$

The amount of *thirty-minute operating reserve* that a dispatchable generation resource is scheduled to provide is limited by its 30-minute reserve loading point. This condition can be enforced by the following constraint for all intervals $i \in I$ and all buses $b \in B^{DG}$ with $RLP30R_{i,b} > 0$:

$$\sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq \left(\sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} \right) \cdot \left(\frac{1}{RLP30R_{i,b}} \right) \cdot \left(min \left\{ 30 \cdot ORRDG_b, \sum_{k \in K_{i,b}^{30R}} Q30RDG_{i,b,k} \right\} \right).$$

PSU Resources

De-rates

De-rates are enforced on the operating region to which they apply as described in Section 3.10.2. These constraints apply to both *energy* and *operating reserve* schedules. For all intervals $i \in I$ and PSU resource buses $b \in B^{PSU}$:

$$\sum_{k \in K_{i,b}^{DR}} SDG_{i,b,k} \leq MaxDR_{i,b},$$

$$\sum_{k \in K_{i,b}^{DF}} SDG_{i,b,k} \leq MaxDF_{i,b},$$

and

$$\sum_{k \in K_{i,b}^{DR}} SDG_{i,b,k} + \sum_{k \in K_{i,b}^{DF}} SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq MaxDR_{i,b} + MaxDF_{i,b}.$$

Translation Between PU and PSU Schedules

Physical unit schedules can be calculated from the *pseudo-unit* schedules using the PSU model and sharing percentages. For all intervals $i \in I$ and PSU resource buses $b \in B^{PSU}$:

$$SCTMod_{i,b} = (1 - STShareMLP_b) \cdot \left(\sum_{k \in K_{i,b}^{MLP}} SDG_{i,b,k} \right) + (1 - STShareDR_b) \cdot \left(\sum_{k \in K_{i,b}^{DR}} SDG_{i,b,k} \right),$$

and for all intervals $i \in I$ and steam turbines $p \in PST$:

$$SSTMod_{i,p} = \sum_{b \in B_p^{ST}} \left(\begin{array}{c} STShareMLP_b \cdot \left(\sum_{k \in K_{i,b}^{MLP}} SDG_{i,b,k} \right) + \\ STShareDR_b \cdot \left(\sum_{k \in K_{i,b}^{DR}} SDG_{i,b,k} \right) + \sum_{k \in K_{i,b}^{DF}} SDG_{i,b,k} \end{array} \right).$$

Transmission constraint sensitivity factors and loss factors are provided on a physical unit basis. Accordingly, the combustion turbine and steam turbine schedules will be used in the *energy* balance constraint and the transmission constraints described in Section 3.6.1.6. For PSU resources ramping to or ramping from MLP, the RT calculation will account for the online status of the associated steam turbine in determining the physical unit schedules.

For the purposes of the *energy* balance and transmission constraints, the combustion turbine schedule for the PSU resource at bus $b \in B^{PSU}$ in interval $i \in I$, $SCT_{i,b}$, will be equal to:

- $SCTMod_{i,b}$ if the PSU resource is scheduled at or above MLP,
- the portion of $UpTraj_{i,b}$ or $DnTraj_{i,b}$ defined in the NQS Start-Up and Shutdown sub-section of Section 3.6.1.5 that was allocated to the combustion turbine per the logic described in Section 3.10.5 if the resource is ramping to or ramping from MLP, or
- 0 otherwise.

For the purposes of the *energy* balance and transmission constraints, the steam turbine schedule for $p \in PST$, $SST_{i,p}$, will be equal to $SSTMod_{i,p}$. However, $SST_{i,p}$ will be corrected to account for the contribution from PSU resources $b \in B_p^{ST}$ ramping to or ramping from MLP as determined by the allocation of $UpTraj_{i,b}$ or $DnTraj_{i,b}$ using the logic described in Section 3.10.5.

The RT calculation engine will evaluate effective sensitivity and loss factors as a function of the unit loading as determined above. For the purposes of the formulations, the *energy* balance and transmission constraints expressed in this document assume that a PSU's effective sensitivity and loss factors are constant across its operating range.

Duct Firing Operating Reserve Limitations

A PSU resource that cannot provide *ten-minute operating reserve* from its duct firing region will not be scheduled to provide *ten-minute operating reserve* when the resource is scheduled for *energy* in its duct firing region.

Hydroelectric Resources

A hydroelectric resource will be scheduled in its *forbidden region* only if the resource is being ramped through the *forbidden region* at its maximum offered ramp capability.

3.6.1.5. Bid/Offer Inter-Interval/Multi-Interval Constraints

Energy Ramping

In the following ramping constraints, a single ramp up rate and a single ramp down rate ($URRDG_b$ and $DRRDG_b$ for dispatchable generation resources, $URRDL_b$ and $DRRDL_b$ for *dispatchable loads*) are used. That is, the ramp rates are considered to be constant over the full operating range of the dispatchable generation resource or *dispatchable load*. However, the RT calculation engine will respect the ramping restrictions determined by the (up to five) *offered* MW quantity, ramp up rate and ramp down rate value sets.

Dispatchable Load

Energy schedules for a *dispatchable load* cannot vary by more than five minute's ramping capability for that resource. This is enforced by the following constraint for all intervals $i \in I$ and buses $b \in B^{DL}$:

$$\sum_{j \in J^E_{i-1,b}} SDL_{i-1,b,j} - 5 \cdot DRRDL_b \le \sum_{j \in J^E_{i,b}} SDL_{i,b,j} \le \sum_{j \in J^E_{i-1,b}} SDL_{i-1,b,j} + 5 \cdot URRDL_b.$$

Dispatchable Generation Resources

Energy schedules for a dispatchable generation resource cannot vary by more than five minute's ramping capability for that resource. This is enforced by the following constraint for all intervals $i \in I$ and buses $b \in B^{DG}$:

$$\sum_{k \in K_{i-1,b}^{E}} SDG_{i-1,b,k} - 5 \cdot DRRDG_b \leq \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} \leq \sum_{k \in K_{i-1,b}^{E}} SDG_{i-1,b,k} + 5 \cdot URRDG_b.$$

As in today's DSO, the RT calculation engine will account for the initial slow loading characteristics of NQS resources to avoid the "stutter step" that would otherwise occur when an NQS resource starts to increase output from either a steady load or at a loading rate less than the offered rate.

NQS Start-up and Shutdown

An NQS resource will be scheduled on a fixed trajectory when the start-up and shutdown statuses provided to the RT calculation engine indicate the resource must start up or shut down.

For intervals in the MIO look-ahead period in which the NQS resource at bus $b \in B^{NQS}$ is scheduled to start up, the resource will be scheduled on a fixed ramp-up trajectory as determined by its offered ramp rates. The ramp-up trajectory for interval $i \in I$ such that $SU_{i,b}$=1 will be denoted $UpTraj_{i,b}$ and is determined as follows:

1. If $i = 1$, then $UpTraj_{i,b}$ is determined from the resource initial schedule and the offered ramp up capability.
2. If $i > 1$ and $SU_{i\text{-}1,b} = 0$, then $UpTraj_{i,b}$ is determined from the offered ramp up capability from 0.
3. If $i > 1$ and $SU_{i\text{-}1,b} = 1$, then $UpTraj_{i,b}$ is determined from the offered ramp up capability from $UpTraj_{i\text{-}1,b}$.

Therefore, for all intervals $i \in I$ such that $SU_{i,b}$=1:

$$\sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} = UpTraj_{i,b}.$$

For intervals in the MIO look-ahead period in which the NQS resource at bus $b \in B^{NQS}$ is scheduled to shut down, the resource will be scheduled on a fixed ramp-down trajectory as determined by its offered ramp rates. The ramp-down trajectory for interval $i \in I$ such that $SD_{i,b} = 1$ will be denoted $DnTraj_{i,b}$ and is determined as follows:

- If $i = 1$, then $DnTraj_{i,b}$ is determined from the resource initial schedule and the offered ramp down capability.

- If $i > 1$ and $SD_{i\text{-}1,b} = 0$, then $DnTraj_{i,b}$ is $MinQDG_b$.
- If $i > 1$ and $SD_{i\text{-}1,b} = 1$, then $DnTraj_{i,b}$ is determined from the offered ramp down capability from $DnTraj_{i\text{-}1,b}$.

Therefore, for all intervals $i \in I$ such that $SD_{i,b} = 1$:

$$\sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} = DnTraj_{i,b}.$$

Operating Reserve Ramping

Dispatchable Loads

Constraints are imposed to recognize that changes in a *dispatchable load*'s *energy* schedule between intervals may modify the amount of *operating reserve* that the resource can reliably provide. For instance, if the *dispatchable load* decreases consumption during the interval, then the amount of *operating reserve* it can provide within ten minutes of the start of the interval will be reduced. For all intervals $i \in I$ and all buses $b \in B^{DL}$:

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} + \sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \le - \sum_{j \in J_{i-1,b}^{E}} SDL_{i-1,b,j} + \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} + 30 \cdot ORRDL_b$$

and

$$\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} + \sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \le - \sum_{j \in J_{i-1,b}^{E}} SDL_{i-1,b,j} + \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} + 10 \cdot ORRDL_b.$$

Dispatchable Generation Resources

Constraints are imposed to recognize that changes in a dispatchable generation resource's *energy* schedule between intervals may modify the amount of *operating reserve* that the resource can reliably provide. For instance, if the resource ramps up during the interval, then the amount of *operating reserve* it can provide within ten minutes of the start of the interval will be reduced.

For all intervals $i \in I$ and all buses $b \in B^{DG}$:

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} + \sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \leq \sum_{k \in K_{i-1,b}^{E}} SDG_{i-1,b,k} - \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} + 30 \cdot ORRDG_b$$

and

$$\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} + \sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \leq \sum_{k \in K_{i-1,b}^{E}} SDG_{i-1,b,k} - \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} + 10 \cdot ORRDG_b.$$

3.6.1.6. Constraints to Ensure Schedules Do Not Violate Reliability Requirements

Energy Balance

For each interval in the MIO look-ahead period, the total amount of *energy* scheduled on internal supply resources and fixed imports must be equal to the forecast *demand*, *energy* scheduled on internal load resources and fixed exports. This constraint will also account for transmission losses and is described further in terms of its constituent parts.

Define the total amount of withdrawals scheduled at load bus $b \in B$ in interval $i \in I$, $With_{i,b}$, as either:

- all *dispatchable load* scheduled at bus b if $b \in B^{DL}$; or
- the fixed schedule of the *hourly demand response* resource at bus b if $b \in B^{HDR}$; or
- the fixed load scheduled at bus b if $b \in B^{NoBid}$

so that

$$With_{i,b} = \begin{cases} \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} & if\ b \in B^{DL} \\ FHDR_{i,b} & if\ b \in B^{HDR} \\ FNBL_{i,b} & if\ b \in B^{NoBid} \end{cases}.$$

Define the total amount of withdrawals scheduled at *intertie zone* sink bus $d \in DX$ in interval $i \in I$, $With_{i,d}$, as the fixed exports from Ontario to the *intertie zone* sink bus. Thus,

$$With_{i,d} = FXLSch_{i,d}.$$

Define the total amount of injections scheduled at internal generation resource bus $b \in B$, in interval $i \in I$, $Inj_{i,b}$, as either:

- non-dispatchable generation scheduled at bus b if $b \in B^{NDG}$; or
- dispatchable generation scheduled at bus b if $b \in B^{DG}$; or
- the fixed generation scheduled at bus b if $b \in B^{NoOffer}$

so that

$$Inj_{i,b} = \begin{cases} \sum_{k \in K_{i,b}^{E}} SNDG_{i,b,k} & if\ b \in B^{NDG} \\ \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} & if\ b \in B^{DG} \\ FNOG_{i,b} & if\ b \in B^{NoOffer} \end{cases}.$$

Define the total amount of injections scheduled at *intertie zone* source bus $d \in DI$ in interval $i \in I$, $Inj_{i,d}$, as the imports into Ontario from that *intertie zone* source bus. Thus,

$$Inj_{i,d} = FIGSch_{i,d}.$$

Injections and withdrawals at each bus must be multiplied by one plus the marginal loss factor to reflect the losses or reduction in losses that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between total and marginal losses. Load or generation reduction associated with the *demand* constraint violation will be subtracted from the total load or generation to ensure that the RT calculation engine will always produce a solution. The resulting *energy* balance constraint for interval $i \in I$ is

$$\begin{aligned} FL_i + & \sum_{b \in B^{DL} \cup B^{HDR} \cup B^{NoBid}} (1 + MglLoss_{i,b}) \cdot With_{i,b} \\ & + \sum_{d \in DX} (1 + MglLoss_{i,d}) \cdot With_{i,d} \\ & - \sum_{w=1..N_{LdViol_i}} SLdViol_{i,w} \\ & = \sum_{b \in B^{NDG} \cup B^{DG} \cup B^{NoOffer}} (1 + MglLoss_{i,b}) \cdot Inj_{i,b} \\ & + \sum_{d \in DI} (1 + MglLoss_{i,d}) \cdot Inj_{i,d} - \sum_{w=1..N_{GenViol_i}} SGenViol_{i,w} \\ & + LossAdj_i. \end{aligned}$$

Operating Reserve Requirements

Sufficient *operating reserve* must be scheduled to meet system-wide requirements for synchronized *ten-minute operating reserve*, total *ten-minute operating reserve,* and *thirty-minute operating reserve* plus, when applicable, flexibility *operating* *reserve*. All applicable regional minimum requirements and maximum restrictions for *operating reserve* must also be respected. Constraint violation penalty curves will be used to impose a penalty cost for not meeting the *IESO*'s system-wide *operating reserve* requirements, not meeting a regional minimum requirement, or not adhering to a regional maximum restriction. The *IESO* will therefore meet its full *operating reserve* requirements unless the cost of doing so would be higher than the applicable penalty cost.

Therefore, the following constraints are required for each interval $i \in I$:

$$\sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \right) + \sum_{w=1..N_{10SViol_i}} S10SViol_{i,w} \geq TOT10S_i;$$

$$\sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \right) + \sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \right) + \sum_{d \in DX} F10NXLSch_{i,d} + \sum_{d \in DI} F10NIGSch_{i,d} + \sum_{w=1..N_{10RViol_i}} S10RViol_{i,w} \geq TOT10R_i;$$

and

$$\sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \right) + \sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \right) + \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \right) + \sum_{d \in DX} F10NXLSch_{i,d} + \sum_{d \in DI} F10NIGSch_{i,d} + \sum_{b \in B^{DL}} \left(\sum_{j \in J_{i,b}^{30R}} S30RDL_{i,b,j} \right)$$

$$+ \sum_{b \in B^{DG}} \left(\sum_{k \in K_{i,b}^{30R}} S30RDG_{i,b,k} \right) + \sum_{d \in DX} F30RXLSch_{i,d} + \sum_{d \in DI} F30RIGSch_{i,d} + \sum_{w=1..N_{30RViol_i}} S30RViol_{i,w} \geq TOT30R_i.$$

The following constraints are required for each interval $i \in I$ and each region $r \in ORREG$:

$$\sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \right) + \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \right) + \sum_{d \in D_r^{REG} \cap DX} F10NXLSch_{i,d} + \sum_{d \in D_r^{REG} \cap DI} F10NIGSch_{i,d} + \sum_{w=1..N_{REG10RViol_i}} SREG10RViol_{r,i,w} \geq REGMin10R_{i,r};$$

$$\sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{i,b}^{10S}} S10SDL_{i,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{i,b}^{10S}} S10SDG_{i,b,k} \right) + \sum_{b \in B_r^{REG} \cap B^{DL}} \left(\sum_{j \in J_{i,b}^{10N}} S10NDL_{i,b,j} \right) + \sum_{b \in B_r^{REG} \cap B^{DG}} \left(\sum_{k \in K_{i,b}^{10N}} S10NDG_{i,b,k} \right) + \sum_{d \in D_r^{REG} \cap DX} F10NXLSch_{i,d} + \sum_{d \in D_r^{REG} \cap DI} F10NIGSch_{i,d} - \sum_{w=1..N_{XREG10RViol_i}} SXREG10RViol_{r,i,w} \leq REGMax10R_{i,r};$$

$$\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{10S}} S10SDL_{i,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{10S}} S10SDG_{i,b,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{10N}} S10NDL_{i,b,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{10N}} S10NDG_{i,b,k}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DX} F10NXLSch_{i,d}+\sum_{d\in D_r^{REG}\cap DI} F10NIGSch_{i,d}$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{30R}} S30RDL_{i,b,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{30R}} S30RDG_{i,b,k}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DX} F30RXLSch_{i,d}+\sum_{d\in D_r^{REG}\cap DI} F30RIGSch_{i,d}$$
$$+\sum_{w=1..N_{REG30RViol_i}} SREG30RViol_{r,i,w} \ \geq\ REGMin30R_{i,r};$$

and

$$\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{10S}} S10SDL_{i,b,j}\right)+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{10S}} S10SDG_{i,b,k}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{10N}} S10NDL_{i,b,j}\right)$$
$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{10N}} S10NDG_{i,b,k}\right)$$
$$+\sum_{d\in D_r^{REG}\cap DX} F10NXLSch_{i,d}+\sum_{d\in D_r^{REG}\cap DI} F10NIGSch_{i,d}$$
$$+\sum_{b\in B_r^{REG}\cap B^{DL}}\left(\sum_{j\in J_{i,b}^{30R}} S30RDL_{i,b,j}\right)$$

$$+\sum_{b\in B_r^{REG}\cap B^{DG}}\left(\sum_{k\in K_{i,b}^{30R}} S30RDG_{i,b,k}\right)+\sum_{d\in D_r^{REG}\cap DX} F30RXLSch_{i,d} + \sum_{d\in D_r^{REG}\cap DI} F30RIGSch_{i,d} - \sum_{w=1..N_{XREG30RViol_i}} SXREG30RViol_{r,i,w} \le REGMax30R_{i,r}.$$

IESO Internal Transmission Limits

The *IESO* must ensure that the set of schedules produced would not violate any *security limits* in either the pre-contingency state or after any contingency. To develop the constraints to ensure that this occurs, the total amount of *energy* scheduled to be injected at each bus and the total amount of *energy* scheduled to be withdrawn at each bus as developed for the *energy* balance constraint will be used.

The *security* assessment function of the RT calculation engine will linearize violated pre-contingency transmission limits on *facilities* within Ontario. For all intervals $i \in I$ and *facilities* $f \in F_i$, the linearized constraints will take the form:

$$\sum_{b\in B^{NDG}\cup B^{DG}\cup B^{NoOffer}} PreConSF_{i,f,b}\cdot Inj_{i,b} - \sum_{b\in B^{DL}\cup B^{HDR}\cup B^{NoBid}} PreConSF_{i,f,b}\cdot With_{i,b} + \sum_{d\in DI} PreConSF_{i,f,d}\cdot Inj_{i,d} - \sum_{d\in DX} PreConSF_{i,f,d}\cdot With_{i,d} - \sum_{w=1..N_{PreITLViol_{f,i}}} SPreITLViol_{f,i,w} \le AdjNormMaxFlow_{i,f}.$$

Similarly, for all intervals $i \in I$, contingencies $c \in C$, and *facilities* $f \in F_{i,c}$, the linearized constraints will take the form:

$$\sum_{b\in B^{NDG}\cup B^{DG}\cup B^{NoOffer}} SF_{i,c,f,b}\cdot Inj_{i,b} - \sum_{b\in B^{DL}\cup B^{HDR}\cup B^{NoBid}} SF_{i,c,f,b}\cdot With_{i,b} + \sum_{d\in DI} SF_{i,c,f,d}\cdot Inj_{i,d} - \sum_{d\in DX} SF_{i,c,f,d}\cdot With_{i,d} - \sum_{w=1..N_{ITLViol_{c,f,i}}} SITLViol_{c,f,i,w} \le AdjEmMaxFlow_{i,c,f}.$$

Penalty Price Variable Bounds

The following constraints restrict the penalty price variables to the ranges determined by the penalty price curves.

For all intervals $i \in I$:

$0 \leq SLdViol_{i,w} \leq QLdViolSch_{i,w}$ for all $w \in \{1,..,N_{LdViol_i}\}$;

$0 \leq SGenViol_{i,w} \leq QGenViolSch_{i,w}$ for all $w \in \{1,..,N_{GenViol_i}\}$;

$0 \leq S10SViol_{i,w} \leq Q10SViolSch_{i,w}$ for all $w \in \{1,..,N_{10SViol_i}\}$;

$0 \leq S10RViol_{i,w} \leq Q10RViolSch_{i,w}$ for all $w \in \{1,..,N_{10RViol_i}\}$;

$0 \leq S30RViol_{i,w} \leq Q30RViolSch_{i,w}$ for all $w \in \{1,..,N_{30RViol_i}\}$;

$0 \leq SREG10RViol_{r,i,w} \leq QREG10RViolSch_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,N_{REG10RViol_i}\}$;

$0 \leq SREG30RViol_{r,i,w} \leq QREG30RViolSch_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,N_{REG30RViol_i}\}$;

$0 \leq SXREG10RViol_{r,i,w} \leq QXREG10RViolSch_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,N_{XREG10RViol_i}\}$;

$0 \leq SXREG30RViol_{r,i,w} \leq QXREG30RViolSch_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,N_{XREG30RViol_i}\}$;

$0 \leq SPreITLViol_{f,i,w} \leq QPreITLViolSch_{f,i,w}$ for all $f \in F_i$, $w \in \{1,..,N_{PreITLViol_{f,i}}\}$; and

$0 \leq SITLViol_{c,f,i,w} \leq QITLViolSch_{c,f,i,w}$ for all $c \in C, f \in F_{i,c}$, $w \in \{1,..,N_{ITLViol_{c,f,i}}\}$.

3.6.1.7. Outputs

Real-Time Scheduling will produce resource schedules. For each variable SXX, SXX^1 shall designate the value determined in Real-Time Scheduling. For example, $SDL^1_{i,b,j}$ shall designate the schedule computed for lamination j of the *dispatchable load bid* at bus $b \in B^{DL}$ in interval $i \in I$.

The RT calculation engine will record all such values for informational purposes. Internal resource schedules are provided to *market participants* at a 0.1 MW granularity. The schedules calculated for the *dispatch interval* will be used to form the *dispatch instructions* that are provided to *registered market participants* for *dispatchable load* and dispatchable generation resources.

In instances where an NQS resource is being evaluated for shutdown in Real-Time Scheduling, the shutdown decisions made in Real-Time Scheduling will be provided to Real-Time Pricing.

3.6.2. Real-Time Pricing

Real-Time Pricing will perform a *security*-constrained economic *dispatch* of available resources to meet the *IESO*'s non-dispatchable *demand* forecast and *IESO*-specified *operating reserve* requirements. It will also evaluate *demand* from *dispatchable loads*.

As in Real-Time Scheduling, schedules for imports, exports, *hourly demand response* resources and operational commitments of NQS resources will be held fixed as determined by the *pre-dispatch scheduling* processes. Schedules for imports and exports will be held fixed to those derived from the pricing algorithm of the PD calculation engine run determining binding *intertie* schedules for the *dispatch hour*. This is done to help reflect the results of constraint violations in pre-dispatch in real-time prices.

Real-Time Pricing will use *bids* and *offers* submitted by *market participants* to maximize the gains from trade. Like Real-Time Scheduling, the optimization is subject to the resource constraints accompanying those *bids* and *offers* and system constraints enforced by the *IESO* to maintain *reliability*. However, the objective function and constraints will reflect the set of constraint violation penalty curves used for determining *market prices*.

Real-Time Pricing will determine LMPs according to the principle for price-setting eligibility. It will also make the necessary adjustments when control actions have been implemented in real time.

The initial resource schedules in Real-Time Pricing will use the initial schedules from Real-Time Scheduling. To facilitate calculating *settlement*-ready prices, the initial resource schedules of Real-Time Pricing also consider schedules from the pricing algorithm of the preceding RT calculation engine run.

The LMPs produced by Real-Time Pricing for the *dispatch interval* will comprise the *settlement*-ready LMPs that are used in the *settlement* of *energy* and *operating reserve* for dispatchable and non-dispatchable generation resources, *dispatchable loads*, price responsive loads and import and export transactions.

Real-time LMPs for *non-dispatchable loads* are used in the calculation of the Load Forecast Deviation Charge (LFDC) of the hourly DAM Ontario Zonal Price. Real-time LMPs from all load types are used in the calculation of zonal prices for the *settlement* of virtual transactions. For the details of the *settlement* for *energy* and *operating reserve* refer to the Market Settlement detailed design document.

3.6.2.1. Inputs

All applicable inputs identified in Section 3.4.1 will be evaluated. Table 3-6 lists the outputs of Real-Time Scheduling that will also be used in Real-Time Pricing.

Table 3-6: Outputs of Real-Time Scheduling as Input to Real-Time Pricing

Input	Description
$SD_{i,b}^{RTS} \in \{0,1\}$	Whether the dispatchable generation resource at bus $b \in B^{NQS}$ was scheduled on a shutdown trajectory in interval $i \in I$ such that $EvalSD_{i,b}=1$.
$SDLInitSch_{0,b}$	The resource initial schedule for the *dispatchable load* at bus $b \in B^{DL}$ used in Real-Time Scheduling.
$SDGInitSch_{0,b}$	The resource initial schedule for the dispatchable generation resource at bus $b \in B^{DG}$ used in Real-Time Scheduling.

3.6.2.2. Variables and Objective Function

The variables used are the same as those used in Real-Time Scheduling. The objective function is the same as in Real-Time Scheduling except the violation cost is calculated using the constraint violation penalty curves for determining *market prices*.

Thus, Real-Time Scheduling will calculate the violation cost in interval $i \in I$ as follows:

$$
\begin{aligned}
ViolCost_i \; = & \sum_{w=1..N_{LdViol_i}} SLdViol_{i,w} \cdot PLdViolPrc_{i,w} \\
& - \sum_{w=1..N_{GenViol_i}} SGenViol_{i,w} \cdot PGenViolPrc_{i,w} \\
& + \sum_{w=1..N_{10SViol_i}} S10SViol_{i,w} \cdot P10SViolPrc_{i,w} \\
& + \sum_{w=1..N_{10RViol_i}} S10RViol_{i,w} \cdot P10RViolPrc_{i,w} \\
& + \sum_{w=1..N_{30RViol_i}} S30RViol_{i,w} \cdot P30RViolPrc_{i,w} \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{REG10RViol_i}} SREG10RViol_{r,i,w} \cdot PREG10RViolPrc_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{REG30RViol_i}} SREG30RViol_{r,i,w} \cdot PREG30RViolPrc_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{XREG10RViol_i}} SXREG10RViol_{r,i,w} \right. \\
& \left. \cdot PXREG10RViolPrc_{i,w} \right) \\
& + \sum_{r \in ORREG} \left(\sum_{w=1..N_{XREG30RViol_i}} SXREG30RViol_{r,i,w} \right. \\
& \left. \cdot PXREG30RViolPrc_{i,w} \right) \\
& + \sum_{f \in F_i} \left(\sum_{w=1..N_{PreITLViol_{f,i}}} SPreITLViol_{f,i,w} \cdot PPreITLViolPrc_{f,i,w} \right) \\
& + \sum_{c \in C} \sum_{f \in F_{i,c}} \left(\sum_{w=1..N_{ITLViol_{c,f,i}}} SITLViol_{c,f,i,w} \cdot PITLViolPrc_{c,f,i,w} \right).
\end{aligned}
$$

This maximization will be subject to the constraints described in the next sections.

