Guide to IESO Market Calculation Engines

IESO Training

November 2025 v0.1

Connecting Today.
Powering Tomorrow.

AN IESO MARKETPLACE TRAINING PUBLICATION

This guide has been prepared to assist in the IESO training of market participants and has been compiled from extracts from the market rules or documents posted on the web site of Ontario's Independent Electricity System Operator. Users of this guide are reminded that they remain responsible for complying with all of their obligations under the market rules and associated policies, standards and procedures relating to the subject matter of this guide, even if such obligations are not specifically referred to herein. While every effort has been made to ensure the provisions of this guide are accurate and up to date, users must be aware that the specific provisions of the market rules or particular document shall govern.

Attention: Customer Relations

The Independent Electricity System Operator Box 4474, Station A

Toronto, Ontario M5W 4E5

Customer Relations: Tel: (905) 403-6900

Toll Free 1-888-448-7777

Website: www.ieso.ca

Contents

1. Introduction

The IESO operates and settles the day-ahead and real-time wholesale electricity markets in Ontario, balancing supply with demand and ensuring reliable power system operation. At the core of the wholesale electricity market are three calculation engines which perform scheduling and pricing optimization in three different timeframes:

- The **day-ahead market** calculation engine runs once per day and produces hourly energy and operating reserve schedules, commitments for non-quick start (NQS) resources that are eligible for generator offer guarantee [1], and locational marginal prices (LMPs) for the next day;
- The **pre-dispatch** calculation engine runs hourly and is used to transition from day-ahead scheduling to real-time operations. The pre-dispatch calculation engine produces hourly energy and operating reserve schedules, incremental NQS commitments, and advisory LMPs over its look-ahead period; and
- The **real-time** market calculation engine runs every five minutes to determine real-rime LMPs, dispatch instructions, and advisory energy and operating reserve schedules for future look-ahead intervals.

This document provides an overview of the functioning of these engines including discussion of the key algorithms used to determine schedules and prices. While this document provides a high-level overview of the functions and processes carried out by the calculation engines, it does not provide details about the various dispatch data inputs required and the pre-processing and verification procedures. For further details on these procedures, refer to **Market Manual 4.1**.

This document does not include technical details of how mathematical functions and processes are implemented within the engines. The details of the variables and parameters used in the mathematical formulations are provided in **Market Rules Appendices 7.5, 7.5A** and **7.6**.

The technical details of various functions in the calculation engines are simplified in this guide. In case there are inconsistencies between this guide and the Market Rules/Manuals, the Market Rules/Manuals prevail. For further details on mathematical formulations, refer to **Market Rules Appendices 7.5, 7.5A** and **7.6**.

[1] A non-quick resource is one that is currently offline, cannot receive a dispatch instruction, start up, synchronize to the grid and fulfill its dispatch instruction within 5 minutes. Please note that all subsequent uses of the term "non-quick start" or "NQS" within this document will refer to generator offer guarantee eligible resources. Unless otherwisely stated, NQS in this document is referred to NQS that is eligible for generation offer guarantee payments.

2. Function and Role of the Calculation Engines

There are three sequential calculation engines – one for each of the DAM, pre-dispatch and real-time market. They use mathematical algorithms to determine market outcomes such as prices and schedules.

2.1 Day-Ahead Market (DAM) Calculation Engine

The day-ahead market (DAM) calculation engine produces financially binding[2] hourly energy and operating reserve schedules, NQS resource commitments, and LMPs for all 24 hours of the next dispatch day.

The engine uses market participants' dispatch data parameters, including offers, bids, non-financial parameters (such as ramp rates, daily maximum number of starts), and approved outages. It also considers IESO inputs such as demand forecasts, variable generation forecasts, and IESO-controlled grid information (e.g., the network model and security limits).[3]

The DAM calculation engine also checks for competitiveness in the market and, when needed, applies ex-ante market power mitigation for economic withholding[4] to alleviate the material impact of exercises of market power. Lack of competition can occur when supply into an area or into Ontario is limited by transmission capability. If such conditions exist, market participant dispatch data would fail the conduct and impact tests and it is subsequently replaced with its reference levels -- IESO-determined estimates of the offer parameters a resource would have submitted if it were operating under competitive conditions. The DAM price and schedule calculations will rerun and the resulting LMPs and schedules are final for settlement.[5]

---

[2] The term "financially binding" means that the resource will be settled (i.e., credited or charged) for their day-ahead schedule at their day-ahead price(s).

[3] Please see Market Manual 4.1: Submission of Dispatch Data in Real-time Energy and Operating Reserve Markets for more information about IESO and market participant inputs to the DAM calculation engine.

[4] Economic withholding is referred to situations where a supplier has offered its capacity at a price higher than its short term incremental cost and above the market clearing price.

[5] For more information on market power mitigation, please see Market Rules Chapter 7, section 22; Chapter 7 Appendices, multiple sections; and Markets Manuals 14.1 and 14.2.

The DAM calculation engine has three sequential 'passes' (see Figure 2-1). Within each pass, one or more mathematical functions are solved.

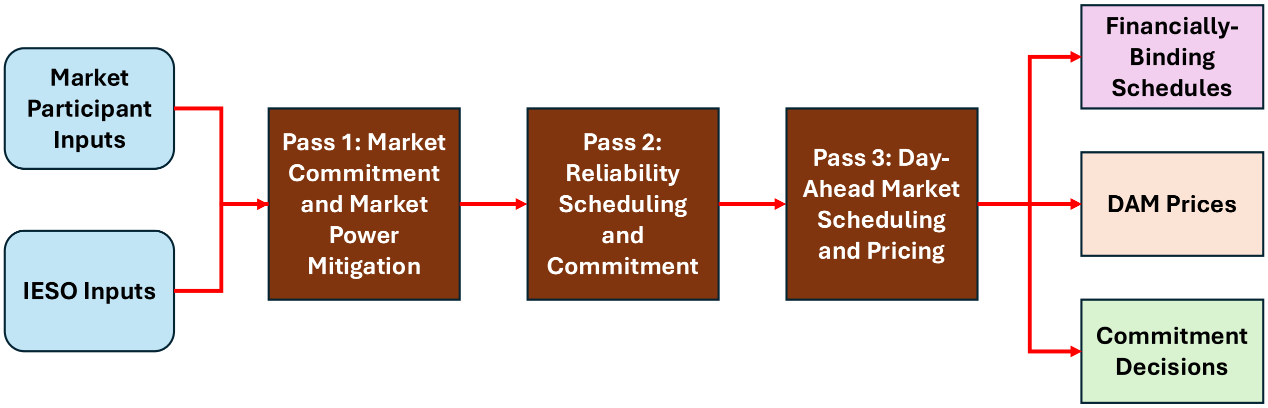


Figure 2-1 DAM calculation engine passes

Each DAM calculation engine pass has a unique purpose:

- Pass 1 – Market Commitment and Market Power Mitigation: This pass determines an initial set of resource schedules and NQS resource commitments for the next day to meet the IESO's operating reserve requirements and average hourly energy demand forecast. This pass also checks for competitiveness and performs conduct and impact tests.
- Pass 2 – Reliability Scheduling and Commitment: This pass checks if the resource commitments and schedules produced by Pass 1 are sufficient to meet the IESO's peak hourly energy demand forecast. If required, Pass 2 can commit additional NQS resources, schedule additional imports, or reduce exports and
- Pass 3 – DAM Scheduling and Pricing: This pass uses the commitments determined by Passes 1 and 2 to produce a final set of resource schedules, commitments and LMPs used for settlement. It preserves the commitments determined by the prior passes while scheduling to meet the IESO's operating reserve requirements and average hourly energy demand forecast. It also respects the mitigation decisions made by Pass 1, if applicable.

Section 3 describes the mathematical functions of the DAM calculation engine. Section 4 discusses the three passes of the DAM calculation engine and the associated steps.

2.2 Pre-dispatch Calculation Engine

The pre-dispatch calculation engine runs hourly to produce resource schedules, NQS commitments, and LMPs for each of future hours while accounting for resource and system constraints. These future hours are referred to as its 'look-ahead period'. This period always includes the remaining hours of the current day and may include the 24 hours of the next dispatch day, depending on the timing of the pre-dispatch run in question. It determines the optimal unit commitment and economic dispatch for energy and operating reserves over the look-ahead period. It also performs ex-ante market power mitigation. Pre-dispatch mitigation decisions are cumulative, meaning that each run of pre-dispatch also respects the mitigation decisions of previous runs including the DAM mitigation.

Schedules determined by the pre-dispatch calculation engine are generally advisory in nature and are not used for settlement. The only exception is that the schedules for intertie transactions calculated by the last pre-dispatch run before a dispatch hour is final, which are carried over to RT.[6]

There are linkages between the information used by pre-dispatch runs and the DAM run:

- Offers and bids for energy and operating reserves as submitted into the DAM[7] are carried over as inputs to pre-dispatch unless updated by the market participant, subject to certain restrictions;[8]
- NQS commitments from DAM are carried over to pre-dispatch as minimum operational constraints: pre-dispatch will schedule a committed NQS resource to no less than its minimum loading point (MLP) for the duration of it's minimum generation block run-time (MGBRT) as scheduled in the DAM. DAM schedules for other Ontario-based resources are not input into the pre-dispatch scheduling process; and
- Pre-dispatch calculation engine considers offers/bids from DAM-scheduled intertie transactions for all hours in the future. Within two hours, pre-dispatch also considers incremental intertie offers/bids submitted post DAM.

The pre-dispatch calculation engine also runs independently from the real-time calculation engine with one exception: it uses past real-time schedules to determine previous cumulative output by energy limited resources, to determine when the resource will meet its maximum daily output.

Section 3 describes the mathematical functions of the pre-dispatch calculation engine. Section 5 discusses the pre-dispatch calculation engine in more detail.

2.3 Real-time Calculation Engine

The real-time calculation engine runs every 5-minutes and builds on the DAM and pre-dispatch calculation engines in many aspects:

- When the minimum daily energy limit (DEL) for a hydroelectric resource is binding, its pre-dispatch schedule for an hour is the minimum constraint for real-time;
- An hourly must-run amount is the real-time minimum constraint for the hour;
- A NQS must operate at or above its minimum loading point (MLP) for at least the length of it's MGBRT if it has a DAM or pre-dispatch commitment;
- The intertie transactions scheduled by the final pre-dispatch run, subject to intertie check-out procedures and real-time curtailments, are fixed and carried over to RT for the whole delivery hour. The net change of intertie schedules across the hour is achieved by ramping Ontario internal resources over a 10-minute period from the last five-minutes in the current hour to the first five-minutes of the next hour; and

---

[6] In advance of a dispatch hour, IESO Control Room operators confer with their counterparts in neighbouring jurisdictions to agree on the final intertie schedules for the hour. This is required because intertie traders must successfully schedule a transaction in the IESO-administered (e.g., and export) as well as a corresponding transaction (e.g., an import) separately in the counterparty jurisdiction in order for the transaction to flow in real-time.

[7] Any offers which were mitigated by the DAM are not passed to pre-dispatch. That is, their unmitigated values are used by pre-dispatch.

[8] Please see Market Manual 4.1: Submission of Dispatch Data in Real-time Energy and Operating Reserve Markets for more information on limitations to dispatch data revisions post-DAM.

- The real-time calculation engine does not perform any market power mitigation test. Instead, if a resource is mitigated in prior PD runs, it uses its reference level values.

The real-time calculation engine performs multi-interval optimization to produce dispatch schedules for the upcoming interval Real-time also provides advisory schedules that might be needed in the subsequent ten 5-minute intervals.

While the real-time calculation engine respects the ramping capability of NQS generation units below MLP, it doesn't assess NQS economics for dispatches below their MLP. Instead, as soon as a resource's breaker closes, it dispatches the unit up to its MLP on a fixed trajectory using its submitted ramp rates. Similarly, once a NQS generation unit is de-committed and dispatched below its MLP, it is continuously dispatched down to 0 MW on a fixed trajectory at the specified ramp rate.

The real-time calculation engine also produces LMPs. The energy and operating reserve LMPs for the dispatch interval are used for market settlement, subject to the price floor and cap, while those calculated for advisory intervals are informational only.

Section 3 describes the mathematical functions of the real-time calculation engine steps. Section 6 discusses the real-time calculation engine and its associated steps.

3. The Scheduling and Pricing Algorithms

All three calculation engines have two algorithms: a scheduling algorithm and a pricing algorithm. Three mathematical functions are used to accomplish their tasks – one for scheduling only, one for pricing only and a common one for both:

- The Unit Commitment (UC) function is used by the scheduling algorithm, determining least cost commitments and resulting hourly schedules;
- The Economic Dispatch (ED) function is used by the pricing algorithm, calculating least-cost resource schedules given unit commitments being fixed and associated shadow prices of constraints. It also produces LMPs (see Section 3.7 for more details on shadow prices); and
- The Security Assessment (SA) function is used by both UC and ED to ensure that their generated schedules do not result in power flow that violates power system security. Information used include operating security limits, thermal ratings, the network model, loop flow[9], and the status of power system equipment etc.

The following section provides an overview of the scheduling and pricing algorithms. It also discusses several concepts embedded in the calculation engines, including but not limited to:

- Gain from trade (see Section 3.3). Maximizing the gain from trade is the primary objective function in UC and ED. This function essentially produces the schedules which maximize total short-term consumer surplus and producer surplus.
- Constraint violation pricing (see Section 3.4). Maximizing the gain from trade is subject to many constraints, such as transmission limits, generators' technical parameters, operating reserve requirements, etc. At times, an optimal solution is unachievable without violating one or more constraints, which could lead to volatile prices, random outcomes, or no solution at all. The introduction of constraint violation pricing, with a price hierarchy on different constraints, allows the optimization to be solved.
- Settlement price floor and cap (see Section 3.5). at the current time, the Settlement price floor for energy is set at -$100/MWh and the cap is at $2,000/MWh. They are established to mitigate the price risks resulting from extreme prices due to the marginal cost pricing mechanism and a hybrid market structure with various contracts and regulation provisions.
- Price setting eligibility (see Section 3.6). Not all offers/bids are allowed to set the LMPs because of various limitations or considerations.
- Shadow prices of constraints (see Section 3.7). There is always a non-zero shadow price associated with a constraint when the constraint is binding or violated. The shadow price generally reflects the benefit of relaxing one MW of that constraint. The shadow price is used in the calculation of LMPs.

---

[9] Loop flows can occur on a grid because electricity will take all available paths from a point of injection to a point of withdrawal. This means that energy which is primarily flowing between two points can cause flows on other paths in the system. These can be an issue if the strength of the unscheduled flow results in grid limitations becoming binding in other grid areas. For example, due to the physical nature of the grid and the location of generation and load centres on both sides of Lake Erie, under certain conditions, unscheduled energy will flow around the lake. If these flows reach sufficient levels, they must be managed through dispatch and/or control actions in order to maintain reliability.

3.1 DAM and Pre-dispatch Scheduling and Pricing Algorithms

3.1.1 The DAM and Pre-dispatch Scheduling Algorithm

In the DAM and pre-dispatch calculation engines, scheduling algorithm performs multiple iterations of the ED and SA functions, as shown in Figure 3-1. UC function determines least cost hourly energy and operating reserve schedules and NQS commitments over the optimization time horizon.

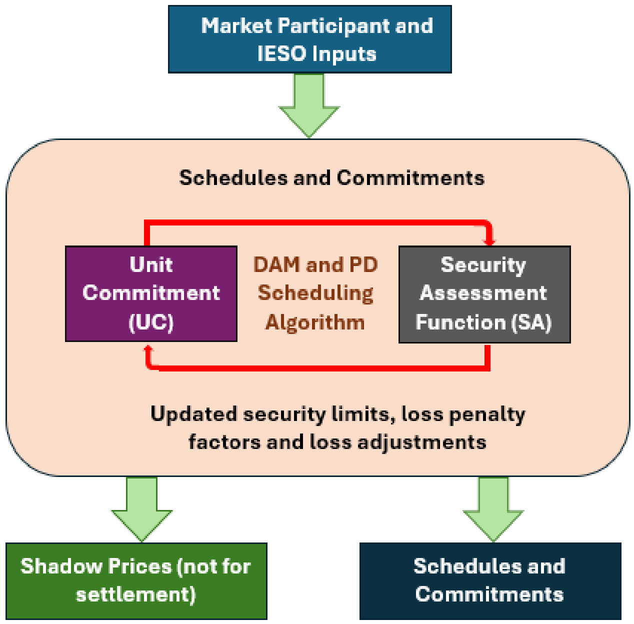


Figure 3-1 The DAM and pre-dispatch Scheduling Algorithm

The NSA function determines whether the resulting energy flows from UC would cause transmission or operating limit violations. If any violation is triggered, the SA updates security limits. The SA function also estimates loss penalty factors at generation units and loss adjustments for the whole system. With the updated information, the UC then reruns and produces updated schedules, which are again assessed by the SA.

The UC and SA functions thus go back and forth until:

- The SA function doesn't find any more limit violations;
- The UC function can't eliminate the remaining allowed limit violations (see Section 3.4); or
- A pre-determined maximum number of UC-SA iterations has been reached.

The optimization objective functions are different: the UC in Passes 1 and 3 of the DAM and in the pre-dispatch maximizes the gain from trade, while the UC in Pass 2 of DAM minimizes the cost of additional unit commitments to meet the forecast peak demand (discussed in Section 4.3.1).

