

# Independent Electricity System Operator

## Review of the dispatch algorithm 's compliance with Market Rules

April 15, 2009



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# 1 Introduction

The Independent Electricity System Operator (IESO) operates at the core of Ontario's power system, connecting all participants - generators that produce electricity, transmitters that send it across the province, retailers that buy and sell it, industries and businesses that use it in large quantities and local distribution companies that deliver it to people's homes.

The IESO is responsible for ensuring that the dispatch of generation and allocation of reserves be managed to maintain the power flows on transmission facilities within security and operational limits. Events of the last decade, such as the market failure in the Western United States and the blackout of 2003, have increased the public and regulatory scrutiny of grid and market operators. The mandate for both reliable and inexpensive energy necessitates that the IESO balance the requirements for secure grid with the market drive to maximize efficiency and minimize costs.

Efficient operation of the electricity market requires that the demand of the system be met with the lowest price generation and operating reserve dispatch as possible, given the bids and offers submitted and applicable constraints on the use of the IESO controlled grid. The dual goals of market efficiency and system security require the solution of a constrained optimization problem: minimizing the cost of generation and reserves, subject to meeting required demand and security constraints. The IESO has modeled such a dispatch algorithm into the Dispatch and Scheduling Optimization tool, "the DSO tool", to determine the most efficient dispatch of resources subject to the constraints for secure operation of the grid.

In accordance with Market Rule 7.4.2.4, the IESO commissions an independent review of the operation and application of the dispatch algorithm and related dispatch processes and procedures at least once every two calendar years. PricewaterhouseCoopers LLP was contracted to perform this review in 2009.

The purpose of this review was to address whether the dispatch algorithm and related dispatch processes and procedures are in compliance with section 4 of Chapter 7 and Appendix 7.5 of the market rules. This report communicates the results of the review performed as of February 12, 2009.

The dispatch algorithm and related dispatch processes and procedures are complex and specialized processes. Accordingly, we have written this report to provide

- An overview of the software that models the dispatch algorithm (the DSO tool);
- A functional description of the DSO tool;
- The specific scope of our review;
- Our review approach;
- Our formal report setting out the results of our review;
- IESO management interpretations applicable to our review; and
- An appendix containing the relevant Market Rules that were reviewed.

## 2 Overview of the DSO tool

The DSO tool is the software program that implements the dispatch algorithm and is used by the IESO to determine schedules and prices for the Ontario Electricity Market. The mathematical formulation for the dispatch algorithm is described in section 4 of Chapter 7 and specified in Appendix 7.5 of the market rules. The IESO requires an independent assessment of whether the implementation and application of the dispatch algorithm is meeting the objectives of the market rules. Assessment of the dispatch algorithm requires a review of the DSO calculations as well as consideration of how the DSO tool is utilized. The following paragraphs describe our understanding of the DSO tool and implementation at the IESO.

The IESO uses the DSO tool to solve the constrained optimization problem in the following circumstances:

- The IESO uses the DSO tool to produce pre-dispatch constrained schedules and projected market schedules and prices which in turn facilitates the efficient and reliable operation of the market by allowing participants to anticipate conditions for the coming hours and next day. The DSO tool is used to produce the pre-dispatch of record to facilitate the Day-Ahead Commitment Process. With the exception of intertie prices, the pre-dispatch market prices are not financially binding. However, the pre-dispatch schedules are used to determine the generators that will be constrained at or above their minimum loading points for the real-time schedules and are eligible to either receive the day-ahead Generation Cost Guarantee (GCG) or the Spare Generation On-Line (SGOL) guarantee.
- The IESO also uses the DSO tool to produce real-time constrained schedules and real-time market-schedules and prices. The real-time schedules reflect the actual generation, reserve allocation, and dispatchable-load levels that achieve secure operation at a minimum cost, subject to the system operator's assessment of the reliability of the network. The IESO issues dispatch instructions according to the real-time schedules. The real-time market prices are used, unless administered prices are necessary, to settle the market.

The DSO tool is used with two different sets of constraints:

- The “constrained IESO-controlled grid” or “constrained DSO”, represents the detailed generation and transmission circuit relationships and security constraints. The constrained DSO tool is used to obtain the pre-dispatch and real time constrained schedules.
- The “unconstrained IESO-controlled grid”, or just “unconstrained DSO”, ignores the internal Ontario transmission circuit relationships and security constraints. The unconstrained DSO tool is used to obtain the pre-dispatch market-schedule and prices and the real-time market-schedule and prices.

The DSO tool performs the functions defined in Chapter 7 Section 4 of the Market Rules, The Dispatch Algorithm. The mathematical description of the functions is provided in Appendix 7.5 of the Market Rules-The Market Clearing and Pricing Process. In several places, these rules refer to other sections of the Market Rules for clarifications. In addition, several public documents such as the Market Manuals refine the descriptions contained in the Market Rules.

Since the last review of the DSO tool in 2006, there were minor changes made to the Market Rules that had minimal impact on the DSO tool. The IESO has modified the tool to reflect these changes including 3 times the ramp rate for the “unconstrained DSO” instead of 12 times the ramp rate which necessitated adjustments to the testing parameters used for this review.

## 3 The DSO Function

The Dispatch Scheduling and Optimization (DSO) tool produces pre-dispatch and real-time dispatch schedules by applying an optimization process to bids and offers of energy and operating reserve. The inputs for the tool consist of data from the Market Operations System (MOS), Energy Management System (EMS), Market Information System (MIS), and Resource Dispatch (RD) application.

The pre-dispatch schedules are used to provide the IESO and market participants with advance information and projections necessary to plan for future hours. After market close (11:00), the DSO tool is used to produce four day ahead pre-dispatch schedules (11:00, 12:00, 13:00, 14:00) to produce the pre-dispatch of record for all the hours in the next day that is used to facilitate the Day-Ahead Commitment Process. Starting hour 15:00, the pre-dispatch scheduling is repeated every hour to produce the schedules for the hours remaining in the current day (hour ahead pre-dispatch) and for all the hours in the next day (day ahead pre-dispatch). The real time scheduling consists of computing the optimal constrained and unconstrained dispatch schedules every five minutes. The dispatch scheduling and pricing process simultaneously optimizes energy and operating reserve schedules, maximizing the sum of the net gain to all market participants.

Both the pre-dispatch and the real-time scheduling processes include a constrained dispatch run that takes into account transmission network constraints and an unconstrained dispatch run where network constraints within Ontario are ignored and all supply offers and demand bids are assumed to be located at the same location. The constrained runs are used to produce physical dispatches and Locational Marginal Prices that vary across locations in the network according to the relative impacts of each location on losses and binding constraints. The unconstrained DSO runs are used to produce the uniform energy and operating reserve prices.

There are certain circumstances where the actual dispatch instructions are different from the outputs of the DSO runs, these circumstances are known as Dispatch Deviations and occur as follows:

- The IESO uses the outputs of the constrained DSO to determine the dispatch instructions that guide actual physical operation of the electricity system. An automatic filter ensures that the energy schedule created by the DSO tool is only used to revise the dispatch instructions to a resource when the revision exceeds the greater of +/-10 MW or 2% of the dispatch instruction for dispatches with the exception of two unfiltered dispatches that are made per hour and dispatches within 2% of the operating limits of the resource.
- A "Dispatch Deviation" is defined as the issue of a resource's Dispatch Instruction that differs from the resource's Real-Time Schedule as determined by the Dispatch Algorithm. Adjustments by control room personnel to DSO inputs, such as a revision to the demand forecast, are not considered dispatch deviations.
- Dispatch Deviations are generally applied by control room personnel in real-time by modifying the Resource Dispatch (RD) application's outputs that reflect each resource's real-time schedule as determined by the DSO tool.
- "Dispatch Deviations" that are less than the greater of +/-10 MW or 2% of the dispatch instruction may not be reported.

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The triggering events or circumstances where the IESO overrides the DSO output include the following:

- The action is required to correct for recognized non-compliance with dispatch instructions by a Market Participant(s).
- The action is required to respect an Operating Security Limit due to differences in the forecast and actual flows.
- The action is required to respect the forecasted (greater than 5 minutes) Operating Reserve requirement.
- The action is required to correct an over / under generation condition (ACE).
- The action is required to mitigate the effects of operational data input failures.
- The action is required to facilitate a planned equipment outage.
- The action is required to mitigate the effects of dispatch algorithm input errors.
- The action is required to meet the SGOL minimum run time constraints.

Dispatch Deviations are generally classified as Blocked, One Time or Constrained Dispatches. Definitions are as follows:

- **Blocked Dispatches** – occur when one or more resources are removed from the RD application's merit order based on Energy, Reserve Capacity and/or Reserve Capacity Activation resource lists, which results in a resource(s) being omitted from the next interval's Dispatch Instruction.
- **One Time Dispatches** – occur when one or more Energy resources offers/bids (not based on merit order cleared offers) are selected for dispatch at or below the resource's offer/bid megawatt quantity contained in the RD application and/or one or more Reserve Capacity resource offers/bids (not based on merit order cleared offers) are selected to provide unloaded generation capacity in the current interval.
- **Constrained Dispatches** – occur when the output of one or more dispatches based on Energy resources contained in RD, are held at a fixed, minimum or maximum MW output.

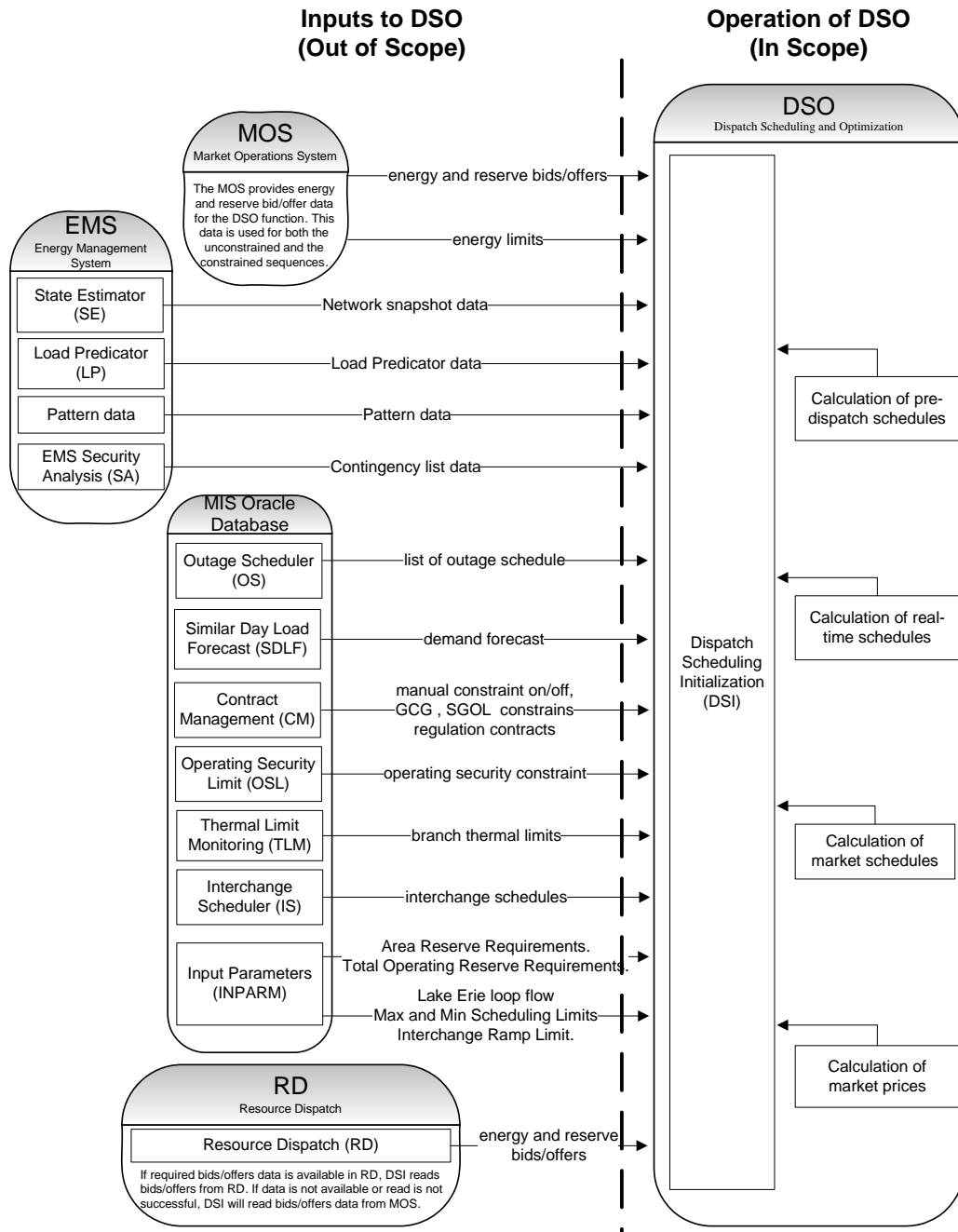
## 4 Scope of Review

Our review addressed the IESO's compliance with Chapter 7.4 (The Dispatch Algorithm) and Appendix 7.5 (The Market Clearing and Pricing Process) of the Market Rules. Since section 4.2 of Chapter 7 allows the IESO to manually modify the results of the DSO tool and requires the IESO to report the reasons for discrepancy between manual dispatch instructions and the outputs of the dispatch algorithm, the manual overrides and reporting are also within scope for this review.

We did not review the inputs into the DSO tool and one specific aspect of the outputs as outlined in the following pages.

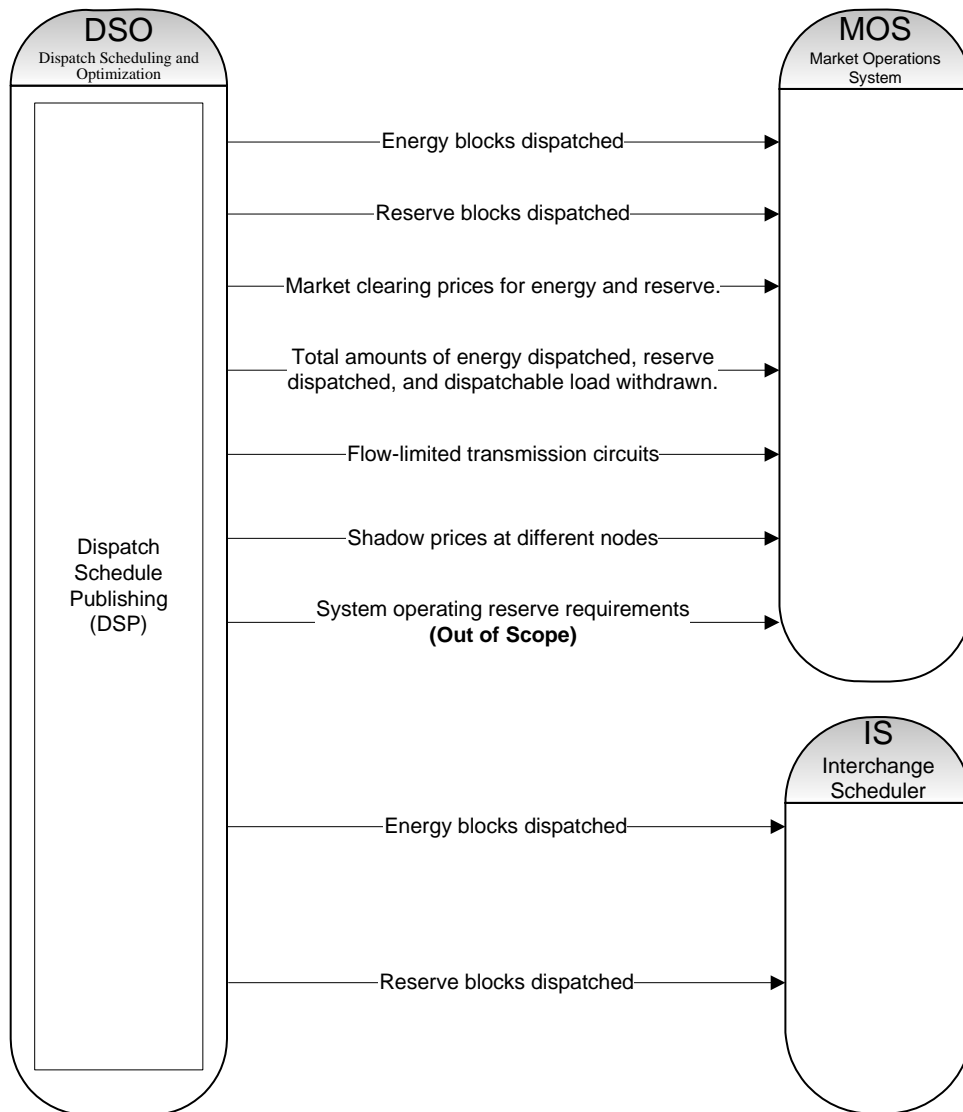
### Inputs

The validity or accuracy of all inputs to the DSO tool as outlined in the following diagram was outside the scope of our review.