3.6.2.3. Constraints Overview

The prices determined in Real-Time Pricing are intended to be a reflection of the marginal value of the *dispatch* decisions made in Real-Time Scheduling. Therefore, many of the constraints enforced in Real-Time Pricing are analogous to the constraints enforced in Real-Time Scheduling. These constraints are subject to adjustments to reflect different *intertie* schedules and initial conditions, in addition to adjustments for control actions that have been implemented. However, additional constraints are required to ensure the eligibility of an *offer* or *bid* lamination to set price is appropriately reflected. The following sub-section describes the additional constraints required.

NQS Resources

An NQS resource may only set prices in the *energy* and *operating reserve* markets in intervals for which it is scheduled at or above its *minimum loading point* (MLP) in Real-Time Scheduling. In intervals where the resource was scheduled at or above its MLP, the resource will also be scheduled at or above its MLP in Real-Time Pricing and the *offer* for *energy* laminations corresponding to production below MLP will be ineligible to set prices.

To reflect the eligibility of an NQS resource to set prices, the NQS start-up and shutdown statuses will be modified in Real-Time Pricing to reflect the shutdown decisions made by Real-Time Scheduling. For NQS resource bus $b \in B^{NQS}$ and interval $i \in I$, the following statuses will be used:

- $AtZero_{i,b}^{RTP} \in \{0,1\}$ shall designate that the resource is scheduled to be offline. It is defined by:
$$AtZero_{i,b}^{RTP} = AtZero_{i,b}.$$
- $SU_{i,b}^{RTP} \in \{0,1\}$ shall designate that the resource must be scheduled on its start-up trajectory. It is defined by:
$$SU_{i,b}^{RTP} = SU_{i,b}.$$
- $AtMLP_{i,b}^{RTP} \in \{0,1\}$ shall designate that the resource is scheduled to operate at or above MLP. It is defined by:
$$AtMLP_{i,b}^{RTP} = \begin{cases} AtMLP_{i,b} & if\ EvalSD_{i,b} = 0 \\ 1 - SD_{i,b}^{RTS} & if\ EvalSD_{i,b} = 1 \end{cases}.$$
- $EvalSD_{i,b}^{RTP} \in \{0,1\}$ shall designate that the resource can be evaluated for *energy* schedules below MLP. It is defined by:
$$EvalSD_{i,b}^{RTP} = 0.$$
- $SD_{i,b}^{RTP} \in \{0,1\}$ shall designate that the resource must be scheduled on its shutdown trajectory. It is defined by:
$$SD_{i,b}^{RTP} = \begin{cases} SD_{i,b} & if\ EvalSD_{i,b} = 0 \\ SD_{i,b}^{RTS} & if\ EvalSD_{i,b} = 1 \end{cases}.$$

These statuses, in conjunction with the *operating reserve* scheduling variable bounds, the NQS start-up and shutdown constraints, and the resource minimum and maximum constraints, determine when NQS resources are eligible to set price.

3.6.2.4. Bid/Offer Constraints Applying to Single Intervals

Scheduling Variable Bounds

The constraints are the same as in Real-Time Scheduling. The NQS start-up and shutdown statuses will be replaced with those described in Section 3.6.2.3. That is, for NQS resource bus $b \in B^{NQS}$ and interval $i \in I$:

- $AtZero_{i,b}$ will be replaced by $AtZero_{i,b}^{RTP}$;
- $AtMLP_{i,b}$ will be replaced by $AtMLP_{i,b}^{RTP}$; and
- $EvalSD_{i,b}$ will be replaced by $EvalSD_{i,b}^{RTP}$.

Resource Initial Conditions

The initial schedules for Real-Time Pricing will be informed by the initial schedules for Real-Time Scheduling and the schedules calculated in the pricing algorithm of the preceding RT calculation engine run.

Dispatchable Load

The initial schedule for the *dispatchable load* at bus $b \in B^{DL}$ will be fixed in the optimization function, where:

- $SDLInitPrc_{0,b}$ shall designate the initial schedule for the *dispatchable load* at bus b.

This parameter will be calculated as follows.

1. If $SDLSch_{0,b}^{Prev} \leq SDLPrc_{0,b}^{Prev} \leq SDLInitSch_{0,b}$ or $SDLInitSch_{0,b} \leq SDLPrc_{0,b}^{Prev} \leq SDLSch_{0,b}^{Prev}$ then:
    a. Set $SDLInitPrc_{0,b} = SDLInitSch_{0,b}$.
2. Otherwise:
    b. Set $SDLInitPrc_{0,b} = SDLPrc_{0,b}^{Prev}$.

The initial scheduling variables will be fixed to the resource initial schedules. For all *dispatchable load* buses $b \in B^{DL}$:

$$\sum_{j \in J_{0,b}^{E}} SDL_{0,b,j} = SDLInitPrc_{0,b}.$$

Dispatchable Generation Resources

The initial schedule for the dispatchable generation resource at bus $b \in B^{DG}$ will be fixed in the optimization function, where:

- $SDGInitPrc_{0,b}$ shall designate the initial schedule for the dispatchable generation resource at bus b.

This parameter will be calculated as follows.

1. If $SDGSch_{0,b}^{Prev} \leq SDGPrc_{0,b}^{Prev} \leq SDGInitSch_{0,b}$ or $SDGInitSch_{0,b} \leq SDGPrc_{0,b}^{Prev} \leq SDGSch_{0,b}^{Prev}$ then:
    a. Set $SDGInitPrc_{0,b} = SDGInitSch_{0,b}$.
2. Otherwise:
    a. Set $SDGInitPrc_{0,b} = SDGPrc_{0,b}^{Prev}$.

The initial scheduling variables will be fixed to the resource initial schedules. For all dispatchable generation resource buses $b \in B^{DG}$:

$$\sum_{k \in K_{0,b}^{E}} SDG_{0,b,k} = SDGInitPrc_{0,b}.$$

Resource Minimums and Maximums

The constraints are the same as in Real-Time Scheduling. The NQS start-up and shutdown statuses will be replaced with those described in Section 3.6.2.3. That is, for NQS resource bus $b \in B^{NQS}$ and interval $i \in I$, $AtMLP_{i,b}$ will be replaced by $AtMLP_{i,b}^{RTP}$.

Resource minimum and maximum constraints limit a resource's ability to set prices to within the operating region defined by such constraints.

Operating Reserve Scheduling

The constraints are the same as in Real-Time Scheduling.

PSU Resources

De-rates

The constraints are the same as in Real-Time Scheduling.

Translation Between PU and PSU Schedules

The constraints are the same as in Real-Time Scheduling.

Duct Firing Operating Reserve Limitations

The ability of a PSU resource to provide *ten-minute operating reserve* from its duct firing region will be respected in Real-Time Pricing in the same manner in which it is respected in Real-Time Scheduling. A PSU resource that cannot provide *ten-minute operating reserve* from its duct firing region will be eligible to set prices within an operating range consistent with the schedules calculated. If the resource is scheduled for *energy* within the duct firing region, it will be eligible to set prices in the *energy* and *thirty-minute operating reserve* markets only. If the resource is not scheduled for *energy* within its duct firing region, it will be eligible to set prices in the *energy* and all *operating reserve* markets.

Hydroelectric Resources

Forbidden region constraints for hydroelectric resources will be respected in Real-Time Pricing in the same manner in which they are respected in Real-Time Scheduling. A hydroelectric resource will be ineligible to set prices when it is ramped through its *forbidden region* at its maximum offered ramp capability.

3.6.2.5. Bid/Offer Inter-Interval/Multi-Interval Constraints

Energy Ramping

The *energy* ramping constraints are the same as Real-Time Scheduling. These constraints will restrict the eligibility of a resource to set *energy* prices to within the bounds determined by the ramping constraints. If the multi-interval optimization determines that a resource must be ramped out of merit in the *dispatch interval* to meet a need in a future interval, such a resource will be ineligible to set price.

NQS Start-up and Shutdown

The constraints are the same as in Real-Time Scheduling except the NQS start-up and shutdown statuses will be modified as described in Section 3.6.2.3.

Operating Reserve Ramping

The constraints are the same as in Real-Time Scheduling.

3.6.2.6. Constraints to Ensure Schedules Do Not Violate Reliability Requirements

Energy Balance

The *energy* balance constraint from Real-Time Scheduling must be modified to:

- reflect the *intertie* schedules calculated by the pricing algorithm in the PD calculation engine run determining binding *intertie* schedules for the *dispatch hour*; and

- account for any *demand* adjustment required to calculate appropriate prices when voltage reductions or load shedding have been implemented.

This constraint is described further in terms of its constituent parts.

Define the total amount of withdrawals scheduled at load bus $b \in B$ in interval $i \in I$, $With_{i,b}$, as either:

- all *dispatchable load* scheduled at bus b if $b \in B^{DL}$; or
- the fixed schedule of the *hourly demand response* resource at bus b if $b \in B^{HDR}$; or
- the fixed load scheduled at bus b if $b \in B^{NoBid}$

so that

$$With_{i,b} = \begin{cases} \sum_{j \in J_{i,b}^{E}} SDL_{i,b,j} & if\ b \in B^{DL} \\ FHDR_{i,b} & if\ b \in B^{HDR} \\ FNBL_{i,b} & if\ b \in B^{NoBid} \end{cases}.$$

Define the total amount of withdrawals scheduled at *intertie zone* sink bus $d \in DX$ in interval $i \in I$, $With_{i,d}$, as the fixed exports from Ontario to the *intertie zone* sink bus. Thus,

$$With_{i,d} = FXLPrc_{i,d}.$$

Define the total amount of injections scheduled at internal generation resource bus $b \in B$, in interval $i \in I$, $Inj_{i,b}$, as either:

- non-dispatchable generation scheduled at bus b if $b \in B^{NDG}$; or
- dispatchable generation scheduled at bus b if $b \in B^{DG}$; or
- the fixed generation scheduled at bus b if $b \in B^{NoOffer}$.

so that

$$Inj_{i,b} = \begin{cases} \sum_{k \in K_{i,b}^{E}} SNDG_{i,b,k} & if\ b \in B^{NDG} \\ \sum_{k \in K_{i,b}^{E}} SDG_{i,b,k} & if\ b \in B^{DG} \\ FNOG_{i,b} & if\ b \in B^{NoOffer} \end{cases}.$$

Define the total amount of injections scheduled at *intertie zone* source bus $d \in DI$ in interval $i \in I$, $Inj_{i,d}$, as the imports into Ontario from that *intertie zone* source bus. Thus,

$$Inj_{i,d} = FIGPrc_{i,d}.$$

Injections and withdrawals at each bus must be multiplied by one plus the marginal loss factor to reflect the losses or reduction in losses that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between total and marginal losses and the adjustment to calculate appropriate prices when control actions have been implemented. Load or generation reduction associated with the *demand* constraint violation will be subtracted from the total load or generation to ensure that the RT calculation engine will always produce a solution. The resulting *energy* balance constraint for interval $i \in I$ is

$$\begin{aligned} FL_i + CAAdj_i + & \sum_{b \in B^{DL} \cup B^{HDR} \cup B^{NoBid}} (1 + MglLoss_{i,b}) \cdot With_{i,b} \\ & + \sum_{d \in DX} (1 + MglLoss_{i,d}) \cdot With_{i,d} - \sum_{w=1..N_{LdViol_i}} SLdViol_{i,w} \\ & = \sum_{b \in B^{NDG} \cup B^{DG} \cup B^{NoOffer}} (1 + MglLoss_{i,b}) \cdot Inj_{i,b} \\ & + \sum_{d \in DI} (1 + MglLoss_{i,d}) \cdot Inj_{i,d} - \sum_{w=1..N_{GenViol_i}} SGenViol_{i,w} \\ & + LossAdj_i. \end{aligned}$$

Operating Reserve Requirements

The constraints are the same as in Real-Time Scheduling, with one exception. The *operating reserve* schedules for imports and exports derived from the pricing algorithm results of the PD calculation engine run determining binding *intertie schedules* for the *dispatch hour* will be used. That is, for all intervals $i \in I$:

- $F10NXLSch_{i,d}$ will be replaced by $F10NXLPrc_{i,d}$ for all $d \in DX$;
- $F10NIGSch_{i,d}$ will be replaced by $F10NIGPrc_{i,d}$ for all $d \in DI$;
- $F30RXLSch_{i,d}$ will be replaced by $F30RXLPrc_{i,d}$ for all $d \in DX$; and
- $F30RIGSch_{i,d}$ will be replaced by $F30RIGPrc_{i,d}$ for all $d \in DI$.

IESO Internal Transmission Limits

The constraints are the same as in Real-Time Scheduling. The sensitivities and limits considered are those provided by the most recent *security* assessment function iteration.

Penalty Price Variable Bounds

The following constraints restrict the penalty price variables to the ranges determined by the penalty price curves. For all intervals $i \in I$:

$0 \leq SLdViol_{i,w} \leq QLdViolPrc_{i,w}$ for all $w \in \{1,..,N_{LdViol_i}\}$;

$0 \leq SGenViol_{i,w} \leq QGenViolPrc_{i,w}$ for all $w \in \{1,..,\mathrm{N}_{\mathrm{GenViol}_i}\}$;

$0 \leq S10SViol_{i,w} \leq Q10SViolPrc_{i,w}$ for all $w \in \{1,..,\mathrm{N}_{\mathrm{10SViol}_i}\}$;

$0 \leq S10RViol_{i,w} \leq Q10RViolPrc_{i,w}$ for all $w \in \{1,..,\mathrm{N}_{\mathrm{10RViol}_i}\}$;

$0 \leq S30RViol_{i,w} \leq Q30RViolPrc_{i,w}$ for all $w \in \{1,..,\mathrm{N}_{\mathrm{30RViol}_i}\}$;

$0 \leq SREG10RViol_{r,i,w} \leq QREG10RViolPrc_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,\mathrm{N}_{\mathrm{REG10RViol}_i}\}$;

$0 \leq SREG30RViol_{r,i,w} \leq QREG30RViolPrc_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,\mathrm{N}_{\mathrm{REG30RViol}_i}\}$;

$0 \leq SXREG10RViol_{r,i,w} \leq QXREG10RViolPrc_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,\mathrm{N}_{\mathrm{XREG10RViol}_i}\}$;

$0 \leq SXREG30RViol_{r,i,w} \leq QXREG30RViolPrc_{i,w}$ for all $r \in ORREG$, $w \in \{1,..,\mathrm{N}_{\mathrm{XREG30RViol}_i}\}$;

$0 \leq SPreITLViol_{f,i,w} \leq QPreITLViolPrc_{f,i,w}$ for all $f \in F_i$, $w \in \{1,..,\mathrm{N}_{\mathrm{PreITLViol}_{f,i}}\}$; and

$0 \leq SITLViol_{c,f,i,w} \leq QITLViolPrc_{c,f,i,w}$ for all $c \in C, f \in F_{i,c}$, $w \in \{1,..,\mathrm{N}_{\mathrm{ITLViol}_{c,f,i}}\}$.

3.6.2.7. Outputs

Real-Time Pricing will produce shadow prices for all constraints contributing to locational prices. A shadow price for a constraint reflects the cost savings achieved by relaxing that constraint a small amount and measuring the marginal response within the interval. LMPs will be calculated using the pricing formulas provided in Section 3.8, which specify how constraint shadow prices, marginal loss factors and constraint sensitivities are used to determine an LMP and its components.

Table 3-7 lists the shadow prices of Real-Time Pricing constraints that will be output for each interval $i \in I$.

Table 3-7: Shadow Price Outputs of Real-Time Pricing

Output	Description
SPL_i^1	shall designate the shadow price for the *energy* balance constraint in interval i.
$SPNormT_{i,f}^1$	shall designate the shadow price for the pre-contingency transmission constraint for *facility* $f \in F$ in interval i.
$SPEmT_{i,c,f}^1$	shall designate the shadow price for the post-contingency transmission constraint for *facility* $f \in F$ in contingency $c \in C$ in interval i.
$SP10S_i^1$	shall designate the shadow price for the total synchronized *ten-minute operating reserve* requirement constraint in interval i.
$SP10R_i^1$	shall designate the shadow price for the total *ten-minute operating reserve* requirement constraint in interval i.

Output	Description
$SP30R_i^1$	shall designate the shadow price for the total *thirty-minute operating reserve* requirement constraint in interval i.
$SPREGMin10R_{i,r}^1$	shall designate the shadow price for the minimum *ten-minute operating reserve* constraint for region $r \in ORREG$ in interval i.
$SPREGMin30R_{i,r}^1$	shall designate the shadow price for the minimum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in interval i.
$SPREGMax10R_{i,r}^1$	shall designate the shadow price for the maximum *ten-minute operating reserve* constraint for region $r \in ORREG$ in interval i.
$SPREGMax30R_{i,r}^1$	shall designate the shadow price for the maximum *thirty-minute operating reserve* constraint for region $r \in ORREG$ in interval i.

3.6.3. Outputs for Energy and OR Settlement

Table 3-8 lists the schedules calculated by Real-Time Scheduling that will be used in the calculation of make-whole payments for *dispatchable loads* and dispatchable generation resources.

Table 3-8: Real-Time Scheduling Output used for the Calculation of Make-Whole Payments for Dispatchable Resources

Output	Description
$SDL_{i,b,j}^1$	The amount of *dispatchable load* scheduled at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J_{i,b}^E$.
$SDG_{i,b,k}^1$	The amount of dispatchable generation scheduled at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K_{i,b}^E$.

Table 3-9 lists the fixed *hourly demand response* resource schedules respected by Real-Time Scheduling. The input parameter represents the *hourly demand response* activation schedules determined by the *pre-dispatch scheduling* process for physical and virtual *hourly demand response* resources associated with *non-dispatchable loads*, and for physical *hourly demand response* resources associated with a price responsive load.

Table 3-9: Real-Time Scheduling Input used to Determine HDR Activation Schedules

Input	Description
$FHDR_{i,b}$	The fixed schedule of *energy* consumption for interval $i \in I$ for the physical or virtual *hourly demand response* resource at bus $b \in B^{HDR}$.

Table 3-10 lists the schedules calculated by Real-Time Scheduling that will be used in the *settlement* of *operating reserve* for *dispatchable loads* and dispatchable generation resources.

Table 3-10: Real-Time Scheduling Output used for the Settlement of the Real-Time Operating Reserve Market

Output	Description
$S10SDL^{1}_{i,b,j}$	The amount of synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J^{10S}_{i,b}$.
$S10NDL^{1}_{i,b,j}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J^{10N}_{i,b}$.
$S30RDL^{1}_{i,b,j}$	The amount of *thirty-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus $b \in B^{DL}$ in interval $i \in I$ in association with lamination $j \in J^{30R}_{i,b}$.
$S10SDG^{1}_{i,b,k}$	The amount of synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K^{10S}_{i,b}$.
$S10NDG^{1}_{i,b,k}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K^{10N}_{i,b}$.
$S30RDG^{1}_{i,b,k}$	The amount of *thirty-minute operating reserve* that a qualified dispatchable generation resource is scheduled to provide at bus $b \in B^{DG}$ in interval $i \in I$ in association with lamination $k \in K^{30R}_{i,b}$.

The set of internal pricing nodes will be designated by L and will include:

- Resources scheduled by the RT calculation engine optimization function (designated B as per Section 3.4.1.2); and

- Other internal locations not provided a schedule by the optimization function such as *non-dispatchable load* locations.

The set of external pricing nodes will be designated by D as in Section 3.4.1.2.

Table 3-11 lists the *settlement*-ready prices that will be established for the *dispatch interval* using the logic described in Section 3.8. The RT Ontario Zonal Price is not listed as it is not used for *settlement* of *energy* for *non-dispatchable loads*.

Table 3-11: Settlement-Ready LMP Outputs of the Real-Time Scheduling and Pricing Pass

Output	Description
$LMP^{1}_{1,b}$	The *dispatch interval* LMP for node $b \in L$.
$ISP^{1}_{1,d}$	The *dispatch interval intertie settlement* price for *intertie zone* bus $d \in D$.
$ICP^{1}_{1,d}$	The *dispatch interval intertie* congestion price for *intertie zone* bus $d \in D$.
$VZonalP^{1}_{1,m}$	The *dispatch interval energy* price for virtual transaction zonal trading entity $m \in M$.
$L30RP^{1}_{1,b}$	The *dispatch interval thirty-minute operating reserve* price for bus $b \in B$.
$L10NP^{1}_{1,b}$	The *dispatch interval* non-synchronized *ten-minute operating reserve* price for bus $b \in B$.
$L10SP^{1}_{1,b}$	The *dispatch interval* synchronized *ten-minute operating reserve* price for bus $b \in B$.
$ExtL30RP^{1}_{1,d}$	The *dispatch interval thirty-minute operating reserve price* for *intertie zone* bus $d \in D$.
$ExtL10NP^{1}_{1,d}$	The *dispatch interval* non-synchronized *ten-minute operating reserve* price for *intertie zone* bus $d \in D$.

3.7. Security Assessment Function

The *security* assessment function assesses power system *security* using the schedules produced by the optimization function. As indicated in Section 3.3, the scheduling and pricing algorithms of the RT calculation engine will include multiple iterations between the optimization function and the *security* assessment function described here. Information about the *IESO-controlled grid* such as operating *security limits*, thermal ratings, the network model, loop flow and the status of power system equipment will be used by the *security* assessment function to evaluate the *security* of the schedules provided by the optimization function against the expected *transmission system* capability. As part of its evaluation, the *security* assessment function will create the following information to provide to the next optimization function iteration:

- A *security* constraint set corresponding to violated thermal and/or operating *security limits*; and
- A loss adjustment.

For each identified *security* constraint, the *security* assessment function will provide the coefficients and limits of a linear constraint in the optimization function variables to be enforced by the optimization function.

The following sections describe the inputs, the process and the outputs of the *security* assessment function.

3.7.1. Inputs

3.7.1.1. Inputs Provided by the Optimization Function

The optimization function will continue to provide the *security* assessment function with schedules for load and supply resources. With the exception of PSU resources, such schedules will be represented at their corresponding electrical buses in the network model. The *security* assessment function will use the physical unit representation of combined cycle *facilities* that have elected to be represented as a *pseudo-unit*.

The following outputs of the optimization function are used by the *security* assessment function:

- The schedules for *dispatchable loads* and *hourly demand response* resources;
- The schedules for non-dispatchable and dispatchable generation; and
- The schedules for *boundary entity* resource sources and sinks at each *intertie zone*.

Some of the above schedules provided by the optimization function are fixed to input values as described in Section 3.4.1.

3.7.1.2. Security Limits

Security limits are operating *security limits* (OSLs) and thermal limits. OSLs are associated with transient stability limits, voltage stability limits, dynamic stability limits and voltage decline limits. They also include limits based on equipment ratings such as thermal ratings and short-circuit capabilities. The RT calculation engine will use OSLs and thermal limits to perform a *security* analysis of the *IESO-controlled grid*.

The *IESO* defines OSLs as a set of equations along with their activation plans. Each OSL equation is applicable for a specific area of the *IESO-controlled grid* under all elements in-service and/or specific *outage* conditions. An activation plan specifies which OSLs are applicable for a time period.

The *security* assessment function of the RT calculation engine will create a linearized constraint when it determines that an OSL is violated. The linearized constraints are passed to the optimization function and are included as new constraints in the next iteration of the optimization function.

An OSL equation will continue to be a function of any of the following network variables:

- Any transformer, line, branch group, or phase shifter MW flow;
- Any generation resource MW outputs;
- Any load MW; and
- The primary *demand*.

The line, transformer, branch group and phase shifter MW flows in the OSL equations will be replaced with the sum of the pre-contingency sensitivity factors multiplied by scheduling variables.

The RT calculation engine will use pre-contingency and post-contingency thermal ratings so that real-time *dispatch* for the next 11 five-minute intervals results in transmission flows that respect the thermal limits. The ratings used by the RT calculation engine will continue to be received from *transmitters*. The *security* assessment function will create a linearized constraint when it determines that a thermal limit is violated.

3.7.1.3. Network Model

The *security* assessment function will continue to use the following data from the network model:

- Power system model data;
- Load distribution factors;

- A list of contingencies; and
- A list of monitored elements.

Power System Model Data

The same base power system model will be used in the DAM, PD and RT calculation engines. In the RT calculation engine, some model data will be supplemented by the EMS data determined based on RT telemetry data, planned transmission outages and confirmed breaker synchronization time of NQS resources.

Loop flows resulting from the *dispatch* within other *control areas* or transactions between other *control areas* that are not recorded as imports or exports within Ontario will affect the loading on transmission within Ontario. The *IESO* will continue to model loop flows into or out of Ontario at various *intertie zones* as though they were generation or load that exist at given buses or combinations of buses in the *control areas* containing those *intertie zones*.

Load Distribution Factors

Load distribution factors define the load pattern that will be used to distribute the *IESO demand* forecast inside each *demand* forecast area. The *security* assessment function will use load distribution factors to determine forecasted MW quantities at *non-dispatchable load* locations and price responsive load locations based on the *IESO demand* forecast.

In the *security* assessment function for the pricing algorithm, the *demand* forecast will be modified to reflect control actions as described in Section 3.4.1.5. This modification will be applied to each *demand* forecast area pro-rata in proportion to the forecast *demand* for the area.

List of Contingencies

The list of contingencies will continue to include contingency name, description of contingencies and configuration settings/flags such as priority setting and flags to indicate whether 115 kV equipment should be monitored when a contingency is simulated.

List of Monitored Equipment

The list of monitored equipment indicates the equipment to be monitored for violation of thermal limits and/or voltage limits. It will continue to include the following information:

- The power system equipment name;
- The equipment type; and
- The monitoring type, i.e. thermal, voltage or no monitoring.

3.7.2. Security Assessment Function Processing

The *security* assessment function will perform the following calculations and analysis:

- Prepare a base case power flow solution for each interval of the MIO look-ahead period;
- Perform a pre-contingency *security* assessment on the base case power flow solution using pre-contingency thermal limits and operating *security limits;*
- Prepare linearized constraints using sensitivity factors for any violated pre-contingency thermal limits and operating *security limits*;
- Calculate total losses, marginal loss factors and the loss adjustment. The loss adjustment is required to account for the difference between the total losses and the linearized losses calculated using marginal loss factors;
- Simulate the specified contingencies to perform a post-contingency *security* assessment on the post-contingency state of the base case power flow solution using post-contingency thermal limits; and
- Prepare linearized constraints using sensitivity factors for any violated post-contingency thermal limits.

3.7.2.1. Base Case Power Flow

An AC power flow solution will continue to be prepared for each interval in the MIO look-ahead period. If the AC power flow solution fails to converge for any interval, a non-linear DC power flow will continue to be used for that interval. If the non-linear DC power flow solution fails to converge for any interval, a linear DC power flow will be used for that interval.

Consistent with future DAM and PD calculation engines, the power flow solution will simulate adjustments of tap angles of phase shifters to control MW flow and taps of transformers, reactors, capacitors, synchronous condensers and generators to control MVAr/voltage.

3.7.2.2. Pre-contingency Security Assessment

When the AC or non-linear DC power flow solution is used, the pre-contingency *security* assessment will continue to check all monitored equipment for violation of their pre-contingency thermal limits. It will also check for violation of any applicable OSL equations. For every violated limit, a linearized constraint will be generated.