The UC function respects the resource constraints submitted by market participants and the system constraints enforced by the IESO. UC constraints can be generally divided into three categories:

- Single hour constraints. They ensure the schedules within each single hour do not violate market participant's or IESO constraints. An example would be resource minimum and maximum capacity limits;
- Multi-hour constraints. They ensure the schedules to respect any inter-temporal linkages as specified by market participants and IESO. For example, a market participant's maximum number of starts for a day must be respected; and
- Reliability requirement constraints. They ensure the schedules not to violate IESO reliability requirements (e.g., operating reserve requirements).

Tie-Breaking

Tie-breaking logic is applied if more than one resource that are offered at the same price are at the margin. When this occurs, the calculation engine will pro-rate schedules among the resources based on the quantity offered. For example, Resources A and B submitted the following offers:

- Resource A: 100 MW at $2/MWh.
- Resource B: 80 MW at $2/MWh.

If the total generation required from both is only 70 MW, the calculation engine will schedule the two resources as follows:

- Resource A: 38.9 MW= 70*(100/180); and
- Resource B: 31.1 MW= 70*(80/180).

3.1.2 The DAM and Pre-dispatch Pricing Algorithm

In the DAM and pre-dispatch calculation engines, the ED function determines the LMPs. If needed, the ED pricing algorithm performs multiple iterations of the ED and SA functions (Figure 3-2).

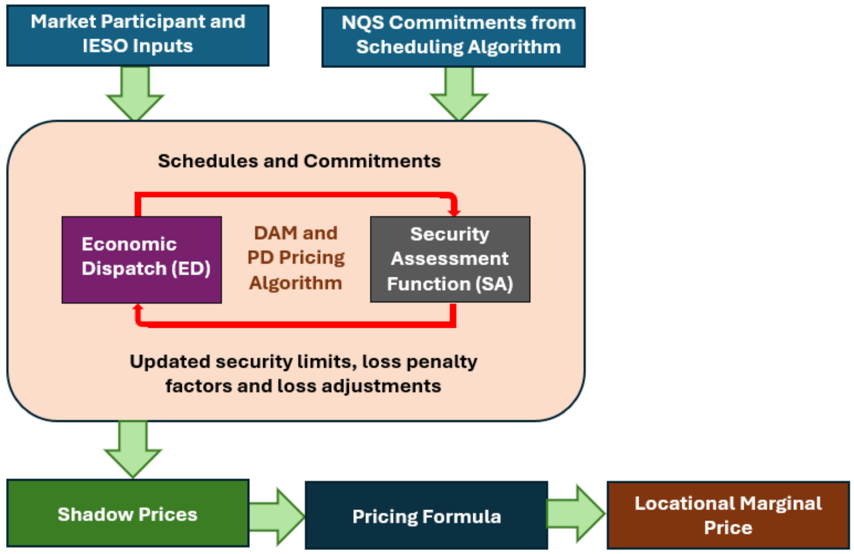


Figure 3-2 DAM and Pre-dispatch Pricing Algorithm

ED uses the same inputs by market participants and IESO as UC in the scheduling algorithm. It also respects the following constraints of the UC:

- the MLP of committed NQS resource. That being said, the committed NQS unit's start-up and speed no-load costs are not considered at this stage.; and
- Hourly energy schedules of energy-limited resources when its daily energy limit is binding.

The constraints applied in the ED mirror those used in the UC, with an additional price setting eligibility requirement (Section 3.6)

ED has different constraint violation penalty curves from the scheduling algorithm (see Section 3.4). ED also interacts with the NSA function, like in the scheduling algorithm, to mitigate the cost of violating transmission and operating limits.

The ED produces a shadow price for every constraint (either zero or non-zero), which is then used to calculate energy and operating reserve LMPs (Section 7).

The UC scheduling algorithm produces commitment decisions and schedules based on multi-hour optimization. The use of multi-hour optimization in UC helps to produce least cost commitment outcomes over the optimization horizon while ensuring that the schedules respect multi-hour resource and system reliability constraints. Multi-hour resource constraints include, for example, daily energy limits and minimum generation block run-time.

In contrast, the ED algorithm also has a multi-hour optimization, but it only generates constraints that are subsequently applied to the single-hour ED optimization for pricing purposes. the single hour optimization for pricing reflects the fundamental principle that the marginal price at each location should be set by an offer or bid from a resource that can serve the next increment of demand at that location during the hour being priced. In so doing, the calculated LMP is transparent and easy to understand.

As a result, among other differences (such as different constraint violation prices), there could be occasional mismatches between an LMP that is mainly calculated based on a single hour optimization and the resource's schedule that is based on a multiple hours optimization.

3.2 Scheduling and Pricing in Real-time

The real-time calculation engine performs multi-interval optimization to determine:

- Dispatch instruction (schedules) for the dispatch interval (i.e., the immediate upcoming interval) and advisory schedules for 10 advisory intervals.
- Settlement-ready LMPs for the dispatch interval, and advisory LMPs for the advisory intervals.

The real-time calculation engine doesn't determine NQS commitments. Instead, it respects the commitment decisions made by the DAM and pre-dispatch calculation engines. When a commitment expires, the real-time calculation engine evaluates the resource according to the economics of its incremental offers and/or reliability needs determined by the IESO to determine if it should be shut down.

The real-time calculation engine uses the ED function with the scheduling function running first and followed by the pricing function.

As shown in Figures 3-3 and 3-4, the real-time calculation engine performs multiple iterations of the ED and the SA functions, as needed. Both scheduling and pricing functions determine the least cost economic scheduling of available resources.

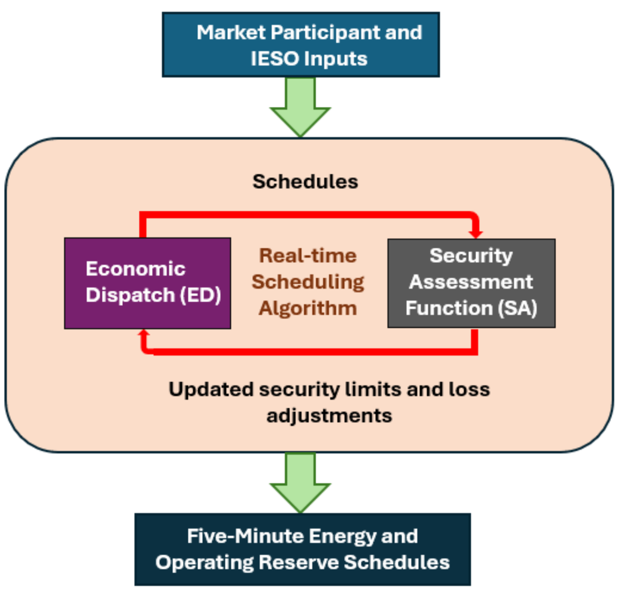


Figure 3-3 Real-time Scheduling Algorithm

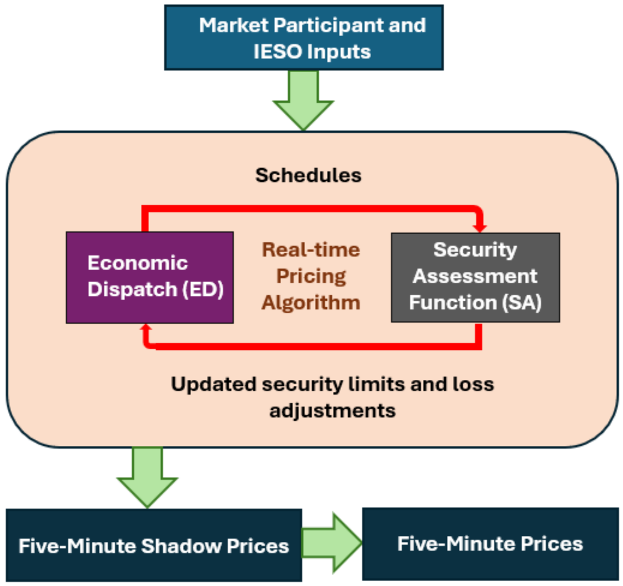


Figure 3-4 Real-time Pricing Algorithm

3.2.1 Real-time Scheduling Function

Real-time Scheduling Function produces five-minute energy and operating reserve schedules. The energy and operating reserve schedules for the immediate upcoming interval are used as the basis for dispatch instructions, while the remaining schedules in the real-time look-ahead period will be advisories for information purposes.

3.2.2 Real-time Pricing Function

Real-time Pricing Function uses the same dispatch data and initial resource schedules as used in Real-time Scheduling Function. However, the initial resource schedules of the pricing pass may get adjusted for dispatch deviations as determined by looking at the ramping limits and the real-time telemetry. (Please see section 6.1 for more details).

Real-time Pricing also uses the same IESO data inputs as Real-time Scheduling except that it uses different constraint violation pricing.

Like in Day-ahead in in PD, the Real-time Pricing, uses a single-interval optimization to calculate settlement-ready prices, reflecting the fundamental design principle that the marginal price should reflects the incremental cost of serving the next Mw of demand at that location at the time. As a result, there could be occasional mismatches between LMPs and resource schedules, especially for those with transactions priced near the margin. This can have the effect of making some scheduled resources offered or bid near the margin uneconomic when compared to the LMP.

3.3 Maximizing Gains from Trade

Gains from trade are maximized when a price is set at the point where the need by all consumers who have who have higher willingness to buy is satisfied, and suppliers who have a lower willingness to sell can produce. At this point, the price is considered as efficient. This section discusses maximizing gains from trade at the general conceptual level, as opposed to delving into how exactly it is respected within the algorithms.

Assume there is a market where all consumers enter bids or maximum willingness to buy and all suppliers enter offers or their minimum willingness to sell. Bids can be stacked from the highest to the lowest willingness to buy to form a demand/bid curve:

Figure 3-5 Consumer Bid Curve

Similarly, offers can be stacked from the lowest to the highest willingness to sell to form a supply/offer curve:

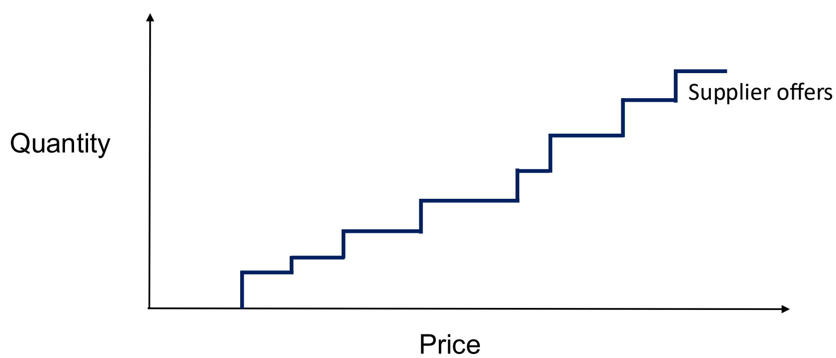


Figure 3-6 Supply Offer Curve

The most efficient market clearing price is set where the two curves intersect. It represents the point at which the sum of consumer surplus and supplier surplus is maximized.

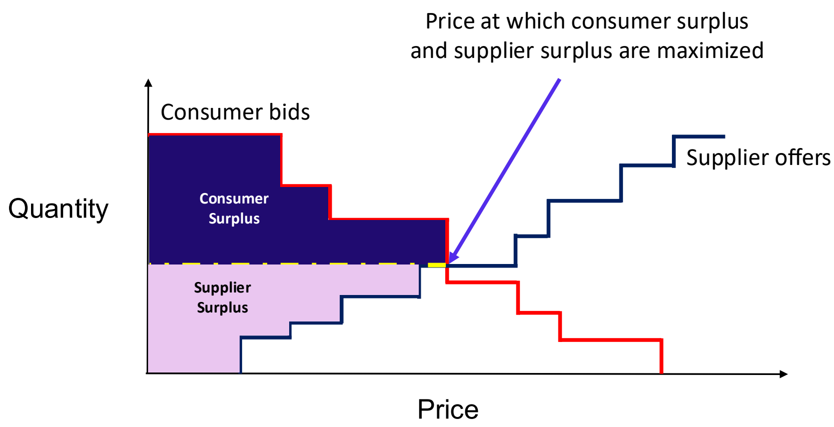


Figure 3-7 Price Maximized

Consumer surplus is represented by the area below the bid curve but above the clearing price, representing that consumers were willing to pay more but will only have to pay the lower clearing price. Similarly, supplier surplus is the area above the offer curve but below the clearing price, representing that suppliers were willing to supply energy at a lower price than the clearing price.

3.4 Constraint Violation Pricing

The calculation engine sometimes is unable to determine a schedule that meets demand while respecting all system and resource constraints. For example, there may be insufficient transmission capacity to meet projected demand, or not enough operating reserve offers to meet reserve requirements. When this happens, constraint violations are permitted and must be properly modelled so that a feasible solution can be reached.

Market prices therefore must also reflect the cost of constraint violations so that transparent and efficient prices are formed. This is done e by applying constraint violation (also called "penalty") prices on the violated constraints, when market prices are produced.

Because the pricing and scheduling functions serve different purposes, penalty prices are different[10]:

- The scheduling algorithm determines dispatchable resource schedules to meet demand while respecting, as far as possible, system and resource constraints. Penalty prices are used to set the order of which constraint can be violated before others, with a constraint having the

[10] Please see Market Manual 4.2: Operation of the Day-ahead Market, Appendix C and Market Manual 4.3: Operation of the Real-time Market, Appendix A for more information on constraint violation penalty curves, including specific types and values.

lowest violation price being violated first. The violation prices largely reflect the IESO's preference.

- The pricing algorithm determines settlement-ready prices. The prices include the congestion component of all constraints, and the penalty price applied on a constraint reflect the cost of violating that constraint that is acceptable to both market participants and the IESO.

Operating Reserve Demand Curves

In the scheduling run, single penalty factors are used depending on the reserve category. For example, the penalty price is $12,000 for 10S, $10,000 for total 10, and $6,000 for total reserve.

Using these same penalties in the pricing run, however, could lead to very high prices regardless of the severity of the operating reserve violation. For example, a same penalty price is applied for a 1 MW shortfall as for a 1,000 MW shortfall.

To more accurately reflect the reliability cost of a violation at different severity levels, operating reserve demand curves (ORDC) are used in the pricing function. An ORDC contains a set of price-quantity pairs with price decreasing as the offered quantity increases (see Figure 4 below). When offers from physical resources are sufficient, the operating reserve prices are set at the offer price of a physical resource. If there is an insufficient offers,, the price may be set by the ORDC. Any MWs which were offered at a price above the ORDC price and were scheduled will receive make-whole payments.

Figure 4 illustrates the ORDC curve. The values included are for demonstration purposes and are not meant to reflect the actual curve. Assume the operating reserve requirement is 600 MW. If 300MW or less was offered, the OR clearing price would be set at $500/MWh of the ORDC. If more than 300 MW but less than 600MW was offered, the price would be set at $250/MWh of the ORDC. If more than 600 MW was offered, the price would be set by the marginal resource of the supply stack.

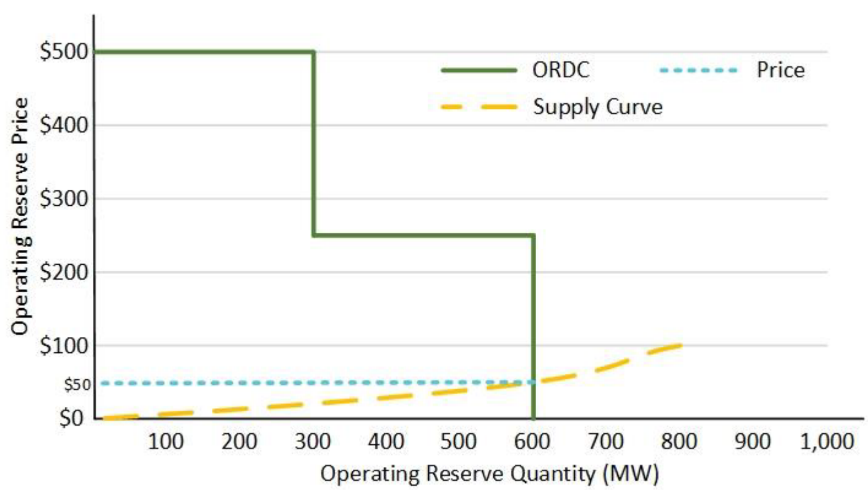


Figure 3-8 Price ORDC and Sufficient Offers

3.5 Settlement Price Floors and Caps

A price cap represents the highest price that can be used to settle the market. Conversely, a price floor is the lowest price can be. Since the opening of the wholesale electricity market, the price used for energy settlement has been capped between the negative Maximum Market Clearing Price (MMCP) and the MMCP; i.e., it must be between -$2,000 and $2,000.

In the renewed market, the MMCP continues to be the upper limit. However, a settlement floor price for energy is implemented, at -$100/MWh at present. The -$100/MWh settlement price floor is not applied to offers or bids. Resources are able to offer or bid at negative MMCP if they like.[11] The settlement floor results in more appropriate price for participants and consumers, while continuing to provide offer flexibility to resources.

3.6 Price Setting Eligibility

The marginal price at each location must be set by the marginal resource that is able to serve the next incremental increase in demand at that location. Resources cannot set the price if they cannot provide that incremental Mw. The following sections describe the constraints that may impact a given resource's ability to set prices.

3.6.1 NQS resources

Offer from an NQS resource are eligible to set energy or operating reserve prices if the resource is committed, and it is scheduled to at least its MLP by the scheduling algorithm.

3.6.2 Energy-Limited Resources

A resource's Maximum Daily Energy Limit (MaxDEL) is binding in DAM for a particular hour in the scheduling algorithm if the sum of energy scheduled from HE 1 up to that hour, plus any operating reserve scheduled for that hour, are more than or equal to the MaxDEL limit.