### Outputs

We reviewed the outputs of the DSO tool depicted below with the exception of the system operating reserve requirements that are developed in a different system and are not modified by the DSO tool.



## 5 PricewaterhouseCoopers's Review Approach

Our review of the Dispatch Algorithm included the following activities:

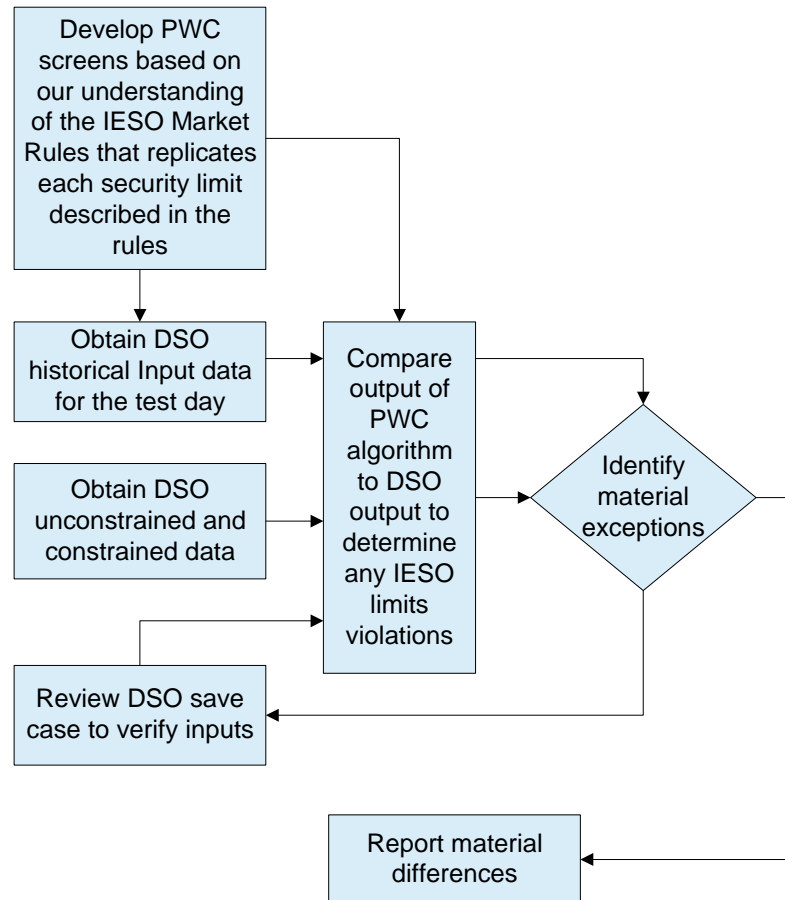
### Understand applicable Market Rules and related processes and procedures

- Reviewing DSO tool documentation including IESO Market Manuals.
- Interviewing IESO personnel responsible for the use, maintenance, and monitoring of the DSO tool.
- Reviewing procedural documentation and the management practice of dispatch deviations.

### Develop and execute Automated Screening Tests

- Screening the DSO schedules for February 12, 2009 to identify individual dispatches that were sub-optimal or in violation of the unit's limits or the security constraints.
- Reviewing the archived historical outputs of the DSO tool for conditions in direct violation of limits defined in the Market Rules. For instance, Rule 6.5 of Appendix 7.5 describes the up and down ramp limits that are applied to the constrained facility schedules. In order to test this, a series of screens were developed to identify possible exceptions where facility dispatches did not respect relevant ramp constraints. Potential material exceptions were investigated in DSO save cases to obtain actual EMS input values and or outage de-rate values to clear the exceptions.
- Developing screens that tested other implications of the Market Rules. For instance, Market Rule 4.3.3 of Chapter 7 states that "... given the market-clearing prices and the dispatch data, no market participant would be economically better off (in terms of the dispatch data it submitted itself) producing or withdrawing more or less than the market-clearing quantity of any physical service." This rule implies that, unless a unit is physically limited or awarded both energy and reserves, every offer block at a price below the market clearing price for a product should be fully awarded and every offer block above the market clearing price for a product should be completely un-awarded. Similarly, a series of screens were developed to identify exceptions for this and potential material exceptions were investigated in DSO save cases to obtain actual EMS input values, outage/derated values, and Minimum Loading Points for Operating Reserves to clear the exceptions.
- A sample of a screening test developed by PwC is depicted on the following page.

## Sample Limits Screening



### Base Case and Save Case Testing

Where required, testing the functionality of the DSO tool in the QA environment by manipulating inputs and observing whether the outputs produced by the tool are as expected.

### Comparison of DSO tool input/output data to DSO save case and IESO website

Validating the information used for testing by comparing a sample of the historical data obtained from the IESO to the save cases of DSO inputs and outputs and the data published on the IESO public web site.

## 6 Review Engagement Report

To the IESO Board of Directors:

We have reviewed the Independent Electricity System Operator (IESO)'s, compliance on February 12, 2009, with Chapter 7.4 (The Dispatch Algorithm) and Appendix 7.5 (The Market Clearing and Pricing Process) of the Market Rules, dated December 10th, 2008, as interpreted by IESO Management and captured in the DSO tool including related processes and procedures. Management's interpretations of the Market Rules are set out in Section 7 of the report and the relevant sections of the Market rules are attached in the Appendices of this report. Our review was made in accordance with Canadian generally accepted standards for review engagements and accordingly consisted primarily of enquiry, analytical procedures, and discussion related to information supplied to us by the IESO. Our review process is further described in the preceding section labelled PricewaterhouseCoopers' Review Approach.

A review does not constitute an audit and consequently we do not express an audit opinion on this matter.

Based on our review, nothing has come to our attention that causes us to believe that the dispatch algorithm was not in compliance, as at February 12, 2009, with Chapter 7.4 (The Dispatch Algorithm) and Appendix 7.5 (The Market Clearing and Pricing Process) of the Market Rules, inclusive of the interpretations made by IESO management described on the following page of our report.



PricewaterhouseCoopers LLP

Toronto, Ontario, Canada

April 15, 2009

## 7 Management Interpretations of Chapter 7.4 and Appendix 7.5 of the Market Rules

### Inputs to the DSO

Where Chapter 7.4, Section 4.2.4 requires a review of the operation and application of the dispatch algorithm and the related processes and procedures, this pertains to the mathematical calculations and the IESO's implementation of the outputs. The completeness and accuracy of the inputs are not included in the scope of the review. However, the review includes the proper use of the inputs where specified by the market rules.

### Dispatch Deviations

Where Chapter 7.4 and Appendix 7.5 refer to the differences between the results of the dispatch algorithm and the dispatch instructions issued, these refer to differences in addition to those automatically filtered. An automatic filter ensures that the energy schedule created by the DSO tool is only used to revise the dispatch instructions to a resource when the revision exceeds the greater of +/-10 MW or 2% of the prior dispatch instruction that was sent.

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## Chapter 7.4 – The Dispatch Algorithm

### 4.1 Purpose of the Dispatch Algorithm

- 4.1.1 The *IESO* shall determine the various schedules and prices required by this Chapter to be developed by it using a *dispatch algorithm* based on the mathematical techniques of constrained optimisation. The form and use of this *dispatch algorithm* are summarised in this section 4 and detailed in Appendix 7.5.

### 4.2 Uses of the Dispatch Algorithm

- 4.2.1 The *IESO* may use different numerical values in, or different computerised versions of, the *dispatch algorithm* for each of the several purposes described in this Chapter, but shall keep the objective, mathematical formulation and solution procedures the same, except as specifically noted.
- 4.2.2 The *IESO* shall, as far as practical, use the outputs of the *dispatch algorithm* to determine the *dispatch instructions* that guide actual physical operations of the *electricity system*. However, because any *dispatch algorithm* is only an approximation of a complex physical reality and may sometimes malfunction, the *IESO* may modify or override the results of the *dispatch algorithm* when issuing *dispatch instructions* pursuant to section 7.
- 4.2.3 The *IESO* shall no less than once in each calendar month, *publish* a report listing and giving reasons for all significant differences between *dispatch instructions* issued and the results of the *dispatch algorithm*.
- 4.2.4 Unless otherwise directed by the *IESO Board*, the *IESO* shall no less than once every two calendar years, commission and *publish* the results of an independent review of the operation and application of the *dispatch algorithm* and the related *dispatch* processes and procedures. The *IESO* shall use the results of such review to determine the need or otherwise for improvements in the related *dispatch* processes and procedures in meeting the objectives of the *market rules* and/or the mathematical representation of the *electricity system* or the solution procedures which form part of the market clearing logic. The first such review shall be completed no later than May 1, 2004.

### 4.3 The Optimisation Objective

- 4.3.1 The *dispatch algorithm* shall have as its mathematical objective function maximising the economic gain from trade among *market participants* as defined in section 4.3.2.

- 4.3.2 The economic gain from trade shall be defined as the difference between the value of the electricity produced (as indicated by the *energy demand* from *non-dispatchable loads* and the *energy bids* from *dispatchable loads*) and the cost of producing that electricity (as indicated by the *offers* to supply the *energy* and *operating reserves* necessary to *reliably* deliver that electricity to loads).
- 4.3.3 Maximising the economic gain from trade will determine quantities and prices that “clear the market,” in the sense that, given the market-clearing prices and the *dispatch data*, no *market participant* would be economically better off (in terms of the *dispatch data* it submitted itself) producing or withdrawing more or less than the market-clearing quantity of any *physical service*.

## 4.4 Inputs to the Dispatch Algorithm

- 4.4.1 The *IESO* shall use as inputs to the *dispatch algorithm* the data and information outlined in section 4.4 and described in more detail in Appendix 7.5.
- 4.4.1A [Intentionally left blank]
- 4.4.2 The cost to suppliers of *energy* and *operating reserves* and the value to *dispatchable loads* of delivered electricity shall be based on the most recent valid *offers* and *bids* (including standing *dispatch data*) submitted by *registered market participants* with respect to *dispatchable generation facilities* and *dispatchable load facilities*.
- 4.4.3 Subject to section 4.4.3A, the price-insensitive load to be met shall be the sum of:
- 4.4.3.1 the net energy injections (injections minus withdrawals) by all *non-dispatchable load facilities*, *self-scheduling generation facilities* and *intermittent generators* and *transitional scheduling generators*; and
  - 4.4.3.2 any net amount by which the actual net injections (injections minus withdrawals) by all *dispatchable generation facilities* and *dispatchable load facilities* is less than the net amount implied by the *IESO's dispatch instructions* to such *facilities*.
- 4.4.3A Until such time that locational pricing is implemented in the *IESO-administered markets*, the price-insensitive load to be met shall be determined solely on the basis of the net *energy injections* referred to in section 4.4.3.1.
- 4.4.4 Limits on *intertie* flows between the *integrated power system* and neighbouring *transmission systems* shall be based on:
- 4.4.4.1 a simple model that assumes that each *intertie meter* is *connected* to an isolated *intertie zone* by a single transmission line;

- 4.4.4.2 the *IESO's* best estimate of the maximum flow on the single transmission line to each *inertie zone*, given the status of the neighbouring *transmission systems* and expected or actual unscheduled flows (including as unscheduled flows any flows planned by the *IESO* to balance interchange accounts with other *control area operators*); and
  - 4.4.4.3 a net *interchange schedule* limit to represent the *integrated power system's* ability to respond to hourly *interchange schedule* deviations and maintain the *reliability* of the *IESO-controlled grid*.
- 4.4.5 Constraints on the use of the *IESO-controlled grid* shall be determined on the basis of such system *security* requirements as the *IESO* may determine necessary to maintain *reliable* system operations, which requirements shall include, at a minimum, the following:
- 4.4.5.1 the largest applicable *contingency events* and any increments above these required to satisfy applicable *reliability standards*;
  - 4.4.5.2 *security* constraints on identified *facilities*;
  - 4.4.5.3 minimum requirements for each class of *operating reserve*;
  - 4.4.5.4 the *IESO's* commitments to neighbouring *transmission systems* for *operating reserves* and regulation;
  - 4.4.5.5 the availability and need for contracted *ancillary services* and *reliability must-run resources*; and
  - 4.4.5.6 *reliability* constraints associated with *interchange schedules* as referred to in section 4.4.4.3.
- 4.4.6 The following basic parameters of the *dispatch algorithm* shall be as specified from time to time by the *IESO Board*:
- 4.4.6.1 the *maximum market clearing price* or *MMCP* that defines the maximum allowable price for *energy*, and the negative of which defines the minimum allowable price for *energy*;
  - 4.4.6.1A the *maximum operating reserve price* or *MORP* that defines the maximum allowable price for any class of *operating reserve*; and
  - 4.4.6.2 the penalty functions for the violation of *dispatch algorithm* constraints.

If the output of the *dispatch algorithm* fails to satisfy *non-dispatchable demand* or the *operating reserve requirements* for any class of *operating reserve* then, subject to section

8.2.2, the penalty functions referred to in section 4.4.6.2 may influence the calculation of *market prices* for *energy* and *operating reserve* in a similar fashion to *offers* and *bids*.

4.4.7 *Interchange schedule data* shall be input as a constant value for the given *dispatch hour* unless otherwise specified by the *IESO* and shall be derived in accordance with the outputs of the *dispatch algorithm* for each *dispatch hour* as determined under section 4.6.

## 4.5 The Constrained and Unconstrained IESO-Controlled Grids

4.5.1 The *dispatch algorithm* shall be used to determine both operating schedules that reflect the realities of the *integrated power system* and uniform prices within the *IESO control area* that ignore *transmission system* constraints. Thus, the *dispatch algorithm* shall be capable of using the following two different models for the *integrated power system*:

4.5.1.1 an *unconstrained IESO-controlled grid model*, which ignores transmission and other *security* constraints on the *IESO-controlled grid* and assumes, in effect, that all *physical services* are provided and consumed at a single, undesignated location *connected* to several isolated *intertie zones* by single transmission lines; and

4.5.1.2 a *constrained IESO-controlled grid model*, which includes a full (but necessarily approximate) mathematical representation of the *integrated power system*, with *interconnections* modelled as single transmission lines to isolated *intertie zones* or as proportionately allocated to *intertie zones*.