When the linear DC power flow solution is used, the pre-contingency *security* assessment may develop linear constraints to help the AC or non-linear DC power flow solution converge in the subsequent iterations.

These linearized constraints will be expressed in terms of scheduling variables and sensitivity factors so they can be provided to the optimization function to be used in the next optimization function iteration.

The sensitivity factors will continue to be derived based on the power flow Jacobian matrix. The sensitivity factor for a resource with respect to a line flow for example, indicates the fraction of *energy* injected at the resource bus which flows on the line.

The pre-contingency *security* assessment will continue to use the following inputs:

- OSL equations;
- pre-contingency thermal limits;
- the list of monitored equipment; and
- base case power flow solution which also includes calculated MW flows on lines, transformers, phase shifters, and branch groups.

The line, transformer, branch group and phase shifter MW flows in the OSL equations and MW flow of monitored equipment will continue to be replaced with the sum of the pre-contingency sensitivity factors multiplied by scheduling variables. The minimum and maximum limits of OSL equations and thermal limits will be adjusted to reflect the difference between the calculated MW flows and the linearized MW flows using the sensitivity factors.

For an *intertie zone* connected to Ontario through regulating phase shifters that receive shares of the *intertie* schedule, the effective sensitivity factor of *boundary entities* in the *intertie zone* will continue to be calculated using the Jacobian matrix, shares of phase shifters in the *intertie* schedule and phase shifter sensitivities.

3.7.2.3. Loss Calculation

The *security* assessment function will calculate total losses, marginal loss factors and a loss adjustment for each interval using the base case power flow solution. All of these loss related quantities can vary from interval to interval.

The RT calculation engine will use a set of fixed marginal loss factors for each *dispatch hour* calculated in advance of the *dispatch hour*. The same set of fixed marginal loss factors will apply to all five-minute intervals of the *dispatch hour.* The scheduling and pricing algorithms will use the same set of fixed marginal loss factors. The set of fixed marginal loss factors will be determined based on the marginal loss factors calculated in the pre-dispatch hour by the scheduling algorithm of the RT calculation engine.

When determining marginal loss factors, the impact of local branches (e.g. load step-down transformers) between the resource bus and the resource *connection point* to the *IESO-controlled grid* will be excluded.

3.7.2.4. Contingency Analysis

The contingency analysis function will use a linear power flow analysis based on base case power flow and consists of the following sub-functions:

- Post-contingency connectivity analysis;
- Post-contingency MW flow calculation; and
- Checking of post-contingency thermal limit violations and building of linearized constraints for violated limits.

The contingency analysis function will be able to model post-contingency control actions such as automatic angle tap adjustments.

The calculated post-contingency MW flows will continue to be compared to the post-contingency branch thermal limits for all the monitored equipment. For each monitored equipment, up to a pre-defined configurable number of the most severe violations will be linearized and passed to the optimization function as a linear constraint.

The calculation of the post-contingency sensitivity factors will be similar to that of the pre-contingency sensitivity factors. The updated power flow Jacobian matrix and post-contingency system states will continue to be used in the calculation of the sensitivity factors.

3.7.3. Outputs

The following outputs of the *security* assessment function will be provided to the optimization function:

- Loss adjustment quantity for every interval which is needed to correct for any discrepancy between total losses in the *IESO-controlled grid* obtained from the base case power flow and the linearized losses calculated using marginal loss factors;
- The linearized constraints for all violated pre-contingency limits for each interval; and
- The linearized constraints for all violated post-contingency thermal limits for each interval.

The sensitivity factors described in Sections 3.7.2.2 and 3.7.2.4 and fixed marginal loss factors described in Section 3.7.2.3 will also be used in LMP calculations.

3.8. Pricing Formulas

The RT calculation engine will calculate LMPs for all pricing nodes using shadow prices, constraint sensitivities and marginal loss factors. The LMPs calculated for the *dispatch interval* will be used for *settlement* of the *energy market* and *operating reserve market* while the LMPs calculated for advisory intervals will be informational.

LMPs for *energy* will be calculated for the following pricing nodes:

- Dispatchable and non-dispatchable generation resource buses;
- *Dispatchable load* and *hourly demand response* resource buses;
- *Non-dispatchable load* and price responsive load buses; and
- *Intertie zone* source and sink buses

LMPs for *operating reserve* will be calculated for the following pricing nodes:

- Dispatchable generation resource buses;
- *Dispatchable load* buses; and
- *Intertie zone* source and sink buses.

The set of internal pricing nodes will be designated by L and will include:

- Resources scheduled by the RT calculation engine optimization function (designated B as per Section 3.4.1.2), and
- Other internal locations not provided a schedule by the optimization function such as *non-dispatchable load* locations.

The set of external pricing nodes will be designed by D as in Section 3.4.1.2.

Prices will be calculated using the shadow prices determined by the pricing algorithm. If a price is not within the maximum clearing price and the *settlement* floor price (the *settlement* bounds), the price and its components will be modified. The following parameters will be used when performing price modification:

- $EngyPrcCeil$ shall designate the maximum *energy* price and be set equal to the *maximum market clearing price* of $2,000/MWh;
- $EngyPrcFlr$ shall designate the *settlement* floor price and be set equal to -$100/MWh;
- $ORPrcCeil$ shall designate the maximum *operating reserve* price for any class of *operating reserve* and be set equal to the maximum market clearing price of $2,000/MW;
- $ORPrcFlr$ shall designate the minimum *operating reserve price* for any class of *operating reserve* and be set equal to $0/MW; and

- $NISLPen$ shall designate the net interchange scheduling limit constraint violation penalty price for determining *market prices*.

A weighted average of the above *settlement*-ready prices will be used to provide zonal prices for the following pricing locations:

- Virtual transaction zonal trading entities; and
- *Non-dispatchable load zones*, including the Ontario Zone. Other *non-dispatchable load* zones are sub-zones of the Ontario Zone. The prices for these zones will be determined for informational purposes.

Non-dispatchable load zones will only contain *non-dispatchable load* buses, whereas virtual transaction zonal trading entities will be assigned buses for all load types. The RT calculation engine will receive virtual transaction trading zone and *non-dispatchable load* zone definitions specifying the buses whose LMPs will contribute to the zonal prices. The load distribution pattern as provided to the *security* assessment function will be used to determine the weight assigned to each bus in contributing to the zonal price for a *non-dispatchable load* zone. The weighting factors will be obtained by renormalizing the load distribution factors so that the sum of weighting factors for an individual zone is one. The weight assigned to each bus in contributing to the zonal price for a virtual transaction zonal trading entity will be equal to the weighting factors used to calculate the virtual zonal price in the day-ahead market for the applicable hour, where:

- M shall designate the set of virtual transaction zonal trading entities within Ontario;
- $L_m^{VIRT} \subseteq L$ shall designate the buses contributing to the price for virtual transaction trading zonal entity $m \in M$;
- $WF_{i,m,b}^{VIRT}$ shall designate the weighting factor for bus $b \in L_m^{VIRT}$ used to calculate the price for virtual transaction zonal trading entity $m \in M$ for interval $i \in I$;
- Y shall designate the *non-dispatchable load* zones in Ontario;
- $L_y^{NDL} \subseteq L$ shall designate the buses contributing to the zonal price for *non-dispatchable load* zone $y \in Y$; and
- $WF_{i,y,b}^{NDL}$ shall designate the weighting factor for bus $b \in L_y^{NDL}$ used to calculate the price for *non-dispatchable load* zone $y \in Y$ for interval $i \in I$.

If there is insufficient information to calculate an accurate price, or if the process fails to produce a *settlement*-ready price for any other reason, this will be flagged for further review by the *IESO*.

3.8.1. Locational Marginal Prices for Energy

The LMP at a bus in an interval measures the *offered* cost of meeting an infinitesimal change in the amount of load at that bus in that interval, or equivalently, measures the value of an incremental amount of generation at that bus in that interval.

3.8.1.1. Energy LMPs for Internal Pricing Nodes

For each interval $i \in I$, *energy* LMPs and components will be calculated for every node $b \in L$ where a non-dispatchable or dispatchable generation resource, a *dispatchable load*, an *hourly demand response* resource, a price responsive load or a *non-dispatchable load* is sited, where:

- $LMP_{i,b}^1$ shall designate the Pass 1 interval i LMP;
- $PRef_i^1$ shall designate the Pass 1 interval i *energy* reference price;
- $PLoss_{i,b}^1$ shall designate the Pass 1 interval i loss component; and
- $PCong_{i,b}^1$ shall designate the Pass 1 interval i congestion component.

The Pass 1 LMP at bus $b \in L$ in interval $i \in I$ will be initially calculated as follows:

$$InitLMP_{i,b}^1 = InitPRef_i^1 + InitPLoss_{i,b}^1 + InitPCong_{i,b}^1$$

where

$$InitPRef_i^1 = SPL_i^1 \,;$$

$$InitPLoss_{i,b}^1 = MglLoss_{i,b} \cdot SPL_i^1 \,;$$

and

$$\begin{aligned} InitPCong_{i,b}^1 = & \sum_{f \in F_i} PreConSF_{i,f,b} \cdot SPNormT_{i,f}^1 \\ & + \sum_{c \in C} \sum_{f \in F_{i,c}} SF_{i,c,f,b} \cdot SPEmT_{i,c,f}^1. \end{aligned}$$

The reference price and loss component together reflect the cost of meeting load at bus b, incorporating the effect of marginal losses and reflect the quantity of *energy* that must be injected at the reference bus to meet additional load at bus b. The congestion component reflects the cost of transmission congestion between the reference bus and bus b and is calculated by adding the individual incremental congestion costs for the binding transmission constraints on the path between the reference bus and bus b. Each congestion cost is obtained by multiplying the shadow price for the binding transmission constraint by the corresponding sensitivity factor for bus b.

An *energy* LMP can fall outside the *settlement* bounds provided by $EngyPrcFlr$ and $EngyPrcCeil$ as a result of joint optimization or constraint violation pricing. When this occurs, the LMP and its components (reference, loss and congestion) will be modified so that the LMP is within the *settlement* bounds.

The reference price will be modified if it is not within the *settlement* bounds. For interval $i \in I$:

a. If $InitPRef_i^1 > EngyPrcCeil$, set $PRef_i^1 = EngyPrcCeil$.

b. If $InitPRef_i^1 < EngyPrcFlr$, set $PRef_i^1 = EngyPrcFlr$.

c. Otherwise, set $PRef_i^1 = InitPRef_i^1$.

The LMP and components at internal bus $b \in L$ in interval $i \in I$ will be modified as follows:

3. Modify the LMP to be within *settlement* bounds.
    a. If $InitLMP_{i,b}^1 > EngyPrcCeil$, set $LMP_{i,b}^1 = EngyPrcCeil$.
    b. If $InitLMP_{i,b}^1 < EngyPrcFlr$, set $LMP_{i,b}^1 = EngyPrcFlr$.
    c. Otherwise, set $LMP_{i,b}^1 = InitLMP_{i,b}^1$.
4. If the reference price has been modified (i.e. $PRef_i^1 \neq InitPRef_i^1$), recalculate the loss component.
    a. If $PRef_i^1 \neq InitPRef_i^1$, set $PLoss_{i,b}^1 = MglLoss_{i,b} \cdot PRef_i^1$.
    b. Otherwise, set $PLoss_{i,b}^1 = InitPLoss_{i,b}^1$.
5. Modify the congestion component so the relationship between LMP, reference price, loss component and congestion component holds, provided the congestion component does not change mathematical signs as a result. If the congestion component changes its mathematical sign, set it to 0 and modify the loss component to maintain the relationship.
    a. If $LMP_{i,b}^1 - PRef_i^1 - PLoss_{i,b}^1$ and $InitPCong_{i,b}^1$ have the same mathematical sign, then set $PCong_{i,b}^1 = LMP_{i,b}^1 - PRef_i^1 - PLoss_{i,b}^1$.
    b. Otherwise, set $PCong_{i,b}^1 = 0$ and set $PLoss_{i,b}^1 = LMP_{i,b}^1 - PRef_i^1$.

If $PRef_i^1 = InitPRef_i^1$, then the LMP and components for nodes with prices within the *settlement* bounds will not be modified. If $PRef_i^1 \neq InitPRef_i^1$, then the LMP for nodes with prices within the *settlement* bounds will not be modified, but the components will be.

3.8.1.2. Energy Intertie Settlement Prices for Intertie Zone Source and Sink Buses

Intertie settlement prices will be calculated from real-time locational prices by incorporating the congestion costs associated with binding *intertie* limits determined by the PD calculation engine. First, the real-time *intertie* border price for the *intertie zone* and proxy location will be calculated. Then, the *intertie settlement* price will be determined using the corresponding rules in instances where the *intertie zone* was import-congested, export-congested, or congestion-free in the pre-dispatch timeframe.

The following outputs of the PD calculation engine will be used in determining *energy intertie settlement* prices in real time. For each interval $i \in I$ and *intertie zone* bus $d \in D$:

- $ExtLMP_{i,d}^{PD}$ shall designate the LMP for the *dispatch hour* in which interval i falls as calculated by the PD calculation engine;
- $ICP_{i,d}^{PD}$ shall designate the *intertie congestion price* (ICP) for the *dispatch hour* in which interval i falls as calculated by the PD calculation engine;
- $PExtCong_{i,d}^{PD}$ shall designate the *intertie* congestion component for the *dispatch hour* in which interval i falls as calculated by the PD calculation engine; and
- $PNISL_{i,d}^{PD}$ shall designate the net interchange scheduling limit congestion component for the *dispatch hour* in which interval i falls as calculated by the PD calculation engine.

These components will be equal for all buses at the same proxy location and *intertie zone*.

For each interval $i \in I$, *energy* LMPs and components will be calculated for *intertie zone* bus $d \in D$, where:

- $ISP_{i,d}^{1}$ shall designate the Pass 1 interval i *intertie settlement* price (ISP);
- $ICP_{i,d}^{1}$ shall designate the Pass 1 interval i *intertie congestion price* (ICP);
- $PExtCong_{i,d}^{1}$ shall designate the Pass 1 interval i *intertie* congestion component;
- $PNISL_{i,d}^{1}$ shall designate the Pass 1 interval i net interchange scheduling limit congestion component.
- $IntLMP_{i,d}^{1}$ shall designate the Pass 1 interval i *intertie* border price (IBP);
- $PRef_{i}^{1}$ shall designate the Pass 1 interval i *energy* reference price;
- $PLoss_{i,d}^{1}$ shall designate the Pass 1 interval i loss component; and

- $PIntCong_{i,d}^{1}$ shall designate the Pass 1 interval i internal congestion component.

The *intertie settlement* price will be the same for all buses at the same proxy location and *intertie zone*. *Intertie* transactions associated with the same proxy location, but specified as occurring at different *intertie zones*, subject to phase shifter operation, will be modelled as flowing across independent paths. Pricing of these transactions will utilize shadow prices associated with the internal transmission constraints and transmission losses applicable to the path associated to the relevant *intertie zone*.

The Pass 1 *intertie* border price at *intertie zone* bus $d \in D_a$ in *intertie zone* $a \in A$ in interval $i \in I$ will be initially calculated as follows:

$$InitIntLMP_{i,d}^{1} = InitPRef_{i}^{1} + InitPLoss_{i,d}^{1} + InitPIntCong_{i,d}^{1};$$

where

$$InitPRef_{i}^{1} = SPL_{i}^{1}\ ;$$

$$InitPLoss_{i,d}^{1} = MglLoss_{i,d} \cdot SPL_{i}^{1}\ ;$$

and

$$InitPIntCong_{i,d}^{1} = \sum_{f \in F_i} PreConSF_{i,f,d} \cdot SPNormT_{i,f}^{1} + \sum_{c \in C} \sum_{f \in F_{i,c}} SF_{i,c,f,d} \cdot SPEmT_{i,c,f}^{1}.$$

The *intertie settlement* price, *intertie congestion price*, internal congestion component and NISL congestion component will then be calculated according to the applicable methodology, which is determined as follows for interval $i \in I$ and *intertie zone* bus $d \in D$:

- If $ICP_{i,d}^{PD} < 0$, then the import-congested methodology applies;
- Otherwise, if $ICP_{i,d}^{PD} > 0$, then the export-congested methodology applies; and
- Otherwise $ICP_{i,d}^{PD} = 0$ and the congestion-free methodology applies.

If an *intertie* is out-of-service in real time, the congestion-free methodology will apply regardless of the pre-dispatch *intertie* congestion.

Import-Congested in Pre-Dispatch

If there is import congestion in pre-dispatch, the real-time *intertie settlement* price will be the lower of pre-dispatch LMP and the *intertie* border price.

For interval $i \in I$ and *intertie zone* bus $d \in D$:

$$InitISP_{i,d}^{1} = min(InitIntLMP_{i,d}^{1}, ExtLMP_{i,d}^{PD})$$

and

$$InitICP_{i,d}^{1} = InitISP_{i,d}^{1} - InitIntLMP_{i,d}^{1}.$$

The effective real-time *intertie congestion price* will be zero whenever the *intertie settlement* price is equal to the *intertie* border price. In such instances, the *intertie* congestion and NISL components will also be equal to zero.

When the *intertie settlement* price is equal to the pre-dispatch LMP, the effective real-time *intertie congestion price* may differ from the *intertie* congestion price calculated in pre-dispatch. In this case, the *intertie* and NISL components will be prorated based on their PD magnitudes so that their sum equals the effective real-time *intertie congestion price* to obtain $InitPExtCong_{i,d}^{1}$ and $InitPNISL_{i,d}^{1}$.

Export-Congested in Pre-Dispatch

If there is export congestion in pre-dispatch, the real-time *intertie settlement* price (ISP) will be equal to the *intertie* border price plus the *intertie* congestion component and NISL congestion component calculated by the PD calculation engine. For interval $i \in I$ and *intertie zone* bus $d \in D$:

$$InitISP_{i,d}^{1} = InitIntLMP_{i,d}^{1} + InitICP_{i,d}^{1}$$

where

$$InitICP_{i,d}^{1} = InitPExtCong_{i,d}^{1} + InitPNISL_{i,d}^{1};$$

$$InitPExtCong_{i,d}^{1} = PExtCong_{i,d}^{PD};$$

and

$$InitPNISL_{i,d}^{1} = PNISL_{i,d}^{PD}.$$

Congestion-Free in Pre-Dispatch

If there is no *intertie* congestion in pre-dispatch, the real-time *intertie settlement* price will be equal to the *intertie* border price and the *intertie* congestion and NISL congestion components will be equal to those calculated by the PD calculation engine. For interval $i \in I$ and *intertie zone* bus $d \in D$:

$$InitISP_{i,d}^{1} = InitIntLMP_{i,d}^{1} + InitICP_{i,d}^{1}$$

where

$$InitICP_{i,d}^{1} = InitPExtCong_{i,d}^{1} + InitPNISL_{i,d}^{1}$$

$$InitPExtCong_{i,d}^{1} = PExtCong_{i,d}^{PD};$$

and

$$InitPNISL_{i,d}^{1} = PNISL_{i,d}^{PD}.$$

In the above formulae, $InitICP_{i,d}^{1} = 0$.

Price Modification

The *intertie settlement* price may fall outside the *settlement* bounds provided by $EngyPrcFlr$ and $EngyPrcCeil$. When this occurs, the *intertie settlement* price and its components will be modified so that the *intertie settlement* price is within the *settlement* bounds.

The modification of the IBP, reference price, loss component and internal congestion component to obtain $IntLMP_{i,d}^{1}$, $PRef_{i}^{1}$, $PLoss_{i,d}^{1}$ and $PIntCong_{i,d}^{1}$ will follow the procedure for price modification for internal nodes as specified in 0. The ISP, ICP, external congestion component and NISL congestion component at *intertie zone* bus $d \in D$ in interval $i \in I$ will then be modified as follows:

1. Revise the *intertie settlement* price to within *settlement* bounds.
   a. If $InitISP_{i,d}^{1} > EngyPrcCeil$, set $ISP_{i,d}^{1} = EngyPrcCeil$.
   b. If $InitISP_{i,d}^{1} < EngyPrcFlr$, set $ISP_{i,d}^{1} = EngyPrcFlr$.
   c. Otherwise, set $ISP_{i,d}^{1} = InitISP_{i,d}^{1}$.
2. If the modified ISP and IBP coincide, set the external and NISL congestion components to zero.
   a. If $ISP_{i,d}^{1} = IntLMP_{i,d}^{1}$, set $PExtCong_{i,d}^{1} = 0$ and $PNISL_{i,d}^{1} = 0$.
3. Otherwise, modify the *intertie* congestion and NISL congestion components pro-rata to maintain the relationship between LMP and price components, capping the NISL congestion component at the NISL penalty price.
   a. If $ISP_{i,d}^{1} \neq IntLMP_{i,d}^{1}$, set
   $$PNISL_{i,d}^{1} = (ISP_{i,d}^{1} - IntLMP_{i,d}^{1}) \cdot \left(\frac{InitPNISL_{i,d}^{1}}{InitPNISL_{i,d}^{1} + InitPExtCong_{i,d}^{1}}\right).$$
      i. If $PNISL_{i,d}^{1} > NISLPen$, set $PNISL_{i,d}^{1} = NISLPen$.
      ii. If $PNISL_{i,d}^{1} < (-1) \cdot NISLPen$, set $PNISL_{i,d}^{1} = (-1) \cdot NISLPen$.
   b. Then set $PExtCong_{i,d}^{1} = ISP_{i,d}^{1} - IntLMP_{i,d}^{1} - PNISL_{i,d}^{1}$.
4. Calculate the ICP as the sum of the modified *intertie* congestion and NISL congestion components.
   a. Calculate $ICP_{i,d}^{1} = PExtCong_{i,d}^{1} + PNISL_{i,d}^{1}$.

3.8.1.3. Zonal Energy Prices

For each pricing zone (including zones for *non-dispatchable load* and virtual transactions), the affiliated zonal *energy* price for an interval will be calculated as the sum of the reference price, the load distribution-weighted loss component within the zone, and the load distribution-weighted congestion component within the zone.

For interval $i \in I$, the *energy* price for virtual transaction zonal trading entity $m \in M$ will be calculated as follows:

$$VZonalP_{i,m}^{1} = PRef_i^1 + VZonalPLoss_{i,m}^1 + VZonalPCong_{i,m}^1$$

where

$$VZonalPLoss_{i,m}^1 = \sum_{b \in L_m^{VIRT}} WF_{i,m,b}^{VIRT} \cdot PLoss_{i,b}^1$$

and

$$VZonalPCong_{i,m}^1 = \sum_{b \in L_m^{VIRT}} WF_{i,m,b}^{VIRT} \cdot PCong_{i,b}^1.$$

For each interval $i \in I$, the *energy* price for *non-dispatchable load* zone $y \in Y$ will be calculated as follows:

$$ZonalP_{i,y}^{1} = PRef_i^1 + ZonalPLoss_{i,y}^1 + ZonalPCong_{i,y}^1$$

where

$$ZonalPLoss_{i,y}^1 = \sum_{b \in L_y^{NDL}} WF_{i,y,b}^{NDL} \cdot PLoss_{i,b}^1$$

and

$$ZonalPCong_{i,y}^1 = \sum_{b \in L_y^{NDL}} WF_{i,y,b}^{NDL} \cdot PCong_{i,b}^1.$$

3.8.2. Locational Marginal Prices for Operating Reserve

The LMP for a category of *operating reserve* at a bus in an interval measures the *offered* cost of meeting an infinitesimal change in the reserve requirement for that category of *operating reserve* in that interval. This is determined while also accounting for binding constraints associated with the reserve areas to which the bus belongs. *Operating reserve* prices will continue to be calculated by co-optimizing *energy* and the three categories as *operating reserve*, as implied by the formulation of the optimization function.

3.8.2.1. Operating Reserve LMPs for Internal Pricing Nodes

For each interval $i \in I$, *operating reserve* LMPs and components will be calculated for every bus $b \in B$ where a dispatchable generation resource or *dispatchable load* is sited, where:

- $L30RP_{i,b}^{1}$ shall designate the Pass 1 interval i *thirty-minute operating reserve* price;
- $P30RRef_{i}^{1}$ shall designate the Pass 1 interval i *thirty-minute operating reserve* reference price;
- $P30RCong_{i,b}^{1}$ shall designate the Pass 1 interval i *thirty-minute operating reserve* congestion component;
- $L10NP_{i,b}^{1}$ shall designate the Pass 1 interval i non-synchronized *ten-minute operating reserve* price;
- $P10NRef_{i}^{1}$ shall designate the Pass 1 interval i non-synchronized *ten-minute operating reserve* reference price;
- $P10NCong_{i,b}^{1}$ shall designate the Pass 1 interval i non-synchronized *ten-minute operating reserve* congestion component;
- $L10SP_{i,b}^{1}$ shall designate the Pass 1 interval i synchronized *ten-minute operating reserve* price;
- $P10SRef_{i}^{1}$ shall designate the Pass 1 interval i synchronized *ten-minute operating reserve* reference price; and
- $P10SCong_{i,b}^{1}$ shall designate the Pass 1 interval i synchronized *ten-minute operating reserve* congestion component.

For each bus $b \in B$, define $ORREG_b \subseteq ORREG$ as the subset of $ORREG$ consisting of regions that include bus b.

The *thirty-minute operating reserve* LMP at bus $b \in B$ in interval $i \in I$ will be initially calculated as follows:

$$InitL30RP_{i,b}^{1} = InitP30RRef_{i}^{1} + InitP30RCong_{i,b}^{1}$$

where

$$InitP30RRef_{i}^{1} = SP30R_{i}^{1}$$

and

$$InitP30RCong_{i,b}^{1} = \sum_{r \in ORREG_b} SPREGMin30R_{i,r}^{1} - \sum_{r \in ORREG_b} SPREGMax30R_{i,r}^{1}.$$

The non-synchronized *ten-minute operating reserve* LMP at bus $b \in B$ in interval $i \in I$ will be initially calculated as follows:

$$InitL10\mathrm{NP}_{i,b}^{1} = InitP10NRef_i^{1} + InitP10NCong_{i,b}^{1}$$

where

$$InitP10NRef_i^{1} = SP10R_i^{1} + SP30R_i^{1}$$

and

$$\begin{aligned} InitP10NCong_{i,b}^{1} &= \sum_{r \in ORREG_b} \left(SPREGMin10R_{i,r}^{1} + SPREGMin30R_{i,r}^{1}\right) \\ &- \sum_{r \in ORREG_b} \left(SPREGMax10R_{i,r}^{1} + SPREGMax30R_{i,r}^{1}\right). \end{aligned}$$

The synchronized *ten-minute operating reserve* LMP at bus $b \in B$ in interval $i \in I$ will be initially calculated as follows:

$$InitL10\mathrm{SP}_{i,b}^{1} = InitP10SRef_i^{1} + InitP10SCong_{i,b}^{1}$$

where

$$InitP10SRef_i^{1} = SP10S_i^{1} + SP10R_i^{1} + SP30R_i^{1}$$

and

$$\begin{aligned} InitP10SCong_{i,b}^{1} &= \sum_{r \in ORREG_b} \left(SPREGMin10R_{i,r}^{1} + SPREGMin30R_{i,r}^{1}\right) \\ &- \sum_{r \in ORREG_b} \left(SPREGMax10R_{i,r}^{1} + SPREGMax30R_{i,r}^{1}\right). \end{aligned}$$

The reference price for a class of *operating reserve* reflects the cost of meeting an infinitesimal change in the requirement for that reserve class. The congestion component reflects the cost of binding constraints associated with reserve areas to which the bus belongs. Such constraints in turn reflect transmission limits that prevent the delivery of activated *operating reserve* into or out of a reserve area.