Similar conditions will be used in the PD calculation engine to determine if a MaxDEL is binding, except:

- If the look-ahead period only covers the current dispatch day, the amount of energy already generated so far during the day is considered.
- If the look-ahead period covers the current and next day, for the current day, the PD engine will use the MaxDEL submitted for that day and account for the energy already generated. For the next day, it will use the MaxDEL submitted specifically for that day.

If the MaxDEL is binding, the amount of energy available for scheduling in each hour is limited by the energy schedules produced for that hour by the scheduling algorithm, and the amount of energy and operating reserve available for scheduling in each hour is less than or equal to the MaxDEL limit minus the sum of the energy schedules up to that hour from the scheduling algorithm.

[11] Except for those such as dispatchable variable generators or flexible nuclear resources which have specific offer floors. Please see Market Rules Chapter 7 section 3.5.5 and Market Manual 4.1: Submitting Dispatch Data in the Physical Market, section 2.1.1.1.

3.6.3 Hydroelectric Resources

A hydroelectric resource faces additional limitation in setting prices:

- Minimum hourly output (MHO): Only offers above the MHO can set the energy or operating reserve prices. When a hydroelectric resource is scheduled for energy at or above its MHO in the UC, it will also be scheduled at or above its MHO in the pricing algorithm. If it receives a zero schedule in the UC, it will also receive a zero schedule in the pricing algorithm and cannot set the prices.
- Limited Number of Starts: If a hydroelectric resource has submitted a maximum number of starts per day, it cannot set the prices in hours following a shutdown as determined by the UC after its last available start.
- Minimum Daily Energy Limit (MinDEL): Hydroelectric resource offers above the submitted MinDEL can set the energy or operating reserve prices. In DAM, a MinDEL constraint is binding if the total energy scheduled throughout the day is less than or equal to the MinDEL. PD calculation engine will use similar conditions to determine if MinDEL constraint is binding, with the following differences:
  - If the look-ahead period spans only the current dispatch day, the energy already provided during the day before the pre-dispatch run is counted.
  - If the look-ahead period covers the current and next day, for the current day, the PD engine will use the MinDEL submitted for that day and account for the energy already generated. For the next day, it will use the MinDEL submitted specifically for that day.

  In both DAM and PD, if the MinDEL is binding in the UC scheduling algorithm, the resulting schedule in an hour serves as the minimum energy schedule in the pricing algorithm.

- Shared MaxDEL: The schedules calculated in the UC for hydroelectric resources with a binding shared MaxDEL determines the resource's price-setting eligibility.

  In the DAM UC scheduling algorithm, a shared MaxDEL constraint is binding if the sum of energy scheduled up to an hour throughout the day and operating reserve schedules in the hour are greater than or equal to the shared MaxDEL limit.

  It is similar in the pre-dispatch calculation engine, with the following differences:

  - If the look-ahead period spans only the current dispatch day, the energy already provided during the day before the pre-dispatch run is considered.
  - If the look-ahead period covers the current and next day, for the current day, the PD engine uses the shared MaxDEL submitted for that day and account for the energy already generated. For the next day, it uses the shared MaxDEL submitted specifically for that day.

  If the shared MaxDEL is binding in the scheduling algorithm, the following constraints apply for all resources on the shared forebay:

  - The available energy in the ED pricing algorithm for the hour is limited by the energy schedule in the UC scheduling algorithm; and
  - The total available energy and operating reserve for the hour is less than or equal to the shared MaxDEL minus total energy schedules up to that hour from the UC scheduling algorithm.

- Shared MinDEL: Hydroelectric resource offers above the shared MinDEL can set energy or operating reserve prices.

  In DAM, a shared MinDEL constraint is binding in the UC scheduling algorithm if total energy scheduled throughout the day is less than or equal to the shared MinDEL.

  It is similar in the pre-dispatch calculation engine except:

  - If the look-ahead period spans only the current day, energy already provided during the day before the pre-dispatch run is counted.
  - If the look-ahead period covers the current and next day, for the current day, the PD engine uses the shared MinDEL submitted for that day and account for the energy already generated. For the next day, it uses the shared MinDEL submitted specifically for that day.

  For all hydroelectric resources on a shared forebay, if the shared MinDEL is binding in the UC scheduling algorithm, the scheduling algorithm energy schedules are the minimum schedule in the ED pricing algorithm.

- Linked Hydroelectric Resources: Energy offer laminations for linked hydroelectric resources can set prices as per the schedules calculated in the UC scheduling algorithm. This means that the pricing algorithm schedules for linked hydro resources will be the same as the scheduling algorithm schedules with some wiggling room to ensure their ability to set price at their energy offer laminations.

3.7 Shadow Prices of Constraints

The ED pricing function produces shadow prices for all constraints that form LMPs. A shadow price for a constraint reflects the overall system cost savings of relaxing that constraint by a small amount. The ED produces the hourly (and/or interval) shadow prices, such as for:

- System energy balance (including under and over generation[12]);
- Transmission limits;
- Import or export limits;
- Net Interchange Scheduling Limit;
- System operating reserve requirements;
- Regional operating reserve requirements.

LMPs are calculated using the pricing formulas provided in Section 7, which specify how constraint shadow prices, marginal loss factors, and constraint sensitivities are used to determine an LMP and its components.

– End of Section –

[12] Under-generation refers to a generation scarcity condition when market demand exceeds available supply. These events can occur as a result of excess system demand or when the system has limited ramp-up capability to match rapidly increasing demand. Over-generation is the case when there is surplus generation in the system which exceeds market demand. These events can occur as a result of excess surplus baseload generation in the system or when the system has limited ramp-down capability to match rapidly decreasing demand.

4. DAM Calculation Engine Execution

4.1 Initialization

The DAM calculation engine performs a few initialization processes before it executes the three passes.

4.1.1 Selecting a Reference Bus

By default, the reference bus is located at the Richview Transformer Station in Toronto. However, if the default reference bus is out of service, another in-service bus is selected.[13]

4.1.2 Determining Islanding Conditions

Conditions can occur where a portion or portions of the grid become physically separated from the rest of the province due to transmission outages but remain stable with load continuing to be served. In this case, only the portion of the grid with the largest number of buses (referred to as the 'main island') is modelled by the pricing and scheduling algorithms. The following rules apply:

- Resources, imports and exports not in the main island are not modelled;
- Only load forecasts for the main island are applied; and
- If necessary, the reference bus is updated to a bus within the main island.

4.1.3 Applying Variable Generation Resource Tie-Breaking Logic

On a monthly basis, the IESO randomly determines a daily dispatch order for variable generation resources for each day of the month. This daily dispatch order is used to decide which variable generation resource is scheduled when two or more have energy offers that create no difference in cost to the market.

4.1.4 Preprocessing Pseudo-Unit Constraints

Any minimum or maximum generation constraints applied to the physical units (PUs) are converted to minimum or maximum constraints to a pseudo unit, if applicable.

4.1.5 Initial Scheduling Assumptions

For DAM to determine reliable and realistic schedules for the next day, it must reasonably assume what the initial schedules and operational commitments are for various resources before the start of the day. To do this, DAM uses the schedules and operational commitments determined for hour ending 24 of the current day as determined by the most recently available pre-dispatch run before the DAM engine starts.

---

[13] As will be discussed in Section 7, changing the Reference Bus does not change the resulting LMPs. LMPs will be the same regardless of where the Reference Bus is.

If an NQS resource has an operational constraint in HE24 of the current day, it will be considered in operation in HE1 of the dispatch day. Any remaining MGBRT for the resource will be respected.

The DAM calculation engine also needs an HE24 net import schedule across all interties so that the Net Interchange Scheduling Limit (NISL) is not violated. It is determined based on the intertie schedules from the most recent pre-dispatch run before the DAM engine runs.

4.2 Pass 1: Market Commitment and Market Power Mitigation

Pass 1 performs ex-ante market power mitigation and determines hourly resource schedules and operational commitments. Pass 1 includes one or more runs of the scheduling and pricing algorithms. The number of runs depends on the results of the ex-ante market power mitigation process.

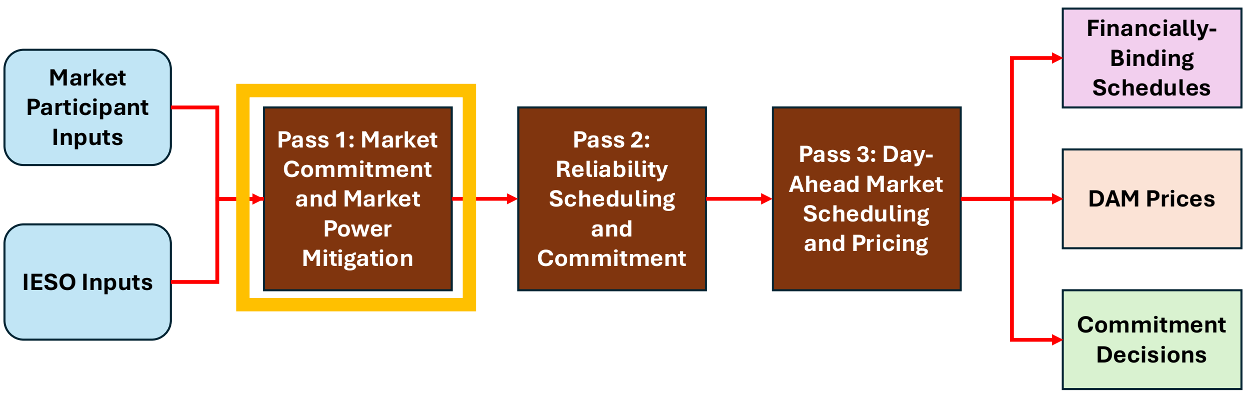


Figure 4-1 DAM Pass 1 Market Commitment and Market Power Mitigation

Schedules and commitments are calculated based on offers from generators, importers and virtual suppliers[14] to meet the IESO's average demand forecast for non-dispatchable loads and operating reserve requirements, bids of virtual demand, dispatchable loads, Price Responsive Loads (PRLs), Hourly Demand Response (HDR) resources, and exports[15]. The schedules and commitment decisions produced by Pass 1 are used as inputs into Pass 2.

As depicted in Figure 4-1 the ex-ante market power mitigation process for energy and operating reserve is embedded in Pass 1.

- A conduct test on offers submitted for resources is first conducted to assess if a resource has offered above its reference level by a certain amount or percentage.
- If it is the case on any resource, the Reference Level Scheduling and Reference Level Pricing algorithms replace the offers with applicable reference levels. The LMPs of the As-Offered

[14] Virtual transactions allow registered market participants to transact virtual energy bids and offers and be settled on zonal price differences between the day-ahead and real-time markets. For the purposes of virtual trading, the IESO has designated nine virtual trading zones. Transactions are scheduled within these zones and each zone will have its own price, determined as the load-weighted average of all load resource LMPs in the zone. For more information on virtual transactions, see the **eLearning course** and Market Rules Chapter 7: System Operations and Physical Markets.

[15] Storage resources which withdraw energy can be registered as either a dispatchable load or a price responsive load, so are included when references are made to these participation types within this document.

results is then compared to the LMPs from the reference level results: the price impact failed if the As-Offered LMP at any resource is greater than the Reference Level LMP by a certain amount or percentage.

- If any resource does fail, Mitigated Scheduling and Mitigated Pricing runs use reference levels in place of any offers which failed both the conduct and impact tests. DAM pass 2 and 3 need LMPs and schedules when using reference levels for resources that are flagged by MPM as mitigated. Note that even if only one resource is mitigated, this could lead to changes in the entire schedules and LMPs.

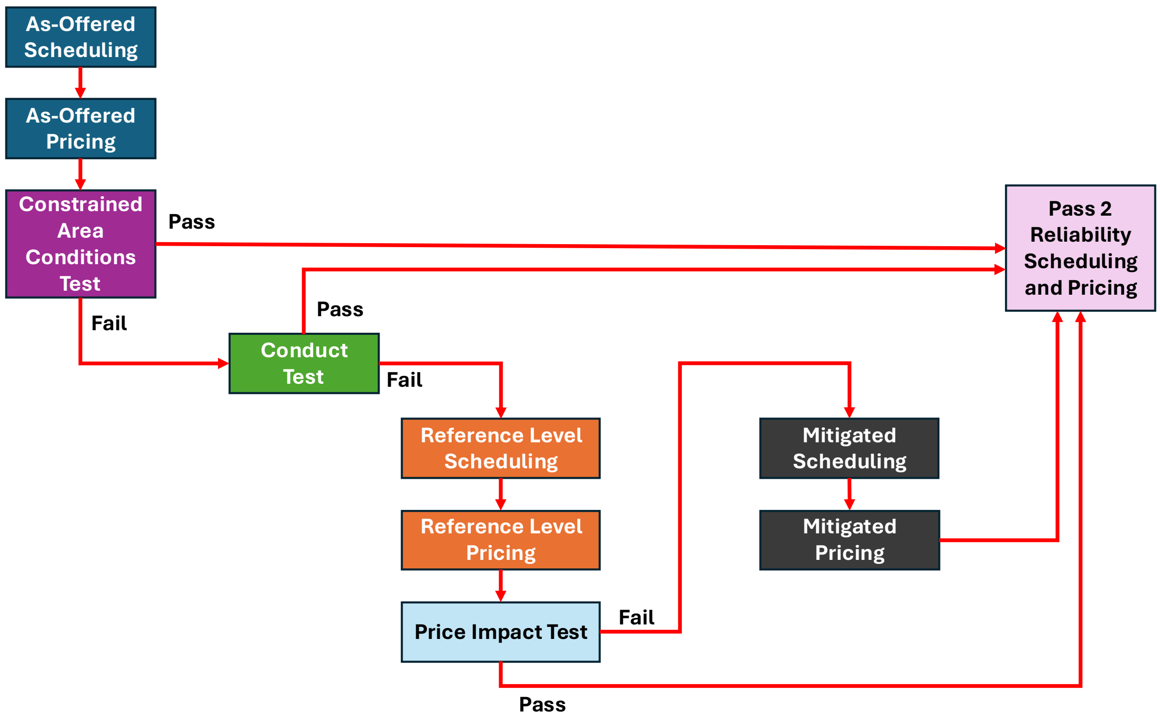


Figure 4-2 - Steps in DAM calculation engine Pass 1

4.2.1 As-Offered Scheduling

As-Offered Scheduling determines an initial set of energy and operating reserve resource schedules and commitments (Section 3.1). The DAM calculation engine models both financial and non-financial dispatch parameters submitted by market participants. The financial dispatch parameters include:

- Hourly energy bids for exports, virtual buyers, PRLs, dispatchable loads, and HDR resources;
- Hourly energy offers for imports, virtual suppliers, dispatchable generators[16] (including variable generation and storage resources proposing to inject), and non-dispatchable generators;
- Hourly start-up offers and speed no-load offers for NQS generation resources; and

[16] Dispatchable storage resources which inject energy and variable generators are included going forward when references are made to dispatchable generations within this document.

- Hourly offers for operating reserves.

The non-financial dispatch parameters include:

- Energy ramp rates for all energy suppliers;
- Ramp rates, and reserve loading point for all operating reserve suppliers except dispatchable loads and dispatchable storage resource registered to withdraw;
- MLP, MGBRT (minimum generation break run time), MGBDT (minimum generation break down time), maximum number of starts per day, thermal state, and ramp up energy to MLP profile for NQS resources;
- Ramp up energy to MLP profile for the combustion and steam turbines; indication of whether the combustion turbine will operate in the single-cycle mode; indication of whether the PSU can provide ten-minute operating reserve while scheduled in its duct firing region; and the MLP of the combustion turbine and steam turbine;
- MP or the IESO submitted variable generation forecast quantity;
- Maximum Daily Energy Limit (MaxDEL) for Energy-limited resources;
- Forbidden regions, Minimum Daily Energy Limit (MinDEL), MaxDEL, minimum hourly output, hourly must run, maximum number of starts per day for Hydroelectric resources;
- time lag and MWh ratio for linked resources;

As-Offered Scheduling also uses IESO inputs, including:

- Reliability requirements and security limits, such as operating reserve requirements, and intertie limits (including flow limits and the Net Interchange Scheduling Limit);
- Resource minimum and maximum constraints; generators constrained on for reliability; and regulation constraints;
- Constraint violation penalty curves (see Section 3.4);
- Demand forecasts for the four demand forecast areas (see the IESO training document **Four-Area Demand Forecasts for Ontario**); and
- The network model that includes the power system model, status of power system equipment, lists of contingencies, and lists of monitored equipment.

The outcomes of As-Offered Scheduling are unit commitments for NQS generation and schedules for energy for all market participants, including generators, Dispatchable loads, PRLs, HDR resources, Virtual transactions, and Imports and exports.

Operating reserve schedules are also produced for Dispatchable generation resources, Dispatchable loads, and Imports/exports (for 30R operating reserve).

The outcomes of Pass 1 As-Offered Scheduling are used by the subsequent Pass 1 As-Offered Pricing step.

4.2.2 As-Offered Pricing

As-Offered Pricing follows the pricing algorithm processes. As-Offered Pricing uses the same as-offered dispatch data and marginal loss factors used in As-Offered Scheduling. It also uses the same IESO data inputs except it uses pricing constraint violation penalty curves. As-Offered Pricing uses the operational commitment statuses and resource schedules determined in As-Offered Scheduling to calculate prices in accordance with price-setting eligibility rules.