## 4.6 Outputs of the Dispatch Algorithm

4.6.1 The *IESO* shall use the *dispatch algorithm* to determine the quantities and prices summarised in this section 4.6 and detailed in Appendix 7.5.

4.6.2 The *dispatch algorithm* shall be used with the *constrained IESO-controlled grid model* to determine, prior to each *dispatch hour* and to each *dispatch interval*, operating schedules and their associated costs and shadow prices. The principal outputs, for each *dispatch hour* or *dispatch interval*, as the case may be, shall be the following:

4.6.2.1 the amounts of *energy* (in MW or MWh/hour) and of each class of *operating reserve* (in MW) scheduled to be provided to the *integrated power system* by each *registered facility*;

4.6.2.2 the amounts of *energy* (in MW or MWh/hour) scheduled to be withdrawn from the *integrated power system* by each *registered facility*;

- 4.6.2.3 the deemed total cost, as defined by the prices in *offers*, of the total amounts of *energy* and *operating reserve* scheduled to be provided by *registered facilities*;
  - 4.6.2.4 the deemed total cost, as defined by the prices in *energy bids*, the *MMCP* and the penalty functions in the *dispatch algorithm*, of any *dispatchable load* reductions, any failure to meet *non-dispatchable loads* and any constraint violations;
  - 4.6.2.5 power flows and *energy* losses on transmission lines;
  - 4.6.2.6 the prices of providing *energy* at each set of transmission nodes identified by the *IESO* for this purpose and, subject to section 4.6.2B, the prices of each class of *operating reserve* in each reserve area identified by the *IESO* for this purpose.
- 4.6.2A [Intentionally left blank]
- 4.6.2B Until the date that is the first day of the fourth calendar month following the *market commencement date*, calculated from the first day of the calendar month immediately following the month in which the *market commencement date* occurs, the prices of each class of *operating reserve* in each reserve area referred to in section 4.6.2.6 shall not be included as a principal output of the *dispatch algorithm*.
- 4.6.3 The *dispatch algorithm* shall be used with the *unconstrained IESO-controlled grid model* to determine, prior to each *dispatch hour* and at several times after each *dispatch interval*, *market schedules* and the corresponding uniform prices within the *IESO control area*. The principal outputs of this process are the following:
- 4.6.3.1 the *market schedule* indicating the amounts of *energy* (in MW or MWh/hour) and of each class of *operating reserve* (in MW) that would be provided to the *integrated power system* by each *registered facility* if transmission were totally unconstrained on the *IESO-controlled grid*;
  - 4.6.3.2 the amounts of *energy* (in MW or MWh/hour) that would be withdrawn from the *integrated power system* by each *registered facility* if transmission were totally unconstrained on the *IESO-controlled grid*;
  - 4.6.3.3 the deemed total cost, as defined by the prices in *offers*, of the total amounts of *energy* and *operating reserve* in the *market schedule*;
  - 4.6.3.4 the deemed total cost, as defined by the prices in *energy bids*, the *MMCP* and the penalty functions in the *dispatch algorithm*, of any *dispatchable load* reductions, any failure to meet *non-dispatchable loads*, and any constraint violations that would occur if transmission were totally unconstrained on the *IESO-controlled grid*; and

- 4.6.3.5 the prices of providing *energy* and each class of *operating reserve* at any point within the *IESO control area* if transmission were totally unconstrained on the *IESO-controlled grid*. As provided in Chapter 9, the unconstrained prices for each *dispatch interval* shall be used for *settlement* purposes, except for *non-dispatchable loads*, who shall pay a uniform *hourly Ontario energy price* (HOEP) determined as described in section 8.3.1.
- 4.6.4 The *dispatch algorithm* shall be used with the constrained *IESO-controlled grid model* to determine, prior to each *dispatch hour*, *interchange schedules* and their associated costs. The *interchange schedule* for each *dispatch hour* shall be constant for the *dispatch hour* and used as inputs into the *dispatch algorithm* in accordance with section 4.4.

## Appendix 7.5 – The Market Clearing and Pricing Process

### 1.1 Process Overview and Interpretation

- 1.1.1 This Appendix sets forth a description of the process to be used to determine *pre-dispatch schedules*, *real-time schedules*, *market schedules* and *market prices*. A detailed mathematical description is also provided in the sections that follow.
- 1.1.2 [Intentionally left blank]
- 1.1.3 References to “outputs” in this Appendix refer to data produced by software and the *IESO* shall not be required to *publish* such data except where expressly required by these *market rules*.

## 2. The Dispatch Scheduling and Pricing Process

### 2.1 Modes of Operation

- 2.1.1 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*. While different numerical values may be used in each mode, the mathematical formulation shall be the same in both modes except that:

- 2.1.1.1 The *pre-dispatch schedule* shall represent between 1 and 24 individual periods each of a duration of 1 hour. The *pre-dispatch schedule* so produced represents the *energy* forecast to be injected into or withdrawn from the *IESO-controlled grid* by each *market participant* in each *dispatch hour*, and each class of *operating reserve* to be maintained by each *market participant* in each *dispatch hour*;
- 2.1.1.2 The *real-time schedule* shall represent individual *dispatch intervals*. The *real-time schedule* so produced represents the *energy* to be injected into or withdrawn from the *IESO-controlled grid* by each *market participant*, and the *operating reserve* to be maintained by each *market participant*, in each *dispatch interval*; and
- 2.1.1.3 Only the *pre-dispatch schedule* shall include daily *energy* limits specified pursuant to section 3.5.7 of this Chapter.
- 2.1.1.4 The schedules corresponding to *offers* and *bids* located in *intertie zones* adjoining the *IESO control area* 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*.

## 2.2 Inputs

2.2.1 The required inputs to the *dispatch* scheduling and pricing process are:

- 2.2.1.1 *offers* for *energy* submitted by *generators*;
- 2.2.1.2 *offers* for each class of *operating reserve* submitted by *generators*;
- 2.2.1.3 self-schedules submitted by self-scheduling generation facilities for *energy* and the *energy* price below which each self-scheduling generation facility reasonably expects to reduce the *energy* output of such self-scheduling generation facility to zero determined in accordance with section 3.4.4A of this Chapter;
- 2.2.1.4 forecasts of *energy* submitted by *transitional scheduling generators* and *intermittent generators*;
- 2.2.1.5 *bids* for *energy* submitted by *dispatchable loads*;
- 2.2.1.6 *offers* for each class of *operating reserve* submitted by *dispatchable loads*;

- 2.2.1.7 forecasts of *energy* expected to be withdrawn by *non-dispatchable loads*;
- 2.2.1.8 coefficients of the penalty functions associated with violation of system constraints (generation, *operating reserves* and transmission) that allow relaxation of these constraints in a specified hierarchical order when the solution to the scheduling problem is otherwise infeasible;
- 2.2.1.9 *generation facility output* and *dispatchable load* levels prevailing at the start of the *dispatch period* calculation;
- 2.2.1.10 in respect of the *pre-dispatch schedule* only, daily *energy* limits where specified pursuant to section 3.5.7 of this Chapter;
- 2.2.1.10A in respect of the *real time* constrained *dispatch schedule* only, the start-up and shut-down times for each *generation facility*;
- 2.2.1.11 the operating characteristics of all *generation facilities* and *dispatchable loads* including, but not limited to ramp-rate limits and *operating reserve* response parameters and for the *real time* constrained *dispatch schedule* only, the *minimum loading point*, *forbidden regions* and *period of steady operation*;
- 2.2.1.12 the operating characteristics of the *IESO-controlled grid* including, but not limited to, the physical flow and loss characteristics and flow limits of *transmission facilities*;
- 2.2.1.13 the requirements for each of *ten-minute operating reserve* that is synchronised to the *IESO-controlled grid*, *ten-minute operating reserve* that is non-synchronised to the *IESO-controlled grid* and *thirty-minute operating reserve*, and the area requirements for *ten-minute operating reserve*;
- 2.2.1.14 security constraints determined by the *IESO* to be applicable;
- 2.2.1.14A the outage schedules for transmission facilities;
- 2.2.1.15 the limits to be applied, where applicable, on *energy bids*, *energy offers* and *offers* for *operating reserve*, as the case may be, to reflect:
  - a. transmission loading relief constraints;
  - b. *generation facility outages*;
  - c. applicable *contracted ancillary services* arranged for use outside of the market clearing mechanism; and for the *real time* constrained *dispatch schedule* only;
  - d. start-up and shut-down times;

- e. *minimum loading point*;
- f. *forbidden regions*; and
- g. *period of steady operation*.

2.2.1.16 imports or exports between the *IESO-control area* and other control areas required by the *IESO* to meet its obligations under requirements established by all relevant standards authorities and which are outside the normal market *bids* and *offers* including but not limited to inadvertent *intertie* flows and shared activation reserve. These shall be represented as an increase or decrease in *non-dispatchable load*.

## 2.3 Optimisation Objective

- 2.3.1 The *dispatch* scheduling and pricing process shall be a mathematical optimisation algorithm that will determine optimal schedules for each time period referred to in section 2.1.1, given the *bids* and *offers* submitted and applicable constraints on the use of the *IESO-controlled grid*. Marginal cost-based prices shall also be produced and, for such purpose, *offer* prices shall be assumed to represent the actual costs of suppliers and *bid* prices shall be assumed to represent the actual benefits of consumption by *dispatchable load facilities*.
- 2.3.2 The *dispatch* scheduling and pricing process shall have as its mathematical objective function maximising the economic gain from trade among *market participants* as described in sections 4.3.2 and 4.3.3 of Chapter 7.
- 2.3.3 In respect of the *real time* constrained *dispatch schedule* only, the *dispatch* scheduling and optimization process shall have as its objective function maximizing the weighted sum of the economic gain from trade among *market participants*, as described in section 4.3.2 and 4.3.3 of Chapter 7, for the *dispatch interval* and for advisory intervals within the study period. Critical intervals are those selected from the study period to be used as input to the objective function. The first critical interval is always the *dispatch interval*. The remaining critical intervals are advisory intervals.

## 2.4 The IESO-Controlled Grid

- 2.4.1 The *dispatch* scheduling and pricing process shall represent power flow relationships between locations on the *IESO-controlled grid* and between the *IESO control area* and adjoining *control areas*.
- 2.4.2 The *dispatch* scheduling and pricing process shall utilise a security-constrained optimal power flow with explicit representation of electrical flows on each transmission element.
- 2.4.3 Limits on transmission flows in either direction of flow shall be explicitly represented.

- 2.4.4 Security constraints may limit *generation facility* output and *dispatchable load* or any other variable so as to represent the *security limits* applicable to the *IESO-controlled grid*.
- 2.4.5 The *IESO* shall estimate static transmission losses and model transmission losses using penalty factors. The *IESO* shall adjust *bid* and *offer* prices using the applicable penalty factor. The *IESO* shall notify *market participants* in a timely manner of any changes to the applicable penalty factors.

## 2.5 Operating Reserve

- 2.5.1 The *dispatch* scheduling and pricing process shall simultaneously optimise *energy* and *operating reserve* schedules, respecting the trade-off functions for *energy* and *operating reserve* of each *registered facility*.
- 2.5.2 *Operating reserve* shall be scheduled to meet all applicable *reliability standards*.
- 2.5.3 For the real-time *dispatch* schedule and immediately following a *contingency event*, the *operating reserve* requirements shall be reduced while *operating reserves* are restored in accordance with all applicable *reliability standards*.
- 2.5.4 The *dispatch* scheduling and pricing process shall respect the trade-off function between *energy* and each class of *operating reserve* separately.
- 2.5.5 The *operating reserve* scheduled for a *generation facility* shall reflect the ability of that *generation facility* to provide *operating reserve* over the *dispatch interval* given its ramping capability.
- 2.5.6 *Offers* for each class of *operating reserve* in an area shall be used to meet the requirements for that class of *operating reserve* in that area.
- 2.5.6A *Offers* for *ten-minute operating reserve* that is synchronised with the *IESO-controlled grid* that are not scheduled to meet that proportion of *ten-minute operating reserve* which is required to be synchronised with the *IESO-controlled grid* may be scheduled to satisfy the remaining portion of *ten-minute operating reserve* that is not synchronised with the *IESO-controlled grid*.
- 2.5.7 *Offers* for *ten-minute operating reserve* –that is synchronised with the *IESO-controlled grid* or for *ten-minute operating reserve* –that is not synchronised with the *IESO-controlled grid* and that are not scheduled to meet the *ten-minute operating reserve* requirement may be scheduled to satisfy the requirements for a *thirty-minute operating reserve*.
- 2.5.8 The penalty function applicable as the result of a deficiency in any class of *operating reserve* shall be allowed to have an impact on the *energy* and *operating reserve* prices in the same *dispatch period*.

## 2.6 Contracted Ancillary Service

- 2.6.1 The *dispatch* scheduling and pricing process shall include constraints specified by the *IESO* to ensure the adequate provision of *contracted ancillary services*.
- 2.6.2 The *IESO* may apply constraints to the scheduling of *offers* submitted by *generators* and *bids* submitted by *dispatchable loads* which have contracted to provide *contracted ancillary services* so as to ensure that they are scheduled in a manner to meet their obligations under their respective contracted *ancillary service contracts*.

## 2.7 Constraint Penalty Functions and Violation Variables

- 2.7.1 The *dispatch* scheduling and pricing process shall include penalty functions and violation variables which will allow it to automatically violate transmission constraints and operational constraints imposed by the *IESO* (but not *bids* or *offers* or the physical limits of the *facilities* of *market participants*) in situations where no solution would otherwise exist.
- 2.7.2 Penalty functions for the violation of constraints shall be as specified from time to time by the *IESO Board* in accordance with section 4.4.6.2 of Chapter 7.
- 2.7.3 Different penalty functions may apply for each of the various *transmission* and operating constraints, reflecting the relative flexibility of *transmission* and operating limits.
- 2.7.4 The use of violation variables shall indicate that a feasible schedule is possible as long as some constraints are relaxed. If relaxation of such constraints is acceptable for purposes of *real-time operations*, such feasible schedule shall be accepted. If relaxation of such constraints is not acceptable for purposes of *real-time operations*, the *dispatch instructions* issued may differ so that an acceptable schedule can be determined.
- 2.7.5 The penalty functions used by the *IESO* in an acceptable schedule determined under section 2.7.4 shall be allowed to influence *energy* and *operating reserve* prices.

## 2.8 Tie-Breaking

- 2.8.1 If two or more *energy offers* have the same *offer price* and interactions with the *operating reserve market* do not create differences in the cost to the market of utilising each *offer*, the schedules from these *offers* shall be prorated based on an adjusted amount of *energy offered* at that *offer price*. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.
- 2.8.2 If two or more *energy bids* have the same *bid price* and interactions with the *operating reserve market* do not create differences in the cost to the market as a whole of utilising

each *bid*, the schedules from these *bids* shall be prorated based on an adjusted amount of *energy bid* at that *bid* price. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.