An *operating reserve* LMP can fall outside the *settlement* bounds of $ORPrcFlr$ and $ORPrcCeil$ as a result of joint optimization or constraint violation pricing. When this occurs, the *operating reserve* LMP and its components (reference and congestion) will be modified so that the LMP is within the *settlement* bounds.

For each class of *operating* reserve, the reference price will be modified when it does not fall within the *settlement* bounds. For interval $i \in I$:

- Set $P30RRef_i^1 = min(max(InitP30RRef_i^1, ORPrcFlr), ORPrcCeil)$.
- Set $P10NRef_i^1 = min(max(InitP10NRef_i^1, ORPrcFlr), ORPrcCeil)$.

- Set $P10SRef_i^1 = min(max(InitP10SRef_i^1, ORPrcFlr), ORPrcCeil)$.

For each class of *operating reserve*, the LMP and components at internal bus $b \in B$ in interval $i \in I$ will be modified as follows:

1. Set $L30RP_{i,b}^1 = min(max(InitL30RP_{i,b}^1, ORPrcFlr), ORPrcCeil)$ and set $P30RCong_{i,b}^1 = L30RP_{i,b}^1 - P30RRef_i^1$.
2. Set $L10NP_{i,b}^1 = min(max(InitL10NP_{i,b}^1, ORPrcFlr), ORPrcCeil)$ and set $P10NCong_{i,b}^1 = L10NP_{i,b}^1 - P10NRef_i^1$.
3. Set $L10SP_{i,b}^1 = min(max(InitL10SP_{i,b}^1, ORPrcFlr), ORPrcCeil)$ and set $P10SCong_{i,b}^1 = L10SP_{i,b}^1 - P10SRef_i^1$.

3.8.2.2. Operating Reserve Intertie Settlement Prices for Intertie Zone Source and Sink Buses

The calculation of *operating reserve* prices for *intertie zone* buses is similar to internal buses except that the congestion associated with binding *intertie* limits determined by the PD calculation engine is also incorporated.

The following outputs of the PD calculation engine will be used in determining *operating reserve intertie settlement* prices in real time. For each interval $i \in I$ and *intertie zone* bus $d \in D$:

- $ExtL30RP_{i,d}^{PD}$ shall designate the *thirty-minute operating reserve* price for the *dispatch hour* in which interval i falls as calculated by the PD calculation engine;
- $P30RExtCong_{i,d}^{PD}$ shall designate the *thirty-minute operating reserve intertie* congestion component for the *dispatch hour* in which interval i falls as calculated by the PD calculation engine;
- $ExtL10NP_{i,d}^{PD}$ shall designate the non-synchronized *ten-minute operating reserve* price for the *dispatch hour* in which interval i falls as calculated by the PD calculation engine; and
- $P10NExtCong_{i,d}^{PD}$ shall designate the non-synchronized *ten-minute operating reserve intertie* congestion component for the *dispatch hour* in which interval i falls as calculated by the PD calculation engine.

For each interval $i \in I$, *operating reserve intertie settlement* prices and components will be calculated for *intertie zone* bus $d \in D$, where:

- $ExtL30RP_{i,d}^1$ shall designate the Pass 1 interval i *thirty-minute operating reserve intertie settlement* price;
- $P30RRef_i^1$ shall designate the Pass 1 interval i *thirty-minute operating reserve* reference price;

- $P30RIntCong^1_{i,d}$ shall designate the Pass 1 interval i *thirty-minute operating reserve* internal congestion component;
- $P30RExtCong^1_{i,d}$ shall designate the Pass 1 interval i *thirty-minute operating reserve intertie* congestion component;
- $ExtL10NP^1_{i,d}$ shall designate the Pass 1 interval i non-synchronized *ten-minute operating reserve intertie settlement* price;
- $P10NRef^1_i$ shall designate the Pass 1 interval i non-synchronized *ten-minute operating reserve* reference price;
- $P10NIntCong^1_{i,d}$ shall designate the Pass 1 interval i non-synchronized *ten-minute operating reserve* internal congestion component; and
- $P10NExtCong^1_{i,d}$ shall designate the Pass 1 interval i non-synchronized *ten-minute operating reserve intertie* congestion component.

The price will be the same for all buses at the same proxy location and *intertie zone*. Reserve imports associated with the same proxy location, but specified as occurring at a different *intertie zone*, subject to phase shifter operation, will be modelled as flowing across independent paths. Pricing of these reserve imports will utilize shadow prices associated with interchange scheduling limits and regional minimum and maximum *operating reserve* requirements applicable to the path associated to the relevant *intertie zone*.

For each *intertie zone* bus $d \in D$, define $ORREG_d \subseteq ORREG$ as the subset of $ORREG$ consisting of regions that include bus d.

The internal *thirty-minute operating reserve* LMP at *intertie zone* bus $d \in D$ in interval $i \in I$ will be initially calculated as follows:

$$InitIntL30RP^1_{i,d} = InitP30RRef^1_i + InitP30RIntCong^1_{i,d}$$

where

$$InitP30RRef^1_i = SP30R^1_i$$

and

$$InitP30RIntCong^1_{i,d} = \sum_{r \in ORREG_d} SPREGMin30R^1_{i,r} - \sum_{r \in ORREG_d} SPREGMax30R^1_{i,r}.$$

Then, the initial *intertie settlement* prices and components for *thirty-minute operating reserve* will be calculated according to the applicable methodology, which depends on the pre-dispatch *intertie* congestion. The calculation is performed as follows:

1. If the *intertie* is import-congested in pre-dispatch (i.e. $P30RExtCong_{i,d}^{PD} < 0$) and the *intertie* is not out of service, then:

    a. Set the initial real-time *intertie settlement* price to the lesser of the real-time internal price and the pre-dispatch price:

    $$InitExtL30RP_{i,d}^{1} = min(InitIntL30RP_{i,d}^{1}, ExtL30RP_{i,d}^{PD}).$$

    b. Set the real-time *intertie* congestion component equal to the difference between the *intertie settlement* price and the internal price:

    $$InitP30RExtCong_{i,d}^{1} = InitExtL30RP_{i,d}^{1} - InitIntL30RP_{i,d}^{1}.$$

2. Otherwise, the initial real-time *intertie settlement* price is the reserve price set in real-time and the congestion component is 0.

    a. Set $InitExtL30RP_{i,d}^{1} = InitIntL30RP_{i,d}^{1}$.

    b. Set $InitP30RExtCong_{i,d}^{1} = 0$.

The internal non-synchronized *ten-minute operating reserve* LMP at *intertie zone* bus $d \in D$ in interval $i \in I$ will be initially calculated as follows:

$$InitIntL10NP_{i,d}^{1} = InitP10NRef_{i}^{1} + InitP10NIntCong_{i,d}^{1}$$

where

$$InitP10NRef_{i}^{1} = SP10R_{i}^{1} + SP30R_{i}^{1}$$

and

$$InitP10NIntCong_{i,d}^{1} = \sum_{r \in ORREG_d} \left(SPREGMin10R_{i,r}^{1} + SPREGMin30R_{i,r}^{1}\right) - \sum_{r \in ORREG_d} \left(SPREGMax10R_{i,r}^{1} + SPREGMax30R_{i,r}^{1}\right).$$

Then, the initial non-synchronized *ten-minute operating reserve operating reserve intertie settlement* prices and components will be calculated according to the applicable methodology, which depends on the pre-dispatch *intertie* congestion. The calculation is performed as follows:

3. If the *intertie* is import-congested (i.e. $P10NExtCong_{i,d}^{PD} < 0$) and the *intertie* is not out of service, then:

    c. Set the initial real-time *intertie settlement* price to the lesser of the real-time internal price and the pre-dispatch price:

    $$InitExtL10NP_{i,d}^{1} = min(InitIntL10NP_{i,d}^{1}, ExtL10NP_{i,d}^{PD}).$$

d. Set the real-time *intertie* congestion component equal to the difference between the *intertie settlement* price and the internal price:

$$InitP10NExtCong^1_{i,d} = InitExtL10NP^1_{i,d}\text{-}InitIntL10NP^1_{i,d}.$$

4. Otherwise, the initial real-time *intertie settlement* price is the reserve price set in real-time and the congestion component is 0.

e. Set $InitExtL10NP^1_{i,d} = InitIntL10NP^1_{i,d}$.

f. Set $InitP10NExtCong^1_{i,d} = 0$.

The *IESO* does not calculate a price for synchronized *ten-minute operating reserve* at *intertie zone* buses because synchronized *ten-minute operating reserve* cannot be imported.

An *operating reserve* price can fall outside the *settlement* bounds of $ORPrcFlr$ and $ORPrcCeil$ as a result of joint optimization or constraint violation pricing. When this occurs, the *operating reserve* price at an *intertie zone* bus and its components (reference, internal congestion and *intertie* congestion) will be modified so that the LMP is within the *settlement* bounds.

For *thirty-minute operating reserve*, the *intertie settlement* price and components at *intertie zone* bus $d \in D$ in interval $i \in I$ will be modified as follows:

1. Calculate $IntL30R = InitP30RRef^1_i + InitP30RIntCong^1_{i,d}$ and modify its components using the procedure for price modification for internal nodes as specified in Section 3.8.2.1 to obtain $P30RRef^1_i$ and $P30RIntCong^1_{i,d}$.
2. Set $ExtL30RP^1_{i,d} = min(max(InitExtL30RP^1_{i,d}, ORPrcFlr), ORPrcCeil)$.
3. Set $P30RExtCong^1_{i,d} = ExtL30RP^1_{i,d} - P30RRef^1_i - P30RIntCong^1_{i,d}$.

For *ten-minute operating reserve*, *the intertie settlement* price and components at *intertie zone* bus $d \in D$ in interval $i \in I$ will be modified as follows:

1. Calculate $IntL10N = InitP10NRef^1_i + InitP10NIntCong^1_{i,d}$ and modify its components using the procedure for price modification for internal nodes as specified in Section 3.8.2.1 to obtain $P10NRef^1_i$ and $P10NIntCong^1_{i,d}$.
2. Set $ExtL10NP^1_{i,d} = min(max(InitExtL10NP^1_{i,d}, ORPrcFlr), ORPrcCeil)$.
3. Set $P10NExtCong^1_{i,d} = ExtL10NP^1_{i,d} - P10NRef^1_i - P10NIntCong^1_{i,d}$.

3.8.3. Pricing for Islanded Nodes

NQS resources that are not connected to the main (i.e. largest) island of the system will be reconnected as inactive units (zero MW and zero MVAr) within the *security* assessment function so as to produce a price. Steps one to three of the pricing for islanded nodes logic will be used to produce a price for NQS resources:

1. Find connection paths over open switches that connect the NQS resource to the main island.
2. Determine the priority rating for each connection path identified based on a weighted sum of the base voltage over all open switches used by the reconnection path and the MW ratings of the newly connected branches.
3. Select the reconnection path with the highest priority rating, breaking ties arbitrarily.

The substitution rules outlined in steps four to eight will be used to produce a price for all other pricing nodes that are not connected to the main island of the system due to a transmission *outage*, disconnection, a resource being out of service or a resource operating in *segregated mode of operation*. These substitutions rules will also apply to NQS resources for which steps one to three was unable to determine a price. The RT calculation engine will be provided a node-level and *facility*-level substitution list for each pricing node to be used in applying the substitution rules. Steps four to eight of the pricing for islanded nodes logic will be as follows:

1. Use the LMP at a node in the node-level substitution list, provided such node is connected to the main island.
2. If no such nodes are identified, use the average LMP of all nodes at the same voltage level within the same *facility* that are connected to the main island.
3. If no such nodes are identified, use the average LMP of all nodes within the same *facility* that are connected to the main island.
4. If no such nodes are identified, use the average LMP of all nodes from another *facility* that is connected to the main island, as determined by the *facility*-level substitution list.
5. If a price is yet to be determined, use the LMP for the *reference bus*.

3.9. Data Generation for Settlement Mitigation

The RT calculation engine will not execute any ex-ante mitigation of *dispatch data* in establishing *dispatch* schedules and real-time LMPs for resources. Instead, the RT calculation engine will use reference levels for *dispatch data* parameters that failed the price impact test in the *pre-dispatch scheduling* process.

The *IESO* may take control actions in real time to maintain system *reliability*, such as manually setting minimum or maximum constraints on a resource's *dispatch* schedule. This can result in a resource being *dispatched* up or *dispatched* down from their economic operating point, which may result in the resource receiving make-whole payments.

If a resource submits new *offers* within the real-time mandatory window that the *IESO* accepts, these offers might not have been tested for price mitigation during the *pre-dispatch scheduling* process. These offers will be tested for make-whole payment impact.

The mitigation of make-whole payments, if necessary, will occur in the *settlement process*. Any resource that meets the conditions for the testing of make-whole payments will be subject to the make-whole payment impact test as described in the Market Settlement detailed design document.

To perform the make-whole payment impact test, the *settlement process* will require additional *dispatch data* from the RT calculation engine as described in this section. The Pre-Settlement Mitigation process will generate this data after the RT calculation engine completes.

3.9.1. RT Calculation Engine Inputs Provided to the Pre-Settlement Mitigation Process

The following information from the RT calculation engine run will be required to generate data for the make-whole payment impact test:

- A list of resources that have *reliability* constraints applied as part of control actions, which were entered as an input to Pass 1;
- For each resource with such a *reliability* constraint, a list of five-minute intervals over which the *reliability* constraint was applied; and
- A list of resources that submitted new *offers* during the real-time mandatory window, which were accepted by the *IESO*.

3.9.2. Outputs of the Pre-Settlement Mitigation Process

The outputs from the Pre-Settlement Mitigation process will be the enhanced mitigated for conduct *dispatch data* set. This data set will include the additional data that is necessary for the make whole payment impact testing in the *settlement process*.

For a detailed description of the enhanced mitigated for conduct *dispatch data* set generated by the Pre-Settlement Mitigation process, refer to the Pre-Dispatch Calculation Engine detailed design document.

3.10. The Pseudo-Unit Model

Combined cycle *facilities* offering in the day-ahead market and *pre-dispatch scheduling* processes as *pseudo-units* (PSUs) will also offer into the *real-time market* as one or more PSUs each comprised of a single combustion turbine (CT) together with its share of the steam turbine (ST) capacity. The CTs and ST are referred to as the physical units (PUs). The PSU model defines the boundaries for PSU schedules and the proportional relationship between the CT and ST.

The RT calculation engine optimization function will evaluate a combined cycle *facility* electing PSU modelling as a set of PSU resources that capture the joint economics of operating the CT and the affiliated portion of the ST together. Each PSU resource is scheduled independently, with each PSU modelling a CT and a portion of the ST. Each PSU resource is scheduled proportionally according to a fixed ratio of *energy* output between the CT and ST within specific operating regions.

The RT calculation engine *security* assessment function models the physical power system and therefore must model the combined cycle *facilities* electing PSU modelling as PUs. Injections into the power system must be simulated at their physical buses. Therefore, PU sensitivity factors will be provided in the transmission limits passed from the *security* assessment function to the optimization function.

Although the optimization function will evaluate resource economics on a PSU basis, it must handle the following operational information that is provided on a PU basis, either within the optimization or via pre-processing:

- Both transmission constraint sensitivity factors and marginal loss factors will be provided on a PU basis to the optimization function and translated using the PSU model;
- Any minimum or maximum generation constraint applied to a CT or ST will be pre-processed before the execution of the RT calculation engine pass to provide limits on the affiliated PSU resources for the optimization function to enforce. *Outages* and de-rates will also be pre-processed before the execution of the RT calculation engine pass; and
- To determine resource initial schedules from the EMS determined output, the RT calculation engine will implement translation logic that allocates the EMS MW value injections at the PUs to the PSUs.

Because the optimization function will calculate resource schedules on a PSU basis, post-processing logic will be used to allocate PSU schedules to the corresponding PUs for the purpose of determining *dispatch instructions*.

3.10.1. Model Parameters

For a combined cycle *facility* with K combustion turbines and one steam turbine, the following registration parameters and daily *dispatch data* parameters determine the underlying relationship between the PSUs and PUs:

- $CMCR_k$ indicating the registered maximum continuous rating of CT $k \in \{1,..,K\}$ in MW;
- $CMLP_k$ indicating the *minimum loading point* of CT $k \in \{1,..,K\}$ in MW;
- $SMCR$ indicating the registered maximum continuous rating of the ST in MW;
- $SMLP$ indicating the *minimum loading point* of the ST in MW for a 1x1 configuration;
- SDF indicating the amount of duct firing capacity available on the ST in MW;
- $STPortion_k$ indicating the percentage of the ST capacity attributed to PSU $k \in \{1,..,K\}$; and
- $CSCM_k \in \{0,1\}$ indicating whether PSU $k \in \{1,..,K\}$ is flagged to operate in single-cycle mode.

From this data, the following model parameters can be calculated for each PSU $k \in \{1,..,K\}$:

- $MMCR_k$ designates the maximum continuous rating of PSU k and is given by
$$CMCR_k + SMCR \cdot STPortion_k \cdot (1 - CSCM_k).$$
- $MMLP_k$ designates the minimum loading point of PSU k and is given by
$$CMLP_k + SMLP \cdot (1 - CSCM_k).$$
- MDF_k designates the duct firing capacity of PSU k and is given by
$$SDF \cdot STPortion_k \cdot (1 - CSCM_k).$$
- MDR_k designates the dispatchable capacity of PSU k and is given by
$$MMCR_k - MMLP_k - MDF_k.$$

The PSU model has three distinct operating regions: MLP, dispatchable and duct firing. The model parameters above determine the three operating regions of PSU $k \in \{1,..,K\}$, each with an affiliated ST and CT share.

- The MLP region refers to capacity between 0 and $MMLP_k$:
  - o The ST share in this region is
$$STShareMLP_k = \frac{SMLP \cdot (1 - CSCM_k)}{MMLP_k}.$$
  - o The CT share in this region is
$$CTShareMLP_k = \frac{CMLP_k}{MMLP_k}.$$

- The dispatchable region refers to capacity between $MMLP_k$ and $MMLP_k + MDR_k$:
  - o The ST share in this region is
$$STShareDR_k = \frac{(1 - CSCM_k)(SMCR \cdot STPortion_k - SMLP - SDF \cdot STPortion_k)}{MDR_k}.$$
  - o The CT share in this region is
$$CTShareDR_k = \frac{CMCR_k - CMLP_k}{MDR_k}.$$
- The duct firing region refers to capacity between $MMLP_k + MDR_k$ and $MMCR_k$:
  - o The ST share in this region is 1.
  - o The CT share in this region is 0.

3.10.2. Application of PU De-rates to the PSU Model

Market participants will continue to be able to submit de-rates on the CTs and ST corresponding to a combined cycle *facility* that has elected PSU modelling. When a de-rate is submitted on a physical unit, the PSU model parameters defining the dispatchable capacity and duct firing capacity will be updated in the RT calculation engine to respect the de-rate.

To enable the RT calculation engine to respect these PU de-rates, the *energy offers* submitted on a PSU basis will be scheduled based on the following logic:

1. A pre-processing step will determine the available parts of the operating regions above based on the CT and ST sharing relationships and the application of the PU de-rates.
2. If part of an operating region is determined to be unavailable, the corresponding *offer* laminations will not be scheduled for *energy* and *operating reserve*.

De-rates will be applied respecting the proportional relationship defined by the PSU model. The pre-processing step will not impact the CT and ST shares within the modelled operating regions and will ensure that both *energy* and *operating reserve* schedules respect the proportional relationship between the CT and the ST.

3.10.2.1. Pre-processing of De-rates

In the pre-processing step, the following operating region parameters for interval $i \in I$ will be calculated for each PSU $k \in \{1,...,K\}$:

- $MLP_{i,k}$ indicating the minimum loading point of PSU k in interval i;
- $DR_{i,k}$ indicating the dispatchable capacity of PSU k in interval i; and

- $DF_{i,k}$ indicating the duct firing capacity of PSU k in interval i.

For each interval $i \in I$, the following data is required for the pre-processing step:

- $CTCap_{i,k}$ indicating the capacity of CT $k \in \{1,..,K\}$ in interval i as determined by submitted de-rates;
- $STCap_i$ indicating the capacity of the ST in interval i as determined by submitted de-rates; and
- $TotalQ_{i,k}$ indicating the total quantity of *energy offered* for PSU $k \in \{1,..,K\}$ in interval i.

The first step is to calculate the amount of *energy offered* attributed to each CT ($CTAmt_{i,k}$) and ST portion ($STAmt_{i,k}$). To do so, the *energy offered* on a PSU is divided between the CT and ST according to the share percentages. For PSU $k \in \{1,..,K\}$ and interval $i \in I$:

1. If $TotalQ_{i,k} < MMLP_k$ then:
    a. Calculate $CTAmt_{i,k}=0$.
    b. Calculate $STAmt_{i,k}=0$.
2. Otherwise:
    a. Calculate $CTAmtMLP=MMLP_k \cdot CTShareMLP_k$.
    b. Calculate $STAmtMLP=MMLP_k \cdot STShareMLP_k$.
    c. If $TotalQ_{i,k} > MMLP_k+MDR_k$, then:
        i. Calculate $CTAmtDR = MDR_k \cdot CTShareDR_k$.
        ii. Calculate $STAmtDR = MDR_k \cdot STShareDR_k$.
        iii. Calculate $STAmtDF = (1 - CSCM_k) \cdot (TotalQ_{i,k} - MMLP_k - MDR_k)$.
    d. Otherwise:
        i. Calculate $CTAmtDR = (TotalQ_{i,k} - MMLP_k) \cdot CTShareDR_k$.
        ii. Calculate $STAmtDR = (TotalQ_{i,k} - MMLP_k) \cdot STShareDR_k$.
        iii. Calculate $STAmtDF = 0$.
    e. Calculate $CTAmt_{i,k}= CTAmtMLP + CTAmtDR$.
    f. Calculate $STAmt_{i,k}=STAmtMLP+STAmtDR+STAmtDF$.

The next step is to allocate the ST capacity to each PSU pro-rata according to the amount of *energy offered* attributed to each ST portion. For PSU $k \in \{1,..,K\}$ and interval $i \in I$:

3. Calculate $PRSTCap_{i,k}=\left(\frac{STAmt_{i,k}}{\sum_{w\in\{1,..,K\}}STAmt_{i,w}}\right)\cdot STCap_i$.

The last step is to recalculate the operating regions based on the application of the PU de-rates and the available parts of the CT and ST. For PSU $k\in\{1,..,K\}$ and interval $i\in I$:

4. Determine if the PSU is unavailable.
    a. If $CTAmt_{i,k} < CMLP_k$, then the PSU is unavailable.
    b. If $STAmt_{i,k} < SMLP\cdot(1 - CSCM_k)$, then the PSU is unavailable.
    c. If $CTCap_{i,k} < CMLP_k$, then the PSU is unavailable.
    d. If $PRSTCap_{i,k} < SMLP\cdot(1 - CSCM_k)$, then the PSU is unavailable.
5. Initialize the operating region parameters for interval $i\in I$ to the model parameter values.
    a. Set $MLP_{i,k} = MMLP_k$.
    b. Set $DR_{i,k} = MDR_k$.
    c. Set $DF_{i,k} = MDF_k$.
6. Apply the de-rate on the CT to the dispatchable region.
    a. Calculate P so that $CMLP_k + P\cdot CTShareDR_k\cdot MDR_k = CTCap_{i,k}$.
    b. Update $DR_{i,k} = min(DR_{i,k}, P\cdot MDR_k)$.
7. If the PSU is not operating in single-cycle mode, then incrementally restrict the capacity by considering the de-rate of the ST, applying the limit first to the duct firing region and then to the dispatchable region. If the PSU is operating in single-cycle mode, then the de-rate of the ST does not apply. If $CSCM_k = 0$:
    a. Calculate R so that $SMLP+R\cdot STShareDR_k\cdot MDR_k = PRSTCap_{i,k}$.
    b. If $R\leq 1$, update $DF_{i,k} = 0$, and $DR_{i,k} = min(DR_{i,k}, R\cdot MDR_k)$.
    c. If $R>1$, update $DF_{i,k} = min(DF_{i,k}, PRSTCap_{i,k} - SMLP - STShareDR_k\cdot MDR_k)$.

3.10.2.2. Identifying Available Energy Laminations

Once the de-rated operating regions have been established, scheduling limitations will be applied so that the corresponding unavailable *offer* laminations will not be scheduled for *energy* and *operating reserve*.

The *offer* quantity laminations that may be scheduled for *energy* and *operating reserve* in each operating region for interval $i\in I$ will be calculated for each PSU $k\in\{1,..,K\}$, where:

- $QMLP_{i,k}$ indicates the total quantity that may be scheduled in the MLP region;
- $QDR_{i,k}$ indicates the total quantity that may be scheduled in the dispatchable region; and
- $QDF_{i,k}$ indicates the total quantity that may be scheduled in the duct firing region.

The available offered quantity laminations will be determined as follows:

- The first *offered* quantity laminations up to $MLP_{i,k}$ will comprise the MLP region *offer* laminations; The available laminations will have an *offered* quantity less than $QMLP_{t,k}$.
- The *offered* quantity laminations between $MLP_{i,k}$ and $MDR_{i,k}$ will comprise the dispatchable region *offer* laminations. The available laminations will have an *offered* quantity between than $MLP_{i,k}$ and $QDR_{i,k}$; and
- The *offered* quantity laminations between $MDR_{i,k}$ and $DF_{i,k}$ will comprise the duct firing region *offer* laminations. The available laminations will have an *offered* quantity between than $MDR_{i,k}$ and $QDF_{i,k}$.

Necessarily, the following conditions will hold:

- $0 \leq QMLP_{i,k} \leq MLP_{i,k}$;
- $0 \leq QDR_{i,k} \leq DR_{i,k}$;
- $0 \leq QDF_{i,k} \leq DF_{i,k}$;
- if $QMLP_{i,k} < MLP_{i,k}$, then the PSU is unavailable and $QDR_{i,k} = QDF_{i,k} = 0$; and
- if $QDR_{i,k} < DR_{i,k}$, then $QDF_{i,k}=0$.

3.10.3. Applying Minimum and Maximum Constraints to PSUs

As described earlier, *market participant* and *IESO* inputs into the RT calculation engine may limit the minimum or maximum output of a resource. The minimum and maximum constraints pertaining to a combined cycle *facility* electing PSU modelling may be provided to the RT calculation engine as either: a constraint on a given CT or ST, or a constraint on a given PSU resource, where:

- Commitment constraints will be provided on a physical unit basis, simultaneously identifying the physical unit as “committed” and indicating the corresponding minimum output of the unit;
- *Outages* and/or de-rates will be provided on a physical unit basis;
- *Reliability* constraints and manual constraints will typically be provided on a physical unit basis; and

- Certain manual actions such as *operating reserve* activations will be provided as a PSU constraint.

For all constraints provided on a physical unit basis, the constraints will be translated to a PSU constraint before the execution of the RT calculation engine pass. Only the most limiting PSU constraints will be enforced within the optimization function.