The outcomes of As-Offered Pricing are a set of shadow prices for constraints which are used to calculate energy and operating reserve LMPs. The LMPs and related shadow prices are used in the Constrained Area Conditions Test (see next section) and, if necessary, in the price impact test. Unless the price impact test is failed, the LMPs calculated for energy-limited resources in As-Offered Pricing will be used in Pass 2 (see Section 4.3.1 for discussion of how Pass 2 processes energy-limited resources). LMPs from As-offered pricing are not financially binding.

4.2.3 Constrained Area Conditions Test

The objective of Constrained Area Conditions Test is to identify when and where competition is limited due to transmission congestion, and to determine which resource, if any, should undergo the conduct test. The conditions that can limit competition are:

- Local market power (energy)
- Global market power (energy)
- Local market power (operating reserve)
- Global market power (operating reserve)

4.2.3.1 Local Market Power (Energy)

Depending on how frequently the transmission constraints bind in an area, that area is classified as one of the following:

- Narrow Constrained Areas (NCAs): Areas where congestion is expected to occur relatively frequently. Resources in these areas are actively monitored for market power; and
- Dynamic Constrained Areas (DCAs): Areas where congestion is expected to occur when certain events materialize. Resources in these areas are only tested when DCA designation is made by the IESO for the duration of the event. An example is increased congestion in an area due to a transmission outage.

If at least one transmission constraint for the NCA or DCA is binding in As-Offered Pricing, all resources in that constrained area will undergo the conduct test.

A Broad Constrained Area is where the congestion component of the resource's LMP is greater than $25, and the resource is in an NCA or an DCA that has at least one binding transmission constraint.

4.2.3.2 Global Market Power (Energy)

Global market power exists if no additional imports can be scheduled and if the Intertie Border Price (IBP) at the reference interties is above $100/MWh. In this case, market participants with resources within Ontario that can meet incremental demand and have an energy offer price over $25/MWh, are tested for global market power.

4.2.3.3 Local Market Power (Operating Reserve)

Local market power in the operating reserve market is tested for if a reserve area has a non-zero minimum operating reserve requirement. Resources offering operating reserves at a price above $5/MWh in the area is subject to the conduct test unless the resource is also located in a reserve area with a binding maximum operating reserve constraint.

4.2.3.4 Global Market Power (operating reserve)

The test for global market power in the operating reserve market occurs if an operating reserve LMP is greater than $15/MWh for any class of operating reserve. All resources offering that class of operating reserve at a price above $5/MWh are tested, except resources in a reserve area with a binding maximum operating reserve constraint.

4.2.3.5 Constrained Area Condition Test Outputs

The outcomes of the Constrained Area Conditions Test are:

- A list of all resources subject to the conduct test. A different set of resources will be identified for each market power condition tested. This list is also used in the Settlement Mitigation process[17]; and
- Constrained area test conditions prevailing for each resource during each hour of the next dispatch day.

4.2.4 Conduct Test

The conduct test occurs if the Constrained Area Condition Test identified resources to be tested.

The inputs to the conduct test include reference levels and conduct thresholds. Conduct thresholds are the allowable tolerances set by the IESO by which a dispatch parameter can deviate from its reference level without failing the test.

The conduct test determines if submitted financial dispatch data for a resource differ from their reference levels by more than the conduct threshold. If a resource qualifies for more than one conduct test, the test with the most stringent conduct threshold levels will be performed.

The following energy financial dispatch data will be evaluated by the energy conduct test:

- Energy offer;
- Energy offer above and below MLP (GOG-eligible NQS resources only);
- Start-up offer (GOG-eligible NQS resources only); and
- Speed no-load offer (GOG-eligible NQS resources only).

The following financial dispatch data will be evaluated for resources that qualify for operating reserve conduct testing:

- Operating reserve offer;
- Start-up offer (GOG-eligible NQS resources only);
- Speed no-load offer (GOG-eligible NQS resources only); and
- Energy offers for the range of production up to MLP (GOG-eligible NQS resources only).

If one or more financial dispatch parameter values for any resource fail the conduct test, the impact test occurs. Otherwise, resource commitments, schedules and prices produced by the As-Offered Scheduling and As-Offered Pricing runs are passed to Pass 2.

[17] For information on Settlement Mitigation, please see Market Manual 5.5: IESO-Administered Markets Settlement Amounts and Market Rules, Chapter 9: Settlements and Billing.

Conduct test outputs include:

- A list of resources that failed the conduct test. This list are used as an input to the price impact test; and
- Financial dispatch parameters that failed the conduct test. These are replaced by relevant reference level values in calculating Reference Level schedules, commitments and LMPs.

4.2.5 Reference Level Scheduling

Reference Level Scheduling only takes place if one or more financial dispatch data for any resource failed the conduct test. It differs from As-Offered Scheduling in that it uses reference level dispatch data for any financial dispatch data that failed the conduct test.

Reference Level Scheduling determines non-financially binding schedules and commitments, which are subsequently used as in Reference Level Pricing.

4.2.6 Reference Level Pricing

Reference Level Pricing uses reference level values for any financial dispatch data that failed the conduct test. Reference Level Pricing price-setting eligibility considers Reference Level Scheduling results.

Reference Level Pricing determines shadow prices for Reference Level LMP calculation. Reference Level LMPs for energy and operating reserve are used as in the Price Impact Test.

4.2.7 Price Impact Test

The price impact test is run if one or more dispatch parameters failed the conduct test. This test compares the As-Offered Pricing LMPs with Reference Level Pricing LMPs for each resource that failed the conduct test. A resource fails the price impact test if its As-Offered Pricing LMP is greater than its LMP from Reference Level Pricing by a specified threshold. In this case, Mitigated Scheduling and Mitigated Pricing will occur. Otherwise, the operational commitments and prices produced by As-Offered Scheduling and As-Offered Pricing are used as inputs to Pass 2.

For a resource that has failed a price impact test, the revised set of dispatch data is determined as follows:

- If a resource failed a price impact test for energy, the dispatch data that failed the energy conduct test will be replaced with applicable reference levels;
- If a resource failed a price impact test for operating reserve, the dispatch data that failed the operating reserve conduct test will be replaced with applicable reference levels;
- If an NQS resource failed a price impact test, the commitment cost values that failed the conduct test will be replaced with the resource's applicable reference level for that hour. Any commitment cost parameters that failed the conduct test will also be replaced with the resource's applicable reference level for all hours before the hour when the NQS resource reaches its MLP;
- If a resource in an NCA or a DCA fails a price impact test, the offer data of all resources that failed the corresponding conduct test within that area are replaced with the resource's applicable reference level for that hour;

- If an NQS resource in an NCA or a DCA fails a price impact test in any hour, the commitment cost parameters for all NQS resources in that area that failed the corresponding conduct test are replaced with the resource's applicable reference level for that hour. For any prior hours, any commitment cost parameters of NQS resources in that area that failed the conduct test are replaced with the resource's applicable reference level in those hours;
- All resources within a reserve area with a non-zero minimum operating reserve requirement are tested for market power. The conduct test checks the resources' operating reserve financial offers; Energy offer up to MLP; Speed-no-Load offer; and Start-up offer. All offer parameters that failed the conduct test are replaced by their applicable reference levels if one or more resources within the same reserve area failed the operating reserve price impact test; and
- If an NQS resource failed the price impact test for local market power for operating reserve in any hour, the commitment cost parameters for all NQS resources in the same reserve area with a non-zero reserve minimum requirement that failed the corresponding conduct test are replaced with the resource's applicable reference level for that hour. For any prior hours, any commitment cost parameters of NQS resources that failed the conduct test will be replaced with the resource's applicable reference level in those hours.

Outputs of the price impact test include the following:

- The set of resources that failed the price impact test and the relevant condition; and
- A revised set of offer data which replaces financial dispatch data that failed the conduct test with applicable reference levels.

4.2.8 Mitigated Scheduling

Mitigated Scheduling will occur if at least one resource fails the price impact test. The scheduling algorithm is described in Section 3.1. Mitigated Scheduling differs from As-Offered Scheduling in that for a given constrained area where at least one resource fails the price impact test, it uses reference level values for any financial dispatch data that failed the Conduct Test for all resources within that area.

If Mitigated Scheduling is performed, it determines NQS operational commitment statuses and schedules which are used as inputs into Mitigated Pricing.

4.2.9 Mitigated Pricing

Mitigated Pricing occurs after Mitigated Scheduling is performed. The pricing algorithm is described in Section 3.1. Mitigated Pricing differs from As-Offered Pricing in that it uses mitigated offers for any financial dispatch data that failed the conduct test. Mitigated Pricing applies price-setting eligibility by considering the Mitigated Scheduling results.

Mitigated Pricing determines an initial set of LMPs which are transferred to Pass 2 where they are used to optimize energy-limited resources across the day.

4.3 Pass 2: Reliability Scheduling and Commitment

Pass 2 schedules available physical resources to meet forecast peak non-dispatchable demand and IESO-specified operating reserve requirements. Pass 2 may make additional NQS operational commitments, increase imports, or decrease exports if needed. Pass 2 provides a set of resource schedules and operational commitments to Pass 3; LMPs are not calculated in Pass 2.

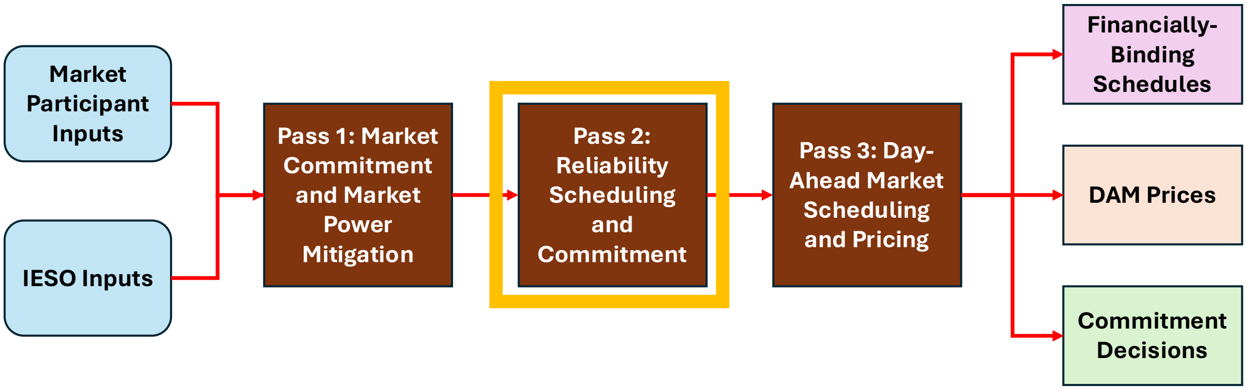


Figure 4-3 DAM Pass 2 Reliability Scheduling and Commitment

4.3.1 Reliability Scheduling

Pass 2 Reliability Scheduling performs a run of the scheduling algorithm as described in Section 3 with following features: An hourly peak demand forecast is used (instead of an average demand forecast in Pass 1);

- The objective of the Pass 2 UC function is to minimize the cost of additional NQS operational commitments rather than maximizing the gains from trade;
- Virtual transactions and PRL bids are excluded;
- PRLs and dispatchable loads that did not submit a bid are considered as NDL and included in the non-dispatchable demand forecast; and
- The IESO's centralized variable generation forecast is used.

Inputs to Reliability Scheduling include dispatch data, LMPs and schedules from Pass 1. Dispatch data from Pass 1 for any specific dispatchable resource could be as-offered or mitigated dispatch data, depending on the outcome of market power mitigation.

The treatment of dispatch data in Pass 1 and Pass 2 differs as follows:

- The energy and operating reserve offer price for internal incrementally dispatchable supply and load resources are set to a small value so the cost of incremental energy from these resources does not materially contribute to the objective function. For example, a dispatchable generation resource energy offer at $50/MWh will be replaced with $0.1/MWh. This is done because Pass 2 is focussed on determining if it is economic to commit additional NQS and/or imports, or reduce exports; and
- The price evaluation for energy and operating reserve from Energy Limited Resources (ELRs) depends on whether the associated quantity was scheduled in Pass 1:
    - For energy scheduled in Pass 1, the price evaluated is intended to maintain that schedule unless the total cost is reduced by shifting its output to another hour.

    - For energy not scheduled in Pass 1, the offered price of the unscheduled energy is compared to the price at the resource's location as determined from Pass 1. This reflects the cost of scheduling additional energy, as a measure against the cost of committing additional resources. This method for unscheduled energy is only applied when the resource's maximum daily energy limit is binding in Pass 1. Otherwise, unscheduled energy will be treated in the same way as other internal incrementally dispatchable energy. This treatment also applies to hydroelectric resources with a shared maximum daily energy limit.

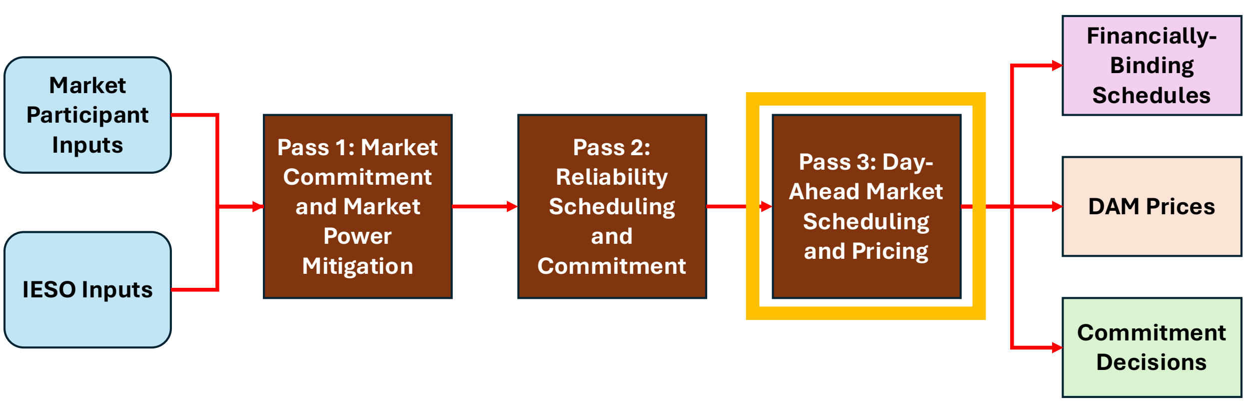
Reliability Scheduling uses the same constraints as used in As-Offered Scheduling, with the following additions:

- <u>Constraints enforcing scheduling and commitment decisions from Pass 1, such as</u>
    - Import schedules do not decrease from Pass 1;
    - Export schedules do not increase from Pass 1; and
    - NQS generation resources committed in Pass 1 can't be de-committed.
- <u>Constraints relating to ELR scheduling variables</u>: For ELRs or hydroelectric resources with a shared maximum daily energy limit, the energy schedule for the resource must be equal to the sum of its corresponding schedule in Pass 1 and the quantity from the unscheduled portions.

The outcomes of Pass 2 include energy and operating reserve resource schedules for all resource types (except PRLs and virtual energy traders who are not modelled), and a set of NQS commitments.

4.4 Pass 3: DAM Scheduling and Pricing

Pass 3 produces financially binding schedules and settlement-ready LMPs. These schedules are calculated to meet the IESO's average hourly non-dispatchable demand forecast and operating reserve requirements. Pass 3 evaluates offers from all participants, including generators, importers, exporters, virtual traders, dispatchable loads, PRLs, and HDR resources. Pass 3 also uses the NQS operational commitment decisions from Passes 1 and 2 and import and export schedules determined by Pass 2.



4.4.1 DAM Scheduling

DAM Scheduling uses the IESO's average non-dispatchable demand forecast and operating reserve requirements as described in Section 3. Because Pass 3 doesn't add new NQS commitments, it uses the ED function instead of the UC function.

In DAM Scheduling, the ED function is the same as the UC function described in Section 3.1, except:

- The operational commitment decisions determined in Passes 1 and 2 are used. NQS that have not been committed are not considered;
- Start-up costs and speed-no-load costs on those NQS that are already committed are not considered;
- Import schedules can't decrease from Pass 2; and Export schedules can't increase from Pass 2.

DAM Scheduling uses final dispatch data from Pass 1, which can include mitigated values.

The outcome of DAM Scheduling includes:

- Financially binding DAM schedules for energy and operating reserves: all market participants will receive their DAM schedules. Non-zero schedules to HDR resources form the basis for day-ahead standby notices;
- Hourly Commitments: DAM hourly NQS commitment statuses are used to issue commitments in the pre-dispatch timeframe; and
- Non-Dispatchable Load (NDL) Schedules: DAM schedules at all NDL delivery points will be used to calculate the Load Forecast Deviation Adjustment.[18]

4.4.2 DAM Pricing

DAM Pricing determines settlement-ready LMPs. DAM Pricing applies the pricing algorithm as described in Section 3 to meet the IESO's average non-dispatchable demand forecast and operating reserve requirements.

DAM Pricing uses Pass 1 the same final dispatch data and system data as used in the DAM Scheduling run. DAM Pricing also uses the commitments determined by Pass 2 and the schedules determined by DAM Scheduling for price setting purpose.

In DAM Pricing, additional constraints include:

- Import schedules can't decrease from Pass 2; and
- Export schedules can't increase from Pass 2.

Constraint violation penalty curves for Pricing are used, instead of Constraint violation penalty prices for Scheduling (see Section 3.4).

The outcome of DAM Pricing are settlement-ready LMPs. The LMP pricing formulas are discussed in Section 7.