- 2.8.3 If two or more *offers* for a given class of *operating reserve* have the same *offer* price and provided that interactions with the *energy* market and markets for other classes of *operating reserve* do not create differences in the cost to the market as a whole of utilising each *offer*, then the schedules from these *offers* shall be prorated based on an adjusted amount of *operating reserve offered* at that *offer* price. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.

## 2.9 Load Curtailment

- 2.9.1 If *non-dispatchable load* cannot be satisfied, the *dispatch* scheduling and pricing process shall violate the power balance for the system as a whole, with *energy* prices being calculated in accordance with section 4.4.6 of this Chapter.

## 2.10 Self-Scheduling Generation

- 2.10.1 A *self-scheduling generation facility* shall be treated as a resource that will be scheduled when *energy* prices exceed the greater of negative *MMCP* and the price, if any, specified by that *self-scheduling generation facility* in its *dispatch data* pursuant to section 3.4.4A of Chapter 7. Within the software that implements the formulation described in this Appendix, each *self-schedule* shall be represented in the form of an *energy offer* each with a single *price-quantity* pair.

## 2.11 Inter-temporal Linkages

- 2.11.1 Except for the *real-time* constrained *dispatch schedule*, the *dispatch* scheduling and pricing process shall solve one *dispatch* period at a time, but shall respect the ramp rate limits applicable to *generation facilities* and *dispatchable load facilities* between *dispatch* periods.
- 2.11.2 In respect of a *real-time* market scheduling process, the *operating reserve* ramp rates submitted by *market participants* may be increased to levels determined by the *IESO*.
- 2.11.3 The *real-time* constrained *dispatch schedule* utilizes a two step optimization technique to maximize the weighted sum of the economic gain from trade among *market participants* for a number of critical intervals over a forward looking study period. For each *real time* constrained *dispatch schedule* critical intervals are selected by the *IESO* from the study period based on defined selection criteria. The first critical interval is always the *dispatch*

*interval*, and the remaining critical intervals are advisory intervals. Both the length of the study period and the number of advisory intervals are configurable and may be changed by the *IESO* in the event of significant improvement or degradation of either computer software and hardware performance, the accuracy of the predicted *demand* values or malfunction of the algorithm. Changing the number of critical intervals will affect the number of intervals provided to *market participants* on the *dispatch* advisory reports. The number of critical intervals and the length of the study period will be documented in the applicable *market manuals*.

- 2.11.4 The *IESO* may switch to a single interval optimization in the event of a malfunction of the multi-interval optimization algorithm.
- 2.11.5 In respect of the *real-time* constrained *dispatch schedule* only, the *dispatch* scheduling and optimization process shall consist of two steps. The first step considers all of the selected critical intervals together to provide an optimal solution. This uses linearized resource characteristics. The second step solves a set of single interval *dispatch* problems to respect the non-linearities that reflect physical characteristics of resources in accordance with section 6.5.

## 2.12 Outputs

- 2.12.1 The *dispatch* scheduling and pricing process shall produce the following outputs:
  - 2.12.1.1 the cost to the marketplace as a whole of the solution;
  - 2.12.1.2 the schedule for each *energy offer* submitted by a *generation facility* for each *dispatch period*;
  - 2.12.1.3 the schedule for each *offer* for each class of *operating reserve* for each *dispatch period*;
  - 2.12.1.4 the schedule for each *energy bid* submitted by a *dispatchable load* for each *dispatch period*;
  - 2.12.1.5 the energy output of each transitional scheduling generator and self-scheduling generation facility for each dispatch period;
  - 2.12.1.6 the level and location of all load curtailment;
  - 2.12.1.7 flows along all transmission lines;
  - 2.12.1.8 losses on the *IESO-controlled grid*, in the aggregate and by transmission line;
  - 2.12.1.9 the locational *energy prices* at each set of nodes identified by the *IESO* for this purpose for each *dispatch period*;

- 2.12.1.10 the uniform Ontario price for each class of *operating reserve* for each *dispatch period*. The *pre-dispatch schedule* shall also produce corresponding prices for all *intertie zones*. The *real-time schedule* need not produce corresponding prices for all *intertie zones* as the *real-time schedule intertie zone* prices are subsequently derived from the *real-time schedule* uniform Ontario prices and the *pre-dispatch schedule intertie congestion prices*;
- 2.12.1.10A the area price of *ten-minute operating reserve*; and
- 2.12.1.11 penalty function values that are greater than zero.

## 3. The Market Scheduling and Pricing Process

### 3.1 Modes of Operation

- 3.1.1 The market scheduling and pricing software may be operated to determine either a projected *market schedule* or a *market schedule*. While different numerical values may be used in each mode, the mathematical formulation shall be the same in both modes except that:
  - 3.1.1.1 the projected *market schedule* shall represent between 1 and 24 individual periods each of a duration of 1 hour. The projected *market schedule* so produced represents the state of the *IESO-controlled grid* at the end of the *dispatch hour*. Unless otherwise provided in these *market rules*, this process shall use the same information and data used for determining the *pre-dispatch schedule* for the corresponding *dispatch hour*;
  - 3.1.1.2 the *market schedules* shall represent individual *dispatch intervals*. Each schedule so produced represents the state of the *IESO-controlled grid* at the end of a *dispatch interval*. Unless otherwise provided in these *market rules*, this process shall use the same information and data used for determining the *real-time schedule* for the corresponding *dispatch interval*;
  - 3.1.1.3 the projected *market schedule* shall include daily *energy limits* where specified pursuant to section 3.5.7 of this Chapter; and
  - 3.1.1.4 subject to section 3.1.2, the *market schedule* process shall take, as inputs, the output levels of *generation facilities* and *dispatchable load facilities* from the preceding period of the corresponding *market schedule* and pricing solution.

- 3.1.2 Section 3.1.1.4 shall not apply if market operations have been suspended or *administrative prices* have been applied pursuant to section 8.4A.2.2 of this Chapter. In such cases, the *generation facility* and *dispatchable load facility* initial condition inputs used to calculate the first *market schedule* determined from the first *dispatch interval* in the *dispatch hour* referred to in section 13.7.1.2 or from the *dispatch interval* referred to in section 8.4A.17.2 of this Chapter 7, as the case may be, shall be the output levels of *generation facilities* and *dispatchable load facilities* from the last *dispatch interval* of the last corresponding *market schedule* and pricing solution solved, with corresponding modifications to the initial ramp rates to reflect the maximum amount of ramping possible during the *dispatch intervals* for which no *market schedules* were produced.

## 3.2 Inputs to and Form of the Market Scheduling and Pricing Process

- 3.2.1 The form of and inputs to the market scheduling and pricing process shall differ from the *dispatch* scheduling and pricing process described in section 2 only as follows:

- 3.2.1.1 all constraints that limit the ability of *energy* to flow from one node to another node within the *IESO control area* shall be removed. The market scheduling and pricing process shall assume that all *physical services* are provided and consumed in the *IESO control area* at a single, undesignated location connected to each *intertie zone* only by a single notional *intertie*. Any link between *intertie zones* that lie outside the *IESO control area* shall be removed;
- 3.2.1.1A all area constraints on *ten-minute operating reserve* shall be removed;
- 3.2.1.1B the market model shall produce a uniform price for *energy* and for each class of *operating reserve* in the *IESO control area*. The projected *market schedule* shall also produce prices for *energy* and for each class of *operating reserve* in each of the *intertie zones* adjoining the *IESO control area*. No *intertie zone* prices are required to be produced by the *market schedule* as these values are subsequently derived from the uniform Ontario prices produced by the *market schedule* and the projected *market schedule* *intertie congestion prices*;
- 3.2.1.2 *security* constraints shall be ignored except for those that impact on *intertie* flows;
- 3.2.1.2A constraints imposed on *offers* and *bids* that relate to transmission loading relief shall be ignored. Constraints relating to *generation facility outage* schedules and *contracted ancillary services* shall remain;

- 3.2.1.3 except for flows across *interties*, transmission losses shall not be associated with transmission line flows. Transmission losses other than in respect of flows across *interties* shall be represented as an increase in *non-dispatchable load*;
- 3.2.1.3A subject to section 3.2.1.3B, the flow across each *intertie* for all *dispatch intervals* within a *dispatch hour* in the *market schedule* shall be equal to the flow on that *intertie* determined for that same *dispatch hour* in the *market schedule* corresponding to the last *pre-dispatch schedule* determined prior to solving the *real-time schedule*;
- 3.2.1.3B where the limits on flows between *control areas* change in real-time as a result of an unplanned *intertie outage*, it shall be possible to reduce those limits in the *market schedule*;
- 3.2.1.4 with the exception of *emergency energy* purchases, any imports or exports between the *IESO control area* and other control areas required by the *IESO* to meet its obligations under requirements established by all relevant standards authorities and which are outside the normal market *bids* and *offers* shall not be represented directly but shall be represented as an increase or a decrease in *non-dispatchable load*. *Emergency energy* purchases shall not be represented as a decrease in *non-dispatchable load* in the *market schedule*;
- 3.2.1.5 [Intentionally left blank]
- 3.2.1.6 [Intentionally left blank]
- 3.2.1.7 [Intentionally left blank]
- 3.2.1.8 [Intentionally left blank]
- 3.2.1.9 [Intentionally left blank]
- 3.2.1.10 in accordance with section 4.13.1 of Appendix 7.5, the *market schedule* may use different trading period length to that of the *real-time schedule*;
- 3.2.1.11 in accordance with section 2.11.2 of Appendix 7.5, the *market schedule* may use a different ramp rate for *operating reserve* to that of the *real-time schedule*; and
- 3.2.1.12 during any period when the *IESO* undertakes an *emergency* control action as described in the applicable *market manual* that affects market *demand*, the *IESO* shall, as software capabilities permit, adjust market *demand* in the *market schedule* to offset the impact of the *emergency* control action on the market *demand* where such impact can be determined with reasonable certainty.

### 3.3 Outputs

- 3.3.1 The market scheduling and pricing process shall produce the following outputs:
- 3.3.1.1 the cost to the marketplace as a whole of the solution;
  - 3.3.1.2 the schedule for each *energy offer* submitted by a *generation facility* for each *dispatch period*;
  - 3.3.1.3 the schedule for each *offer* for each class of *operating reserve* for each *dispatch period*;
  - 3.3.1.4 the schedule for each *energy bid* submitted by a *dispatchable load* for each *dispatch period*;
  - 3.3.1.5 the output of each transitional scheduling generator and self-scheduling generation facility for each dispatch period;
  - 3.3.1.6 the uniform Ontario *energy price*. The projected *market schedule* shall also produce *energy prices* for each *intertie zone*;
  - 3.3.1.7 the uniform Ontario price for each class of *operating reserve* for each *dispatch period*. The *pre-dispatch schedule* shall also produce corresponding prices for all *intertie zones*. The *real-time schedule* need not produce corresponding prices for all *intertie zones* as the *real-time schedule intertie zone prices* are subsequently derived from the *real-time schedule uniform Ontario prices* and the *pre-dispatch schedule intertie congestion prices*; and
  - 3.3.1.8 [Intentionally left blank]
  - 3.3.1.9 penalty function values that are greater than zero.
- 3.3.2 As described in section 8.2.2 of this Chapter, the prices produced as part of the output of the market scheduling and pricing process shall not necessarily be the prices that are used for *settlement* purposes.

## 4. Glossary of Sets, Indices, Variables, and Parameters

### 4.1 Interpretation

4.1.1 Unless otherwise noted, all variables and parameters shall be non-negative.

4.1.2 [Intentionally left blank]

### 4.2 Time

4.2.1 Except where explicitly stated otherwise in Appendix 7.5 or elsewhere, the formulation presented in this Appendix represents a single *dispatch period*.

### 4.3 Fundamental Sets and Indices

#### 4.3.1 Areas and Nodes

4.3.1.1 An area, interpreted in accordance with section 1.2.3 of this Chapter, is represented by an element of the set AREAS and is indexed by a.

4.3.1.2 [Intentionally left blank]

4.3.1.3 [Intentionally left blank]

4.3.1.4 Any *energy offer*, *energy bid* or *offer for operating reserve* can be associated with a node belonging to the set NODES. NODES has a subset INTERNALACNODES to represent those nodes in the *IESO control area* and a subset EXTERNALACNODES to represent those nodes in the *intertie zones* adjoining the *IESO control area*. NODES also has subsets INTERTIEZONE, indexed by *z*, describing all of those nodes within *intertie zone z*.

#### 4.3.2 Offers

4.3.2.1 An *offer* is represented by an element of the set OFFERS and is indexed by *g*.

4.3.2.2 An *offer* has associated with it an area and a node.

- 4.3.2.3 [Intentionally left blank]
- 4.3.2.4 [Intentionally left blank]
- 4.3.2.5 A subset of OFFERS called OFFERS<sub>ENERGYLIMITED</sub> represents the *offers* which have a daily *energy* limit in force in accordance with section 3.5.7 of this Chapter.
- 4.3.2.6 Each element of  $g$  of OFFERS has a set of offer blocks, GENERATIONOFFERBLOCKS <sub>$g$</sub> .
- 4.3.2.7 SECURITYGENERATIONGROUP <sub>$v$</sub>  is the group of *offers* constrained with security constraint  $v$ .
- 4.3.2.8 Each *energy offer* has associated with it a set of GENERATIONRAMPUPBLOCKS <sub>$g$</sub>  and a set of GENERATIONRAMPDOWNBLOCKS <sub>$g$</sub> . Each set may be used to specify not less than 1 and not more than 5 ramp rates associated with the *energy offer*.
- 4.3.2.9 The set ENERGYOFFERBOUNDS, which is indexed by  $g$ , describes the set of *energy offers* to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits, *generation facility outages* as well as limits imposed by *contracted ancillary services* contracts. These limits restrict both the *energy* and *operating reserve* output of a *generation facility*.
- 4.3.3 *Bids*
  - 4.3.3.1 A *bid* is represented by an element of the set BIDS and is indexed by  $p$
  - 4.3.3.2 A *bid* has associated with it an area and a node.
  - 4.3.3.3 [Intentionally left blank]
  - 4.3.3.4 Each element of  $p$  of BIDS has a set of load blocks, PURCHASEBIDBLOCKS <sub>$p$</sub> .
  - 4.3.3.5 SECURITYPURCHASEGROUP <sub>$v$</sub>  is the group of *bids* constrained with security constraint  $v$ .

- 4.3.3.6 Each *energy bid*  $p$  has associated with it a set of  $PURCHASERAMPUPBLOCKS_p$  and a set of  $PURCHASERAMPDOWNBLOCKS_p$ . Each set may be used to specify not less than 1 and not more than 5 ramp rates associated with the *energy bid*.
- 4.3.3.7 The set  $PURCHASEBOUNDS$ , which is indexed by  $p$ , describes the set of *energy bids* to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits.
- 4.3.4 Operating Reserve Offers
- 4.3.4.1 An *offer* to provide *operating reserve* by either a *generator* or a *dispatchable load* is represented by an element of the set  $RESERVEOFFERS$  and is indexed by  $r$ . The index elements  $r(g)$  and  $r(p)$  mean the value of  $r$  denoting the *operating reserve offer* associated with *generator*  $g$  and *dispatchable load*  $p$ , respectively.
- 4.3.4.2 An *offer* to provide *operating reserve* has associated with it an area and a node.
- 4.3.4.3 Each element  $r$  of  $RESERVEOFFERS$  and  $c$  of  $RESERVECLASSES$  has a set of offer blocks,  $RESERVEOFFERBLOCKS_{r,c,j}$  where  $j$  is the index for the blocks.
- 4.3.4.4 The set  $RESERVEBOUNDS_c$ , which is indexed by  $r$ , describes the set of *operating reserve offers*, for each *operating reserve* class  $c$ , to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits.
- 4.3.5 [Intentionally left blank]
- 4.3.5.1 [Intentionally left blank]
- 4.3.5.2 [Intentionally left blank]
- a. [Intentionally left blank]
- b. [Intentionally left blank]
- c. [Intentionally left blank]
- 4.3.6 Classes of *Operating Reserve*
- 4.3.6.1 A class of *operating reserve* is represented by an element of the set  $RESERVECLASSES$  and is indexed by  $c$ .
- 4.3.6.2  $RESERVECLASSES = \{RS10,RNS10,R30\}$  where:

- a. RS10 denotes the *ten-minute operating reserve* that is synchronised with the *IESO-controlled grid*;
- b. RNS10 denotes *ten-minute operating reserve* that is not synchronised with the *IESO-controlled grid*; and
- c. R30 denotes *thirty-minute operating reserve*.