For a combined cycle *facility* with K CTs and one ST, the following data will be required to translate PSU and PU constraints to the limits enforced by the RT calculation engine optimization function:

- The model parameters $MMLP_k$, MDR_k, MDF_k, $STShareMLP_k$, $CTShareMLP_k$, $STShareDR_k$ and $CTShareDR_k$ for PSU $k \in \{1,..,K\}$;
- The effective operation regions $MLP_{i,k}$, $DR_{i,k}$ and $DF_{i,k}$ for interval $i \in I$ and PSU $k \in \{1,..,K\}$;
- The offer quantities $QMLP_{i,k}$, $QDR_{i,k}$ and $QDF_{i,k}$ that may be scheduled for *energy* and *operating reserve* in each operating region for interval $i \in I$ and PSU $k \in \{1,..,K\}$;
- The amount of *energy* offered attributed to the ST portion, $STAmt_{i,k}$ for interval $i \in I$ and PSU $k \in \{1,..,K\}$;
- The single-cycle flag $CSCM_k \in \{0,1\}$ indicating whether PSU $k \in \{1,..,K\}$ is flagged to operate in single-cycle mode, accounting for consideration of ST forced outages as described in Section 3.10.6; and
- $CTCmtd_{i,k} \in \{0,1\}$ indicating whether CT $k \in \{1,..K\}$ is considered committed in interval $i \in I$.

The following sub-sections describe how each category of constraint can be translated into either:

- PSU maximum limitations, denoted $PSUMax_{i,k}$ for PSU $k \in \{1,..,K\}$ and interval $i \in I$, or
- PSU minimum limitations, denoted $PSUMin_{i,k}$ for PSU $k \in \{1,..,K\}$ and interval $i \in I$.

Suppose Q constraints impacting the combined cycle *facility* have been provided to the RT calculation engine. For interval $i \in I$ and for constraint $q \in \{1,..,Q\}$, the following limitations will be calculated:

- $PSUMin^q_{i,k}$ indicating the minimum limitation on PSU k determined by translating constraint q. When constraint q does not provide a minimum limitation on PSU k, then $PSUMin^q_{i,k}$ shall be set equal to 0; and

- $PSUMax_{i,k}^{q}$ indicating the maximum limitation on PSU k determined by translating constraint q. When constraint q does not provide a maximum limitation on PSU k, then $PSUMax_{i,k}^{q}$ shall be set equal to $MLP_{i,k}+DR_{i,k}+DF_{i,k}$.

The minimum and maximum limitations applied within the optimization function will be calculated as follows:

$$MinDG_{i,k} = max_{q\in\{1,..Q\}} PSUMin_{i,k}^{q}$$

and

$$MaxDG_{i,k} = min_{q\in\{1,..Q\}} PSUMax_{i,k}^{q}$$

where the necessary mapping from PSU $k\in\{1,..,K\}$ to bus $b\in B^{PSU}$ identifying a PSU resource applies.

3.10.3.1. PSU Minimum Constraints

PSU minimum constraints can modify the minimum operating limit for a given PSU resource to maintain output at or above a specific value. Unlike other PSU constraints that are provided on the physical CT or ST, PSU minimum constraints do not require any pre-processing translations and can be applied directly to the PSU resource. The minimum constraint will revise the resource's lower operating limit so that the apportioned PU schedules produced by the RT calculation engine will collectively respect the minimum constraint value.

Suppose a minimum constraint of $PMin$ is provided on PSU $k\in\{1,..,K\}$ for interval $i\in I$. The PSU constraint is mapped directly to a PSU minimum constraint for the same amount, and so

$$PSUMin_{i,k}=PMin.$$

3.10.3.2. PSU Maximum Constraints

PSU maximum constraints can modify the high operating limit for a given PSU resource to maintain output at or below a specific value. Like PSU minimum constraints, PSU maximum constraints will also be applied directly to the PSU resource without additional pre-processing. These maximum constraints will be respected so that the collective apportioned PU schedules produced by the RT calculation engine do not exceed the maximum constraint value.

Suppose a maximum constraint of $PMax$ is provided on PSU $k\in\{1,..,K\}$ for interval $i\in I$. The PSU constraint is mapped directly to a PSU maximum constraint for the same amount, and so

$$PSUMax_{i,k}=PMax.$$

3.10.3.3. CT Minimum Constraints

At times, it may be necessary to apply minimum physical unit constraints directly to the CT of an associated PSU resource to maintain an output at or above a specified value. The minimum constraint on the physical unit will be translated to an equivalent minimum constraint on the PSU. For a PSU resource in combined cycle mode, the CT minimum constraint will place an implied minimum restriction on the associated ST due to the PSU model relationship. The RT calculation engine will schedule the PSU resource to respect the PSU equivalent constraint, resulting in apportioned PU schedules that respect the CT minimum limitation and implied ST limitation.

Suppose a minimum constraint of $CTMin$ is provided on CT $k \in \{1,..,K\}$ for interval $i \in I$. The constraint will be translated to PSU k as follows:

1. If the PSU is not flagged to operate in single-cycle mode (i.e. if $CSCM_k = 0$), then map the CT constraint directly to a PSU constraint using the PSU model. A restriction on the ST will be implicitly applied according to the sharing percentages.
    a. First calculate the effect of the constraint on the ST within the MLP and dispatchable regions.
        i. If $CTMin < MLP_{i,k} \cdot CTShareMLP_k$, then set

        $$STMinMLP = CTMin \cdot \left(\frac{STShareMLP_k}{CTShareMLP_k}\right),$$
        $$STMinDR = 0.$$

        ii. Otherwise, if $CTMin \geq MLP_{i,k} \cdot CTShareMLP_k$, then set

        $$STMinMLP = MLP_{i,k} \cdot STShareMLP_k,$$
        $$STMinDR = \left(CTMin - MLP_{i,k} \cdot CTShareMLP_k\right) \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right).$$

    b. Calculate $PSUMin_{i,k} = CTMin + STMinMLP + STMinDR$.
2. Otherwise, if the PSU is flagged to operate in single-cycle mode (i.e. if $CSCM_k = 1$), then map the CT constraint directly to the PSU. A restriction on the ST will not be implicitly applied according to the PSU model, and so

$$PSUMin_{i,k} = CTMin.$$

3.10.3.4. CT Maximum Constraints

It may also be necessary to apply maximum physical unit limitations on the CT of an associated PSU resource to limit the CT's maximum output at or below a specific value. The maximum constraint on the physical unit will be translated to an equivalent maximum constraint on the PSU. For a PSU resource in combined cycle mode, the CT maximum constraint will place an implied maximum restriction on the associated ST due to the PSU model relationship. The RT calculation engine will schedule the PSU resource to respect the PSU equivalent constraint, resulting in apportioned PU schedules that respect the CT maximum output and implied ST limitation.

Suppose a maximum constraint of $CTMax$ is provided on CT $k \in \{1,..,K\}$ for interval $i \in I$. The constraint will be translated to PSU k as follows:

1. If the PSU is not flagged to operate in single-cycle mode (i.e. if $CSCM_k = 0$), then map the CT constraint directly to a PSU constraint using the PSU model. A restriction on the ST will be implicitly applied according to the sharing percentages. A CT maximum constraint will always prevent the PSU from being scheduled in its duct firing region.
    a. If $CTMax < MLP_{I,k} \cdot CTShareMLP_k$, then the PSU is unavailable (i.e. $PSUMax_{I,k} = 0$).
    a. Otherwise, calculate the effect of the constraint on the ST within the MLP and dispatchable regions.
        i. Set
        $$STMaxMLP = MLP_{i,k} \cdot STShareMLP_k \ ,$$
        $$STMaxDR = \left(CTMax - MLP_{i,k} \cdot CTShareMLP_k\right) \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right).$$
        ii. Calculate $PSUMax_{i,k} = CTMax + STMaxMLP + STMaxDR$.
2. Otherwise, if the PSU is flagged to operate in single-cycle mode (i.e. if $CSCM_k = 1$), then map the CT constraint directly to the PSU. A restriction on the ST will not be implicitly applied according to the PSU model, and so

$$PSUMax_{i,k} = CTMax.$$

3.10.3.5. ST Minimum Constraints

ST minimum constraints are required to limit the minimum output of a physical ST unit such that the output of the ST is maintained at or above a specific value. An ST minimum constraint can be mapped to one or more PSU resources. It will be assigned equally to committed PSUs and translated to one or more equivalent PSU minimum constraints. The ST minimum constraint will place an implied minimum constraint on associated CT resources due to the PSU model relationship. The RT calculation engine will schedule impacted PSU resources to respect the PSU equivalent constraint(s), resulting in apportioned PU schedules that respect the ST minimum output and the associated CT implied limitations.

Suppose a minimum constraint of $STMin$ is provided on the ST for interval $i \in I$. The constraint will be translated to PSUs that are committed and not operating in single-cycle mode as follows:

1. Identify $A \subseteq \{1,..,K\}$ indicating the set of PSUs to which the constraint may be allocated. PSU $k \in \{1,..,K\}$ is placed in set A if and only if $CSCM_k = 0$ and $CTCmtd_{i,k} = 1$. If the set A is empty (i.e. there are no PSUs on which to allocate the constraint), then no further steps are required and the ST minimum constraint will not be translated to any PSU constraints.

2. Determine the ST portion of the capacity of PSU $k \in A$. $STCap_k$ designates this portion and is given by

$$STCap_k = QMLP_{i,k} \cdot STShareMLP_k + QDR_{i,k} \cdot STShareDR_k + QDF_{i,k}.$$

4. Allocate the $STMin$ constraint equally to each PSU $k \in A$. $STPMin_k$ designates the amount allocated to the ST portion of PSU $k \in A$ and is determined by allocating $STMin$ equally to each PSU $k \in A$, while limiting the amount allocated to the ST portion of PSU k by $STCap_k$.

5. Map the ST portion minimum constraint to a PSU constraint using the PSU model. A restriction on the CT will be implicitly applied according to the sharing percentages. For each PSU $k \in A$:

   a. First calculate the effect of the constraint on the CT within the MLP and dispatchable regions.

      i. If $STPMin_k < MLP_{i,k} \cdot STShareMLP_k$, then set

$$CTMinMLP_k = STPMin_k \cdot \left(\frac{CTShareMLP_k}{STShareMLP_k}\right),$$
$$CTMinDR_k = 0.$$

      ii. Otherwise, if $STPMin_k \geq MLP_{i,k} \cdot STShareMLP_k$, then set

$$CTMinMLP_k = MLP_{i,k} \cdot CTShareMLP_k,$$
$$CTMinDR_k = \left(STPMin_k - MLP_{i,k} \cdot STShareMLP_k\right) \cdot \left(\frac{CTShareDR_k}{STShareDR_k}\right).$$

   b. Calculate $PSUMin_{i,k} = STPMin_k + CTMinMLP_k + CTMinDR_k$.

If not enough PSUs with sufficient ST capacity are committed to allocate the constraint amount fully, this process may not translate the entire quantity of the ST minimum constraint to PSU constraints.

3.10.3.6. ST Maximum Constraints

ST maximum constraints are required to limit the output of a physical ST at or below a specific value. An ST maximum constraint will be prorated across the available capacity of associated in service PSU resources and translated to one or more equivalent PSU maximum constraints. The ST maximum constraint may place an implied maximum constraint on associated CT resources due to the PSU model relationship. The RT calculation engine will schedule impacted PSU resources to respect the PSU equivalent constraint(s), resulting in apportioned PU dispatches that respect the ST maximum output and any associated CT implied limitations.

Suppose a maximum constraint of $STMax$ is provided on the ST for interval $i \in I$. The constraint will be translated to all PSUs in the same way in which a ST de-rate is translated to all PSUs as follows:

1. Allocate the ST maximum constraint to each PSU pro-rata according to the amount of *energy* offered attributed to each ST portion. For PSU $k \in \{1,..,K\}$ and interval $i \in I$, calculate:

$$PRSTMax_{i,k} = \left(\frac{STAmt_{i,k}}{\sum_{w \in \{1,..,K\}} STAmt_{i,w}}\right) \cdot STMax.$$

2. Map the ST portion maximum constraint to a PSU constraint using the PSU model. A restriction on the CT will be implicitly applied according to the sharing percentages. For each PSU $k \in \{1,..,K\}$ such that $CSCM_k = 0$:

   a. If the prorated ST maximum constraint limits the ST portion to below its MLP (i.e. $PRSTMax_{i,k} < SMLP \cdot (1 - CSCM_k)$, then the PSU is unavailable (i.e. $PSUMax_{i,k} = 0$).

   b. Otherwise, calculate R so that $SMLP + R \cdot STShareDR_k \cdot MDR_k = PRSTMax_{i,k}$

      i. If $R \leq 1$, set

$$PSUMax_{i,k} = MLP_{i,k} + min(DR_{i,k}, R \cdot MDR_k).$$

      ii. If $R > 1$, set

$$PSUMax_{i,k} = MLP_{i,k} + DR_{i,k} + PRSTMax_{i,k} - SMLP - STShareDR_k \cdot MDR_k.$$

3.10.3.7. Equal ST Minimum and Maximum Constraints

ST minimum constraints and maximum constraints of equal amounts may not result in PSU resource minimum and maximum constraints of equal amounts. This may occur because ST minimum constraints are only allocated to committed PSUs and are allocated equally to committed PSUs as opposed to pro-rated across available capacity. Equal minimum and maximum ST constraints may be applied to fix the steam turbine to a given output for safety, equipment or *reliability* reasons. In these circumstances, the ST minimum constraint allocation logic will be used to determine equal minimum and maximum constraints to be applied to the PSUs because the constraint represents an operational concern and is best allocated to committed PSUs.

3.10.4. Determining RT Effective PSU Values from PU Values

For the purposes of determining resource initial conditions for PSU resources as described in Section 3.4.1.6, an effective PSU EMS MW value for each PSU resource must be determined. This quantity will be derived from the EMS MW values determined based on telemetry values of the CT and affiliated ST.

For a combined cycle *facility* with K CTs and one ST, the following effective PSU EMS MW values will be computed from the PU EMS MW values:

- $PSUTel_k$ indicating the effective EMS MW value for PSU $k \in \{1,..,K\}$.

The following EMS MW values and additional data is required to perform the translation:

- $CTTel_k$ indicating the EMS MW value for CT $k \in \{1,..,K\}$;
- $STTel$ indicating the EMS MW value for the ST;
- The model parameters $STShareMLP_k$, $CTShareMLP_k$, $STShareDR_k$ and $CTShareDR_k$ for PSU $k \in \{1,..K\}$; and
- $TMLP_k$, TDR_k, and TDF_k, indicating the effective operating ranges for the time at which EMS MW value was determined.

The procedure for determining the effective PSU EMS MW values is as follows:

1. For all combustion turbines, assign the EMS MW values to the corresponding PSU. The value should be first assigned to the CT's share of the MLP region and then to its share of the dispatchable region. For PSU $k \in \{1,..,K\}$:
   a. $CTMLPTel_k$ designates the amount assigned to the CT's share of the MLP region and is given by
   $$CTMLPTel_k = min\{\ CTTel_k\ ,CTShareMLP_k \cdot TMLP_k\ \}.$$
   b. $CTDRTel_k$ designates the amount assigned to the CT's share of the dispatchable region and is calculated as follows:
      i. If $CTMLPTel_k < CTTel_k$, then set
      $$CTDRTel_k = min\{(CTTel_k\text{-}CTMLPTel_k)\ ,\ CTShareDR_k \cdot TDR_k\ \}.$$
      ii. Otherwise, set $CTDRTel_k = 0$.
2. Determine the maximum amount of the ST EMS MW value that may be assigned to the ST's share of the PSU's MLP and dispatchable regions based on the amount assigned to the CT's share of the MLP and dispatchable regions. For PSU $k \in \{1,..,K\}$:
   a. $STMLPMax_k$ designates the maximum amount that may be assigned to the ST's share of the MLP region and is given by

$$STMLPMax_k = CTMLPTel_k \cdot \left(\frac{STShareMLP_k}{CTShareMLP_k}\right).$$

b. $STDRMax_k$ designates the maximum amount that may be assigned to the ST's share of the dispatchable region and is given by

$$STDRMax_k = CTDRTel_k \cdot \left(\frac{STShareDR_k}{CTShareDR_k}\right).$$

3. Distribute the EMS MW value for the ST to the MLP and dispatchable regions of the PSUs in proportion to the maximum amount that may be allocated. For PSU $k \in \{1,..,K\}$:

   a. $STMLPTel_k$ designates the amount assigned to the ST share of the MLP region and is given by

$$min\left\{STMLPMax_k , \left(\frac{STMLPMax_k}{\sum_{w=1..K}(STMLPMax_w + STDRMax_w)}\right) \cdot STTel\right\}.$$

   b. $STDRTel_k$ designates the amount assigned the ST share of the dispatchable region and is given by

$$min\left\{STDRMax_k , \left(\frac{STDRMax_k}{\sum_{w=1..K}(STMLPMax_w + STDRMax_w)}\right) \cdot STTel\right\}.$$

4. Determine $STRemTel$, the remaining portion of the EMS MW value for the ST that is yet to be distributed, given by

$$STTel - \sum_{k=1..K}(STMLPTel_k + STDRTel_k).$$

5. Determine the maximum amount of the remaining ST EMS MW value that may be assigned to the PSU's duct firing region based on whether the PSU is fully loaded for its MLP and dispatchable regions. For PSU $k \in \{1,..,K\}$, $STDFMax_k$ designates the maximum amount that may be assigned to the duct firing region and is calculated as follows:

   a. If $(CTMLPTel_k + CTDRTel_k + STMLPTel_k + STDRTel_k) \geq TMLP_k + TDR_k$, then set

$$STDFMax_k = TDF_k.$$

   b. Otherwise, set $STDFMax_k = 0$.

2. Distribute the remaining portion of the ST EMS MW value to the duct firing regions of the PSUs in proportion to the maximum amount that may be allocated. For PSU $k \in \{1,..,K\}$, $STDFTel_k$ designates the amount assigned to the duct firing region and is given by

$$STDFTel_k = min\left\{STDFMax_k , \left(\frac{STDFMax_k}{\sum_{w=1..K} STDFMax_w}\right) \cdot STRemTel\right\}.$$

3. The effective real-time EMS MW value of the PSU is then calculated by summing the amounts assigned to the PSU operating regions. For PSU $k \in \{1,..,K\}$:

$$PSUTel_k = CTMLPTel_k + CTDRTel_k + STMLPTel_k + STDRTel_k + STDFTel_k.$$

This process may not distribute the entire ST EMS MW value.

3.10.5. Translation of PSU Schedules to PU Schedules

The PSU model determines the logic for translating *energy* and *operating reserve* schedules for the PSUs representing a combined cycle *facility* to *energy* and *operating reserve* schedules for the corresponding physical units. When a PSU resource is scheduled below its *minimum loading point*, logic is applied to appropriately translate schedules depending on the online status of the associated ST.

For a combined cycle *facility* with K combustion turbines and one steam turbine, the following *energy* and *operating reserve* schedules for the physical units will be computed from the PSU schedules for interval $i \in I$:

- $CTE_{i,k}$ indicating the *energy* schedule for CT $k \in \{1,..,K\}$;
- $STPE_{i,k}$ indicating the *energy* schedule for the ST portion of PSU $k \in \{1,..,K\}$;
- STE_i indicating the *energy* schedule for the ST;
- $CT10S_{i,k}$ indicating the synchronized *ten-minute operating reserve* schedule for CT $k \in \{1,..,K\}$;
- $STP10S_{i,k}$ indicating the synchronized *ten-minute operating reserve* schedule for the ST portion of PSU $k \in \{1,..,K\}$;
- $ST10S_i$ indicating the synchronized *ten-minute operating reserve* schedule for the ST;
- $CT10N_{i,k}$ indicating the non-synchronized *ten-minute operating reserve* schedule for CT $k \in \{1,..,K\}$;
- $STP10N_{i,k}$ indicating the non-synchronized *ten-minute operating reserve* schedule for the ST portion of PSU $k \in \{1,..,K\}$;
- $ST10N_i$ indicating the non-synchronized *ten-minute operating reserve* schedule for the ST;
- $CT30R_{i,k}$ indicating the *thirty-minute operating reserve* schedule for CT $k \in \{1,..,K\}$;
- $STP30R_{i,k}$ indicating the *thirty-minute operating reserve* schedule for the ST portion of PSU $k \in \{1,..,K\}$; and

- $ST30R_i$ indicating the *thirty-minute operating reserve* schedule for the ST.

Suppose the RT calculation engine has determined the following *energy* and *operating reserve* schedules for PSU $k \in \{1,..,K\}$ in interval $i \in I$:

- $SE_{i,k}$ indicating the total amount of *energy* scheduled. This schedule can be broken into three components so that $SE_{i,k} = SEMLP_{i,k} + SEDR_{i,k} + SEDF_{i,k}$ where:
    - o $SEMLP_{i,k}$ indicates the portion of the schedule corresponding to the MLP region. Necessarily $0 \le SEMLP_{i,k} \le QMLP_{i,k}$;
    - o $SEDR_{i,k}$ indicates the portion of the schedule corresponding to the dispatchable region. Necessarily $0 \le SEDR_{i,k} \le QDR_{i,k}$ and $SEDR_{i,k} > 0$ only if $SEMLP_{i,k} = QMLP_{i,k}$;
    - o $SEDF_{i,k}$ indicates the portion of the schedule corresponding to the duct firing region. Necessarily $0 \le SEDF_{i,k} \le QDF_{i,k}$ and $SEDF_{i,k} > 0$ only if $SEDR_{i,k} = QDR_{i,k}$;
- $S10S_{i,k}$ indicating the total amount of synchronized *ten-minute operating reserve* scheduled;
- $S10N_{i,k}$ indicating the total amount of non-synchronized *ten-minute operating reserve* scheduled. If the PSU cannot provide *operating reserve* from its duct firing region then necessarily $0 \le SE_{i,k} + S10S_{i,k} + S10N_{i,k} \le QMLP_{i,k} + QDR_{i,k}$; and
- $S30R_{i,k}$ indicating the total amount of *thirty-minute operating reserve* scheduled. Necessarily $0 \le SE_{i,k} + S10S_{i,k} + S10N_{i,k} + S30R_{i,k} \le QMLP_{i,k} + QDR_{i,k} + QDF_{i,k}$.

The following additional data is required to translate these PSU schedules to PU schedules for the purposes of determining *dispatch instructions*:

- $STOn \in \{0,1\}$ indicating if the ST is currently online (i.e. breaker closed);
- $CTE_{0,k}$ indicating the initial *energy* schedule allocated to the CT $k \in \{1,..,K\}$;
- $STPE_{0,k}$ indicating the initial *energy* schedule allocated to the ST portion of PSU $k \in \{1,..,K\}$;
- The *offer* quantities $QMLP_{i,k}$, $QDR_{i,k}$ and $QDF_{i,k}$ that may be scheduled for *energy* and *operating reserve* in each operating region for interval $i \in I$ and PSU $k \in \{1,..K\}$; and
- The ST and CT shares of the MLP and dispatchable regions for PSU $k \in K$ given by $STShareMLP_k$, $CTShareMLP_k$, $STShareDR_k$, and $CTShareDR_k$.

Note that PSU $k \in K$ will only be assigned a non-zero schedule by the RT calculation engine if the CT corresponding to PSU k is online (i.e. breaker closed).

The logic to calculate the *energy* and *operating reserve* schedules for the CT and ST portion for PSU $k \in \{1,..,K\}$ in interval $i \in I$ depends on whether the PSU is scheduled at or above its *minimum loading point*. The procedure is as follows:

1. If $SE_{i,k} \geq MLP_{i,k}$, then the PSU model applies and the following logic used:
    a. The *energy* schedules from the MLP, dispatchable and duct firing regions are assigned to the CT and ST according to the sharing percentages as follows:

$$CTE_{i,k} = SEMLP_{i,k} \cdot CTShareMLP_k + SEDR_{i,k} \cdot CTShareDR_k,$$
$$STPE_{i,k} = SEMLP_{i,k} \cdot STShareMLP_k + SEDR_{i,k} \cdot STShareDR_k + SEDF_{i,k}.$$

    b. The *operating reserve* schedules are then assigned to the dispatchable and duct firing regions based on remaining capacity, assigning the spinning reserve first and then non-spinning as follows:

$$RoomDR_{i,k} = QDR_{i,k} - SEDR_{i,k},$$
$$10SDR_{i,k} = min(RoomDR_{i,k}, S10S_{i,k}),$$
$$10NDR_{i,k} = min(RoomDR_{i,k} \text{-} 10SDR_{i,k}, S10N_{i,k}),$$
$$30RDR_{i,k} = min(RoomDR_{i,k} \text{-} 10SDR_{i,k} - 10NDR_{i,k}, S30R_{i,k}),$$
$$CT10S_{i,k} = 10SDR_{i,k} \cdot CTShareDR_k,$$
$$STP10S_{i,k} = 10SDR_{i,k} \cdot STShareDR_k + (S10S_{i,k} - 10SDR_{i,k}),$$
$$CT10N_{i,k} = 10NDR_{i,k} \cdot CTShareDR_k,$$
$$STP10N_{i,k} = 10NDR_{i,k} \cdot STShareDR_k + (S10N_{i,k} - 10NDR_{i,k}),$$
$$CT30R_{i,k} = 30RDR_{i,k} \cdot CTShareDR_k,$$
$$STP30R_{i,k} = 30RDR_{i,k} \cdot STShareDR_k + (S30R_{i,k} - 30RDR_{i,k}).$$

2. If $SE_{i,k} < MLP_{i,k}$ and the PSU resource is on a ramp-up trajectory, then the PSU model does not apply until the ST is online and the following logic is used:
    a. If the ST is not online (i.e. $STOn = 0$), then the PSU schedule will be assigned to the CT as follows:

$$CTE_{i,k} = SE_{i,k},$$
$$STPE_{i,k} = 0.$$

    b. If the ST is online (i.e. $STOn = 1$), the incremental PSU schedule will be assigned to the ST until the assigned CT and ST schedules adhere to the PSU model as follows:
        i. If $\left(\frac{STPE_{i-1,k}}{STPE_{i-1,k}+CTE_{i-1,k}}\right) < STShareMLP_k$, then:

$$CTE_{i,k} = CTE_{i\text{-}1,k},$$
$$STPE_{i,k} = SE_{i,k} - CTE_{i\text{-}1,k}.$$

ii. Otherwise:

$$CTE_{i,k} = SE_{i,k} \cdot CTShareMLP_k,$$
$$STPE_{i,k} = SE_{i,k} \cdot STShareMLP_k.$$

c. Necessarily $S10S_{i,k} = S10N_{i,k} = S30R_{i,k} = 0$ and so

$$CT10S_{i,k} = 0,$$
$$STP10S_{i,k} = 0,$$
$$CT10N_{i,k} = 0,$$
$$STP10N_{i,k} = 0,$$
$$CT30R_{i,k} = 0,$$
$$STP30R_{i,k} = 0.$$

3. If $SE_{i,k} < MLP_{i,k}$ and the PSU resource is on a ramp-down trajectory, then the PSU model does not apply if the ST is offline and the following logic is used:

a. If the ST is not online (i.e. $STOn = 0$), then the PSU schedule will be assigned to the CT as follows:

$$CTE_{i,k} = SE_{i,k},$$
$$STPE_{i,k} = 0.$$

b. If the ST is online (i.e. $STOn = 1$), the PSU schedule will be assigned according to the PSU model as follows:

$$CTE_{i,k} = SE_{i,k} \cdot CTShareMLP_k,$$
$$STPE_{i,k} = SE_{i,k} \cdot STShareMLP_k.$$

c. Necessarily $S10S_{i,k} = S10N_{i,k} = S30R_{i,k} = 0$ and so

$$CT10S_{i,k} = 0,$$
$$STP10S_{i,k} = 0,$$
$$CT10N_{i,k} = 0,$$
$$STP10N_{i,k} = 0,$$
$$CT30R_{i,k} = 0,$$
$$STP30R_{i,k} = 0.$$

After the PSU schedules are allocated to the CT and ST portion, the ST portion schedules are summed to obtain the ST schedule as follows:

$$STE_i = \sum_{k=1,..,K} STPE_{i,k},$$

$$ST10S_i = \sum_{k=1,..,K} STP10S_{i,k},$$

$$ST10N_i = \sum_{k=1,..,K} STP10N_{i,k},$$

and

$$ST30R_i = \sum_{k=1,..,K} STP30R_{i,k}.$$

3.10.6. Steam Turbine Forced Outages

When the steam turbine of a combined cycle *facility* electing PSU modelling experiences a *forced outage*, the RT calculation engine will automatically evaluate the corresponding PSUs as if the resources were being offered in single-cycle mode. This treatment will prevent the RT calculation engine from dispatching the PSUs to zero so that the *registered market participant* for the *facility* can either submit an outage slip or update their single-cycle mode flag to indicate their operational intent. For more information, see the Grid and Market Operations Integration detailed design document

3.10.7. Pricing for PSUs

The RT calculation engine will produce prices for PSUs by calculating weighted average marginal loss factors and weighted average sensitivities based on the PSU model parameters and scheduling results.