---

[18] For more information on non-dispatchable load pricing, see the Renewed Market Prices Guide

DAM Pricing also produces the shadow prices for constraints such as:

- Energy balance;
- Security limits;
- Import or export limit;
- Net Intertie Scheduling Limit;
- Total synchronized ten-minute, total ten-minute, and total thirty-minute operating reserve requirement;
- Minimum and maximum regional ten-minute and thirty-minute operating reserve requirements.

4.4.3 LMP Calculation

LMPs are calculated at each stage, including As-Offered Pricing, Reference Level pricing, Mitigated Pricing, and DAM pricing runs. Settlement-ready LMPs, however, are calculated at DAM Pricing. The pricing formulas used in LMP calculation are discussed in Section 7.

– End of Section –

5. Pre-dispatch Calculation Engine Execution

5.1 Pre-dispatch Look-Ahead Period

The pre-dispatch optimizes commitment and schedules over the future hours (called the ‘time horizon’). As shown in Figure 5-1, the pre-dispatch run starting at 20:00PM(EST) is the first run of including all remaining hours of today and all hours of tomorrow. Every hour that it runs after 20:00PM looks ahead one less hour until 20:00PM EST the next day is reached, at which point the cycle repeats.

Figure 5-1 pre-dispatch look-ahead period

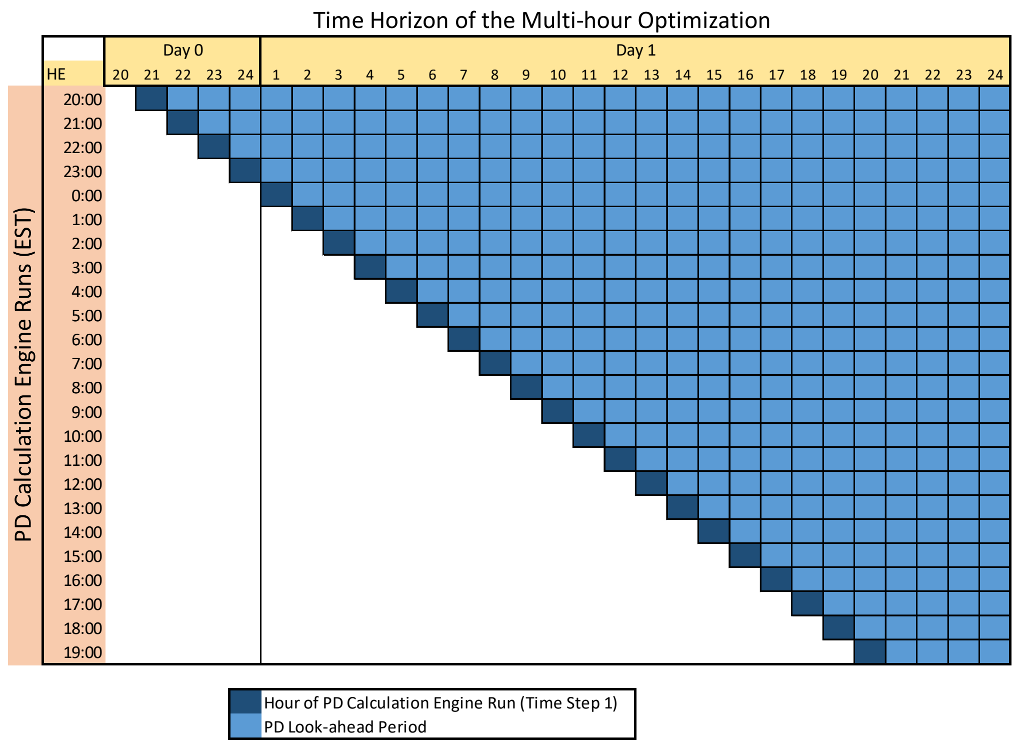


Figure 5-1 pre-dispatch look-ahead period

5.2 Initialization

The pre-dispatch performs several initialization procedures, some of which are similar to the DAM:

- Select a reference bus and determine islanding conditions as described in Section 4.1.1 and Section 4.1.2;
- Apply variable generation resource tie-breaking logic as described in Section 4.1.3; and
- Pre-process minimum and maximum generation constraints applicable to PSUs as described in Section 8.3.

Additional initialization procedures are discussed in the following subsections.

5.2.1 Initial Scheduling Assumptions

The pre-dispatch uses data specifying initial resource statuses. These form the starting point from which the pre-dispatch optimizes the rest of its look-ahead period.

5.2.1.1 Initial Resource Schedules

Initial resource schedules for time-step 1 are determined based on:

- A telemetry snapshot taken five minutes before the pre-dispatch run; and
- The anticipated schedule

If a NQS resource is not committed in current hour (see next section), it will receive an initial schedule of zero; otherwise, the NQS resource receives an initial schedule consistent with the most recent real-time advisory schedule.

The initial schedules are used to identify which resources are online and to respect their constraints, such as ramp rates, cascade resource scheduling, and energy limited resource schedules.

5.2.1.2 Initial NQS Commitment Status, Number of Hours in Operation and Number of Hours Down

The NQS commitment status for the current hour is determined from its commitment status in the previous pre-dispatch run. For example, NQS commitment status for HE21 at the 20:00 PD run is determined by looking at the results of the PD run at 19:00.

An exception to this is if the resource is kept online in RT at or above its MLP after the NQS resource has completed its MGBRT, the real-time advisory schedule determines the commitment status.

The remaining MGBRT and MGBDT based on the resource’s time up or time down at the end of the current hour are respected:

- The initial hours in operation define the number of consecutive hours at the end of the current hour for which the resource has been, and is anticipated to be, operating at or above its MLP. It will be set to zero for resources that aren’t committed; and
- The number of hours down defines the number of consecutive hours at the end of the current hour when the resource has not been, and is not anticipated to be, operating at or above its MLP. It will be set to zero for resources that are committed.

5.2.1.3 Initial Net Interchange Schedule

The pre-dispatch, like the DAM, must respect the net interchange scheduling limit (normally at 700MW). As such, it requires an initial net interchange schedule value to ensure that changes across the hours do not exceed the limit.

5.2.1.4 Initial Number of Starts That Has Been Completed for NQS and Hydroelectric Resources

NQS and hydroelectric resources can submit a maximum number of starts per day. The number of starts allowed for the future hours must account for the number of starts it has already completed in the current day. When the look-ahead horizon spans two days, only starts that have happened in the current day (day 0) are counted. In other words, the initial number of starts is only considered for day 0.

5.2.1.5 Cumulative Energy Production for Energy-Limited and Hydroelectric Resources

The actual generation up to the current hour in the current day plus the energy scheduled for future hours is the maximum energy limit for the day. It reduces the amount of energy that must be scheduled to satisfy a hydroelectric resource's minimum daily energy limit or to satisfy shared daily energy limits.

5.2.1.6 Past Hourly Production for Linked Hydroelectric Resources

For linked hydroelectric resources, the past hourly production (based on telemetry) of upstream resources is considered when scheduling downstream resources. Please note that any production resulting from an operating reserve activation will not be included.

Figure 5-2 is an example where an upstream resource has a time lag of 3 hours to a downstream resource and the resources have a one-to-one MWh ratio (i.e. 1Mw produced at the upstream resource can produce 1MW at the downstream resource). The pre-dispatch calculation engine will schedule the downstream resource in the first two hours of the pre-dispatch look-ahead period based on the actual output of the upstream resource in the two hours before the pre-dispatch run.

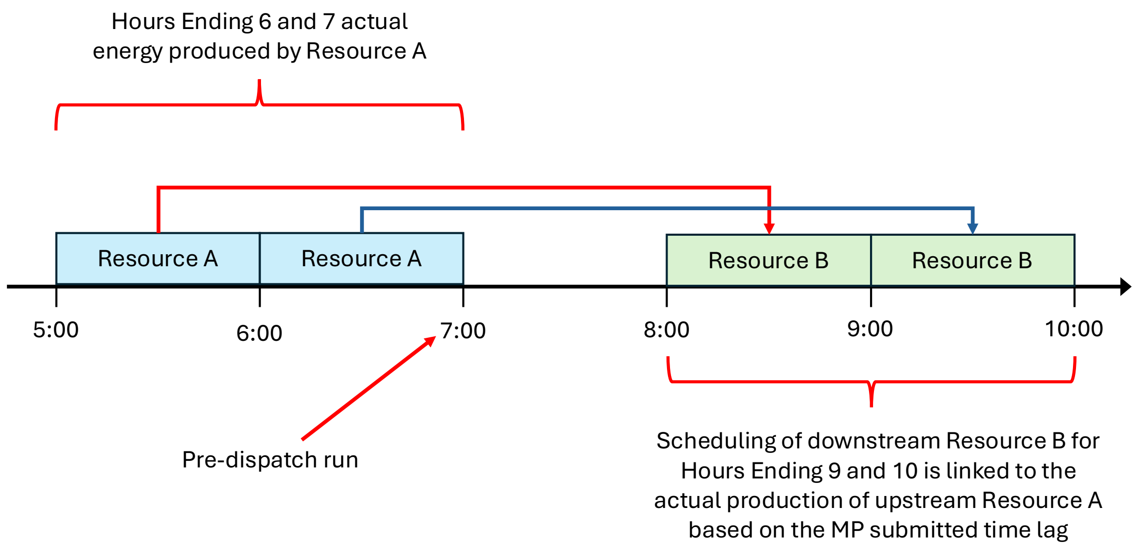


Figure 5-2 NQS Status and Time Steps

Initial upstream resource schedules are the average value of the resource's advisory schedules from the last real-time calculation engine run. If these advisory schedules reflect an operating reserve activation, the schedule determined by the real-time calculation run before the activation is used.

5.2.2 Selection of Daily Dispatch Data for the Pre-dispatch Look-Ahead Period

When the pre-dispatch look-ahead period covers hours in the same day, the daily dispatch data submitted for that day is used.

When the pre-dispatch look-ahead period spans for two days (as for the 20:00 to 23:00 EST runs), some daily dispatch data applies to the day for which it was submitted, while other dispatch data submitted for the second day applies to both days, as showed below:

Next day dispatch data applied to both days	Current day and next day dispatch data apply to each respective day
Linked resources, time lag and MWh ratio	Forbidden regions
MLP	MaxDEL
MGBRT	MinDEL
MGBDT	Maximum number of starts per day
Lead time	
Ramp up energy to MLP and ramp up hours to MLP	
Daily Energy Ramp Rate	

Table 5-1 Selection of daily dispatch data across two dispatch days

There are two exceptions:

- When an NQS resource receives a commitment before the 20:00 EST run and that commitment is not yet complete, the MLP and MGBRT of the current dispatch day will be applied until the NQS is OFF, even if that isn't until the next day;
- The second exception relates to the single-cycle mode flag for PSUs. This will be discussed in Section 8.5.

5.2.3 Selection of Start-Up Cost for NQS Resources with DAM Commitments

The pre-dispatch can advance the start of a DAM NQS commitment. Whether or not the start-up costs is used for a commitment advancement depends on whether the commitment is extended inside or outside of the 'advancement window'. The advancement window are the total hours of the resource's MGBRT and its hot MGBDT[19] minus one hour before the first hour of the DAM commitment.

Before each PD run, the start-up cost to evaluate the advancement of a DAM commitment is selected based on:

- the higher value of the DAM or pre-dispatch start-up cost in the hour of advancement if it is within the advancement window; or

[19] MGBDT dispatch data is submitted with values for hot, warm and cold starts.

- the pre-dispatch start-up cost in the hour of advancement if it is before the advancement window begins.

Figure 5-3 shows an example of an advancement window for a NQS resource with a DAM operational commitment between HE17 to HE20. If the pre-dispatch start-up cost in the advancement period is greater than the DAM start-up cost, the pre-dispatch start-up cost is used. Otherwise, the DAM start-up cost is used.

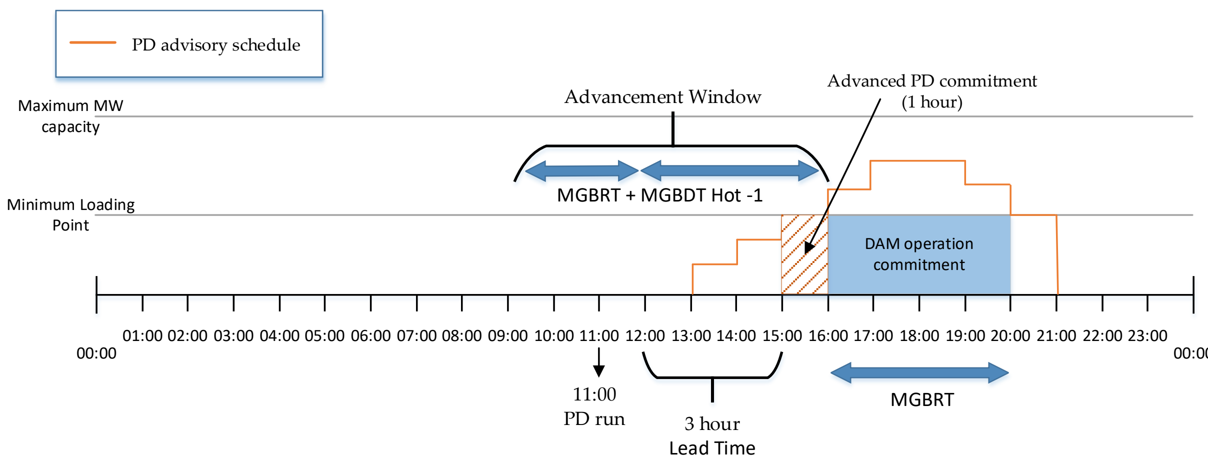


Figure 5-3 Pre-dispatch NQS scheduling – Pre-dispatch advancements

5.2.4 Evaluation of NQS Thermal State

The pre-dispatch determines the thermal state of a NQS resource based on when it was last at its MLP before desynchronization. If an NQS resource is currently offline, a thermal state (hot/warm/cold) is assigned for each future hour using its MGBDT (hot/warm/cold) parameters.

The NQS resource's thermal state is needed for several parameters:

- Hot/warm/cold MGBDT: MGBDT is the number of hours a resource needs to reach its MLP after re-synchronizing;
- Hot/warm/cold lead time: Lead time is the number of hours a resource needs to start, synchronize and reach MLP;
- Hot/warm/cold start-up cost: Start-up cost is the cost a unit incurs to reach its MLP; and
- Hot/warm/cold Ramp up energy to MLP profile: it is the energy that the resource is expected to inject in each hour from the time of synchronization to the time it reaches its MLP.

A second start involves bringing a unit up, shutting it down, and then starting it up again within the pre-dispatch look-ahead period. A decision to shut down the unit in a specific hour determines the anticipated thermal state in future hours. These decisions are made simultaneously, and lead time is not considered.

5.3 Pre-Dispatch Scheduling Process

PD Scheduling Process uses market participant and IESO inputs to determine a set of resource PD schedules and commitments. These schedules and commitments are calculated to meet the IESO's hourly non-dispatchable forecast demand and the demand from dispatchable loads, HDR resources and exports. PD Scheduling Process also calculated PD LMPs.

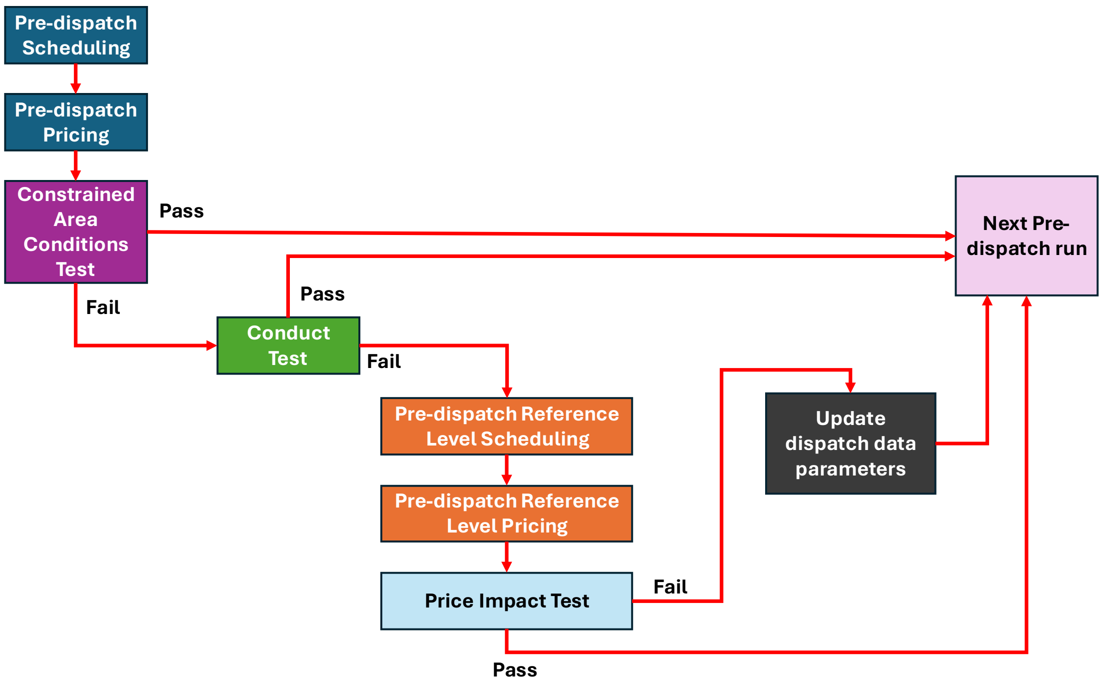


Figure 5-4 Steps in Pass 1 of the Pre-dispatch calculation engine

The steps of pre-dispatch scheduling process are shown in Figure 5-4. Pre-dispatch assesses whether ex-ante Market Power Mitigation need to be performed. If both the conduct and price impact tests are failed for a resource, the relevant dispatch data input for the resource is replaced with its corresponding reference levels. These reference levels are used in the subsequent pre-dispatch runs and in real-time. The steps are discussed in the following subsections.