#### 4.3.7 Security Measures

- 4.3.7.1 A security measure is represented by an element of the set SECURITY and is indexed by v.
- 4.3.7.2 The *IESO* may establish parameters for these security measures so as to maintain the security and adequacy of the electricity system.
- 4.3.7.3 [Intentionally left blank]
- 4.3.7.4 [Intentionally left blank]

#### 4.3.8 Security Classes

- 4.3.8.1 Security classes represent the different types of security constraints that may be imposed by the *IESO* and are represented by SECURITYCLASSES.
- 4.3.8.2 SECURITYCLASSES = {GenericMaximum, GenericMinimum} where GenericMaximum and GenericMinimum are generic constraints that can place limits on combinations of *generation facilities* that are *dispatched* by the *IESO*, *dispatchable load* and AC branch flow simultaneously.

#### 4.3.9 Penalty Functions

- 4.3.9.1 The formulation contains a number of penalty functions that allow certain constraints to be violated to some extent, with a high penalty cost.
  - 4.3.9.2 Penalty functions have five blocks, indexed by j, so that the per unit penalty can be increased for larger violations. The blocks used are:
    - a. DEFICITGENERATIONBLOCKS;
    - b. SURPLUSGENERATIONBLOCKS;
    - c. [Intentionally left blank]
1. (i) [Intentionally left blank]
  2. (ii) [Intentionally left blank]

3. (iii) [Intentionally left blank]
  - c1. DEFICIT10MINRESERVEBLOCKS;
  - c2. DEFICITSYNCH10MINRESERVEBLOCKS;
  - c3. DEFICITTOTALRESERVEBLOCKS;
  - c4. DEFICITAREARESERVEBLOCKS;
  - c5. SURPLUSAREARESERVEBLOCKS;
  - c6. DEFICITINTERTIEBLOCKS;
  - c7. SURPLUSINTERTIEBLOCKS;
  - c8. DEFICITEXPORT<sup>MMCP</sup>BLOCKS;
  - d. For each  $v$  in DEFICITSECURITYBLOCKS <sub>$v$</sub> ; and
  - e. For each  $v$  in SURPLUSSECURITYBLOCKS <sub>$v$</sub> .

## 4.4 Derived Sets

4.4.1 There are numerous subsets that can be derived from the fundamental sets described above. A subscripted fundamental set represents all elements of the fundamental set having the attribute represented by the subscript where the subscript is either the unique index identifier or a set of specified elements of another fundamental set.

4.4.2 Examples of derived sets are:

4.4.2.1 RESERVEOFFERS <sub>$a$</sub> , which is the set of all *offers* for *operating reserve* located within *operating reserve* area  $a$ ; and

4.4.2.2 [Intentionally left blank]

4.4.2.3 OFFERS<sub>INTERNALACNODES</sub>, which is the set of all *energy offers* at nodes in the set INTERNALACNODES (*energy offers* made from within the *IESO control area*).

4.4.2.4 [Intentionally left blank]

4.4.2.5 [Intentionally left blank]

## 4.5 Functions Defined on Sets

4.5.1 For ease of description, the following functions are defined that operate on elements of sets and return either another set or a single element:

- 4.5.1.1  $g(\cdot)$ , where the argument could be an *operating reserve offer*  $r$ , or a security measure  $v$ , gives the *offer* associated with the argument.
- 4.5.1.2  $p(\cdot)$ , where the argument could be an *operating reserve offer*  $r$  or security measure  $v$ , gives the *bid* associated with the argument.
- 4.5.1.3 [Intentionally left blank]

## 4.6 Offers and Bids

### 4.6.1 Parameters

GenerationBlockMax <sub><math>g,j</math></sub>	The MW element of the $j^{\text{th}}$ block of the <i>offer</i> .
GenerationOfferPrice <sub><math>g,j</math></sub>	The price element of the $j^{\text{th}}$ block of the <i>offer</i> . The parameter is unbounded.
PurchaseBlockMax <sub><math>p,j</math></sub>	The MW element of the $j^{\text{th}}$ block of the <i>bid</i> .
PurchaseBidPrice <sub><math>p,j</math></sub>	The price element of the $j^{\text{th}}$ block of the <i>bid</i> . The parameter is unbounded.
EnergyOfferMax <sub><math>g</math></sub>	The maximum MW level for <i>energy</i> and <i>operating reserve</i> associated with <i>energy offer</i> $g \in \mathbf{ENERGYOFFERBOUNDS}$
EnergyOfferMin <sub><math>g</math></sub>	The minimum MW <i>energy</i> level associated with <i>energy offer</i> $g \in \mathbf{ENERGYOFFERBOUNDS}$
EnergyBidMax <sub><math>p</math></sub>	The maximum MW <i>energy</i> level associated with <i>energy bid</i> $p \in \mathbf{PURCHASEBOUND}$
EnergyBidMin <sub><math>p</math></sub>	The minimum MW <i>energy</i> level associated with <i>energy bid</i> $p \in \mathbf{PURCHASEBOUND}$

### 4.6.2 Derived Parameters

GenerationMaximum <sub><math>g</math></sub>	The maximum MW <i>energy</i> level associated with <i>energy offer</i> $g \in \mathbf{OFFERS}$ .
PurchaseMaximum <sub><math>p</math></sub>	The maximum MW <i>energy</i> level associated with <i>energy bid</i> $p \in \mathbf{BIDS}$ .

FixedPurchases	A representation of the net amount of non-price responsive withdrawal to be supplied from <i>energy offers</i> and <i>energy bids</i> .
GenPF <sub>g</sub>	The loss penalty factor for <i>energy offer</i> $g \in$ <b>OFFERS</b> .
PurPF <sub>p</sub>	The loss penalty factor for <i>energy bid</i> $p \in$ <b>BIDS</b> .

#### 4.6.3 Variables

Generation <sub>g</sub>	The total MW <i>energy</i> scheduled as at the end of the <i>dispatch period</i> corresponding to <i>energy offer</i> $g \in$ <b>OFFERS</b> .
GenerationBlock <sub>gj</sub>	The MW <i>energy</i> scheduled from the $j^{\text{th}}$ block of <i>energy offer</i> $g \in$ <b>OFFERS</b> .
Purchase <sub>p</sub>	The total MW <i>energy</i> scheduled as at the end of the <i>dispatch period</i> corresponding to <i>energy bid</i> $p \in$ <b>BIDS</b> .
PurchaseBlock <sub>pj</sub>	The MW <i>energy</i> scheduled from the $j^{\text{th}}$ block of <i>energy bid</i> $p \in$ <b>BIDS</b> .

## 4.7 Power Balance

4.7.1 Parameters [Intentionally left blank]

4.7.2 Derived Parameters [Intentionally left blank]

4.7.3 Variables

LOSS	The MW losses for the entire <i>IESO-controlled grid</i> .
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## 4.8 Operating Reserve

4.8.1 [Intentionally left blank]

4.8.2 Parameters

ReserveOfferPrice <sub>r,c,j</sub>	The price element of block <i>j</i> of <i>operating reserve</i> of class <i>c</i> associated with <i>operating reserve offer</i> <i>r</i> . The parameter is unbounded.
ReserveBlockMaximum <sub>r,c,j</sub>	The maximum MW <i>operating reserve</i> of class <i>c</i> available from block <i>j</i> of <i>operating reserve offer</i> <i>r</i> .
ReserveLoadingPoint10 <sub>r</sub>	The <i>operating reserve</i> loading point for <i>ten-minute operating reserve</i> that is synchronised with the <i>IESO-controlled grid</i> associated with <i>operating reserve offer</i> <i>r</i> . This defines the minimum <i>energy</i> value required for a generator to reach its maximum <i>ten-minute operating reserve offer</i> .
ReserveLoadingPoint30 <sub>r</sub>	The <i>operating reserve</i> loading point for <i>thirty-minute operating reserve</i> associated with <i>operating reserve offer</i> <i>r</i> . This defines the minimum <i>energy</i> value required for a generator to reach its maximum <i>thirty-minute operating reserve offer</i> .
ReserveRequirement10	The amount of <i>operating reserve</i> required to meet the <i>ten-minute operating reserve</i> requirement of the <i>IESO control area</i> .
ReserveRequirement30	The amount of <i>operating reserve</i> required to meet the <i>thirty-minute operating reserve</i> requirement of the <i>IESO control area</i> .
SynchReserveProportion	The fraction of <i>ten-minute operating reserve</i> that must be supplied by <i>operating reserve</i> that is synchronised to the <i>IESO-controlled grid</i> .
ReserveOfferMax <sub>r</sub>	The maximum MW level associated with <i>operating reserve offer</i> <i>r</i> ∈ <b>RESERVEBOUNDS</b> .
ReserveOfferMin <sub>r</sub>	The minimum MW level associated with <i>operating reserve offers</i> <i>r</i> ∈ <b>RESERVEBOUNDS</b> .

### 4.8.3 Derived Parameters

ReserveMaximum10 <sub>r</sub>	The maximum total <i>ten-minute operating reserve</i> from <i>operating reserve offer r</i> that can be delivered within ten minutes given the ramping rate for <i>operating reserve</i> .
ReserveMaximum30 <sub>r</sub>	The maximum total <i>operating reserve</i> from <i>operating reserve offer r</i> that can be delivered within thirty minutes given the ramping rate for <i>operating reserve</i> .

### 4.8.4 Variables

Reserve <sub>r,c</sub>	The scheduled <i>operating reserve</i> of class <i>c</i> corresponding to <i>operating reserve offer r</i> .
ReserveBlock <sub>r,c,j</sub>	The scheduled <i>operating reserve</i> of class <i>c</i> corresponding to block <i>j</i> of <i>operating reserve offer r</i> .

## 4.9 Security

4.9.1 Limits may be imposed on the output of *generation facilities*, *dispatchable load facilities* and flow on *transmission equipment* for *security* reasons.

### 4.9.2 Parameters

GenericSecurityMinLimit <sub>v</sub>	The lower limit imposed on the combination of <i>energy offers</i> and <i>energy bids</i> in security constraint $v \in \mathbf{SECURITY}$ . The parameter is unbounded.
GenericSecurityMaxLimit <sub>v</sub>	The upper limit imposed on the combination of <i>energy offers</i> and <i>energy bids</i> in security constraint $v \in \mathbf{SECURITY}$ . The parameter is unbounded.
SecurityGroupGenerationWeight <sub>v,g</sub>	The weight associated with <i>energy offer</i> $g \in \mathbf{SECURITYGENERATIONGROUP}_v$ in security constraint <i>v</i> . The parameter is unbounded.

SecurityGroup Purchase Weight <sub>v,p</sub>	The weight associated with <i>energy bid</i> $p \in \text{SECURITYPURCHASEGROUP}_v$ in security constraint $v$ . The parameter is unbounded.
MaxIntertieZoneFlow <sub>z</sub>	The upper limit imposed on the combination of <i>energy</i> and <i>operating reserve</i> by constraint $z \in \text{INTERTIEZONES}$ . The parameter is unbounded.
MinIntertieZoneFlow <sub>z</sub>	The lower limit imposed on the combination of <i>energy</i> and <i>operating reserve</i> by constraint $z \in \text{INTERTIEZONES}$ . The parameter is unbounded.

## 4.10 Ramping

4.10.1 *Dispatchable load facilities* and *dispatchable generation facilities* have limits on their ability to move from one level of consumption or production to another. Ramping constraints are enforced by constraining the level of consumption or production to be between an upper and a lower limit. These limits are pre-determined, based on starting load and generation levels and *bid* and *offer* ramp rates. These limits are applicable to all *pre-dispatch schedules*, *market schedule* intervals, and to the first *dispatch interval* of each *real-time* constrained *dispatch*.

4.10.1A In the first step, of the *real time* constrained *dispatch schedule*, as described in section 2.11.5, the ramp limits are linearized and respected in the optimization.

4.10.1B In the second step, the ramp limits are determined by pre-processing based on *dispatch* load and generation in the critical intervals that precede and follow the interval under consideration. The solution is bounded by:

- a) the prior critical interval solution as calculated by the second step and applicable non-linearized ramp rates; and
- b) back calculating from the following critical interval solution as calculated from the first step using the applicable non-linearized ramp rates.

In the event that these two sets of bounds do not intersect then a) governs.

#### 4.10.2 Parameters for the optimisation determined by pre-processing

$GenerationEndMax_g$	The maximum <i>generation facility</i> output level associated with <i>energy offer</i> $g \in \mathbf{OFFERS}$ , given the corresponding starting <i>generation facility</i> output level.
$GenerationEndMin_g$	The minimum <i>generation facility</i> output level associated with <i>energy offer</i> $g \in \mathbf{OFFERS}$ , given the corresponding starting <i>generation facility</i> output level.
$PurchaseEndMax_p$	The maximum load level associated with <i>energy bid</i> $p \in \mathbf{BIDS}$ , given the corresponding starting load level.
$PurchaseEndMin_p$	The minimum load level associated with <i>energy bid</i> $p \in \mathbf{BIDS}$ , given the corresponding starting load level.

#### 4.10.3 Parameters for Pre-processing

$RampRate_{g,j}^{Up}$	The <i>energy</i> ramping up rate in MW per minute associated with the $j^{\text{th}}$ block of $GENERATIONRAMPUPBLOCK_g$ for $g \in \mathbf{OFFERS}$ .
$RampRate_{g,j}^{Down}$	The <i>energy</i> ramping down rate in MW per minute associated with the $j^{\text{th}}$ block of $GENERATIONRAMPDOWNBLOCK_g$ for $g \in \mathbf{OFFERS}$ .
$Generation_g^{Start}$	The MW <i>energy</i> level associated with the <i>energy offer</i> at the start of a <i>dispatch period</i> . This will be the corresponding $Generation_g$ variable from the previous <i>dispatch period</i> for the <i>market schedule</i> and the constrained <i>pre-dispatch schedule</i> , but will be based on operational <i>metering data</i> and/or the schedule from the previous <i>dispatch period</i> for the <i>real-time schedule</i> . If the schedule from the previous <i>dispatch period</i> is not available (non-critical intervals in the <i>real time</i> constrained <i>dispatch schedule</i> ) it will be produced by interpolating the <i>dispatches</i> from the critical intervals before and after it.