3.11. Determination of the Non-Dispatchable Demand Forecast

The *IESO* will produce five-minute *demand* forecasts for each *demand* forecast area. These *demand* forecasts are representative of transmission losses and forecast consumption of all *load facilities* and *hourly demand response* resources.

The RT calculation engine optimization function uses a five-minute province-wide non-dispatchable *demand* forecast quantity for each interval i, denoted by FL_i. This quantity will be derived from the five-minute *demand* forecasts for each *demand* forecast area by removing the portion of the forecasts attributed to loads that are considered dispatchable in the *real-time market*, through the following steps:

1. Sum the *IESO* five-minute *demand* forecasts for each *demand* forecast area (which are inclusive of losses);
2. Subtract the forecast consumption of all physical *hourly demand response* resources associated with *non-dispatchable loads* and price responsive loads when a *bid* for such a resource is present during the current hour in the MIO look-ahead period. Forecast consumption for each physical *hourly demand response* resource will be equal to:
    - the EMS MW quantity if the resource has operational telemetry; or
    - the scheduled quantity for the *hourly demand response* resource in the *dispatch interval* of the preceding RT calculation engine run if the resource does not have operational telemetry or when operational telemetry has failed and the state estimator solution is not available in the EMS.
3. Subtract the forecast consumption of all virtual *hourly demand response* resources associated with *non-dispatchable loads* when a *bid* for these resources is present during the current hour in the MIO look-ahead period. Forecast consumption for each virtual *hourly demand response* resource will be equal to:
    - the scheduled quantity for the virtual *hourly demand response* resource in the *dispatch interval* of the preceding RT calculation engine run.
4. Subtract the forecast consumption of all *dispatchable loads*. Forecast consumption for each *dispatchable load* will be equal to:
    - the EMS MW quantity; or
    - the scheduled quantity in the *dispatch interval* of the preceding RT calculation engine run when operational telemetry has failed and the state estimator solution is not available in the EMS.

– 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 RT Calculation Engine 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 classify 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.
- New: Identifies new *market rules* that will likely need to be added to support the design requirements.

The Table 4-1: Market Rule Appendix 7.5 Impacts

Market Rule Section	Type	Topic	Requirement
Appendix 7.5 – The Market Clearing and Pricing Process			
All Sections	Existing - requires amendment	All Topics	• This appendix describes the process to be used to determine *pre-dispatch schedules*, *real-time schedules*, *market schedules* and *market prices.* • This appendix will be retired and replaced with new appendices to describe the *dispatch* scheduling and pricing process, the PD Calculation Engine process and the RT Calculation Engine process. Note: The inventory for the new appendix to describe the PD Calculation Engine process will be included in the PD Calculation Engine detailed design document.

Table 4-2: Market Rule Appendix 7.X Impacts

Market Rule Section	Type	Topic	Requirement
Appendix 7.X – The Dispatch Scheduling and Pricing Process			
Appendix 7.X.1	New	Interpretation	This new section includes a description of the appendix and what information will be included in the appendix. • Section 1.1 will clarify the purpose of the appendix. The appendix describes the process to be used to determine *pre-dispatch schedules*, *real-time schedules*, and prices. The appendix will detail the following: o Modes of operation; o The inputs to the *dispatch* scheduling and pricing process; and o The outputs from the *dispatch* scheduling and pricing process.
Appendix 7.X.2	New	Modes of Operation	This new section sets out the *market rules* around the operation of the *dispatch* scheduling and pricing process.

Market Rule Section	Type	Topic	Requirement
			• Section 1.1 will clarify the two modes of operation used by the PD Calculation Engine process and the RT Calculation Engine process. The *dispatch* scheduling and pricing software may be operated to determine either a *pre-dispatch schedule* or a *real-time schedule* and any associated prices as required by these *market rules*. • Section 1.2 will include the details around the *real-time schedules* and the resulting *dispatch instructions* from the RT Calculation Engine process. The *real-time schedule* shall be issued for individual *dispatch intervals*. It represents the *energy* to be injected into or withdrawn from the *IESO-controlled grid*, and the *operating reserve* to be maintained, by dispatchable resources supplying *energy* or *operating reserve*, or consuming *energy*, in each *dispatch interval*. • Section 1.3 will include the details around *intertie* schedules *intertie zones* adjoining the *IESO control area*. The schedules shall be fixed for all *dispatch intervals* within a *dispatch hour* in the *real-time schedule* to equal the *interchange schedules* determined for that same *dispatch hour* based on the last *pre-dispatch schedule* determined prior to solving the *real-time schedule*. Note: This section will be updated to include any *market rules* around *pre-dispatch schedules*. Overlap: PD Calculation Engine detailed design document.
Appendix 7.X.3	New	Inputs	This new section sets out the *market rules* around the inputs to the *dispatch* scheduling and pricing process. • Section 1.1 will include the inputs to the *dispatch* scheduling and pricing process. Note: The inputs to the *dispatch* scheduling and pricing process that are common to both the PD

Market Rule Section	Type	Topic	Requirement
			Calculation Engine and the RT Calculation Engine processes will be identified in this section. For the purposes of this inventory, all inputs to the RT Calculation Engine process are identified in Appendix 7.XB. Overlap: PD Calculation Engine detailed design document.
Appendix 7.X.4	New	Outputs	This new section sets out the *market rules* around the outputs in the *dispatch* scheduling and pricing process. • Section 1.1 will include the outputs to the *dispatch* scheduling and pricing process. • Section 1.2 – Dispatch Instructions: The section will include a reference to the *market rules* section in Chapter 7. Note: The outputs from the RT Calculation Engine processes will be identified in this section. For the purposes of this inventory, all outputs from the RT Calculation Engine process are identified in Appendix 7.XB. Some outputs from the pre-dispatch calculation engine may also be included in this section. Overlap: PD Calculation Engine detailed design document.

Table 4-3: Market Rule Appendix 7.XA Impacts

Market Rule Section	Type	Topic	Requirement
Appendix 7.XA – The Pre-Dispatch Calculation Engine Process			
All Sections	New	All Topics	This appendix describes the PD Calculation Engine process and will be included in the PD Calculation Engine detailed design document.

Table 4-4: Market Rule Appendix 7.XB Impacts

Market Rule Section	Type	Topic	Requirement
Appendix 7.XB – The Real-Time Calculation Engine Process			
Section 1	New	Interpretation	This new section includes a description of the appendix and what information will be included in the appendix. • Section 1.1 will clarify the purpose of the appendix. The appendix describes the RT Calculation Engine process used to determine *dispatch* schedules and prices. The appendix will detail the following: o The inputs to the RT calculation engine; o The outputs from the RT calculation engine; and o The mathematical description of the algorithms for the single pass in the RT calculation engine. Similar to the existing Appendix 7.5 – The Market Clearing and Pricing Process, the *market rules* will state that the RT calculation engine output data described in Appendix 7.XB will not require the *IESO* to *publish* the output data except where expressly required by the *market rules*.
Section 2	New	The Real-Time Calculation Engine - Overview	This new section provides an overview of the RT calculation engine. • Section 2.1 will set out the purpose of the RT calculation engine and will describe the single pass. Pass 1, the Real-Time Scheduling and Pricing Pass, determines a set of resource schedules to meet the *IESO*'s forecast *demand* and the *demand* from *dispatchable loads*. Pass 1 also determines locational marginal prices consistent with the scheduling decisions made in the pass.
Section 3	New	Inputs into the Real-Time Calculation Engine	This new section sets out the *market rules* around the inputs into the RT calculation engine.

Market Rule Section	Type	Topic	Requirement
			• Section 3.1 – Overview: The inputs will be categorized by the RT calculation engine's two functions: o Optimization function; and o *Security* assessment function. • Section 3.2 – Inputs into the Optimization Function • Section 3.2.1 – Demand Forecasts: The section will include details of the five-minute *demand* forecast prepared by the *IESO* for each of the *IESO demand* forecast areas. The *demand* forecasts will be modified to a quantity that is representative of load that is considered non-dispatchable and is inclusive of losses. The forecasts will be produced for all intervals of the study period (i.e. the *dispatch interval* and the next ten five-minute intervals after the *dispatch interval*). • Section 3.2.2 – Forecasts from Non-Dispatchable Generation Resources: The section will include details on the forecast output from *self-scheduling generation facilities, transitional scheduling generators* and *intermittent generators* submitted by *registered market participants* in accordance with Chapter 7. • Section 3.2.3 – Forecasts from Variable Generation Resources: The section will include details on the forecast for *variable generation* produced by the *IESO* for all intervals of the study period (i.e. the *dispatch interval* and the next ten five-minute intervals after the *dispatch interval*). • Section 3.2.4 – Energy Bids and Offers: The section will include *energy offers* and *energy bids* and other associated *dispatch data* parameters submitted by *registered market participants* submitted in accordance with Chapter 7.

Market Rule Section	Type	Topic	Requirement
			• Section 3.2.5 – Operating Reserve Offers: The section will include *operating reserve offers* and other associated *dispatch data* parameters submitted in accordance with Chapter 7. • Section 3.2.6 – Operating Characteristics of Generation Facilities and Dispatchable Loads: The section will list the operating characteristics of all *generation facilities* and *dispatchable loads* including, but not limited to ramp-rate limits and *operating reserve* response parameters in accordance with Chapter 7. • Section 3.2.7 – Non-Quick Start Resources: The section will list the inputs for non-quick-start resources including observed resource operation (whether the resource is (1) scheduled to be offline, (2) scheduled on its start-up trajectory status, (3) scheduled to operate at or above *minimum loading point*, (4) de-committed by the pre-dispatch calculation engine, and (5) scheduled on its shutdown trajectory), as well as confirmed start-up and shutdown times, and *minimum loading point* are required. • Section 3.2.8 – Pseudo-Units: The section will list the inputs for *pseudo-units* including the steam turbine share of the *minimum loading point* region, steam turbine share of the dispatchable region, and whether the *pseudo-unit* may not provide *ten-minute operating reserve* while scheduled in its duct firing region. • Section 3.2.9 – Hydroelectric Resources: The section will list the input for hydroelectric resources, which include *forbidden regions*, hourly must run, and minimum daily *energy* limit *dispatch data* parameters. • Section 3.2.10 – No-Offer Generation: The section will list the input for no-offer generation, which includes schedules for

Market Rule Section	Type	Topic	Requirement
			generation without an active *offer* currently injecting into the *IESO-controlled grid*. • Section 3.2.11 – Imports and Exports: The section will include details on the inputs for imports and exports, specifically those outside the normal market *bids* and *offers* including, but not limited to, *emergency energy*, inadvertent *intertie* flows and simultaneous activation of reserve. • Section 3.2.12 – Inputs Provided by the Security Assessment Function: The section will include details on the inputs provided by the Security Assessment Function, which include: o Transmission constraints; and o Transmission losses. • Section 3.2.13– Inputs Provided by the Ex-Ante Market Power Mitigation Process. The section will include details on the inputs provided by the Ex-Ante Market Power Mitigation Process, which include *dispatch data* replaced by reference level values resulting from the failure of conduct and price impact tests executed by the pre-dispatch calculation engine for *dispatchable loads* and dispatchable generation resources. • Section 3.2.14 – Other Inputs: The *IESO* shall also provide other inputs into the RT calculation engine for the optimization function. These include: o Marginal loss factors; o Operating reserve requirements; o Resource minimum and maximum constraints; o Control action adjustments for pricing; and o Constraint violation penalties. • Section 3.3 – Inputs into the Security Assessment Function

Market Rule Section	Type	Topic	Requirement
			• Section 3.3.1 – Inputs Provided by the Optimization Function: The Optimization Function will provide schedules for load and supply resources (withdrawals and injections). • Section 3.3.2 – Other inputs: o Security limits; o Power system model data; o List of contingencies; o List of monitored equipment; and o Load distribution factors. • Section 3.4 – Inputs into the Pricing Formulation • Section 3.4.1 – Inputs Provided by the Pre-Dispatch Calculation Engine. The pre-dispatch calculation engine will provide the following for the *dispatch hour* in which the interval falls (for both *energy* and *operating reserve*): o Fixed schedules for import transactions; o Fixed schedules for export transactions; o Locational marginal price for *intertie zone* source and sink buses; o *Intertie* congestion price; o *Intertie* congestion component; and o Net *interchange schedule* limit congestion component. Overlap: Market Power Mitigation detailed design document, Offers, Bids and Data Input detailed design document, PD Calculation Engine detailed design document.
Section 4	New	Initialization	This new section sets out the *market rules* around the initialization processes. • Section 4.1 – Overview: The section will include an overview of the initialization processes. Prior to the execution of its single pass, the RT calculation engine will perform the initialization processes, which include: o Selecting a *reference bus*;

Market Rule Section	Type	Topic	Requirement
			o Determining islanding conditions; o Applying the *variable generator* tie-breaking logic; o Determining initial schedules; and o Pre-processing maximum generation constraints that apply to *pseudo-units*. • Section 4.1.1 – References Buses: The section will include details on the selection of a *reference bus*. • Section 4.1.2 – Islanding: The section will include details determining islanding conditions. • Section 4.1.3 - Variable Generation Resource Tie-Breaking: The section will include details on the application of the *variable generator* tie-breaking logic. • Section 4.1.4 – Initial Schedules: The section will include details on the calculation of initial schedules used in the Real-Time Scheduling and Real-Time Pricing algorithms. • Section 4.1.5 - Pseudo-Unit Minimum and Maximum Constraints: The section will include details on the pre-processing of minimum and maximum generation constraints that apply to *pseudo-units*.
Section 5	New	Security Assessment	This new section will set out the *market rules* around the *security* assessment function. • Section 5.1 – Overview: The section will provide an overview of the *security* assessment function. The *security* assessment function assesses power system *security* using the schedules produced by the optimization function. For resource schedules and prices, the RT calculation engine iterates between an optimization function and a *security* assessment function. • Section 5.2 – Inputs: The section will include the inputs into the *security* assessment

Market Rule Section	Type	Topic	Requirement
			function by referencing the inputs identified in Section 3. • Section 5.3 – Security Assessment Function Processing: The *security* assessment function performs the following calculations and analyses (the details for these will be included in the *market rules*): o Base case power flow; o Pre-contingency *security* assessment; o Loss calculation; and o Contingency analysis. • Section 5.4 – Outputs: The section will list the outputs from the *security* assessment function. The outputs include, but are not limited to: • *Security* constraint set corresponding to violated pre-contingency limits and post-contingency thermal limits; o Loss adjustment; o Sensitivity factors (pre-contingency and post-contingency); and o Fixed marginal loss factors.
Section 6	New	Pass 1: Real-Time Scheduling and Pricing Pass	This new section sets out the *market rules* around the single pass of the RT calculation engine, including the inputs, mathematical formulations, and outputs. • Section 6.1 – Overview: The section will contain an overview of Pass 1. Pass 1 determines a set of resource schedules to meet the *IESO*'s forecast *demand* and the *demand* from *dispatchable loads*. • Sections 6.2 and 6.3 will detail the algorithms within Pass 1. For the purposes of this inventory, these sections are broken out by algorithm as follows: o Real-Time Scheduling o Real-time Pricing. • Section 6.4 – Locational Marginal Prices: The section will outline the locational marginal

Market Rule Section	Type	Topic	Requirement
			prices for Pass 1. Pass 1 will also produce locational marginal prices that may be used for *settlement* in accordance with Section 8. • Section 6.5 – Outputs: The section will list the outputs from Pass 1, which include but are not limited to: o Schedules; o Start-up and shutdown statuses for non-quick-start resources; o Shadow prices; and o Locational marginal prices.
Appendix 7.XB Section 6.2	New	Real-Time Scheduling	This new section sets out the *market rules* around the Real-Time Scheduling algorithm. • Section 6.2.1 – Overview: The section includes an overview of the Real-Time Scheduling algorithm. Real-Time Scheduling will perform a *security*-constrained economic *dispatch* to meet the *IESO's* non-dispatchable *demand* forecast and *IESO*-specified *operating reserve* requirements. • Section 6.2.2 – Inputs: The section lists the inputs to the Real-Time Scheduling algorithm by referencing the inputs identified in Section 3. • Section 6.2.3 – Optimization Function for Real-Time Scheduling: The section includes details on the optimization function including: o Optimization Objective: The section will include the objective (to maximize the gains from trade). o Variables: The section will list the variables for which the calculation engine will solve for. o Objective Function: The section will include the optimization of the objective function in Real-Time Scheduling, which is to maximize the expression (Note: the

Market Rule Section	Type	Topic	Requirement
			expression will be included in the *market rules*). • Section 6.2.4 – Optimization Constraints: The section outlines the three constraint categories that apply to the schedules determined in the optimization: o Single interval constraints that ensure no violation of parameters specified in the dispatch data submitted by *registered market participants*; o Inter-interval and multi-interval constraints that ensure no violation of parameters specified in the dispatch data submitted by *registered market participants*; and o Constraints that ensure no violations of IESO established reliability criteria. • Section 6.2.5 – Bid/Offer Constraints Applying to Single Intervals: The section will include details on the single interval constraints including: o Scheduling variable bounds; o Initial conditions for determining schedules; o Resource minimum and maximums; o *Operating reserve* scheduling; and o Pseudo-units. • Section 6.2.6 – Bid/Offer Inter-Interval/Multi-Interval Constraints: The section will include details on the inter-interval/multi-interval constraints including: o *Energy* ramping; o *Operating reserve* ramping; and o Non-quick-start resource start-up and shutdown. • Section 6.2.7 – Constraints to Ensure Schedules Do Not Violate Reliability Requirements: The section will include details on the constraints

Market Rule Section	Type	Topic	Requirement
			that ensure no *IESO* established *reliability* criteria are violated including: o *Energy* balance; o *Operating reserve* requirements; o *IESO* internal transmission limits; and o Penalty price variable bounds. • Section 6.2.8 – Outputs: The section will list the outputs from the Real-Time Scheduling algorithm. Real-Time Scheduling will produce *dispatch* schedules. For non-quick-start resources being evaluated for shutdown, the algorithm will produce start-up and shutdown statuses. Note: The schedules produced for the *dispatch interval* will be used for producing real-time *dispatch instructions*. The schedules produced for the advisory intervals are advisory schedules.
Appendix 7.XB Section 6.3	New	Real-Time Pricing	This new section sets out the *market rules* around the Real-Time Pricing algorithm. • Section 6.3.1 – Overview: The section includes an overview of the Real-Time Pricing algorithm. Real-Time Pricing will perform a *security*-constrained economic *dispatch* to meet the *IESO's* non-dispatchable *demand* forecast and *IESO*-specified *operating reserve* requirements, as well as *demand* from *dispatchable loads*. • Section 6.3.2 – Inputs: The section includes the inputs to the Real-Time Pricing algorithm by referencing the inputs identified in Section 3. The section will also include a list of outputs from Real-Time Scheduling that are used as inputs to the Real-Time Pricing algorithm. • Section 6.3.3 – Optimization Function for Real-Time Pricing: The section includes details on the optimization function including: o Optimization Objective: The section will include the objective (to maximize the gains from trade).

Market Rule Section	Type	Topic	Requirement
			o Variables: The section will list the variables for which the RT calculation engine will solve for. o Objective Function: The optimization of the objective function in Real-Time Pricing is to maximize the expression (the expression will be included in the *market rules*). The objective function for the Real-Time Pricing is similar to Real-Time Scheduling, with the following exception: o The violation cost is calculated using the set of constraint violation penalty curves for determining *market prices*. • Section 6.3.4 – Optimization Constraints: The section outlines the four constraint categories that apply to the schedules and prices determined in the optimization: o Single interval constraints that ensure no violation of parameters specified in the dispatch data submitted by *registered market participants*; o Inter-interval and multi-interval constraints that ensure no violation of parameters specified in the dispatch data submitted by *registered market participants*; and o Constraints that ensure no violations of IESO established reliability inputs; and o Constraints that ensure the eligibility of an offer or bid lamination to set price is appropriately reflected. • Section 6.3.5 – Bid/Offer Constraints Applying to Single Intervals: The section will include details on the single interval constraints including: o Scheduling variable bounds; o Initial conditions for calculating market prices; o Resource minimum and maximums;

Market Rule Section	Type	Topic	Requirement
			o *Operating reserve* scheduling; and o Pseudo-units. • Section 6.3.6 – Bid/Offer Inter-Interval/Multi-Interval Constraints: The section will include details on the inter-interval/multi-interval constraints including: o *Energy* ramping; o *Operating reserve* ramping; and o Non-quick-start resources (Note: This constraint reflects the shutdown decisions made by Real-Time Scheduling). • Section 6.3.7 – Constraints to Ensure Schedules Do Not Violate Reliability Requirements: The section will include details on the constraints that ensure no *IESO* established *reliability* criteria is violated including: o *Energy* balance; o *Operating reserve* requirements; o *IESO* internal transmission limits; and o Penalty price variable bounds. • Section 6.3.8 - Constraints to Ensure Price-Setting Eligibility Reflect Offer/B*id* Laminations. The section will include details on the constraints that ensure the eligibility of an *offer* or *bid* lamination to set price is appropriately reflected including: o For non-quick-start resources: o Start-up and shutdown constraints; and o *Operating reserve* scheduling variable bounds. • Section 6.3.9 – Outputs: The section will list the outputs from the Real-Time Pricing algorithm. Real-Time Pricing will produce shadow prices for all constraints contributing to locational prices. Real-Time Pricing will also produce *settlement*-ready locational marginal prices and the RT Ontario Zonal Price for *energy*.

Market Rule Section	Type	Topic	Requirement
			Note: The locational marginal prices calculated for the *dispatch interval* will be used for the *settlement* of the *energy market* and the *operating reserve market* while the location marginal prices calculated for advisory intervals will be informational.
Section 7	New	Combined Cycle Modelling	This new section sets out the *market rules* around combined cycle modelling. • Section 7.1 – Overview: The section will provide an overview of combined cycle modelling. *Registered market participants* with combined cycle plants of one or more combustion turbines and one steam turbine may choose to have the associated generation units modelled as one or more *pseudo-units*. • Section 7.2 – Modelling by the Real-Time Calculation Engine: The section will include details on the modelling of *pseudo-units* and the pricing for *pseudo-units* in the real-time calculation engine. • Section 7.2.1 – The section will include details on the modelling of *pseudo-units* in the optimization function and in the *security* assessment function. The real-time calculation engine will evaluate combined cycle facilities electing to be modelled as a *pseudo-unit*(*s*) in (1) the optimization function as a *pseudo-unit*(*s*) and (2) in the *security* assessment function as physical units. • Section 7.2.1.1 – Model Parameters: The section will include the parameters used for modelling, including facility registration and daily *dispatch data*. • Section 7.2.1.2 – Physical Unit De-rates and Pseudo-Units: The section will include details on the impact of the application of the physical unit de-rates to the operating regions and associated *energy offers* for *pseudo-units*.

Market Rule Section	Type	Topic	Requirement
			• Section 7.2.1.3 – Minimum and Maximum Constraints: The section will include details on the application of minimum and maximum constraints to *pseudo-units* for the following constraints: o *Pseudo-unit* minimum and maximum constraints; o Combustion turbine minimum and maximum constraints; o Steam turbine minimum and maximum constraints; and o Equal steam turbine minimum and maximum constraints. • Section 7.2.1.4 – Translation of Physical Unit Energy Management System Values to Pseudo-Unit Energy Management System Values: The section will include details on the translation of physical unit energy management system values to *pseudo-unit* energy management system values, including the use of telemetry data and model parameters. • Section 7.2.1.5 – Translation of Pseudo-Unit Schedules to Physical Unit Schedules: The section will include details on the translation of *pseudo-unit* schedules to physical unit schedules. The section will detail the translation for (1) when a *pseudo-unit* is scheduled above or at its *minimum loading point* and (2) when a *pseudo-unit* is scheduled below its *minimum loading point*. • Section 7.2.1.6 – Treatment of Steam Turbine Forced Outages: The section will include details on the treatment of a *forced outage* for steam turbines associated to a *pseudo-unit*. The RT calculation engine will model the corresponding *pseudo-units* as if the resources were in single-cycle mode. • Section 7.2.2 – Pricing for Pseudo-Units: The section will include details on the prices for

Market Rule Section	Type	Topic	Requirement
			pseudo-units produced by the RT calculation engine.
Section 8	New	Pricing Formulation	This new section sets out the *market rules* around the calculation of locational marginal prices. • Section 8.1 – Overview: The section will provide an overview of the pricing formulation for calculating locational marginal prices including: o Locational marginal prices for *energy*; o Locational marginal prices for *operating reserve*; and o Prices for islanded nodes. o The prices will be determined as follows: • Prices will be calculated using the shadow prices determined by the pricing algorithm, accounting for constraint sensitivities and marginal loss factors. If the prices are not within the maximum clearing price and the *settlement* floor price, the price and its components will be modified by the RT calculation engine. • A weighted average of the above *settlement*-ready locational marginal prices will be used to provide zonal prices for virtual transaction zonal trading entities and for *non-dispatchable load* zones, including the Ontario Zone. Note: • If locational marginal prices are unable to be produced due to insufficient information, or if the process fails, it will be flagged for further review by the *IESO*. • Section 8.2 – Locational Marginal Prices for Energy: The section will include details on the price formulation for *energy* locational marginal prices for: o Internal pricing nodes; and o *Intertie zone* source and sink buses.