5.3.1 Pre-Dispatch Scheduling

Pre-dispatch scheduling determines advisory schedules for all dispatchable resources, non-dispatchable generation resources, and intertie transactions. It also determines pre-dispatch commitments for eligible NQS resources. It uses as-offered dispatch data except for any dispatch data that was mitigated in a previous pre-dispatch run. The scheduling algorithm is described in section 3.1.

Pre-dispatch scheduling requires various inputs from market participants, IESO, and results from prior runs of the DAM, pre-dispatch, and real-time calculation engines. Pre-dispatch scheduling uses all applicable inputs identified in Section 4.2.1, except for dispatch data for PRLs and virtual transactions.[20]

Pre-dispatch scheduling uses the hourly demand forecasted for each of the four IESO demand areas and for each time-step of the pre-dispatch look-ahead period. The IESO can specify whether the average or peak demand forecast is used for a given hour within the pre-dispatch look-ahead period.

Initial scheduling assumptions represent the state of each resource at the start of each pre-dispatch run (for more details, see Section 5.2).

The pre-dispatch evaluates all intertie transactions that have been scheduled in DAM. It also assesses day-at-hand intertie transactions for the first two upcoming hours of the run. This logic is illustrated in Figure 5-5 for the pre-dispatch run that starts at 05:00 EST.

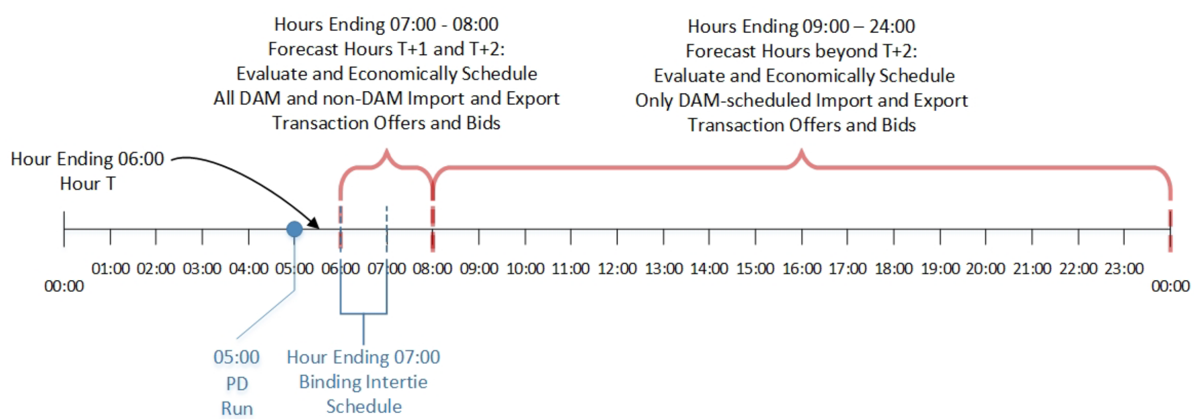


Figure 5-5 Scheduling of intertie transactions in Pre-dispatch calculation engine

DAM commitments create a minimum constraint for an NQS resource to at least its MLP for its MGBRT hours during the hours immediately following the ramp up hours to MLP. The pre-dispatch respects DAM commitments, and may also make additional and revised commitments

- Advancement of a DAM commitment: Pre-dispatch can advance a DAM commitment by starting the resource earlier;
- Extension to existing commitment: Pre-dispatch can extend a resource's DAM or pre-dispatch commitments beyond its MGBRT hours. These extensions are issued on an hour-by-hour basis for one hour at a time; and
- Stand-alone commitment: Pre-dispatch can also issue a stand-alone commitment which is neither an advancement nor an extension of a DAM/PD commitment.

Pre-dispatch NQS commitments from prior pre-dispatch calculation engine runs create a minimum constraint for the resource to at least its MLP for the time-steps covered by the commitment.

The results of the pre-dispatch MPM process are used in subsequent pre-dispatch runs. if triggered, an as-offered financial dispatch data parameter might be mitigated to its reference level, which

[20] PRLs are treated as non-dispatchable load beyond the DAM. Virtual transactions are only considered in the DAM.

replaces that as-offered financial dispatch data parameter for the given hour in the current and every subsequent run of the pre-dispatch, unless it is resubmitted with a price below the reference level.

Pre-dispatch Scheduling produces advisory schedules, NQS commitments, and intertie schedules. The pre-dispatch intertie schedules for the first hour of the pre-dispatch are the schedules used by the real-time calculation engine (subject to intertie check-out with neighboring jurisdictions and curtailments). Pre-dispatch scheduling also produces binding minimum constraints for hydroelectric resources, which in RT the hydroelectric resource must be scheduled to a minimum quantity to respect its minimum daily energy limit.

5.3.2 Pre-Dispatch Pricing

Pre-dispatch Pricing produced Scheduling PD LMPs and associated shadow prices for constraints. The pricing algorithm is described in Section 3.

Pre-dispatch Pricing uses the following same inputs as Pre-dispatch Scheduling:

- the same as-offered and mitigated dispatch data;
- the same initial scheduling assumptions, real-time telemetry data, and DAM import and export schedules;
- the same NQS commitment statuses and resource schedules determined; and
- the same IESO data inputs (except it uses constraint violation penalty curves for pricing instead of those for scheduling (see Section 3.4)).

The outcomes of Pre-dispatch Pricing are hourly Pricing LMPs and associated shadow prices for constraints (see Section 3.7). These prices are used in the Pre-dispatch Constrained Area Conditions Test (see below) and, if necessary, in the price impact test.

5.3.3 Market Power Mitigation in Pre-dispatch

The following market power mitigation steps are executed in pre-dispatch:

- Pre-dispatch Constrained Area Conditions Test: the potential for the exercise of market power exists when an area is import congested. . The Constrained Area Conditions Test checks if an area meets global or local constrained conditions. If they triggered, the results of Pre-dispatch Pricing are used to determine if conduct tests need to be initiated. This process is similar to the DAM Constrained Area Conditions Test described in Section 4.2.3.
- Conduct Test: It takes place if competition is limited by the Constrained Area Conditions Test. The conduct test determines if any submitted financial data parameters differ from applicable reference levels by more than the relevant threshold. If all financial data parameters pass the conduct test, no mitigation will be applied. This process is similar to the DAM conduct test described in Section 4.2.4.
- Pre-dispatch Reference Level Scheduling: This process is identical to Pre-dispatch Scheduling except that it uses mitigated financial data for any resources that failed the conduct test.
- Pre-dispatch Reference Level Pricing: This process produces LMPs similar to Pre-dispatch Pricing, except it uses reference level data for any dispatch data parameter that failed the conduct test. Pre-dispatch Reference Level Pricing also considers the results of Pre-dispatch Reference Level Scheduling.

- Price Impact Test: If one or more financial data values for any resource failed the conduct test, the price impact test occurs. The process is similar to the one described in Section 4.2.7 for the DAM: it compares the LMPs from Pre-dispatch Pricing to the LMPs from Pre-dispatch Reference Level Pricing for each resource that failed the conduct test. The price impact test is failed if a resource's LMPs in Pre-dispatch Pricing are greater than the LMP from the Pre-dispatch Reference Level Pricing by a specified threshold. The resources which fail the price impact test in an hour will be added to the set of resources from previous pre-dispatch runs which failed the price impact test in the same hour. All the parameters that failed for those resources in that hour is replaced by their reference levels in subsequent pre-dispatch runs through to real-time.

– End of Section –

6. Real-time Calculation Engine

The real-time calculation engine includes a ‘Real-time Scheduling and Pricing pass’, which performs a multi-interval optimization function, followed by a single-interval optimization function to determine:

- Resource schedules for the dispatch interval and advisory intervals, these schedules are the results from the multi-interval optimization of the scheduling pass. The multi-intervals are comprised of one dispatch interval and 10 advisory intervals;
- Actual LMPs for the dispatch interval, and advisory LMPs for the advisory intervals, these results are from the single-interval optimization function of the pricing pass

The real-time calculation engine uses NQS commitments as constraints as determined in DAM/PD. The ED scheduling function is run first to calculate the schedules, followed by the pricing function to determine the prices.

6.1 Initialization

Before starting to optimize the schedules and calculating the prices, the real-time calculation engine performs several initialization procedures, some of which are similar to the DAM and pre-dispatch:

- Select a reference bus and determine islanding conditions as described in Sections 4.1.1 and 4.1.2;
- Apply variable generation resource tie-breaking logic as described in Section 4.1.3; and
- Pre-process PSU minimum and maximum generation constraints as described in Section 8.3.

Additional initialization procedures are discussed in the following subsections.

6.1.1 Resource Initial Schedules

The initial schedule of a dispatchable resource is called “initial loading point”, i.e., the initial consumption or injection point. It accounts for both real-time telemetry value and its schedule from the preceding real-time calculation engine run. In the scheduling function, dispatch deviations are measured by the difference between the prior scheduling function schedule and the real-time telemetry values. If the measured difference exceeds a resource ramping capability, the resource is deemed unable to meet its prior scheduling function schedule. Instead of using the prior scheduling function schedule as a starting point to determine the next dispatch instruction, the starting point is adjusted with respect to real-time telemetry and ramping capability to a point considered achievable by the resource.

The initial schedule used in the pricing function additionally considers the resource schedule calculated by the real-time pricing function of the preceding real-time calculation engine run. It will also incorporate the dispatch deviation found in the scheduling pass under two circumstances:

- When the initial schedules of scheduling and pricing pass are aligned, or
- When the initial schedules of scheduling and pricing pass are different, and the dispatch deviation bridges the difference.

Under these two circumstances the effects of the dispatch deviation found in the scheduling function can be associated to the pricing function, and when incorporated, adjusts the price setting ability of the resource within the physical capabilities of the resource.

6.1.2 NQS Resource Start-Up and Shutdown Status

The state can be any one of the following:

- It is going offline;
- It is on its start-up trajectory. This input may indicate an upcoming confirmed start-up or that the resource has already started ramping up;
- It is going to operate at or above its MLP
- It has been de-committed. As such, it can be scheduled below its MLP; or
- It is going offline on its shutdown trajectory.

6.2 Real-Time Scheduling and Pricing

Real-time uses market participant and IESO inputs. The resulting schedules are the basis for dispatch instructions and advisory schedules for the following advisory intervals. Real-time also determines LMPs consistent with the schedules.

6.2.1 Real-Time ED Objective Function

The Real-time ED function maximizes the gains from trade by maximizing the sum of the following quantities over the next 11 five-minute intervals:

- The values of:
    - scheduled energy from dispatchable loads;
- less the as-offered (or mitigated offered) costs of:
    - scheduled operating reserve (10S, 10N, and 30R) from all MPs;
    - scheduled energy from both dispatchable and non-dispatchable generation resources;
- less the costs of:
    - tie-breaking terms; and
    - violating constraints based on constraint violation pricing:
        - Energy balance allowing surplus or shortfall energy to be scheduled;
        - Total 10S, 10N and 30R operating reserve requirement;
        - 10R area reserve minimum and maximum requirement;
        - 30R area reserve minimum and maximum requirement; and
        - Operating security limits.

The RT scheduling and pricing function use different constraint violation penalty curves.

6.2.1 Real-Time Scheduling

Real-time Scheduling generally uses the same data inputs as pre-dispatch. The telemetered values of the real-time output or consumption of internal resources and the schedules from the preceding real-time run are also used to determine each resource's initial schedules (Section 6.1.1.)

NQS resources' DAM commitments are carried into real-time as minimum constraints (at minimum loading point) for all intervals of the hour.

Real-time Scheduling uses the following data inputs from the pre-dispatch calculation engine:

- Intertie schedules determined by the most recent pre-dispatch scheduling run are fixed for the dispatch hour.
- Pre-dispatch commitments for NQS resources are carried through into real-time as minimum constraints at the resources' minimum loading point;
- HDR resource schedules are fixed to 0MW for the hour when HDR activation is determined by the pre-dispatch scheduling run three hours before the dispatch hour; and
- mitigated financial dispatch data from the most recent pre-dispatch run is used, when applicable.

Real-time Scheduling produces five-minute energy and operating reserve schedules. The energy and operating reserve schedules for each dispatch interval are dispatch instructions. The remaining schedules for future intervals are for information only. Real-time Scheduling also produces NQS shutdown flag information for the Real-time Pricing process. Moreover, this step produces real-time five-minute HDR resource activation schedules that are fixed for the real-time calculation engine according to the hourly schedules calculated by the pre-dispatch scheduling process.

6.2.2 Real-Time Pricing

Real-time Pricing calculates settlement-ready LMPs for each five-minute interval. It also makes the necessary adjustments when IESO control actions have been implemented in real time. Real-time Pricing algorithm is described in Section 3.2.

Real-time Pricing generally uses the same dispatch data as Real-time Scheduling. The initial schedules in Real-time Pricing and Scheduling are the same. The initial schedules also consider schedules from the pricing function of the preceding real-time run, as described in Section 6.1.1. Real-time Pricing and Scheduling have different constraint violation penalty curves (Section 3.4).

Real-Time Pricing may have additional constraints for NQS resources. An NQS resource can only set prices in intervals for which it was scheduled at or above its MLP by Real-time Scheduling.

Schedules for imports, exports, HDR resources and NQS commitments are held fixed. Schedules for imports and exports are held fixed to those from final pre-dispatch for the hour.

Real-time Pricing, for each five-minute interval, produces shadow prices for the following constraints:

- Energy balance;
- Operating Security limits;
- Operating reserve requirement for all three classes; and
- Minimum and maximum regional ten-minute and thirty-minute operating reserve.

Settlement-ready energy and operating reserve LMPs are calculated for dispatchable and non-dispatchable generation resources, dispatchable loads, PRLs, virtual transactions, and import and export transactions.

Real-time LMPs for non-dispatchable loads are used in the calculation of the Load Forecast Deviation Adjustment.[21]

Real-time LMPs at all load locations are used in zonal prices for virtual transactions settlement. The weighting factors are the same as the ones used in the DAM.

– End of Section –

[21] For more information on non-dispatchable load prices, including the Load Forecast Deviation Adjustment, see the **Guide to Prices in the Renewed Market**.

7. Pricing Formulas

Energy LMPs for all pricing nodes (i.e., internal delivery points and intertie metering points) include shadow prices, constraint sensitivities and marginal loss factors. Operating reserve LMPs are calculated for dispatchable generation, dispatchable load, intertie buses.

7.1 Energy LMPs for Internal Pricing Nodes

Energy LMPs are calculated for every node where a non-dispatchable generator, dispatchable generation resource, dispatchable load, PRL, HDR resource, or non-dispatchable load is sited. As shown in Figure 7-1, energy LMPs are the sum of three components: The Energy Reference Price; the Energy Loss Price; and the Energy Congestion Price.

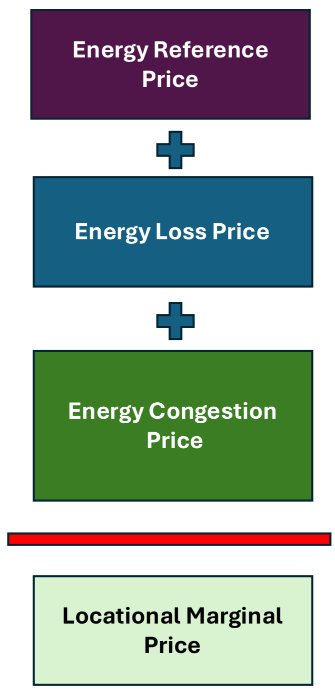


Figure 7-1 Energy LMP components for internal pricing nodes

The Energy Reference Price is the cost of consuming additional one more MW at the reference bus[22]. At the reference bus, losses and congestion are both equal to zero.

[22] Ontario's current reference bus is the Richview Transformer Station.

The same reference bus is used to determine all LMPs on the system. Differences in LMPs are the result of variation in Congestion Price (due to transmission system congestion) and Losses (due to transmission losses).

Even though the Reference Price may change if it relocated, LMPs at each location will not change. That being said, changing the reference bus would change all three components, but leaving the final LMPs unchanged.

The Energy Loss Price reflects the marginal cost of transmission losses at a given location relative to the reference bus. For a given hour, it is equal to the Marginal Loss Factor of the resource node times the Energy Reference Price. The Marginal Loss Factor at a location represents the marginal transmission losses incurred from meeting additional one more MW of load at the location with energy supplied from the reference bus. Marginal Loss Factors are calculated in the SA function.

The Energy Congestion Price represents the cost re-dispatching resources to meet load requirements due to transmission congestion. It is the additional system cost of a higher cost generation resource to be dispatched locally instead of a lower cost resource in another location. It is established within a calculation engine by relaxing each transmission constraint in turn by a small amount, and then calculating the resulting difference in overall system costs of re-dispatching. The congestion cost at a location is the sum of the individual congestion costs for each relevant transmission constraint. It uses sensitivity factors (also called "shift factors") which indicate the degree to which changes in flows between the reference bus and the pricing location affect a given constraint. The total congestion cost for a pricing location is:

- Positive when flows are limited away from the reference bus towards the pricing location.
- Negative when flows are limited towards the reference bus from the pricing location.
- Zero when there are no binding constraints.