OperatingReserveRampRate <sub>g</sub>	The single <i>operating reserve</i> ramp rate in MW per minute associated with $g \in \mathbf{OFFERS}$ .
RampRate <sub>p,j</sub> <sup>Up</sup>	The <i>energy</i> ramping up rate in MW per minute associated with the $j^{\text{th}}$ block of PURCHASERAMPUPBLOCK <sub>p</sub> $p \in \mathbf{BIDS}$
RampRate <sub>p,j</sub> <sup>Down</sup>	The <i>energy</i> ramping down rate in MW per minute associated with the $j^{\text{th}}$ block of PURCHASERAMPDOWNBLOCK <sub>p</sub> for $p \in \mathbf{BIDS}$
Purchase <sub>p</sub> <sup>Start</sup>	The MW <i>energy</i> level associated with the <i>energy bid</i> at the start of a <i>dispatch period</i> . This will be the corresponding Purchase <sub>p</sub> variable from the previous <i>dispatch period</i> for the <i>market schedule</i> and the constrained <i>pre-dispatch schedule</i> , but will be based on operational <i>metering data</i> and/or the schedule from the previous <i>dispatch period</i> for the <i>real-time schedule</i> .
OperatingReserveRampRate <sub>p</sub>	The single <i>operating reserve</i> ramp rate in MW per minute associated with $p \in \mathbf{BIDS}$ .
GenerationRampBlockMax <sub>g,j</sub>	The MW component of the $j^{\text{th}}$ block of the generator ramp up/down block minus the MW component of the $(j-1)^{\text{th}}$ block of the generator ramp up/down block.
PurchaseRampBlockMax <sub>p,j</sub>	The MW component of the $j^{\text{th}}$ block of the <i>dispatchable load</i> ramp up/down block minus the MW component of the $(j-1)^{\text{th}}$ block of the <i>dispatchable load</i> ramp up/down block.

#### 4.10.4 Variables Used in Pre-processing

TimeTrajStart <sub>g</sub> <sup>Up</sup>	The time, on the ramp up trajectory for the <i>energy offer</i> , associated with the Generation <sub>g</sub> variable from the previous <i>dispatch period</i> .
RampTraj <sub>g</sub> <sup>Up</sup>	The ramp up trajectory for the <i>energy offer</i>
TimeTrajStart <sub>g</sub> <sup>Down</sup>	The time, on the ramp down trajectory for the <i>energy offer</i> , associated with the Generation <sub>g</sub> variable from the previous <i>dispatch period</i> .

$\text{RampTraj}_g^{\text{Down}}$	The ramp down trajectory for the <i>energy offer</i>
$\text{TimeTrajStart}_p^{\text{Up}}$	The time, on the ramp up trajectory for the <i>energy bid</i> , associated with the <i>Purchase<sub>p</sub></i> variable from the previous <i>dispatch period</i> .
$\text{RampTraj}_p^{\text{Up}}$	The ramp up trajectory for the <i>energy bid</i>
$\text{TimeTrajStart}_p^{\text{Down}}$	The time, on the ramp down trajectory for the <i>energy bid</i> , associated with the <i>Purchase<sub>p</sub></i> variable from the previous <i>dispatch period</i> .
$\text{RampTraj}_p^{\text{Down}}$	The ramp down trajectory for the <i>energy bid</i>

#### 4.10.5 Parameters Determined by Pre-processing and Multi-Interval Optimization

$\text{GenerationRampBlock}_{g,j}$	The MW <i>dispatched</i> from the <i>j</i> th block of the <i>generation facility</i> ramp up/down block.
$\text{PurchaseRampBlock}_{p,j}$	The MW <i>dispatched</i> from the <i>j</i> th block of the <i>dispatchable load</i> ramp up/down block.

## 4.11 Energy Constrained Generation Units

### 4.11.1 Parameters for the Optimisation Determined by Pre-processing

$\text{EnergyRemaining}_g$	The amount of <i>energy</i> remaining at the beginning of the current <i>dispatch period</i> for <i>energy constrained generation facility</i> , as described in sections 6.6 and 8.3, associated with <i>energy offer g</i> .
$\text{Generation}_g^{\text{Previous}}$	The amount of <i>energy</i> scheduled from <i>energy offer g</i> in the preceding <i>dispatch period</i> .

### 4.11.2 Parameters for Pre-processing

$\text{EnergyOffered}_g$	The total <i>energy</i> limit for the <i>trading day</i> associated with <i>energy offer g</i> ∈ <b>OFFERS</b> .
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## 4.12 Violation Variables

4.12.1 Violation variables have been added to all constraints which might potentially be violated. Most will have a very high cost indicating that the problem has no solution, but some may have lower costs indicating that the constraint can be relaxed to some degree.

### 4.12.1.1 Parameters

DeficitGenerationPenalty <sub>j</sub>	The penalty per unit of the <i>DeficitGenerationBlock<sub>j</sub></i> variable.
SurplusGenerationPenalty <sub>j</sub>	The penalty per unit of the <i>SurplusGenerationBlock<sub>j</sub></i> variable.
Deficit10MinReservePenalty <sub>j</sub>	The penalty per unit of the <i>Deficit10MinReserveBlock<sub>j</sub></i> variable.
DeficitSynch10MinReservePenalty <sub>j</sub>	The penalty per unit of the <i>DeficitSynch10MinReserveBlock<sub>j</sub></i> variable.
DeficitTotalReservePenalty <sub>j</sub>	The penalty per unit of the <i>DeficitTotalReserveBlock<sub>j</sub></i> variable.
DeficitSecurityPenalty <sub>j,v</sub>	The penalty per unit of the <i>DeficitSecurityBlock<sub>j,v</sub></i> variable.
SurplusSecurityPenalty <sub>v,j</sub>	The penalty per unit of the <i>SurplusSecurityBlock<sub>v,j</sub></i> variable.
SurplusIntertiePenalty <sub>z,j</sub>	The penalty per unit of the <i>SurplusIntertieBlock<sub>z,j</sub></i> variable.
DeficitIntertiePenalty <sub>z,j</sub>	The penalty per unit of the <i>DeficitIntertieBlock<sub>z,j</sub></i> variable.
Deficit Export <sup>MMCP</sup> Penalty <sub>z,j</sub>	The penalty per unit of the <i>Deficit Export<sup>MMCP</sup> Block<sub>z,j</sub></i> variable.

These penalties, which are set by the *IESO Board* as specified in section 4.4.6 of this Chapter, equal a fixed number multiplied by a quadratic function equal to  $\text{constant1}(x^2) + \text{constant2}(x) + \text{constant3}$ . The three constants are user-defined for each penalty function while  $x$  equals the sum of total fixed demand and transmission losses divided by the total capacity represented by the *energy offers*.

#### 4.12.1.2 Variables

<i>DeficitGenerationBlock<sub>j</sub></i>	The amount by which the aggregate of load plus losses exceeds the <i>energy</i> generated. The blocks are cleared in order of increasing cost, so the further the power balance equation is violated, the more extreme the penalty per unit.
<i>SurplusGenerationBlock<sub>j</sub></i>	The amount by which <i>energy</i> generated exceeds the aggregate of load plus losses.
<i>Deficit10MinReserveBlock<sub>j</sub></i>	The amount contributed by block <i>j</i> in accounting for the amount by which the <i>ten-minute operating reserve</i> requirement exceeds the <i>ten-minute operating reserve</i> scheduled.
<i>Deficit Export<sup>MMCP</sup> Block<sub>j</sub></i>	The amount contributed by block <i>j</i> in accounting for the amount by which the exports (bid at MMCP) have been unsatisfied.
<i>DeficitSynch10MinReserveBlock<sub>j</sub></i>	The amount contributed by block <i>j</i> in accounting for the amount by which the <i>ten-minute operating reserve</i> requirement that is synchronised to the <i>IESO-controlled grid</i> exceeds the <i>ten-minute operating reserve</i> scheduled.
<i>DeficitTotalReserveBlock<sub>j</sub></i>	The amount contributed by block <i>j</i> in accounting for the amount by which the total <i>operating reserve</i> requirement exceeds the total <i>operating reserve</i> scheduled.
<i>DeficitSecurityBlock<sub>v,j</sub></i>	The amount of deficit in meeting security constraint <i>v</i> , in violation block <i>j</i> .
<i>SurplusSecurityBlock<sub>v,j</sub></i>	The amount of surplus in security constraint <i>v</i> , in violation block <i>j</i> .
<i>SurplusIntertieBlock<sub>z,j</sub></i>	The amount of surplus in <i>intertie zone</i> constraint <i>z</i> , in violation block <i>j</i> .
<i>DeficitIntertieBlock<sub>z,j</sub></i>	The amount of deficit in <i>intertie zone</i> constraint <i>z</i> , in violation block <i>j</i> .

*DeficitAreaReserveBlock*<sub>a,j</sub> The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement in area a exceeds the *ten-minute operating reserve* scheduled in area a.

*SurplusAreaReserveBlock*<sub>a,j</sub> The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement in area a is less than the *ten-minute operating reserve* scheduled in area a.

## 4.13 General Parameters

### 4.13.1 Parameters

*TradingPeriodLength* Being either 60 minutes, in respect of a *pre-dispatch schedule*, or 5 minutes, in respect of a constrained *real-time schedule*, or 15 minutes in respect of a *market schedule*, as the case may be.

## 5. Objective Function

5.1.1 As well as the market terms that are used in the objective function, violation variables associated with the various constraints also appear in the objective function.

5.1.1.1 The NetBenefit is maximised, where:

$$\begin{aligned}
 \text{NetBenefit} = & \sum_{\{j,p|j \in \text{PURCHASEBIDBLOCKS}_p, \text{ where } p \in \text{BIDS}\}} \text{PurchaseBidPrice}_{p,j} \times \text{PurPF}_p \times \text{PurchaseBlock}_{p,j} \\
 - & \sum_{\{j,g|j \in \text{GENERATIONOFFERBLOCKS}_g, \text{ where } g \in \text{OFFERS}\}} \text{GenerationOfferPrice}_{g,j} \times \text{GenPF}_g \times \text{GenerationBlock}_{g,j} \\
 - & \sum_{\{j,r,c|j \in \text{RESERVEOFFERBLOCKS}_{r,c}, \text{ where } r \in \text{RESERVEOFFERS and } c \in \text{RESERVECLASSES}\}} \text{ReserveOfferPrice}_{r,c,j} \times \text{ReserveBlock}_{r,c,j} \\
 - & \text{ViolationVariables} - \text{TieBreaking}
 \end{aligned}$$

In respect of the *real time* constrained *dispatch schedule* only, the first step of the optimization process will maximize the weighted sum of the net benefits from trades in the *dispatch interval* and the advisory intervals. The *IESO* will set the weights for the intervals in the *real time* constrained *dispatch* study period to account for reduced accuracy of inputs for future intervals. The *IESO* shall establish the process by which weights assigned to non-critical intervals are allocated to the critical intervals.

$$NetBenefit = \sum_{\{c \in \text{all critical intervals}\}} W_c \left[ \begin{aligned} & \sum_{\{j,p \mid j \in \text{PURCHASEBIDBLOCKS}_p, \text{ where } p \in \text{BIDS}\}} \text{PurchaseBidPrice}_{p,j} \times \text{PurPF}_p \times \text{PurchaseBlock}_{p,j} \\ & - \sum_{\{j,g \mid j \in \text{GENERATIONOFFERBLOCKS}_g, \text{ where } g \in \text{OFFERS}\}} \text{GenerationOfferPrice}_{g,j} \times \text{GenPF}_g \times \text{GenerationBlock}_{g,j} \\ & - \sum_{\{j,r,c \mid j \in \text{RESERVEOFFERBLOCKS}_{r,c}, \text{ where } r \in \text{RESERVEOFFERS and } c \in \text{RESERVECLASSES}\}} \text{ReserveOfferPrice}_{r,c,j} \times \text{ReserveBlock}_{r,c,j} \\ & - \text{ViolationVariables} - \text{TieBreaking} \end{aligned} \right]$$

Where  $W_c$  is the weight assigned to the critical interval  $c$ .

5.1.1.2 Wherever the following notation is found:

$$\{j, x \mid j \in \mathbf{XBLOCKS}_x, \text{ where } x \in \mathbf{GROUP}\}$$

it shall be interpreted as, for each  $x$  in the set **GROUP**, take each of the corresponding blocks from **XBLOCKS**.

5.1.1.3 Violation Variable Terms

*ViolationVariables* =

$$\begin{aligned} & \sum_{\{j \mid j \in \text{DEFICITGENERATIONBLOCKS}\}} \text{DeficitGenerationPenalty}_j \times \text{DeficitGenerationBlock}_j \\ + & \sum_{\{j \mid j \in \text{SURPLUSGENERATIONBLOCKS}\}} \text{SurplusGenerationPenalty}_j \times \text{SurplusGenerationBlock}_j \\ + & \sum_{\{j \mid j \in \text{DEFICIT10MINRESERVEBLOCKS}\}} \text{Deficit10MinReservePenalty}_j \times \text{Deficit10MinReserveBlock}_j \\ + & \sum_{\{j \mid j \in \text{DEFICIT10MINSYNCHRESERVEBLOCKS}\}} \text{Deficit10MinSynchReservePenalty}_j \times \text{DeficitSynch10MinReserveBlock}_j \\ + & \sum_{\{j \mid j \in \text{DEFICITTOTALRESERVEBLOCKS}\}} \text{DeficitTotalReservePenalty}_j \times \text{DeficitTotalReserveBlock}_j \\ + & \sum_{\{j,a \mid j \in \text{DEFICITAREARESERVEBLOCKS}_A, \text{ where } a \in \text{AREAS}\}} \text{Deficit10MinReservePenalty}_j \times \text{DeficitAreaReserveBlock}_{a,j} \\ + & \sum_{\{j,a \mid j \in \text{SURPLUSAREARESERVEBLOCKS}_A, \text{ where } a \in \text{AREAS}\}} \text{Surplus10MinReservePenalty}_j \times \text{SurplusAreaReserveBlock}_{a,j} \\ + & \sum_{\{j,v \mid j \in \text{DEFICITSECURITYBLOCKS}_v, \text{ where } v \in \text{SECURITYMIN}\}} \text{DeficitSecurityPenalty}_{v,j} \times \text{DeficitSecurityBlock}_{v,j} \\ + & \sum_{\{j,v \mid j \in \text{SURPLUSSECURITYBLOCKS}_v, \text{ where } v \in \text{SECURITYMAX}\}} \text{SurplusSecurityPenalty}_{v,j} \times \text{SurplusSecurityBlock}_{v,j} \\ + & \sum_{\{j,z \mid j \in \text{SURPLUSINTERTIEBLOCKS}_z, \text{ where } z \in \text{INTERTIEZONES}\}} \text{SurplusIntertiePenalty}_{z,j} \times \text{SurplusIntertieBlock}_{z,j} \\ + & \sum_{\{j,z \mid j \in \text{DEFICITINTERTIEBLOCKS}_z, \text{ where } z \in \text{INTERTIEZONES}\}} \text{DeficitIntertiePenalty}_{z,j} \times \text{DeficitIntertieBlock}_{z,j} \\ + & \sum_{\{j,z \mid j \in \text{DEFICITEXPORT}^{\text{MMCP}}\text{BLOCKS}_z, \text{ where } z \in \text{INTERTIEZONES}\}} \text{DeficitExport}^{\text{MMCP}}\text{Penalty}_{z,j} \times \text{DeficitExport}^{\text{MMCP}}\text{Block}_{z,j} \end{aligned}$$

#### 5.1.1.4 The Tie Breaking Term

$$\begin{aligned}
 TieBreaking = & \sum_{\{j,p|j \in PURCHASEBIDBLOCKS_p, \text{ where } p \in BIDS\}} \left\{ \frac{0.0005 \times (PurchaseBlock_{p,j})^2}{PurchaseBlockMax_{p,j}} \right\} \\
 & + \sum_{\{j,g|j \in GENERATIONOFFERBLOCKS_g, \text{ where } g \in OFFERS\}} \left\{ \frac{0.0005 \times (GenerationBlock_{g,j})^2}{GenerationBlockMax_{g,j}} \right\} \\
 & + \sum_{\{j,r,c|j \in RESERVEOFFERBLOCKS_{r,c}, \text{ where } r \in RESERVEOFFERS \text{ and } c \in RESERVECLASSES\}} \left\{ \frac{0.0005 \times (ReserveBlock_{r,c,j})^2}{ReserveBlockMax_{r,c,j}} \right\}
 \end{aligned}$$

The tie breaking term involves a penalty cost of 0.0005 prorated by the amount scheduled over the maximum amount that could be scheduled from each block. When this cost is multiplied by the amount scheduled from that block, we get a quadratic function that increases as the amount scheduled increases. The penalty cost adds effectively increases the *bid* or *offer* price by zero if nothing is scheduled from the block but by 0.0005 if the entire amount represented by the *bid* or *offer* block is scheduled. This slight price gradient, which is smaller than the minimum step size of *bid* or *offer* prices, will ensure that, for example, two otherwise tied *energy offer* blocks will be scheduled to the point where their modified costs are identical, effectively achieving a prorated result.