Market Rule Section	Type	Topic	Requirement
			Note: *Intertie settlement* prices will be calculated for *intertie zone* source and sink buses using the locational marginal prices and taking into account the congestion costs associated with binding *intertie* limits determined by the pre-dispatch calculation engine. • Section 8.3 – Locational Marginal Prices for Operating Reserve: The section will include details on the price formulation for *operating reserve* locational marginal prices for: o Internal pricing nodes; and o *Intertie zone* source and sink buses. Note: *Intertie settlement* prices will be calculated for *intertie zone* source and sink buses using the locational marginal prices and taking into account the congestion costs associated with binding *intertie* limits determined by the pre-dispatch calculation engine. • Section 8.4 – Prices for Islanded Nodes: The section will include details for: o The reconnection methodology for non-quick-start resources that are not connected to the main island of the system; and o The substitution methodology used to produce a price for all other pricing nodes that are not connected to the main island of the system due to one of the following reasons: o Transmission *outage*; o Disconnection; o A resource being out of service; or o Operation in segregated mode of operation.
Section 9	New	Tie-Breaking	This new section sets out the *market rules* around the tie-breaking methodology. • Section 9.1 – Overview: The section will provide an overview of the tie-breaking

Market Rule Section	Type	Topic	Requirement
			methodology used in the optimization function. Two tie-breaking methods will be used as follows: • Section 9.1.1 - Except as otherwise noted in section 9.1.2, if two or more *bids/offers* for *energy* or *offers* for *operating reserve* have the same *bid/offer* price that does not cause differences in the cost to the market of utilising each *offer*, the schedules from these *bids/offers* shall be prorated based on an adjusted amount of *energy bid/offered* at that *bid/offer price* (or based on the on adjusted amount *operating reserved offered* at the *offer price*). • Section 9.1.2 - For *variable generators* that are *registered market participants*, if two or more *energy offers* have the same *offer* price resulting in no differences in the cost to the *IESO-administered market* of utilising any of the *offers*. The schedules for these *offers* shall be determined using the daily *dispatch* order for *variable generation* using a tie-breaking modifier.

– End of Section –

5. Procedural Requirements

5.1. Market-Facing Procedural Impacts

Existing *market manuals* and training materials related to the RT Calculation Engine processes will be retained to the extent possible. Updates will be made to all applicable *market manuals* that reflect changes to the RT Calculation Engine processes. The documents most directly related to the Real-Time Calculation Engine detailed design are the following:

Market Manuals:

- Market Manual 4: Market Operations, Part 4.2 - Submission of Dispatch Data in the RT Energy and Operating Reserve Markets;
- Market Manual 4: Market Operations, Part 4.3 - Real Time Scheduling of the Physical Markets;
- Market Manual 4: Market Operations, Part 4.4 - Transmission Rights Auction;
- Market Manual 4: Market Operations, Part 4.5 - Market Suspension and Resumption;
- Market Manual 7: System Operations, Part 7.1 - IESO-Controlled Grid Operating Procedures;
- Market Manual 7: System Operations, Part 7.2 - Near-Term Assessments and Reports;
- Market Manual 7: System Operations, Part 7.4 - IESO-Controlled Grid Operating Policies
- Market Manual 9: Day-Ahead Commitment, Part 9.2 - Submitting Operational and Market Data for the DACP;
- Market Manual 9: Day-Ahead Commitment, Part 9.3 - Operation of the DACP;
- Market Manual 9: Day-Ahead Commitment, Part 9.4 - Real-Time Integration of the DACP; and
- Market Manual 9: Day-Ahead Commitment, Part 9.5 - Settlement for the DACP;
- Market Manual 13.1: Capacity Export Requests.

Training Material:

- Introduction to Ontario's Physical Markets

Quick Take:

- Joint Optimization of Energy and Operating Reserve;
- Multi-Interval Optimization.

The following tables identify sections within market manuals and training materials that will not require changes, will require modification and new sections that will need to be added to support the RT Calculation Engine processes in the future market.

Table 5-1: 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 RT Energy and Operating Reserve Markets	Modification	All Sections	• Reference to market clearing price to be replaced by location marginal pricing.
	No change	2.0 Real-Time Energy and Operating Reserve Markets	• This detailed design document does not impact this section.
	Modification	2.1 Offers and Bids for Energy and Offers for Operating Reserve in the Real-Time Energy Markets	• Reference to CAOR to be removed. The *IESO* will no longer include voltage reductions and reductions in the *thirty-minute operating reserve* requirements as standing *offers* in the *operating reserve market*. A new section on constraint violation penalty curves will be created.
	No change	2.2 Energy Schedules and Forecasts	• This detailed design document does not impact this section.
	No change	2.3 Timing of the Real-Time Energy and Operating Reserve Markets	• This detailed design document does not impact this section.

Procedure	Type of Change (no change, modification, new)	Section	Description
Part 4.2 – Submission of Dispatch data in the RT Energy and Operating Reserve Markets	No change	2.3.1 Generation Units with Start-Up Delays	• This detailed design document does not impact this section.
	No change	2.3.2 Replacement Energy Offers Program	• This detailed design document does not impact this section.
	Modification	2.3.3 - Procedural Steps for Submitting Dispatch Data and Revisions Until Two Hours Prior to the Dispatch Hour 2.3.4 - Procedural Steps for Submitting Dispatch Data and Revisions Within Two Hours of the Dispatch Hour	• Reference to *market clearing price* to be replaced by location marginal pricing.
	Modification	2.4 - The Structure of Dispatch Data: 2.4.1. Energy Offers and Bids 2.4.2. OR Offers 2.4.3 Energy Schedules and Forecasts	• Refer to the Offers, Bids and Data Inputs detailed design document for the list of modifications to this market manual section.
	No change	2.4.4. Standing Dispatch Data	• This detailed design document does not impact this section.
	Modification	2.5 Dispatch Data for Importing and Exporting Energy and Importing Operating Reserve	• Refer to the Offers, Bids and Data Inputs detailed design document for a list of modifications to this *market manual* section.

Procedure	Type of Change (no change, modification, new)	Section	Description
Part 4.2 – Submission of Dispatch data in the RT Energy and Operating Reserve Markets	Modification	2.5.1 Boundary Entity Resources	• Refer to the Offers, Bids and Data Inputs detailed design document for a list of modifications to this *market manual* section.
	No change	2.5.2 Ramp Rates	• This detailed design document does not impact this section.
	Modification	2.5.3 e-Tagging	• Reference to CMSC to be updated to reflect make-whole eligibility. The DSO will no longer produce market schedules, and CMSC that is calculated from these market schedules will be eliminated.
	No change	2.5.4 Wheeling Through Interchange Schedules	• This detailed design document does not impact this section.
	No change	2.5.5 Validation	• This detailed design document does not impact this section.
	No change	2.6 Capacity Exports	• This detailed design document does not impact this section.
	No change	2.6.1 Dispatch Data Requirements for Scheduling a Called Capacity Export	• This detailed design document does not impact this section.
	No change	2.6.2 Changes/Updates to Called Capacity Exports or Capacity Resources	• This detailed design document does not impact this section.
	No change	2.7 Requests for Segregated Mode of Operation	• This detailed design document does not impact this section.

Procedure	**Type of Change (no change, modification, new)**	**Section**	**Description**
Part 4.2 – Submission of Dispatch data in the RT Energy and Operating Reserve Markets	No change	2.8 Publication of Pre-Dispatch Schedules	• This detailed design document does not impact this section.
	Modification	Appendix A: Content of Dispatch Data	• Refer to the Offers, Bids and Data Inputs detailed design document for the list of modifications to this market manual section.
	No change	Appendix B: Short Notice Change Criteria	• This detailed design document does not impact this section.
	No change	Appendix C: Contingency Plan	• This detailed design document does not impact this section.
	Modification	Appendix D: Pre-Dispatch Schedule Production and Publication	• Reference to the Ontario *demand* forecast will be updated to reflect that area *demand* forecasting is used.
	No change	Appendix E: Boundary Entity Resources Appendix F: Ontario Specific E-Tag Requirements	• This detailed design document does not impact this section.
Part 4.3 – Real Time Scheduling of the Physical Markets	Modification	1.3 Roles and Responsibilities	• Reference to market schedules to be removed, and reference to market prices to be replaced by locational marginal prices.
	No change	2.0 Participant Workstation and Dispatch Workstation	• This detailed design document does not impact this section.

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	• The list of information used to determine real-time schedules will be updated to reflect the submitted *dispatch data* that is used to determine real-time schedules, for e.g., forbidden regions and MLP, and references to the related registered data will be removed. • Reference in the footnote to Ontario *demand* forecast will be updated to reflect new area *demand* forecasting, and reference to daily energy limits will be updated to include both maximum and minimum daily *energy* limits. The real-time constrained dispatch schedule will be replaced by the real-time dispatch schedule. • Additional changes to this section are described in the Offers, Bids and Data Inputs, and the Grid and Market Operations Integration detailed design documents.

Procedure	Type of Change (no change, modification, new)	Section	Description
Part 4.3 – Real Time Scheduling of the Physical Markets	Modification	4.0 Determining Market Information	• This section will be updated to reflect the changes to the real-time pricing algorithm. The DSO will determine real-time schedules and locational marginal prices at the same time, approximately ten minutes prior to the start of the *dispatch* interval. References to market schedules will be removed, and references to market prices will be replaced with locational marginal prices. • The list of exceptions to information used in determining schedules and locational marginal prices needs to be updated. The same information used to determine schedules will be used to determine locational marginal prices, except: • initial conditions used are the final conditions from the pricing algorithm in the preceding *dispatch interval*; • *intertie* schedules used are from the pre-dispatch pricing algorithm; • Ontario *demand* will continue to be adjusted when the *IESO* initiates a voltage reduction and/or load shedding; and • a different set of constraint violation penalty price curves is used for market *settlement*.

Procedure	Type of Change (no change, modification, new)	Section	Description
Part 4.3 – Real Time Scheduling of the Physical Markets	Modification	5.0 Releasing Real-Time and Market Information 5.1 Publication of Real-Time Schedule Information 5.1.1 Registered Facilities (other than boundary entities and HDR resources) 5.1.3 Boundary Entities 5.1.4 All Market Participants 5.2 Publication of Real-Time Dispatch Information	• References to market schedules to be removed. References to market prices, including uniform market prices and uniform Hourly Ontario Energy Price, to be updated to reflect locational marginal prices. • Additional changes to this section are described in the Publishing and Reporting Market Information detailed design documents.
	No change	5.1.2 Hourly Demand Response (HDR) Resources	• This detailed design document does not impact this section.
	Modification	6.0 Determining Dispatch Instructions 6.1 Registered Facilities (other than HDR resources and boundary entities)	• Section 6.1 will be updated to reflect that *dispatch instructions* are determined for *pseudo unit* resources and hydroelectric parameters that are respected in the real-time *dispatch*. Additional changes to this section are described in the Grid and Market Operations Integration detailed design document.
	No change	6.2 Hourly Demand Response (HDR) Resources 6.3 Boundary Entities	• This detailed design document does not impact this section.

Procedure	Type of Change (no change, modification, new)	Section	Description
	Modification	6.4 Intertie Scheduling Protocols 6.4.1 IESO/NYISO Protocol: NY90 6.4.2 Curtailed and Failed Interchange Schedules 6.4.3 IESO/MISO Protocol: MISO Protocol 6.4.4 IESO/Hydro-Quebec: Bilateral Capacity Agreements	• Section 6.4.4 reference to market schedules and market prices will be updated to reflect the change to real-time scheduling and locational marginal prices. • Refer to the Grid and Market Operations Integration detailed design document for details of the updates required to this section.
Part 4.3 – Real Time Scheduling of the Physical Markets	No change	6.5 Pre-Emptive Curtailments	• This detailed design document does not impact this section.
	No change	6.6 Transaction Coding 6.6.1 Principles of Coding 6.6.2 Methodology for Failure Code Application	• This detailed design document does not impact this section.
	No change	6.7 Capacity Export Scheduling and Curtailment 6.7.1 Capacity Export Delivery 6.7.2 Curtailment Provisions	• This detailed design document does not impact this section.

Procedure	Type of Change (no change, modification, new)	Section	Description
	Modification	7. Issuing Dispatch Instructions 7.1 Registered Facilities (other than HDR resources and boundary entities)	• Section 7.1 will be updated to include information on the real-time dispatching of pseudo-unit resources, and the translation to physical unit *dispatch instructions*. Additional changes to this section are described in the Grid and Market Operations Integration detailed design document.
	No change	7.2 Hourly Demand Response Resources 7.2.1 Dispatch Instructions for CMPs with HDR Resources	• This detailed design document does not impact this section.
Part 4.3 – Real Time Scheduling of the Physical Markets	No change	7.3 Boundary Entities 7.3.1 Dispatch Instructions for Boundary Entities	• This detailed design document does not impact this section.
	No change	7.4 Dispatch of Operating Reserve (OR) 7.5 Manual Procurement of Operating Reserve during forced or planned tools outages	• This detailed design document does not impact this section.
	Modification	7.6 Compliance with Dispatch Instructions	• Section to be updated to reflect off-*dispatch* resources' impact on schedule and price.

Procedure	Type of Change (no change, modification, new)	Section	Description
Part 4.3 – Real Time Scheduling of the Physical Markets	Modification	7.7 Generation Units Turnaround Time	• Procedure to be updated to reflect that the minimum generation block down time (MGBDT) submitted for different thermal states is respected in DAM and PD scheduling. • Refer to the Grid and Market Operations Integration detailed design document for details of the updates required to this section.
	No change	8. Issuing Dispatch Advisories 8.1 Registered Facilities (other than HDR resources and boundary entities) 8.2 Boundary Entities and HDR Resources 8.2.1 Compliance with Dispatch Advisories	• This detailed design document does not impact this section.
	Modification	9. Administrative Pricing Appendix A: Administrative Guidelines	• Section will be updated to reflect that administrative prices will be applied to locational marginal prices, and an offline study tool that is a replica of the RT calculation engine may be used to determine administrative prices. Reference to market price and Hourly Ontario Energy Price will be updated to reflect the change. • Reference to market schedule and actions to administer the market schedule corresponding to the market price will be removed.

Procedure	Type of Change (no change, modification, new)	Section	Description
			Additional changes to this section are described in the Grid and Market Operations Integration detailed design document.
Part 4.3 – Real Time Scheduling of the Physical Markets	No change	10. Compliance Aggregation	• This detailed design document does not impact this section.
Part 4.4 – Transmission Rights Auction	No change	All Sections other than Appendix B, Appendix C, and Appendix G	• No changes required to sections other than Appendix B: Pre-auction Publication, Appendix C: TR Monthly Financial Report, and Appendix G: Summary of Transmission Rights.
	Modification	Appendix B: Pre-auction Publication Appendix C: TR Monthly Financial Report Appendix G: Summary of Transmission Rights	• References to the market clearing price, market price, and uniform price will be updated.
Part 4.5 – Market Suspension and Resumption	No Change	All Sections other than Section 2.2.4 and Appendix A	• No changes required to sections other than Section 2.2.4 Set Administrative Price and Appendix A: Administrative Pricing.
	Modification	Section 2.2.4 Set Administrative Price Appendix A: Administrative Pricing	• Reference to market schedule and market price, including Hourly Ontario Energy Price (HOEP), will be updated to reflect the change to locational marginal prices. • Refer to the Grid and Market Operations Integration detailed design document for details of the updates required to this section.

Procedure	Type of Change (no change, modification, new)	Section	Description
Part 4.6 – RT Generation Cost Guarantee Program	No change	Entire document	• This detailed design document does not impact this section.

Table 5-2: 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	No change	All Sections other than Appendix B	• No changes required to sections other than Appendix B: Emergency Operating State Control Actions.
	Modification	Appendix B: Emergency Operating State Control Actions	• Table B.2: Emergency Operating State Actions (IESO and External Control Area Deficiency) reference to unconstrained will be removed. • Refer to the Grid and Market Operations Integration detailed design document for details of the updates required to this section.
Part 7.2: Near-Term Assessments and Reports	No change	All Sections other than Section 4.4 and Section 5.0	• No changes required to sections other than Section 4.4 IESO Control Actions (Nuclear Manoeuvres Forecasted or Occurring) and Section 5.0 Control Action Operating Reserve.
	No change	2. Adequacy and Transmission Limits Reports 2.4 Producing and Publishing the Ontario Zonal Demand Forecast	• This detailed design document does not impact this section.

Procedure	Type of Change (no change, modification, new)	Section	Description
		Report Appendix D.2 Forecast Demand	
Part 7.2: Near-Term Assessments and Reports	Modification	4.4 IESO Control Actions (Nuclear Manoeuvres Forecasted or Occurring)	• Reference to CMSC to be updated to reflect make-whole eligibility. The DSO will no longer produce market schedules, and CMSC that is calculated from these market schedules will be eliminated.
	Modification	5.0 Control Action Operating Reserve	• Refer to the Offers, Bids and Data Inputs detailed design document for details of the updates required to this section.
Part 7.3: Outage Management	No change	Entire document	• This detailed design document does not impact this section.
Part 7.4: IESO-Controlled Grid Operating Policies	No change	All Sections other than Section 2.7 and Section 3.3	• No changes required to sections other than Section 2.7 Grid Control Actions and 3.3 Operating Reserve Policy.
	Modification	2.7 Grid Control Actions	• Section 2.7.1: Principles reference to unconstrained dispatch to be updated.
	Modification	3.3 Operating Reserve Policy	• Reference to voltage reduction being used to provide operating reserve to be removed.

Table 5-3: Impacts to Market Manual 9: Day-Ahead Commitment

Procedure	Type of Change (no change, modification, new)	Section	Description
Part 9.0: Day-Ahead Commitment Process Overview	No change	Entire document	• Market Manual 9 will be replaced. DACP will be replaced with a financially-binding DAM. • This detailed design document does not impact this section.
Part 9.2: Submitting Operational and Market Data for the DACP	Modification	Entire document	• Update required to reflect that PSU resources will be evaluated by the real-time pass. • Additional changes are described in the Offers, Bids and Data Inputs, and the Grid and Market Operations Integration detailed design documents.
Part 9.3: Operation of the Day-Ahead Commitment Process	No change	All Sections other than Section 4.6 and Section 4.7	• No changes required to sections other than Section 4.6 IESO Reliability Commitment Actions and 4.7 Principles for Applying DACP Commitment Actions.
	Modification	4.6 IESO Reliability Commitment Actions 4.7 Principles for Applying DACP Commitment Actions	• Refer to DAM Calculation Engine detailed design document for the list of changes to this market manual section.
Part 9.4: Real-Time Integration of the DACP	No change	All Sections other than Section 4.1, Section 4.2, and Section 4.4	• No changes required to sections other than Section 4.1 Observing Day-Ahead Commitments in Real Time, 4.2 De-commitment and Withdrawal, and 4.4 Real-Time Market Integration.

Procedure	**Type of Change (no change, modification, new)**	**Section**	**Description**
Part 9.4: Real-Time Integration of the DACP	Modification	4.1 Observing Day-Ahead Commitments in Real Time 4.1.2 Passing DACP Commitments to Real Time	• Reference to minimum constraint will be updated to reflect that it is applied to the MGBRT hours of the commitment. Refer to Grid and Market Operations Integration detailed design document for the list of additional modifications to this market manual section.
	Modification	4.2 De-commitment and Withdrawal	• Reference to Ontario *energy* price, Ontario market clearing price, and real-time market clearing price will be updated to reflect locational marginal pricing.
	Modification	4.4 Real-Time Market Integration 4.4.1 Pseudo Unit Offer Submission—Real Time 4.4.2 Minimum Loading Point Price Cap	• Update required to reflect that PSU resources will be evaluated by the real-time pass. • Reference to CMSC to be updated to reflect make-whole eligibility. • Additional changes are described in the Offers, Bids and Data Inputs, and the Grid and Market Operations Integration detailed design documents.
Part 9.5: Settlement for the Day-Ahead Commitment Process	Modification	Entire document	• Refer to the Market Settlement detailed design document for details of the updates required to this section.

Table 5-4: Impacts to Market Manual 13: Capacity Exports

Procedure	Type of change (no change, modification, new)	Section	Description
Part 13.1: Capacity Export Requests	No change	All Sections other than Section 5.1	• No changes required to sections other than Section 5.1 Congestion Screen and 5.6 Congestion Review
	Modification	5.1 Congestion Screen 5.6 Congestion Review	• Reference to unconstrained market schedules, flows, and generator schedules will be updated to reflect the change to real-time schedules.

5.2. Internal Procedural Impacts

Some of the internal procedures identified in this section are related to *IESO* processes that interact with the RT Calculation Engine process. Changes to the RT Calculation Engine under the market renewal program will have an impact on other internal *manuals* related to the day-ahead, pre-dispatch and real-time dispatch and scheduling processes.

In addition, some areas of the current internal procedures heavily reference relevant *market rules* and supporting tools, most of which will be undergoing 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 *real-time market* and day-ahead 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 RT Calculation Engine processes 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 RT Calculation Engine. This section now presents the RT Calculation Engine processes 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 RT Calculation Engine processes. Specifically, the data flow diagram presented below illustrates:

- the RT Calculation Engine processes 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 RT Calculation Engine processes;
- external destinations of key information from the RT Calculation Engine processes; and
- the same logical boundary of the RT Calculation Engine processes 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 RT Calculation Engine 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 RT Calculation Engine processes. The following sections of this document will provide an overview to each of the main sub-processes of the RT Calculation Engine process.

The process map illustrated in Figure 6-1 presents the context and components of the RT Calculation Engine processes.

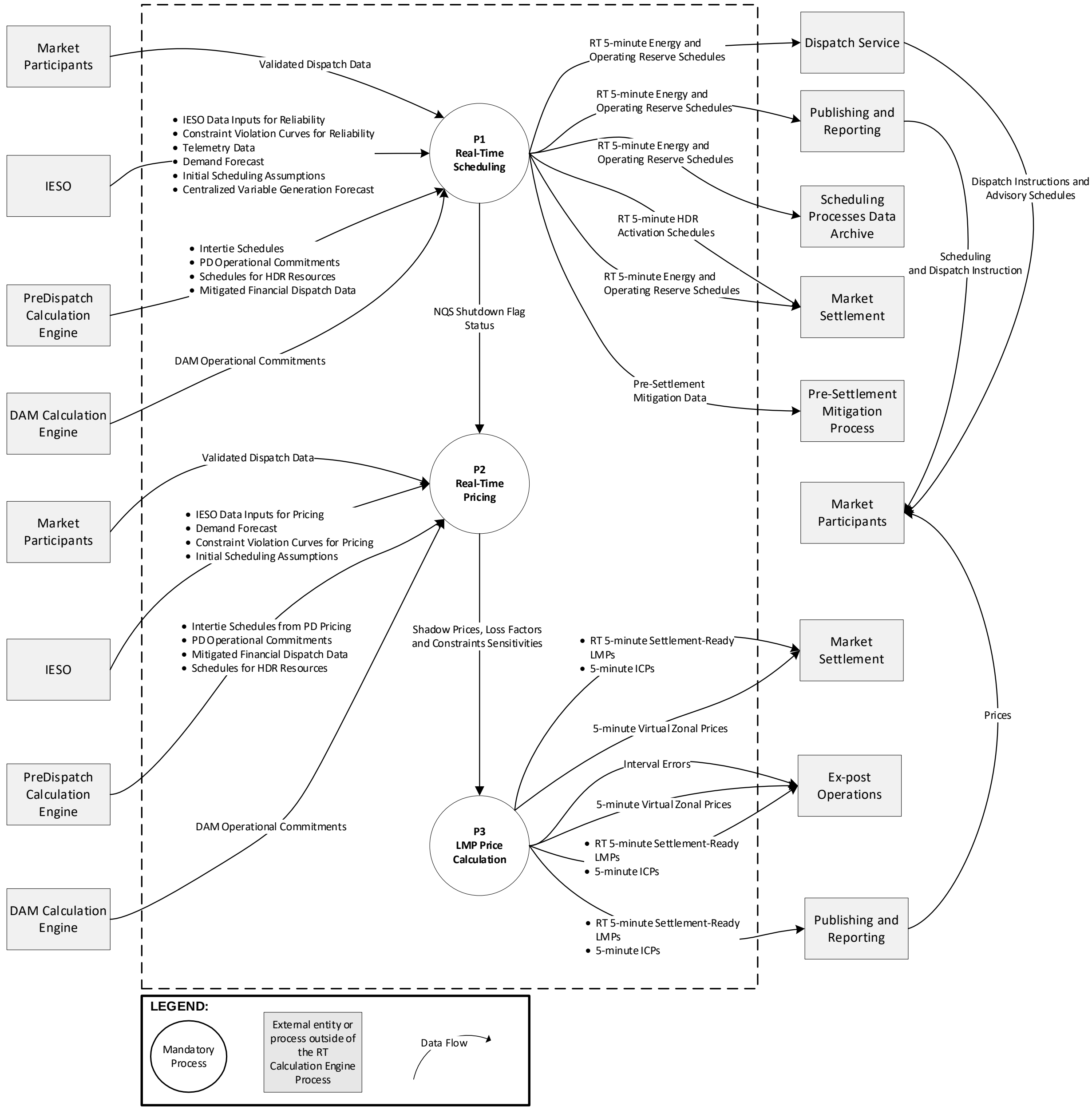

Figure 6-1: RT Calculation Engine Market Facing Process

6.1.1. Process P1: Real-Time Scheduling

Description

This process produces five-minute *dispatch* schedules for available resources internal to Ontario to meet forecast non-dispatchable *demand*, and it evaluates *bids* to consume *energy* from *dispatchable loads*, *offers* to supply *energy* from dispatchable and non-dispatchable *generation facilities* and *offers* to supply *operating reserve* from dispatchable *generation facilities* and *dispatchable loads*. The *dispatch* schedules produced will form the basis for the real-time *dispatch instructions* and advisory schedules for dispatchable resources. Certain results from this process will also be used to determine prices as part of Process P2: Real-Time Pricing.

Input and Output Information Flows

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

<table>
<tr><th>Flow</th><th>Source</th><th>Target</th><th>Frequency</th></tr>
<tr><td>Validated Dispatch Data</td><td>Market Participants</td><td>Process P1</td><td>Hourly</td></tr>
<tr><td colspan="4">Description:
Registered market participants will submit dispatch data that is validated by the IESO systems before it is used by the P1 process. The dispatch data includes:
For dispatchable loads:
• Hourly bids for energy including:
o Price-quantity pair data for the consumption of energy;
o Ramp rate data associated with the consumption of energy.
• Hourly offers for operating reserve including:
o Price-quantity pair data for the supply of synchronized ten-minute operating reserve;
o Price-quantity pair data for the supply of non-synchronized ten-minute operating reserve;
o Price-quantity pair data for the supply of thirty-minute operating reserve;
o Ramp rate data associated with the supply of operating reserve.
Refer to Section 3, Table 3-1 for a detailed description of dispatch data parameters submitted for dispatchable loads.
For non-dispatchable generation resources, registered market participants for self-scheduling generation facilities, transitional scheduling generators and intermittent</td></tr>
</table>

generators will provide dispatch data on forecast production and the lowest price at which they wish the generation resource to be scheduled.

The forecast production and price for these non-dispatchable generation resources will be treated as an *offer* for *energy* with a single *price-quantity pair*.

For all dispatchable *generation* resources, including PSU resources for which a *market participant* has elected PSU modelling for their *combined cycle facility*:

- Hourly offers for *energy* and *operating reserve* including:
  - *Price-quantity pair* data for the supply of *energy*;
  - Ramp rate data associated with the supply of *energy*.
  - *Price-quantity pair* data for the supply of synchronized *ten-minute operating reserve*;
  - *Price-quantity pair* data for the supply of non-synchronized *ten-minute operating reserve*;
  - *Price-quantity pair* data for the supply of *thirty-minute operating reserve*; and
  - Ramp rate data associated with the supply of *operating reserve*.