If an energy LMP falls outside the settlement bounds of -$100/MWh to $2000/MWh, the LMP is modified so it falls within the settlement bounds. In so doing, all components (reference, loss and congestion) may be correspondingly adjusted.

7.2 Energy LMPs for Intertie Zone Buses

LMPs are the same for all buses at the same intertie zone.

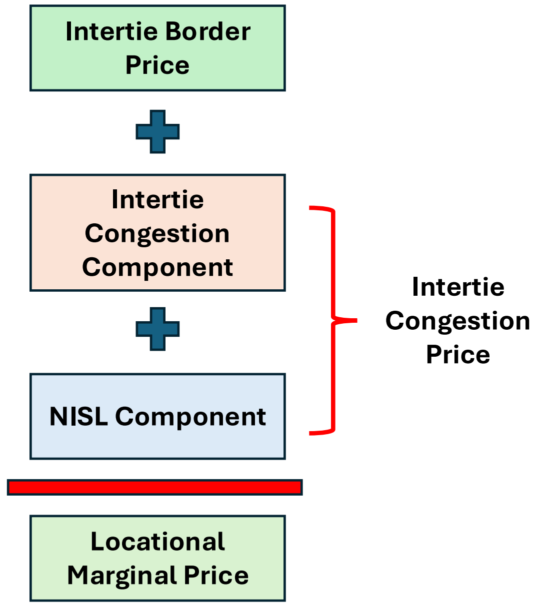


Figure 7-2 Energy LMP Components for Intertie Zones

As shown in Figure 7-2, in the DAM and pre-dispatch, LMPs at an intertie zone are made up of the Intertie Border Price (IBP) and the Intertie Congestion Price (ICP).

The IBP is the RT LMP on the Ontario side of the intertie. The marginal loss factor used to calculate the loss component of the IBP only accounts for losses from the Reference Bus to the intertie.

The ICP is the sum of the intertie congestion and NISL components. The intertie congestion component reflects the cost of congestion on the intertie. The NISL congestion component reflects the cost of congestion due to hour-to-hour limitations on changes in net flows over all interties.

In real-time, intertie LMPs include the intertie congestion costs. calculated by final pre-dispatch RT intertie LMPs for settlement may be adjusted according to the following rules:

- If there is import congestion in pre-dispatch, the real-time intertie LMP is the lower of the pre-dispatch LMP and the IBP. The effective real-time intertie congestion price is zero whenever the intertie real-time LMP is equal to the IBP and therefore the ICP (i.e. the intertie congestion plus NISL components) is also zero.
- If there is export congestion in pre-dispatch, the real-time LMP equals the IBP plus the ICP calculated in final pre-dispatch.
- If there is no congestion in pre-dispatch, the real-time LMP equals the IBP and the ICP is same as the ICP in final PD.

An energy LMP may fall outside the settlement bounds (-$100 ~ $2,000). When this occurs, the LMP at the intertie zone bus and its components (reference loss, internal congestion, intertie congestion, and NISL congestion) are modified so the LMP falls within the bounds.

7.3 Zonal Energy Prices

For each pricing zone (including both the Ontario zone and virtual zones), the zonal energy price is calculated as the sum of the reference price, the zonal non-dispatchable load distribution-weighted loss component, and the zonal load distribution-weighted congestion component (Figure 7-3). The weighting factors are calculated by the SA function. The weighting factors used in the calculation of real-time and pre-dispatch LMPs for virtual transaction zones are the same as the ones used in the DAM.

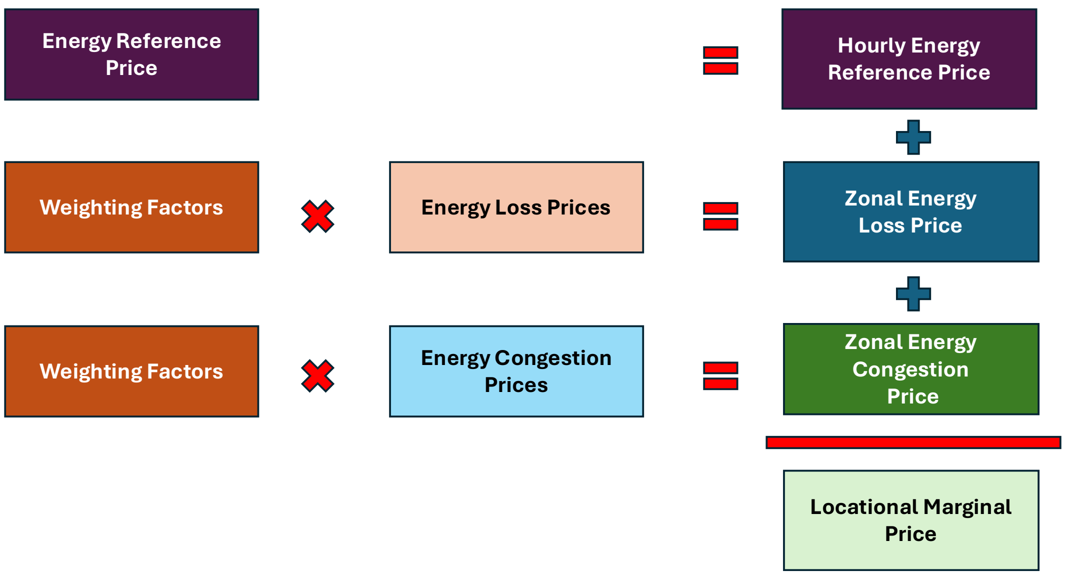


Figure 7-3 Zonal energy price components

7.4 Operating Reserve LMPs for Internal Pricing Nodes

The LMP for operating reserves at a specific location reflects the cost of meeting additional one MW increase in the reserve requirement for that category of operating reserve. This also accounts for transmission constraints associated with any relevant reserve areas.

LMP components for 30-minute (or 30R) operating reserve are summarized in Figure 7-4. These include the 30R reference price and a congestion component. The reference price reflects the cost of meeting additional one MW in the 30R requirement. The congestion component reflects the cost of binding area reserve requirement. They reflect transmission limits that prevent the delivery of activated operating reserve into or out of the area.

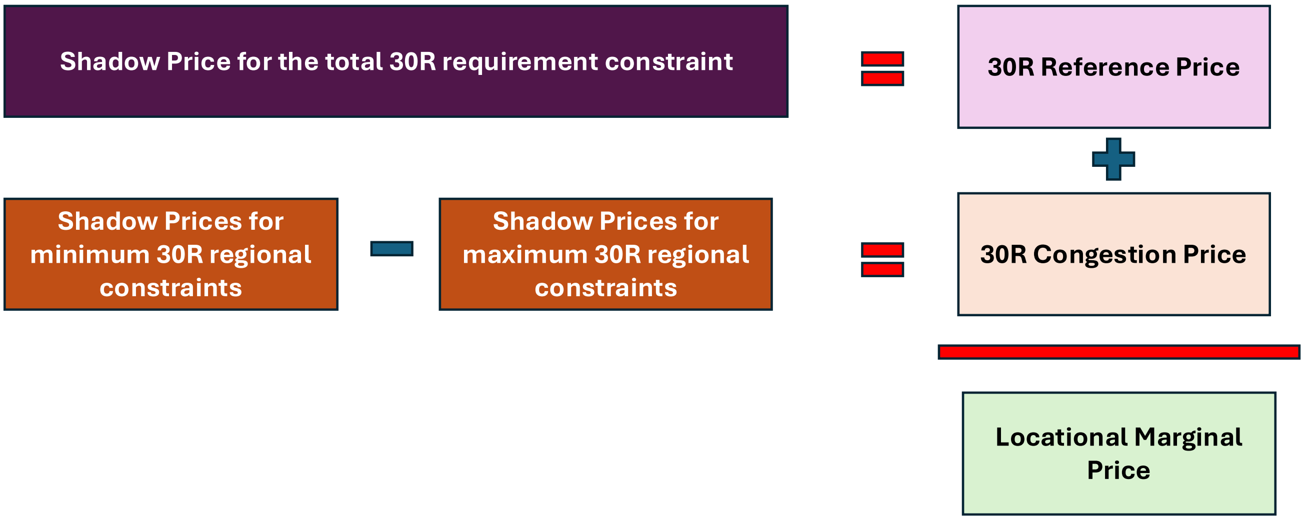


Figure 7-4 30R LMP Components

LMP components for 10-minute non-spinning (or 10N) operating reserve are summarized in Figure 7-5. The reference price reflects the cost of meeting additional one MW in the 10N requirement. The congestion component reflects the cost of binding area reserve requirement for 10N and 30R. They reflect transmission limits that prevent the delivery of activated operating reserve into or out of a reserve area.

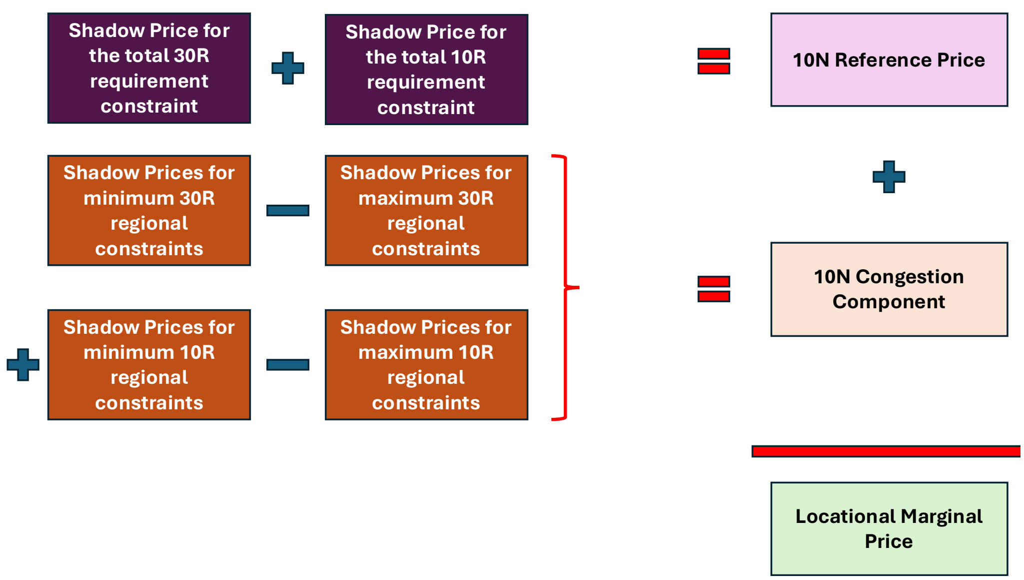


Figure 7-5 10N LMP Components

LMP components for 10-minute (10S) synchronized operating reserve are summarized in Figure 7-6. The reference price reflects the cost of meeting additional one MW in the 10S requirement. The congestion component reflects the cost of binding area reserve requirement. They reflect transmission limits that prevent the delivery of activated operating reserve into or out of a reserve area.

Figure 7-6 10S LMP Components

An operating reserve LMP can fall outside the settlement bounds. When this occurs, the operating reserve LMP and its components (reference and congestion) are modified so that the LMP is within the settlement bounds.

7.5 Operating Reserve LMPs for Intertie Zones

operating reserve LMPs in DAM and pre-dispatch at an intertie is calculated in a similar way as internal locations, except the LMPs at an intertie also account for import congestion. Intertie congestion limits the amount of operating reserve that can be imported into Ontario.

The 30R/10N LMP components consist of the 30R reference price, internal congestion component and the intertie congestion component (Figure 7-7 and Figure 7.8). The congestion component reflects the cost of import congestion.

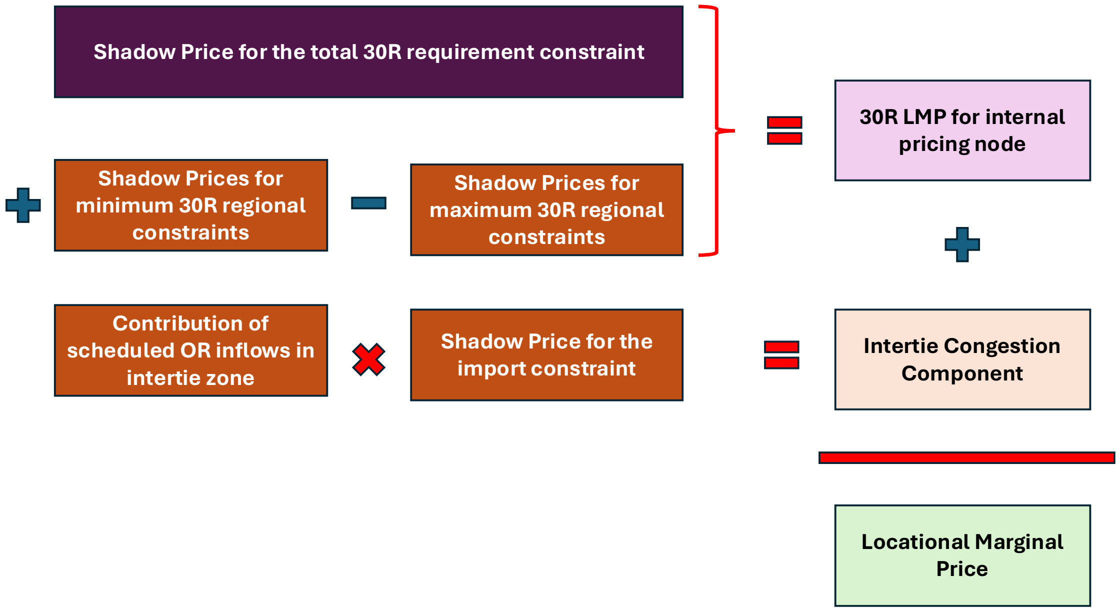


Figure 7-7 Intertie 30R LMP Components

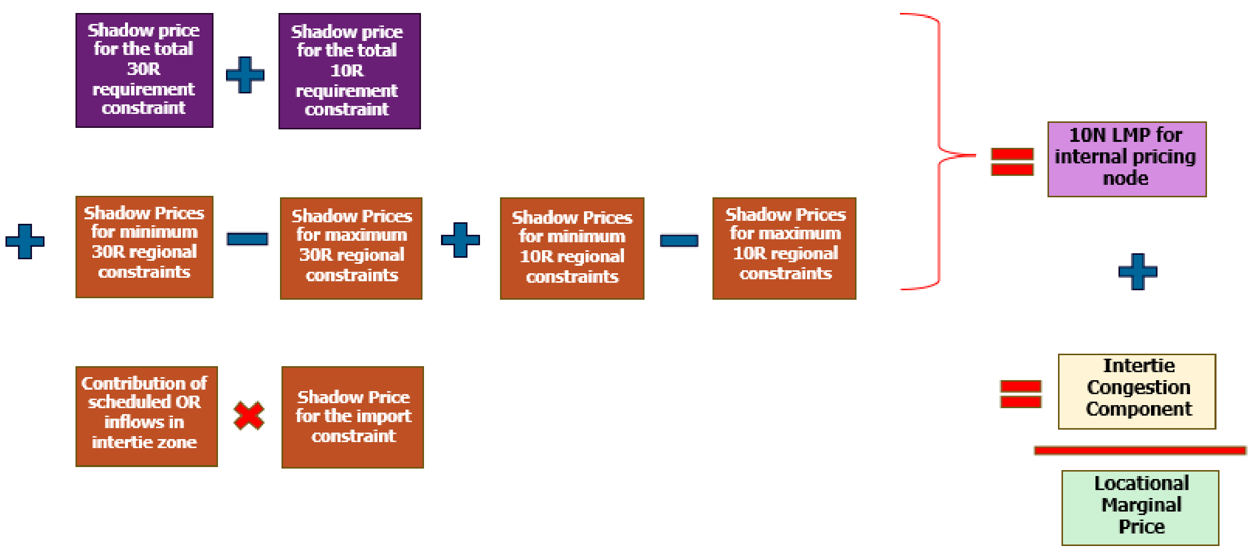


Figure 7-8 Intertie 10N LMP components

It is worth noting that the IESO doesn't allow importing 10S from external markets.

In real-time, operating reserve LMPs are calculated similarly for interties and internal locations, except that intertie LMP has a congestion component from final PD.

The initial real-time 30R and 10N LMPs are calculated based on the direction of intertie congestion in pre-dispatch:

- If the intertie is import congested, then:

- The initial real-time operating reserve LMP is the lesser of the real-time internal price and the pre-dispatch price.
- The real-time intertie operating reserve congestion component is equal to the difference between the real-time intertie operating reserve LMP and the internal price.

- Otherwise, the initial real-time operating reserve LMP is the reserve price in real-time and the congestion component is 0.

An operating reserve LMP may fall outside the settlement bounds. When this occurs, the operating reserve LMP for an intertie zone and its components (reference, internal congestion and intertie congestion) are modified so the LMP is within the settlement bounds.

7.6 Pricing for Islanded Nodes

Transmission outages may split the grid into two or more isolated areas, each of which continues to operate independently (as opposed to a full blackout in the area). When this happens, the areas are referred to as "islands", with the largest one called "main island".

For all resources not within the main island the calculation engines calculate LMPs, using a node-level and a facility-level substitution list in the following order:

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

– End of Section –

8. The Pseudo-Unit Model

A combined cycle plant (CCP) (Figure 8-1), typically has one or more combustion turbine (CT) units and a single steam turbine (ST) unit. A CCP recycles waste heat from the CTs to produce steam for the ST.

CCPs are classified as NQS resources since they cannot be synchronized within 5 minutes.

CCPs have three operating regions:

- Minimum loading point;
- Dispatchable region (above MLP); and
- Duct-firing region (if equipped) on the ST.