## 6. Dispatch Constraints

### 6.1 Offers and Bids

#### 6.1.1

$$Generation\ Block_{g,j} \leq Generation\ BlockMax_{g,j}$$

$$\{j, g \mid j \in \mathbf{GENERATIONOFFERBLOCKS}_g, \text{ where } g \in \mathbf{OFFERS}\}$$

#### 6.1.2

$$Generation_g = \sum_{j \in \mathbf{GENERATIONOFFERBLOCKS}_g} GenerationBlock_{g,j}$$

$$\{g \in \mathbf{OFFERS}\}$$

6.1.3

$$Generation_g \geq EnergyOfferMin_g$$

$$\{ g \in \mathbf{ENERGYOFFERBOUNDS} \}$$

6.1.4

$$Generation_g + \sum_{c \in \mathbf{RESERVECLASSES}} Reserve_{r(g),c} \leq EnergyOfferMax_g$$

$$\{ g \in \mathbf{ENERGYOFFERBOUNDS} \}$$

6.1.5

$$PurchaseBlock_{p,j} \leq PurchaseBlockMax_{p,j}$$

$$\{ j, p \mid j \in \mathbf{PURCHASEBIDBLOCKS}_p, \text{ where } p \in \mathbf{PURCHASES} \}$$

6.1.6

$$Purchase_p = \sum_{j \in \mathbf{PURCHASEBIDBLOCKS}_p} PurchaseBlock_{p,j}$$

$$\{ p \in \mathbf{PURCHASES} \}$$

6.1.7

$$Purchase_p \geq EnergyBidMin_p$$

$$\{ p \in \mathbf{PURCHASEBOUNDS} \}$$

6.1.8

$$Purchase_p \leq EnergyBidMax_p$$

$$\{ p \in \mathbf{PURCHASEBOUNDS} \}$$

All *energy offers* are entered as *offers* to supply a block of *energy* at a minimum price. Similarly, *energy bids* for *dispatchable load* are entered as *bids* to buy a block of *energy*

at a maximum price. *Energy offers* must have the price increasing with increasing quantity while *energy bids* must have the price decreasing with increasing quantity.

## 6.2 Power Balance

6.2.1 The power balance equation states that the total generation must equal the sum of scheduled *energy bids*, withdrawals by *non-dispatchable load* and losses. The sum of withdrawals by *non-dispatchable load* and associated losses are input based on forecasted demand.

6.2.1.1

$$\begin{aligned} \sum_{g \in \text{OFFERS}} \text{Generation}_g &= \sum_{p \in \text{BIDS}} \text{Purchase}_p + \text{FixedPurchases} + \text{LOSS} \\ &- \sum_{j \in \text{DEFICITGENERATIONBLOCKS}} \text{DeficitGenerationBlock}_j \\ &+ \sum_{j \in \text{SURPLUSGENERATIONBLOCKS}} \text{SurplusGenerationBlock}_j \end{aligned}$$

6.2.1.2 [Intentionally left blank]

6.2.1.3 [Intentionally left blank]

## 6.3 Operating Reserve

6.3.1 [Intentionally left blank]

6.3.2 Operating reserve requirements for the IESO control area are specified for each of ten-minute operating reserve and thirty-minute operating reserve. The ten-minute operating reserve that is required to be synchronised with the IESO-controlled grid is given as a fraction of the ten-minute operating reserve requirement. Since ten-minute operating reserve that is not required for purposes of the ten-minute operating reserve requirement can be used to satisfy the thirty-minute operating reserve requirement, a total operating reserve requirement is defined and is the sum of the ten-minute operating reserve requirement and the thirty-minute operating reserve requirement.

6.3.2A Following a *contingency event*, and subject to section 4.5.10 and 4.5.21 of Chapter 5, the IESO shall, over one or more *dispatch intervals*, restore at a constant rate the *operating reserve* requirements to be input into the *dispatch algorithm*. To the extent practicable,

the *IESO* shall restore *operating reserve* requirements so as to avoid exceeding the ability to meet those requirements through the *IESO-administered markets*.

6.3.2B *Operating reserve* requirements for areas within the *IESO control area* are specified as lower and upper limits on the amount of *ten-minute operating reserve* to be scheduled in each such area.

6.3.3 [Intentionally left blank]

6.3.3.1

$$ReserveBlock_{r,c,j} \leq ReserveBlockMax_{r,c,j}$$

$$\{j, r, c \mid j \in \mathbf{RESERVEOFFERBLOCKS}_r, \text{ where } r \in \mathbf{RESERVEOFFERS} \\ \text{and } c \in \mathbf{RESERVECLASSES}\}$$

6.3.3.2

$$Reserve_{r,c} = \sum_{j \in \mathbf{RESERVEOFFERBLOCKS}_{r,c}} ReserveBlock_{r,c,j}$$

$$\{r \in \mathbf{RESERVEOFFERS}, c \in \mathbf{RESERVECLASSES}\}$$

6.3.3.3 [Intentionally left blank]

6.3.3A

$$Reserve_{r,c} \geq ReserveOfferMin_{r,c}$$

$$\{r \in \mathbf{RESERVEBOUNDS}_c, c \in \mathbf{RESERVECLASSES}\}$$

6.3.3B

$$Reserve_{r,c} \leq ReserveOfferMax_{r,c}$$

$$\{r \in \mathbf{RESERVEBOUNDS}_c, c \in \mathbf{RESERVECLASSES}\}$$

- 6.3.3C The *operating reserve* scheduled from *dispatchable loads* cannot exceed the amount of *dispatchable load* scheduled.

$$\sum_{c \in \text{RESERVECLASSES}} \text{Reserve}_{r(p),c} \leq \text{Purchase}_p$$

{  $p \in \mathbf{BIDS}$  }

- 6.3.4 The *energy* and *operating reserves* scheduled from a *generation facility* must be within the capacity of the *generation facility*.

6.3.4.1

$$\text{Generation}_g + \sum_{c \in \text{RESERVECLASSES}} \text{Reserve}_{r(g),c} \leq \text{GenerationMaximum}_g$$

{  $g \in \mathbf{OFFERS}$  }

- 6.3.5 If a *generation facility* is operating at a low level of output, then the amount of *operating reserve* it is capable of providing may be restricted. The Reserve Loading Point corresponds to the minimum level of output at which generators can supply the maximum *operating reserve* within the time required. This maximum *operating reserve* quantity declines to zero as output reduces to zero. The maximum *operating reserve* that can be provided differs for *ten-minute operating reserve* and *thirty-minute operating reserve*, and reflects the differing amount of time available for the *generation facility* to increase its output if the *operating reserve* is activated.

6.3.5.1

$$\text{Reserve}_{r(g),RS10} \leq \text{Generation}_g \times \frac{\text{ReserveMaximum10}_g}{\text{ReserveLoadingPoint10}_{r(g)}}$$

{  $g \in \mathbf{OFFERS}$  }

$$\text{Reserve}_{r(g),R30} \leq \text{Generation}_g \times \frac{\text{ReserveMaximum30}_g}{\text{ReserveLoadingPoint30}_{r(g)}}$$

{  $g \in \mathbf{OFFERS}$  }

Where:

$$\text{ReserveMaximum10}_g = \text{OperatingReserveRampRate}_{r(g)} \times 10$$

$$\text{ReserveMaximum30}_g = \text{OperatingReserveRampRate}_{r(g)} \times 30$$

If either one of  $\text{ReserveLoadingPoint10}_{r(g)}$  or  $\text{ReserveLoadingPoint30}_{r(g)}$  equals zero then the corresponding equation shall not be included in formulation.

6.3.5.2 [Intentionally left blank]

6.3.5.3 [Intentionally left blank]

6.3.5A The amount of *ten-minute operating reserve* scheduled from a *generation facility* cannot exceed the maximum amount by which *operating reserve* can be ramped up by that *generation facility* within ten minutes. The total *operating reserve* scheduled from a *generation facility* cannot exceed the maximum amount by which *operating reserve* can be ramped up by that *generation facility* within thirty minutes.

6.3.5A.1

$$\sum_{c \in \{RS10, RNS10\}} \text{Reserve}_{r(g),c} \leq \text{Reserve Maximum } 10_g$$

{g ∈ OFFERS }

6.3.5A.2

$$\sum_{c \in \text{RESERVECLASSES}} \text{Reserve}_{r(g),c} \leq \text{ReserveMaximum30}_g$$

{g ∈ OFFERS }

6.3.5B Constraints are imposed in *real-time dispatch* scheduling to recognize that the amount by which a *generation facility's* energy output is scheduled to change during a *dispatch interval* modifies the amount of *operating reserve* that the *generation facility* can reliably provide. For instance, if the *generation facility* ramps up during the *dispatch interval*, then the amount of *ten-minute operating reserve* it can provide within ten minutes of the start of the *dispatch interval* will be reduced.

6.3.5B.1

$$\text{Generation}_g + \sum_{\substack{r \in \text{RESERVEOFFERS}, \\ c \in \{RS10, RNS10\}}} \text{Reserve}_{r(g),c} \leq \text{Generation}_g^{\text{start}} + \text{ReserveMaximum10}_g$$

{g ∈ OFFERS }

6.3.5B.2

$$Generation_g + \sum_{\substack{r \in \text{RESERVEOFFERS}, \\ c \in \text{RESERVECLASSES}}} Reserve_{r(g),c} \leq Generation_g^{start} + ReserveMaximum30_g$$

{ g ∈ OFFERS }

6.3.5C The constraints of 6.3.5B are imposed in *real-time market* scheduling and consistent with the TradingPeriodLength determined by the IESO in accordance with section 4.13.1 of Appendix 7.5.

6.3.6 *Operating reserve* is scheduled to meet the *operating reserve* requirements of the IESO control area.

6.3.6.1 Ten-minute operating reserve

$$ReserveRequirement10 \leq \sum_{\substack{r \in \text{RESERVEOFFERS}, \\ c \in \{RS10, RNS10\}}} Reserve_{r,c} + \sum_{j \in \text{DEFICT10MINRESERVEBLOCKS}} Deficit10MinReserveBlock_j$$

6.3.6.2 Ten-minute operating reserve synchronised with the IESO-controlled grid

$$\text{SynchReserveProportion} \times ReserveRequirement10$$

$$\leq \sum_{r \in \text{RESERVEOFFERS}, c \in \{RS10\}} Reserve_{r,c} + \sum_{j \in \text{DEFICTSYNCH10MINRESERVEBLOCKS}} DeficitSynch10MinReserveBlock_j$$

6.3.6.3 Total operating reserve

$$ReserveRequirement10 + ReserveRequirement30$$

$$\leq \sum_{r \in \text{RESERVEOFFERS}, c \in \text{RESERVECLASSES}} Reserve_{r,c} + \sum_{j \in \text{DEFICTTOTALRESERVEBLOCKS}} DeficitTotalReserveBlock_j$$

### 6.3.6.3A Area operating reserve requirements

MinimumAreaOperatingReserve<sub>a</sub> ≤

$$\sum_{r \in \text{RESERVEOFFERS}_{a,c \in \{RS10,RNS10\}}} Reserve_{r,c} + \sum_{j \in \text{DEFICITAREARESERVEBLOCKS}} DeficitAreaReserve_{j,a}$$

MaximumAreaOperating Reserve<sub>a</sub> ≥

$$\sum_{r \in \text{RESERVEOFFERS}_{a,c \in \{RS10,RNS10\}}} Reserve_{r,c} - \sum_{j \in \text{SURPLUSAREARESERVEBLOCKS}} SurplusAreaReserve_{j,a}$$

$\{a \in \mathbf{AREAS}\}$

6.3.6.4 The SynchReserveProportion shall be set in accordance with requirements established by *NERC*.

## 6.4 Security Constraints

6.4.1 In order to enable the *IESO* to direct the operations of the *IESO-controlled grid* so as to fulfil its obligations under Chapter 5, the *IESO* must define network security constraints. These network security constraints are specified in the form of maximum and minimum constraints on linear combinations of line flows, *energy offers*, and *energy bids*. During the process of solving for schedules and prices, these network security constraints, as well as other transmission constraints represented automatically within the tools, are reduced to generic *security* constraints which impose limits on the weighted sum of the *Generation<sub>g</sub>* and *Purchase<sub>p</sub>* variables, with flows being converted to constants.

6.4.2 [Intentionally left blank]

6.4.3 Generic *security* constraints only appear in the *dispatch* scheduling and pricing process and are expressed as:

6.4.3.1

$$\sum_{n \in \text{SECURITYPURCHASEGROUP}_v} \text{SecurityGroupPurchaseWeight}_{v,p} \times \text{Purchase}_p$$

$$+ \sum_{g \in \text{SECURITYGENERATIONGROUP}_v} \text{SecurityGroupGenerationWeight}_{v,g} \times \text{Generation}_g$$

$$- \sum_{j \in \text{SURPLUSSECURITYBLOCKS}_v} \text{SurplusSecurityBlock}_{j,v} \leq \text{Generic Max SecurityLimit}_v$$

$\{v \in \mathbf{SECURITY}_{\text{GenericMaximum}}\}$

### 6.4.3.2

$$\begin{aligned}
 & \sum_{p \in \text{SECURITYPURCHASEGROUP}_v} \text{SecurityGroupPurchaseWeight}_{v,p} \times \text{Purchase}_p \\
 & + \sum_{g \in \text{SECURITYGENERATIONGROUP}_v} \text{SecurityGroupGenerationWeight}_{v,g} \times \text{Generation}_g \\
 & + \sum_{j \in \text{DEFICITSECURITYBLOCKS}_v} \text{DeficitSecurityBlock}_{v,j} \geq \text{GenericMinSecurityLimit}_v
 \end{aligned}$$

{v ∈ SECURITY<sub>GenericMinimum</sub>}

6.4.4 Constraints separate from the generic security constraints impose limits on the total energy flows and operating reserve scheduled from *intertie zones* outside the *IESO control area*. These constraints apply to both the *pre-dispatch schedule* and the *market schedule*.

$$\begin{aligned}
 & \sum_{g \in \text{OFFERS}_z} \text{Generation}_g - \sum_{p \in \text{BIDS}_z} \text{Purchase}_p + \sum_{r \in \text{RESERVEOFFERS}_z, c \in \text{RESERVECLASSES}} \text{Reserve}_{r,c} \\
 & - \sum_{j \in \text{SURPLUSINTERTIEBLOCKS}_z} \text{SurplusIntertieBlock}_{z,j} \leq \text{MaxIntertieZoneFlow}_z
 \end{aligned}$$

$$\begin{aligned}
 & \sum_{g \in \text{OFFERS}_z} \text{Generation}_g - \sum_{p \in \text{BIDS}_z} \text{Purchase}_p + \\
 & + \sum_{j \in \text{DEFICITINTERTIEBLOCKS}_z} \text{DeficitIntertieBlock}_{z,j} \geq \text{MinIntertieZoneFlow}_z
 \end{aligned}$$

{z ∈ INTERTIEZONES}

## 6.5 Ramping

6.5.1 Any change in the output of a *generation facility* or the consumption by a *dispatchable load facility* is subject to up and down ramp rate limits. These constrain the schedule for these *facilities* at the end of the *dispatch period* to be within a band which is set by pre-processing based on knowledge of the schedule at the start of the *dispatch period* and the ramp rates.