Refer to Section 3, Table 3-2 for a detailed description of *dispatch data* parameters submitted for all dispatchable *generation facilities*.

For NQS resources, additional *dispatch data* parameters include:

- *Minimum loading point*

Refer to Section 3, Table 3-3 for details of this *dispatch data* parameter.

For hydroelectric *generation* resources, additional *dispatch data* parameters include:

- Hourly must run;
- Minimum daily *energy* limit; and
- *Forbidden regions*.

Refer to Section 3, Table 3-5 for details of this *dispatch data* parameter.

Refer to Section 3, Table 3-4 for details of these *dispatch data* parameters and Section 3.10 for the derivation of data for combustion turbines (CTs) and steam turbines (STs).

Flow	**Source**	**Target**	**Frequency**
IESO Data Inputs for Reliability	IESO	Process P1	Every five minutes Event-based for control actions

Description:

The following *IESO* inputs will be used for the future *real-time market* as part of the Process P1.

- Marginal loss factors calculated by the *security* assessment function near the end of the *pre-dispatch hour* will be used as fixed marginal loss factors for every execution of the P1 process applicable for the next *dispatch hour*.
- *Operating reserve* (OR) requirements for:
    - Synchronized and non-synchronized ten-minute *operating reserve*;
    - *Thirty-minute operating reserve*; and
    - Regional *operating reserve* minimum requirements and maximum restrictions.

Refer to Section 3.4.1.5 for details of *operating reserve* requirements.

- Resource minimum and maximum constraint*s* for:
    - *Dispatchable loads*;
    - Dispatchable generation resources; and
    - PSU resources.

Refer to Section 3.4.1.5 for details of resource minimum and maximum constraints for *dispatchable loads*, dispatchable generation resources, and PSU resources.

- Network model: The network model contains a detailed topology representation of the *IESO-controlled grid* and a simplified representation of power systems in neighboring jurisdictions.

Refer to Section 3.4.1.5 for additional details about inputs provided by the network model.

Flow	**Source**	**Target**	**Frequency**
Constraint Violation Curves for Reliability	IESO	Process P1	Every five minutes

Description:

- Constraint violation penalty curves will continue to be defined as the penalty functions for the violation of constraints in the *dispatch algorithm*. These penalty curves establish the value placed on satisfying a constraint and indicate the relative priority of satisfying a certain constraint compared to other constraints.
- The constraint violation penalty curves for *reliability* will be used by the scheduling algorithm to produce a solution when satisfying all constraints is not feasible and to evaluate if the cost of satisfying a constraint is too high relative to the applicable penalty cost.
- Refer to Section 3.4.1.5 for detailed description on Constraint Violation Penalties.

Flow	**Source**	**Target**	**Frequency**
EMS MW Data	IESO	Process P1	Every five minutes

Description:

The P1 process uses telemetry data to determine energy management system (EMS) MW values that identify the real-time output or consumption of *facilities* within the *IESO-controlled grid* as follows:

- The current MW consumption observed through EMS for a *dispatchable load* without an active bid will be used to inform the dispatch interval schedule and advisory schedules across the MIO look-ahead period.
- The current MW output observed through EMS for a dispatchable generation resource without an active offer will be used to inform the dispatch interval schedule and advisory schedules across the MIO look-ahead period.
- The current MW output observed through EMS for non-dispatchable generation resources will be used to determine a fixed schedule across the MIO look-ahead period. These resources include:
    - self-scheduling generation facilities;
    - transitional scheduling generators; and
    - intermittent generators.
- The current MW consumption observed through EMS available for all *dispatchable loads*, physical *hourly demand response* resources associated with a *non-dispatchable load*, and physical *hourly demand response* resources associated with a price responsive load will be used to determine the amount of forecast consumption to subtract from the IESO demand forecast to arrive at the non-dispatchable *demand* forecast quantity.
- EMS MW values will also be used to inform the Initial Scheduling Assumptions.

Refer to Section 3.4.1.3 for details of how EMS MW data is used to produce schedules for *dispatchable loads* without an active *bid*.

Refer to Section 3.4.1.4 for how EMS MW data is used to produce schedules for *generation facilities* injecting without an active *offer*.

Refer to Section 3.11 for how EMS MW data is used to adjust the *IESO demand* forecast to arrive at the NDL forecast quantity.

Refer to Section 3.4.1.6 for how EMS MW data is used to inform Initial Scheduling Assumptions.

Flow	Source	Target	Frequency
Demand Forecast	IESO	Process P1	Every five minutes

Description:

- The five-minute *demand* forecast produced by the *IESO* will continue to be used as an input for the expected *non-dispatchable demand* in the RT calculation engine. 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 RT calculation engine will also use *demand* forecast for each area when distributing *demand* forecast to loads inside the area.
- Refer to Sections 3.4.1.3, 3.7.1.3 and 3.11 for details of how the RT calculation engine uses the *demand* forecast.

Flow	Source	Target	Frequency
Initial Scheduling Assumptions	IESO	Process P1	Every five minutes

Description:

The initial set of data representing current resource operating conditions will be determined in accordance with the specific methodology as described in Section 3.4.1.6. These operating conditions include:

- Initial schedules for dispatchable generation resources and *dispatchable loads* based on:
  - EMS MW values, and
  - Prior *dispatch interval* schedule produced by the preceding RT scheduling run.
- NQS resource start-up and shutdown statuses including:
  - NQS resources scheduled to be offline;
  - NQS resources with confirmed upcoming start-up or start-up ramping already started;
  - NQS resources scheduled at or above MLP;
  - NQS resources de-committed which may be scheduled below MLP; and
  - NQS resources with upcoming mandatory shutdown or shutdown ramp-down already started.

Flow	Source	Target	Frequency
Centralized Variable Generation Forecast	IESO	Process P1	Every five minutes

Description:

- The *IESO* produces a centralized *variable generation* forecast over multiple timeframes, for all *variable generation* resources*.* This forecast will continue to be used by the RT calculation engine to determine the maximum amount of *energy* for which a *variable* *generator* can be *dispatched*. The *IESO* will also retain the ability to adjust the centralized *variable generation* forecast as needed.

- This *variable generation* forecast data includes:
  - o *Variable generation* forecast quantity. The *IESO* produces a centralized *variable generation* forecast over multiple timeframes, for all *registered facilities* with *variable generation* resources.
- Refer to Section 3.4.1.4, for a detailed usage of Variable Generation Resources in the RT Calculation Engine.

Flow	Source	Target	Frequency
Intertie Schedules	Pre-Dispatch Calculation Engine	Process P1	Hourly

Description:

Intertie schedules include export and import schedules for *energy* and *operating reserve*. *Intertie* schedules will be fixed for the *dispatch hour* in the RT calculation engine according to the schedules calculated by the most recent *pre-dispatch scheduling* run and established as per the *intertie* check-out procedure.

- Export and import schedules are fixed within the *dispatch hour* and ramping between these schedules is performed in the interval preceding and interval succeeding the top of the *dispatch hour*.
- Pre-dispatch *intertie* schedules will be used by the RT calculation engine to calculate real-time *dispatch* schedules in P1 and *real-time market prices* for P2. Schedules received from the *pre-dispatch scheduling* processes for the *dispatch hour* will be comprised of:
  - o *Energy* scheduled for export;
  - o Non-synchronized *ten-minute operating reserve* scheduled from exporters;
  - o *Thirty-minute operating reserve* scheduled from exporters;
  - o *Energy* scheduled for import;
  - o Non-synchronized *ten-minute reserve* scheduled from importers, and
  - o *Thirty-minute operating reserve* scheduled from importers.
- Pre-dispatch *intertie* schedules may include *emergency* sales, *emergency* purchases or inadvertent payback transactions.
- Pre-dispatch export and import schedules can be modified in real time at the interval level to reflect:
  - o *Intertie* curtailment performed for adequacy or *security* reasons, or
  - o Unplanned *intertie* outages.

Refer to Section 3.4.1.3 for details on Export Schedules and Section 3.4.1.4 for details on Import Schedules.

Flow	Source	Target	Frequency
DAM Operational Commitments	DAM Calculation Engine	Process P1	Hourly

Description:

DAM operational commitments for NQS *generation facilities* will be carried through into real time.

- DAM operational commitments will be applied in the RT calculation engine as a minimum constraint such that the NQS *generation facility* is scheduled to its *minimum loading point* in the intervals of the commitment.

Refer to Section 3.4.1.5 for detailed description of the treatment of operational commitments.

Flow	Source	Target	Frequency
PD Operational Commitments	Pre-Dispatch Calculation Engine	Process P1	Hourly

Description:

PD operational commitments for NQS *generation facilities* will be carried through into real time.

- PD operational commitments will be applied in the RT calculation engine as a minimum constraint such that the NQS *generation facility* is scheduled to its minimum loading point in the intervals of the commitment.

Operational commitments can occur in the following ways:

- Pre-Dispatch Operational Commitment
- Pre-Dispatch Advancement of a DAM Operational Commitment
- Pre-Dispatch Extension to Existing Operational Commitments

Refer to Section 3.4.1.5 for detailed description of the treatment of operational commitments.

Flow	Source	Target	Frequency
Schedules For HDR Resources	Pre-Dispatch Calculation Engine	Process P1	Hourly

Description:

Hourly demand response resource schedules will be fixed for the *dispatch hour* in the RT calculation engine according to the schedules calculated by the *pre-dispatch scheduling* run three hours prior to the *dispatch hour*.

- *Hourly demand response* (HDR) schedules represents the quantity of MWs scheduled for:
  - Virtual *hourly demand response* resources;
  - Physical *hourly demand response* (HDR) resources for which a *registered wholesale meter* and *delivery point* has been defined. These resources will include:
    - Physical HDR resources associated with a *non-dispatchable load*; and
    - Physical HDR resources associated with a price responsive load.

Refer to Section 3.4.1.3 for additional details on Schedules for Hourly Demand Response Resources.

Flow	Source	Target	Frequency
Mitigated Financial Dispatch Data	Pre-Dispatch Calculation Engine	Process P1	Hourly

Description:

Mitigated financial *dispatch data* is the set of reference level values for *dispatchable loads* and dispatchable generation resources that replace as-offered *dispatch data* parameters that failed the price impact test during the pre-dispatch ex-ante Market Power Mitigation process.

- The following financial *dispatch* data parameters are applicable to the RT calculation engine and may be mitigated due to failure of the ex-ante pre-dispatch price impact testing are:
  - Hourly *energy offers* for dispatchable *generation* resources*;* and
  - Hourly offers for *operating reserve* for dispatchable generation resources and *dispatchable loads*.
- The RT calculation engine will not mitigate any *dispatch data* as a result of its processes. Instead, the RT calculation engine will use the mitigated financial *dispatch data* determined by the most recent pre-dispatch ex-ante Market Power Mitigation process.

Refer to Section 3.4.1.8 for additional details about inputs provided by the pre-dispatch ex-ante Market Power Mitigation process.

Flow	Source	Target	Frequency
NQS Shutdown Flag Status	Process P1	Process P2	Every five minutes

Description:

The following output from Real Time Scheduling will be used by the Real Time Pricing process:

- NQS shutdown flag information. RT Pricing Process will utilize NQS shutdown results from RT Scheduling.

Refer to Section 3.6.2.1, Table 3-6 for details of the Real-Time Scheduling output data that will be used by the RT Pricing calculation.

Flow	Source	Target	Frequency
Energy and Operating Reserve Schedules	Process P1	Dispatch Service Publishing and Reporting Market Settlement Scheduling Processes Data Archive - IESO	Every five minutes

Description:

These are the set of five-minute interval schedules for *energy* and *operating reserve* to meet *IESO's* five-minute non-dispatchable *demand* forecast and *operating reserve* requirements. The *energy* and *operating reserve* schedules for each *dispatch interval* will be used as the basis for the *dispatch instructions*, and the remaining schedules in the MIO look-ahead period will be *dispatch* advisories.

Description

Five-minute *dispatch* schedules will be produced for each *dispatch interval* for:

- *Energy* for dispatchable generation resources and *dispatchable load* resources;
- Synchronized *ten-minute operating reserve* for dispatchable generation resources and *dispatchable load* resources;
- Non-synchronized *ten-minute operating reserve* for dispatchable generation resources and *dispatchable load* resources;
- *Thirty-minute operating reserve* for dispatchable generation resources and *dispatchable load* resources;
- *Energy* schedules for the CT and ST physical units operating as a *pseudo-unit* (PSU) will be computed from the PSU *energy* schedules;
- *Energy* schedules for price responsive loads; and
- *Energy* schedules for *non-dispatchable loads*.
- *Dispatch instructions* and advisory schedules are generated by the Dispatch Service processes as illustrated in Figure 2-2 and sent to all *registered market participants* via

their *dispatch workstations* for all dispatchable generation resources and *dispatchable loads.*

- *Dispatch* schedules for *energy* and *operating reserve* will be used for *settlement* of dispatchable generation resources and *dispatchable load* resources.

Flow	Source	Target	Frequency
RT HDR Activation Schedules	Process P1	Market Settlement	Every five minutes

Description:

Real-time five-minute *hourly demand response* resource activation schedules will be fixed for the RT calculation engine according to the hourly schedules calculated by the *pre-dispatch scheduling* process. These schedules are fixed within a *dispatch hour* and ramping between these schedules is performed across the top of the *dispatch hour*.

RT HDR activation schedules represent the *energy* scheduled for withdrawal in MW for *hourly demand response* resources with active bids. five-minute HDR activation schedules will be produced for:

- Virtual *hourly demand response* resources;
- Physical HDR resources associated with a *non-dispatchable load*; and
- Physical HDR resources associated with a price responsive load.

RT HDR activation schedules will be used in the *settlement* of *demand response capacity obligations* fulfilled by virtual and physical *hourly demand response* resources.

Flow	Source	Target	Frequency
Pre-Settlement Mitigation Data	Process P1	Pre-Settlement Mitigation process	Every five minutes

Description:

The Real Time Scheduling process will send *reliability* constraints data and other data applied in real-time to the Pre-Settlement Mitigation Process to generate data required for the Settlement Mitigation make-whole payment impact test. This set of data includes:

- A list of resources that have *reliability* constraints applied as part of control actions.
- For each resource with control action *reliability* constraint, a list of five-minute intervals over which the *reliability* constraint was applied.
- A list of resources that submitted new *offers* during the real-time mandatory window, which were accepted by the *IESO.*

Refer to Section 3.9 for additional details about the RT Calculation Engine inputs for the Pre-Settlement Mitigation process.

6.1.2. Process P2: Real-Time Pricing

Description

This process produces a set of shadow prices for all constraints contributing to LMPs for physical and virtual supply and consumption internal to Ontario, and *intertie settlement* prices and *intertie* congestion prices for *energy* and *operating reserve* for *intertie zones* in accordance with the principle for price-setting eligibility, that account for all resource and system constraints.

Input and Output Information Flows

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

Flow	Source	Target	Frequency
Validated Dispatch Data	Market Participants	Process P2	Hourly
Description: • See description in Process P1 above.			
Flow	**Source**	**Target**	**Frequency**
IESO Data Inputs for Pricing	IESO	Process P2	Every five minutes
Description: • See description in Process P1 above.			
Flow	**Source**	**Target**	**Frequency**
Demand Forecast	IESO	Process P2	Every five minutes
Description: • See description in Process P1 above. • In addition, Demand Forecast will include control action adjustments for pricing: In a scenario where the *IESO* has implemented control actions as part of Grid and Market Operations Integration processes, the following may be required: o *Demand* forecast adjustments to calculate market prices when voltage reduction or load shedding is implemented. • Refer to Section 3.4.1.5 for details of control action adjustments for pricing.			

Flow	Source	Target	Frequency
Constraint Violation Curves for Pricing	IESO	Process P2	Daily

Description:

- Constraint violation penalty curves will continue to be defined as the penalty functions for the violation of constraints in the pricing algorithm. These penalty curves establish the value placed on satisfying a constraint and indicate the relative priority of satisfying a certain constraint compared to other constraints.
- The constraint violation penalty curves for pricing will be used by the pricing algorithm to calculate market prices in order to produce *settlement*-ready prices.

Flow	Source	Target	Frequency
Initial Scheduling Assumptions	IESO	Process P2	Every five minutes

Description:

- The initial resource schedules in Real-Time Pricing will use the initial schedules from Real-Time Scheduling and also consider schedules from the pricing algorithm of the preceding RT calculation engine run.
- The initial set of data representing current resource operating conditions will be determined according with the specific methodology as described in Section 3.6.2.4. These operating conditions include:
    - Initial schedules; and
    - NQS resource start-up and shutdown statuses.

Refer to Section 3.6.2.3 for additional details on the NQS Statuses for Pricing.

Flow	Source	Target	Frequency
Intertie Schedules from PD Pricing	Pre-Dispatch Calculation Engine	Process P2	Hourly

Description:

- See description in Process P1 above.
- *Intertie* schedules calculated by the pricing algorithm of the PD calculation engine determining binding *intertie* schedules for the *dispatch hour* will be used within the Real-Time Pricing *energy* balance constraint and *operating reserve* requirements constraints.

Flow	Source	Target	Frequency
DAM Operational Commitments	DAM Calculation Engine	Process P2	Hourly

Description:

- See description in Process P1 above.

Flow	Source	Target	Frequency
PD Operational Commitments	Pre-Dispatch Calculation Engine	Process P2	Hourly

Description:

- See description in Process P1 above.

Flow	Source	Target	Frequency
Mitigated Financial Dispatch Data	Pre-Dispatch Calculation Engine	Process P2	Hourly

Description:

- See description in Process P1 above.

Flow	Source	Target	Frequency
Schedules For HDR Resources	Pre-Dispatch Calculation Engine	Process P2	Hourly

Description:

- See description in Process P1 above.

Flow	Source	Target	Frequency
NQS Shutdown Flag Information	Process P1	Process P2	Hourly

Description:

- See description in Process P1 above.

Flow	Source	Target	Frequency
Shadow Prices, Loss Factors and Constraints Sensitivities	Process P2	Process P3	Every five minutes

Description:

Process P3: LMP Price Calculation will calculate LMPs using shadow prices, marginal loss factors, and constraint sensitivities.

- A shadow price reflects the cost savings achieved by relaxing a constraint by a small amount and measuring the marginal response on the objective function.
- Marginal loss factors reflect the losses or reduction in losses that result when injections or withdrawals occur at locations other than the *reference bus.*
- Sensitivity factors indicate the fraction of *energy* injected at the resource bus which flows on a specific piece of power system equipment on the system or interface.

The shadow price outputs of Real-Time Pricing and associated constraints are detailed in Table 3-7.

6.1.3. Process P3: LMP Price Calculation

Description

This process produces the following sets of *settlement*-ready real-time five-minute LMPs: five-minute *intertie* congestion prices (ICP), five-minute virtual zonal prices, and the five-minute RT Ontario Zonal Price. Real-time five-minute *settlement*-ready LMPs and five-minute ICPs will be used to *settle* the *real-time markets* for *energy* and *operating reserve* for dispatchable and non-dispatchable generation resources, *dispatchable loads*, price responsive loads and import and export transactions.

Input and Output Information Flows

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

Flow	Source	Target	Frequency
Shadow Prices, Loss Factors and Constraints Sensitivities	Process P2	Process P3	Every five minutes
Description: • See description in Process P2 above.			
Flow	**Source**	**Target**	**Frequency**
RT Five-minute Settlement-Ready LMPs	Process 3	Market Settlement Publishing and Reporting Ex-Post Operations	Every five minutes

Description:
Five-minute LMPs) will be calculated using the shadow prices determined by the pricing algorithm.
• Five-minute LMPs for *energy* will be calculated for the following buses:
  o Dispatchable and non-dispatchable generation resource buses;
  o *Dispatchable load* and *hourly demand response* resource buses;
  o *Non-dispatchable load* and price responsive load buses; and
  o *Intertie zone* source and sink buses.
• Five-minute LMPs for *operating reserve* for all classes of *operating reserve* will be calculated for the following buses:
  o Dispatchable generation resource buses;
  o *Dispatchable load* buses; and
  o *Intertie zone* source and sink buses (non-synchronized *ten-minute operating reserve* and *thirty-minute operating reserve* only)
• Five-minute *energy* and *operating reserve intertie settlement* price (ISP) for *intertie zones*;
• Five-minute *intertie* congestion price (ICP) for *intertie zones*.

Description: *Settlement*-ready LMP outputs of Real-Time Pricing are detailed in Section 3.6.3 Table 3-11. • The five-minute LMPs calculated for the *dispatch interval* will be used for *settlement* of the *energy* and *operating reserve* for dispatchable generation resources, *dispatchable loads*, price responsive loads, and *intertie* transactions. • The five-minute LMPs calculated for advisory intervals will be informational. • The five-minute LMP's for *energy* for *non-dispatchable loads* will be used for the *settlement* calculation of the Real-Time Purchase Cost/Benefit component of the Load Forecast Deviation Charge of the hourly DAM Ontario Zonal Price in the *settlement* of *energy* withdrawn by *non-dispatchable loads*. Pricing results will be used for the ex-post operations to analyze *real-time market* results after they have occurred. These pricing results will be used to validate and administrate real-time prices and corresponding schedules as required.

Flow	Source	Target	Frequency
five-minute Virtual Zonal Prices	Process 3	Market Settlement Ex-Post Operations	Every five minutes

Description: The RT calculation engine will also produce nine *settlement*-ready zonal prices for the *settlement* of virtual transactions. These prices are based on the weighted average of

settlement-ready LMPs at load locations within each virtual transaction trading zone. five-minute *energy* prices for virtual transaction zonal trading entities will be determined for the following virtual transaction trading zones:

- Northwest virtual transaction trading zone;
- Northeast virtual transaction trading zone;
- Essa virtual transaction trading zone;
- Ottawa virtual transaction trading zone;
- East virtual transaction trading zone;
- Toronto virtual transaction trading zone;
- Southwest virtual transaction trading zone;
- Niagara virtual transaction trading zone; and
- West virtual transaction trading zone.

Settlement-ready LMP outputs of Real-Time Pricing are detailed in Section 3.6.3 Table 3-11.

Pricing results will be used for the ex-post operations to analyze *real-time market* results after they have occurred. These pricing results will be used to validate and administrate real-time prices and corresponding schedules as required.

Flow	Source	Target	Frequency
Interval Errors	Process 3	Ex-Post Operations	Every five minutes

Description:

- The LMP Price Calculation process will deliver any failure events or errors identified at any interval, for validation and correction of prices, if required.

6.2. Internal Process Impacts

The internal processes currently used for the RT Calculation Engine process will continue to have relevance in the future day-ahead market and *real-time market*.

Internal *IESO* processes related to the RT Calculation Engine process include:

- Direct Short-Term Operations;
- Administer Dispatch Results; and
- Implement Ex-Post Operations.

The above internal processes interact with various *IESO* processes as illustrated in Section 6.1. Some changes to the RT Calculation Engine process under MRP will impact other internal *IESO* processes. This impact will be contingent upon the tools of the future day-ahead market and *real-time market,* which will be developed during the next phases of the project.

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 market requirements, existing activities that need to be updated, and process and information models that may need to be updated to support the future market.

– End of Section –

Appendix A: Market Participant Interfaces

There are no interfaces between *market participants* and the RT calculation engine. However, *market participant* interfaces with *IESO* real-time processes are covered in the Offers, Bids and Data Inputs as well as the Grid and Market Operations Integration detailed design documents.

– End of Appendix –

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

This section is confidential to the *IESO*.

– End of Appendix –

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

This section is confidential to the IESO.

– End of Appendix –

Appendix D: Mathematical Notation and Conventions

Let A and B be sets. Let n be a positive integer. The following mathematical notation will be adopted.

Table D-1: Mathematical Notation and Conventions

Notation	Description	Sample Usage
$a \in A$	Denotes that item a is an element of set A.	If B is the set of all buses, then "$b \in B$" denotes that b identifies a specific bus.
$\{1,..,n\}$	Denotes the set of all positive integers between 1 and n, inclusive.	"For interval $i \in \{1,..,n_I\}$" denotes that i identifies one of the n_I intervals of the MIO look-ahead period.
$A \subseteq B$	Denotes that set A is a subset of set B. That is, if $a \in A$, then $a \in B$.	If B is the set of all buses and B^{DL} is the set of *dispatchable load* buses, then "$B^{DL} \subseteq B$" indicates that all *dispatchable load* buses are also elements of the set of buses.
$A \cap B$	Denotes the intersection of sets A and B. That is, if $c \in A$ and $c \in B$, then $c \in A \cap B$.	If B_r^{REG} is the set of buses in *operating reserve* region r and B^{DG} is the set of dispatchable generation buses, then "$B_r^{REG} \cap B^{DG}$" denotes the set of buses in *operating reserve* region r that are also dispatchable generation buses.
$A \cup B$	Denotes the union of sets A and B. That is, if $c \in A$ or $c \in B$, then $c \in A \cup B$.	If B^{DL} is the set of *dispatchable load* buses and B^{HDR} is the set of *hourly demand response* resource buses, then "$B^{DL} \cup B^{HDR}$" denotes the set containing all *dispatchable load* buses and all *hourly demand response* resource buses.

Let n be a positive integer. Let a_1, a_2, ..., a_n be numbers. Then, standard notation for summation, minimum and maximum will be adopted as follows:

- $\sum_{i=1..n} a_i$ denotes $a_1 + a_2 + \cdots + a_n$;
- $min(a_1,..,a_n)$ denotes the minimum (i.e. the smallest) of the values a_1, a_2, ..., a_n; and

- $max(a_1,..,a_n)$ denotes the maximum (i.e. the largest) of the values a_1, a_2, ..., a_n.

As far as feasible, the following conventions have been adopted for the purposes of naming parameters, variables and outputs:

- Parameters denoting price quantity pairs will begin with the letters "P" and "Q" respectively while the remainder of the parameter name is identical;
- Variables and parameters pertaining to a particular resource or transaction type will contain an indication in the name. For example, many parameters and variables for dispatchable generation resources will contain "DG" in the name and many parameters for exports will contain "XL" in the name;
- Subsets of a given set will either be denoted by the same name with a superscript or be prefixed with that name; and
- Outputs from a specific optimization problem will be denoted by the corresponding variable with a superscript abbreviating the problem information.

– End of Appendix –

References

Document Name	Document ID
MRP Detailed Design: Overview	DES-16
MRP Detailed Design: Facility Registration	DES-19
MRP Detailed Design: Offers, Bids and Data Inputs	DES-21
MRP Detailed Design: Grid and Market Operations Integration	DES-22
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 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 4 Market Operations, Part 4.5 - Market Suspension and Resumption	MDP_PRO_0030
Market Manual 4: Market Operations, Part 4.6 - RT Generation Cost Guarantee Program	PRO_324
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 7.3 - Outage Management	IMP_PRO_0035
Guide to the Day-Ahead Commitment Process	N/A
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 9.1 - Submitting Registration Data for the DACP	IESO_MAN_0076
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 for the DACP	IESO_MAN_0080
Market Rules for the Ontario Electricity Market (Market Rules)	MDP_RUL_0002

End of Document –