6.5.2 Except for the advisory intervals in the *real time constrained dispatch*, ramping constraints are expressed as:

### 6.5.2.1

$$Generation_g \leq GenerationEndMax_g \quad \{g \in \mathbf{OFFERS}\}$$

6.5.2.2

$$Generation_g \geq GenerationEndMin_g \quad \{g \in \mathbf{OFFERS}\}$$

6.5.2.3

$$Purchase_p \leq PurchaseEndMax_p \quad \{p \in \mathbf{BIDS}\}$$

6.5.2.4

$$Purchase_p \geq PurchaseEndMin_p \quad \{p \in \mathbf{BIDS}\}$$

6.5.3 For purposes of sections 6.5.2.1 to 6.5.2.4,  $GenerationEndMax_g$ ,  $GenerationEndMin_g$ ,  $PurchaseEndMax_p$  and  $PurchaseEndMin_p$  are determined by pre-processing as described in section 8.2.

6.5.4 The ramping constraints for the advisory intervals in the first step of the multi-interval optimization of the *real time* constrained *dispatch* are linearized and included in the optimization as follows:

6.5.4.1

$$Generation_g = \sum GenerationRampBlock_{g,j} \quad \{g \in \mathbf{OFFERS}\}$$

6.5.4.2

$$Purchase_p = \sum PurchaseRampBlock_{p,j} \quad \{p \in \mathbf{BIDS}\}$$

6.5.4.3

$$0 \leq GenerationRampBlock_{g,j} \leq GenerationRampBlockMax_{g,j} \quad \{g \in \mathbf{OFFERS}\}$$

6.5.4.4

$$0 \leq PurchaseRampBlock_{p,j} \leq PurchaseRampBlockMax_{p,j} \quad \{p \in \mathbf{BIDS}\}$$

#### 6.5.4.5

$$\begin{aligned}
 & - RampRate_{g,j}^{Down} \times T_{g,j} \leq GeneratorRampBlock(i + 1th \text{ int erval}) \\
 & - GeneratorRampBlock_{g,j}(ith \text{ int erval}) \leq RampRate_{g,j}^{Up} \times T_{g,j}
 \end{aligned}$$

Where  $T_{g,j} \geq 0$  and  $\sum T_{g,j} \leq \text{Time Interval}$ ; and

$T_{g,j}$  is the time that the generator ramps in the  $GeneratorRampBlock_{g,j}$ ; where Time Interval is equal to the length of the *dispatch interval*.

#### 6.5.4.6

$$\begin{aligned}
 & RampRate_{p,j}^{Down} \times T_{p,j} \leq PurchaseRampBlock(i + 1th \text{ int erval}) \\
 & - PurchaseRampBlock_{p,j}(ith \text{ int erval}) \leq RampRate_{p,j}^{Up} \times T_{p,j}
 \end{aligned}$$

Where  $T_{p,j} \geq 0$  and  $\sum T_{p,j} \leq \text{Time Interval}$ ; and

$T_{p,j}$  is the time that the purchase ramps in the  $PurchaseRampBlock_{p,j}$ ; where Time Interval is equal to the length of the *dispatch interval*.

## 6.6 Energy Constrained Generation Units

6.6.1 Some *generation units*, referred to as “*energy constrained generation units*”, have a defined amount of *energy* which they are able to generate within the course of a *trading day*. Each *energy constrained generation unit* may specify an *energy limit* which will apply over the *trading day*. Where an *energy limit* is specified pursuant to section 3.5.7 of this Chapter, starting with this value a running total, *EnergyRemaining*, is kept by subtracting the *energy* scheduled in each *dispatch hour* from the quantity of *energy* available at the start of the *dispatch hour*.

6.6.2 Because the model is not inter-temporal, it will not use *energy* at the times at which it is of most value. Instead, it will use *energy* over the first opportunities in which it is economical to do so. Thus, it may use all of the *energy* during the low load early morning period, leaving none left during the higher price periods. It is left to the *generator* to submit *energy offers* for a *generation unit* at appropriate times to maximise the value of the *energy* available.

6.6.3 The following constraint is included only in the *pre-dispatch schedules*:

$$TradingPeriodLength \times Generation_g \leq EnergyRemaining_g$$

$$\{g \in \mathbf{OFFERS}_{ENERGYLIMITED}\}$$

## 6.7 Nodal Price Calculation

$$6.7.1 \quad \lambda_n = \lambda_s + (DF_n - 1) * \lambda_s + \sum_k DF_n * a_{nk} * \mu_k$$

where:

$\lambda_n$  nodal price at an injection or withdrawal node  $n$  (i.e., a node connected to a *generation facility* or *load facility*)

$\lambda_s$  system marginal cost

$DF_n$  delivery factor for node  $n$  (reciprocal of penalty factor )

$a_{nk}$  sensitivity factor for injection at node  $n$  on *transmission* line  $k$

$\mu_k$  shadow price for *transmission* line  $k$  constraint

6.7.2 Nodal prices may be decomposed into an *energy* component, a loss component, and a component for all other *transmission* and system constraints (the three terms on the right hand side, respectively.)

## 7. Market Constraints

### 7.1 Introduction

7.1.1 The market model removes all of the AC *transmission* lines inside the *IESO control area*, and consolidates the nodes into a single representative node, the ONTARIONODE. The losses associated with the *transmission* lines in the *IESO control area* are consolidated to this node.

7.1.2 The only AC *transmission* lines in the market model are the *interties* with neighbouring *control areas*. Although these *interties* have flow variables in the market model, under current procedures each interface will have its flows constrained to the scheduled quantities for the relevant *dispatch period*, using *security* constraints.

### 7.2 Offers and Bids

7.2.1 The market constraints for *energy offers* and *energy bids* are identical to the *dispatch* constraints described in section 6.1 with the exception that constraints associated with the

sets ENERGYOFFERBOUNDS and PURCHASEBOUNDS shall not be present if those constraints pertain to transmission loading relief.

## 7.3 Power Balance

7.3.1 The market power balance equations are identical to the *dispatch* power balance equations described in section 6.2, with the following exceptions:

7.3.1.1 subject to section 7.3.2, losses within the *IESO control area* will be added to FixedPurchases;

7.3.1.2 all loss sensitivity parameters (and corresponding penalty functions) for *generators* and *loads* within each *control area* outside the *IESO control grid* will be identical and will reflect the losses on the external area and the relevant *inertie*; and

7.3.1.3 subject to section 7.3.2, the following adjustments, as further defined in section 8.4, shall be made in the *real-time schedule* to reflect deviations between scheduled and actual MW output and load:

ActualPurchaseAdjustment – ActualGenerationAdjustment

7.3.2 Until such time that locational pricing is implemented in the *IESO-administered markets*:

7.3.2.1 the losses referred to in section 7.3.1.1 shall be incorporated in FixedPurchases in the manner described in section 8.4.3 ; and

7.3.2.2 no adjustments shall be made pursuant to section 7.3.1.3.

## 7.4 Operating Reserve

7.4.1 The market treatment of risk and *operating reserve* is identical to the *dispatch* treatment of these elements as described in section 6.3, with the exception that:

7.4.1.1 constraints on *offers* for *operating reserve* associated with the set RESERVEBOUNDS<sub>c</sub> for *operating reserve* class c shall not be present if those constraints pertain to transmission loading relief; and

7.4.1.2 the area *operating reserve* requirements are ignored.

## 7.5 Security Constraints

7.5.1 The only security constraints to be represented are the limits imposed on the flows of energy and on *operating reserve* scheduled from *inertie zones* outside the *IESO control area* as described in section 6.4.4.

## 7.6 Ramping

7.6.1 The mathematical description of the market constraints for ramping is identical to the mathematical description of the ramping *dispatch* constraints used in the *pre-dispatch* and the *dispatch interval* of the *real time* multi-interval *dispatch*, as described in section 6.5, except for the information and data differences specified in section 6.4 of Chapter 7.

## 7.7 Energy Constrained Generation Units

7.7.1 This constraint is only included in the *pre-dispatch schedules*. The market energy constraints are identical to the *dispatch energy* constraints as described in section 6.6.

# 8. Parameters and Pre-processing

## 8.1 Introduction

8.1.1 This section 8 contains calculations that take place before the optimization algorithm. The purpose of these calculations is to convert raw input data into the specific inputs required by the optimisation algorithm.

## 8.2 Ramping

8.2.1 The pre-processing calculations described in sections 8.2.2 and 8.2.3 are performed for all *energy offers*  $\{g \in \mathbf{OFFERS}\}$ . The pre-processing calculations described in sections 7.2.4 and 7.2.5 are performed for all *bids by dispatchable loads*  $\{p \in \mathbf{BIDS}\}$ .

8.2.2 The *energy offer* ramp up model is defined by the set of ramp up rates and ramp up blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum increase of output as a function of time. The output at the end of a *dispatch period* is then calculated by:

$$\text{GenerationEndMax}_g = \text{RampTraj}_g^{Up}(\text{TimeTrajStart}_g^{Up} + \text{TradingPeriodlength})$$

where

$$Generation_g^{Start} = RampTraj_g^{Up}(TimeTrajStart_p^{Up})$$

- 8.2.3 The *energy offer* ramp down model is defined by the set of ramp down rates and ramp down blocks. Combined these rates and blocks define the ramp trajectory which gives the maximum decrease of output as a function of time. The output at the end of a *dispatch period* is then calculated by:

$$GenerationEndMin_g = RampTraj_g^{Down}(TimeTrajStart_g^{Down} + TradingPeriodlength).$$

where

$$Generation_g = RampTraj_g^{Down}(TimeTrajStart_g^{Down})$$

- 8.2.4 The *energy bid* ramp up model is defined by the set of ramp up rates and ramp up blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum increase of *dispatchable load* as a function of time. The *dispatchable load* at the end of a *dispatch period* is then calculated by:

$$PurchaseEndMax_p = RampTraj_p^{Up}(TimeTrajStart_p^{Up} + TradingPeriodlength)$$

where

$$Purchase_p^{Start} = RampTraj_p^{Up}(TimeTrajStart_p^{Up})$$

- 8.2.5 The *energy bid* ramp down model is defined by the set of ramp down rates and ramp down blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum decrease of *dispatchable load* as a function of time. The *dispatchable load* at the end of a *dispatch period* is then calculated by:

$$PurchaseEndMin_p = RampTraj_p^{Down}(TimeTrajStart_p^{Down} + TradingPeriodlength).$$

where

$$Purchase_p = RampTraj_p^{Down}(TimeTrajStart_p^{Down})$$

## 8.3 Energy Constrained Generation Units

### 8.3.1

$$EnergyRemaining_g = EnergyRemaining_g^{Previous} - Generation_g^{Previous} \times SchedPeriod$$

where SchedPeriod is the scheduling period measured in hours, currently 1 hour. If EnergyRemaining<sub>g</sub> ever takes a value of less than zero then it shall be set to zero. If EnergyRemaining<sub>g</sub> is ever lower than a lower bound constraint imposed on *energy offer g*, then as part of the pre-processing process the relevant lower bounds will be reduced accordingly.

### 8.3.2

EnergyRemaining<sub>g</sub> = EnergyOffered<sub>g</sub> in the first *dispatch period*.

## 8.4 Actual Dispatch Adjustment

8.4.1 Subject to section 8.4.3, Actual Generation Adjustment shall be:

8.4.1.1 for the ONTARIONODE:

$$\text{ActualGenerationAdjustment}_{\text{ONTARIONODE}} = \sum_{n \in \text{INTERNALNODES}} \sum_{g \in \text{OFFERS}_n} (\text{Generation}_g^{\text{Actual}} - \text{Generation}_g^{\text{Scheduled}})$$

where Generation<sub>g</sub><sup>Actual</sup> is the actual generation for generator g, and Generation<sub>g</sub><sup>Scheduled</sup> is the *dispatch instruction* issued for generator g; and

8.4.1.2 for n ∈ EXTERNALACNODES:

$$\text{ActualGenerationAdjustment}_n = \sum_{g \in \text{OFFERS}_n} (\text{Generation}_g^{\text{Actual}} - \text{Generation}_g^{\text{Scheduled}})$$

where Generation<sub>g</sub><sup>Actual</sup> is the actual generation for generator g, and Generation<sub>g</sub><sup>Scheduled</sup> is the *dispatch instruction* issued for generator g.

8.4.2 Subject to section 8.4.3, Actual Purchase Adjustment shall be:

8.4.2.1 for the ONTARIONODE:

$$\text{ActualPurchaseAdjustment}_{\text{ONTARIONODE}} = \sum_{n \in \text{INTERNALNODES}} \sum_{p \in \text{BIDS}_n} (\text{Purchase}_p^{\text{Actual}} - \text{Purchase}_p^{\text{Scheduled}})$$

where Purchase<sub>p</sub><sup>Actual</sup> is the actual load for *dispatchable load p*, and Purchase<sub>p</sub><sup>Scheduled</sup> is the *dispatch instruction* issued for *dispatchable load p*; and

8.4.2.2 for  $n \in \text{EXTERNALACNODES}$ :

$$\text{ActualPurchaseAdjustment}_n = \sum_{p \in \text{BIDS}_n} (\text{Purchase}_p^{\text{Actual}} - \text{Purchase}_p^{\text{Scheduled}})$$

where  $\text{Purchase}_p^{\text{Actual}}$  is the actual load for *dispatchable load* p, and  $\text{Purchase}_p^{\text{Scheduled}}$  is the *dispatch instruction* issued for *dispatchable load* p.

8.4.3 Until such time that locational pricing is implemented in the *IESO-administered markets*, there shall be no actual dispatch adjustment effected pursuant to section 8.4.1 or 8.4.2 and rather than adding the losses within the *IESO control area* to FixedPurchases, FixedPurchases shall be defined to include losses and shall be:

8.4.3.1 the sum of:

- a. actual metered generation within the *IESO control area*; and
- b. net scheduled flows over all *interties*,

minus

8.4.3.2 the amount of scheduled *dispatchable load* within the *IESO control area*.

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