Duct-firing is an ST operating mode where extra fuel is used to heat the CT exhaust gas. This increases the steam produced by the ST, increasing its MW output.

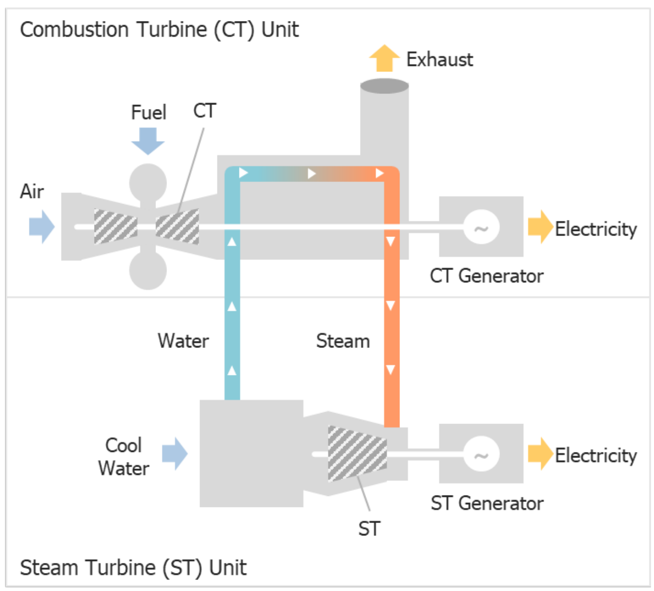


Figure 8-1 Combined Cycle Plant

The output of the ST depends on the output of the CTs. Each CT has a defined contribution (in percentage) to the ST. The dependency between CT and ST units creates unique challenges for scheduling CCPs.

CT and ST resources can be offered into the market as individual resources, also known as the physical unit (PU) model, or jointly using a pseudo-unit (PSU) model.

With the PU model, calculation engines do not recognize that the inter-dependence of the ST and the CT. Each CT and ST resource is independently evaluated and scheduled. As a result, the ST may get scheduled without the CTs or vice versa.

With the PSU model, calculation engines recognize that the output of the ST is dependent on the output of the CTs. A single PSU resource captures the output relationship between one CT and an ST. For each additional CT at a CCP facility, an additional PSU resource is required to capture the CT-ST output relationship. Figure 8-2 shows a PSU model for a CCP with a 3 CT x 1 ST configuration, with each CT equally contributing to the ST.

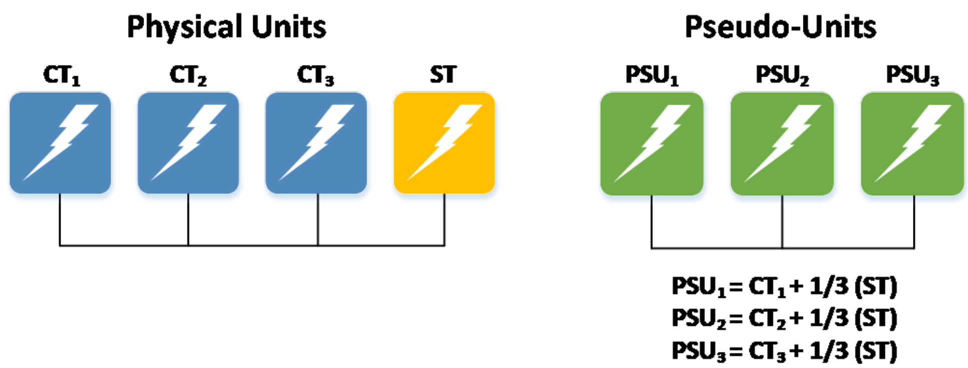


Figure 8-2 Three by one ST PSU model

The offer for each PSU resource reflects the cost of operating a CT and the applicable portion of the ST jointly. A PSU resource is scheduled independently from other PSUs at the same facility. Each PSU resource is scheduled according to a fixed ratio of energy output between the CT and ST within each specific operating region. Dispatch instructions to each PU are determined by applying the appropriate ratios to PSU schedules.

8.1 Mapping Operating Regions of PUs to PSUs

The PSU model recognizes operating region dependencies between CT and ST, where PUs and PSUs have the following operating regions:

- CTs have two operating regions:
  - MLP region; and
  - Dispatchable region.
- STs can have three operating regions:
  - MLP region;
  - Dispatchable region; and
  - Duct firing region (if applicable).

The PSU will have the same operating regions as the ST.

As illustrated in Figure 8-3, the MLP operating region of a PSU is the sum of the CT's MLP and the ST's MLP. ST units have multiple MLP values, depending on the number of online CT units. For example, the MLP of the ST may be 20 MW if only one CT is online (a 1X1 configuration) and 40 MW if two CTs are online (a 2X1 configuration). Each PSU is modelled using the (1x1) ST MLP (e.g., MLP_1 in the below figure).

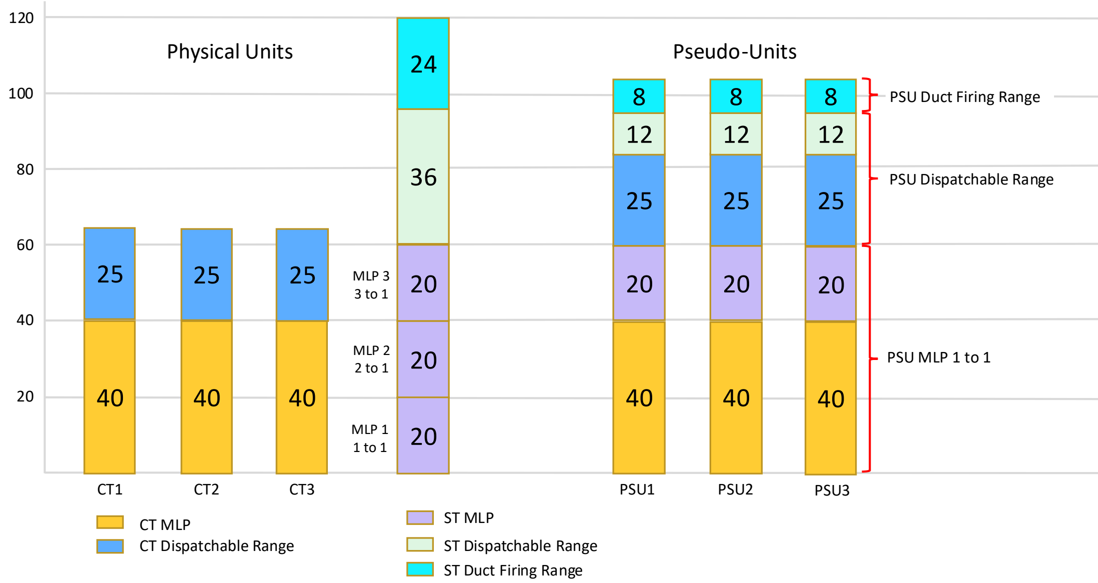


Figure 8-3 Mapping operating rangers of CTs and ST to PSUs (3x1)

The dispatchable operating region of a PSU is the sum of the dispatchable region of the CT and the corresponding portion of the ST's dispatchable region when there is only one CT online. If a CCP has all three CTs online, each PSU would be modelled with a third of the ST's dispatchable region.

The duct firing region is calculated by apportioning the ST's duct firing capacity. For example, if there are three PSUs online, each PSU is modelled with a third of the ST's duct firing capacity.

A PSU can opt to operate in single-cycle mode (i.e., without the steam turbine) by submitting a Single-Cycle Mode Flag as part of it's daily dispatch data. In this case, the ST's contributions to the operating regions of the PSU are ignored.

8.2 Scheduling Pseudo-Units

The calculation engines calculate schedules and prices for PSU resources. PSU schedules are then translated to PU schedules for the CT and ST units. For example, the calculation engines will determine energy and operating reserve schedules for each of a CPP's three PSUs (i.e., PSU1, PSU2, PSU3), which are then translated into schedules for each of the physical resources (i.e., CT1, CT2, CT3, and ST).

PU schedules are needed for security analysis, scheduling, dispatch and settlements. For example, the SA function uses PU schedules to check that PSU schedules respect security limits. If it identifies a security violation, a PU constraint is created. This constraint is then converted to a PSU equivalent so that the security limit is respected in the next iteration.

8.2.1 Ramp up Energy to MLP

Market participants submit the profile of Ramp up Energy to MLP for both the CT and the ST in the PSU. The Ramp up Energy to MLP profile for the ST represents its ramp profile in a 1x1 configuration. The calculation engines will combine the Ramp up Energy to MLP for the CT and ST to determine the PSU ramp profile, which in turn is used to schedule the PSU.

Example

Assume a market participant submits the parameters in Table 8-1 in DAM or the PUs in one of its PSUs:

Parameter	CT_1	ST
Number of hours ramping	2	2
Quantity for Hour 1 (MW)	50	0
Quantity for Hour 2 (MW)	70	30

Table 8-2 Example: Submitted ramp up energy to MLP for a PSU

DAM would construct the PSU Ramp Up Energy to MLP profile as follows:

PSU

PSU Ramp up energy to MLP for Hour 1

= CT_1 Ramp $_{\text{Hour 1}}$ + ST Ramp $_{\text{Hour 1}}$

= 50 MW + 0 MW

= 50 MW

PSU Ramp up energy to MLP for Hour 2

= CT_1 Ramp $_{\text{Hour 2}}$ + ST Ramp $_{\text{Hour 2}}$

= 70 MW + 30 MW

= 100 MW

DAM then schedules the PSU ramp up to MLP hours based on the calculated PSU ramp up energy to MLP profile. Should the DAM engine commit the PSU, the PSU would receive a schedule like Figure 8-5.

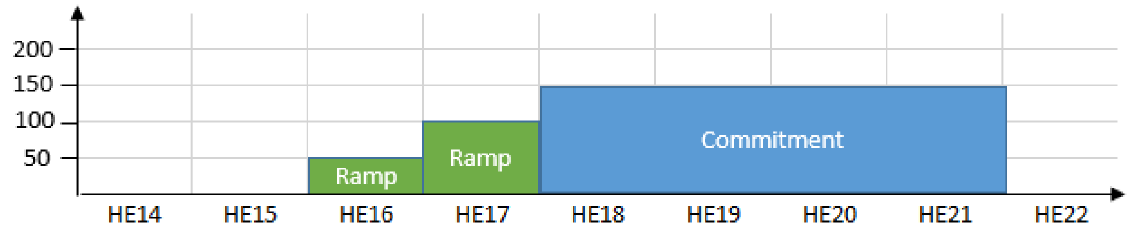


Figure 8-4 PSU ramp up to MLP schedule

After determining the PSU schedule, the DAM calculation engine translates the PSU schedule into individual PU schedules. For example, the PU ramp up to MLP schedules would match the submitted ramp up to MLP energy profile of the CT and ST, as shown in Figure 8-6.

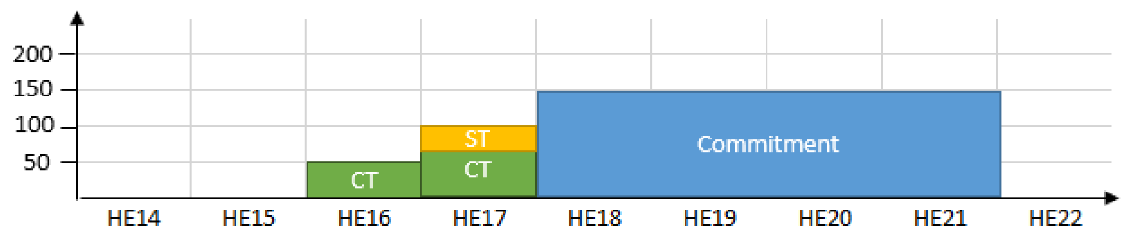


Figure 8-5 PSU ramp up to MLP schedules

8.3 Applying Minimum and Maximum Constraints to PSUs

all three calculation engines model minimum and maximum constraints as either constraints on CT or ST, or as constraints on the PSU:

- Commitment constraints are applied to PUs, identifying that the physical unit is "committed" and indicating the corresponding minimum unit output;
- Outages and de-rates are applied to PUs;
- Reliability constraints and manual constraints are applied to PUs; and
- In real-time, certain manual actions such as operating reserve activations are applied to PSUs.

All constraints applied to PUs are translated to PSU constraints before execution of the calculation engine. If more than one constraints are applied to the same PU, only the most limiting constraint will be applied.

8.3.1 PSU Minimum Constraints

PSU minimum constraints are the minimum output that a PSU unit has to maintain. Unlike other constraints on the PUs, PSU minimum constraints are applied directly to the PSU resource.

8.3.2 PSU Maximum Constraints

PSU maximum constraints are the high operating limit for a PSU. Like PSU minimum constraints, PSU maximum constraints are applied directly to the PSU without additional pre-processing.

8.3.3 CT Minimum Constraints

It is often necessary to apply a minimum PU constraint directly to a CT. The minimum constraint on the CT is then translated to an equivalent minimum constraint on the PSU. The CT minimum constraint also places an implied minimum constraint on the associated ST, to account for the interdependency between the CT and the ST.

8.3.4 CT Maximum Constraints

A maximum constraint limits the output of a CT at or below a specific value. The maximum constraint is translated to an equivalent maximum constraint on the PSU. For a PSU resource not in single cycle mode, the CT maximum constraint also places an implied maximum constraint on the associated ST.

8.3.5 ST Minimum Constraints

A minimum constraint limits the output of an ST at or above a specific value. An ST minimum constraint is assigned to committed PSUs and translated to one or more equivalent PSU minimum constraints. The ST minimum constraint places an implied minimum constraint on the CT resources.

8.3.6 ST Maximum Constraints

A maximum constraint limits the output of an ST to at or below a specific value. The maximum constraint is prorated across the available capacity of associated in-service PSU resources and translated to one or more equivalent PSU maximum constraints. The ST maximum constraint also places an implied maximum constraint on CT resources due to PSU model interdependencies.

8.3.7 Equal ST Minimum and Maximum Constraints

Equal minimum and maximum ST constraints fix the steam turbine to a given output for safety, equipment or reliability reasons.

Equal ST minimum and maximum constraints may not result in equal PSU minimum and maximum constraints. This is because an ST minimum constraint is only allocated to committed PSUs and is allocated equally to committed PSUs. The ST minimum constraint allocation logic is applied because the constraint represents an operational concern and is best allocated to committed PSUs. In contrast, a maximum constraint is pro-rated across available capacity.

8.4 Pricing for PSUs

The calculation engines produce PSU LMPs by calculating effective weighted average marginal loss factors and weighted average sensitivity factors based on the PSU model parameters and scheduling results.

8.5 Single-Cycle Flag Across Two Dispatch Days in pre-dispatch Calculation Engine

The Single Cycle Flag determines whether the PSU resource is evaluated as a single cycle (i.e., the CT alone), or as a combined cycle (i.e., CT+ST). The flag is a daily dispatch parameter that can be changed at midnight.

In general, when the pre-dispatch look-ahead period spans two dispatch days, the Single-Cycle Flag for the second day is used for the entire pre-dispatch look-ahead period if the PSU is currently offline and it has no commitment previously issued during the pre-dispatch look-ahead period. For example, a market participant intends to run a PSU in the single cycle mode on Day 0 but in the combined cycle mode on Day 1 (Figure 8-7). At 20:00, the pre-dispatch calculation engine starts to evaluate for Day 1. It only uses the Day 1 Single Cycle Flag. It will evaluate the PSU in Combined Cycle mode for the rest of Day 0 (HE22-HE24) and all of Day 1.

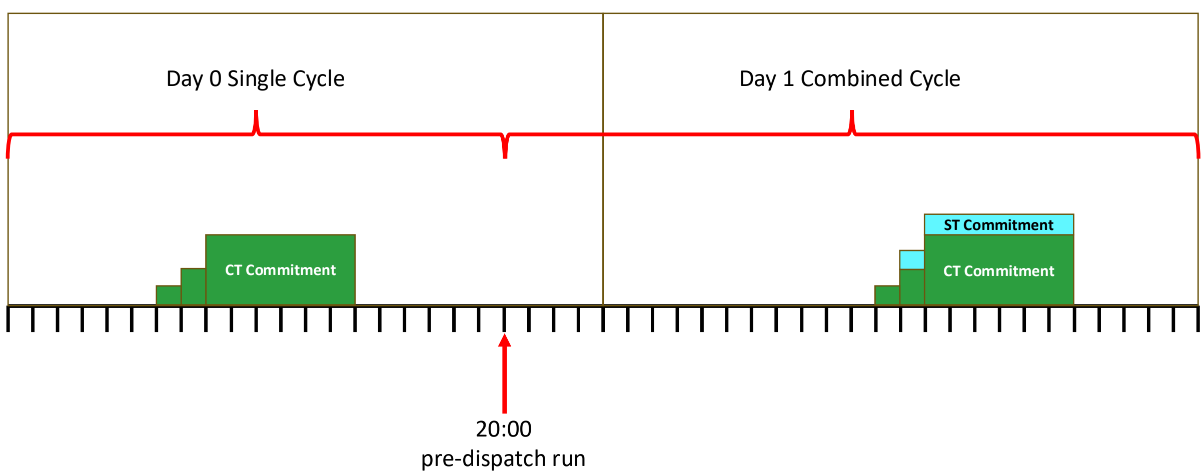


Figure 8-6 Single cycle flag across two dispatch days – general case

If the flag differs between the two days and the PSU is currently online or is expected to be online before the end of day 0, two exceptions apply:

- If the PSU does not have a minimum constraint to keep it in service across the two dispatch days, and either the PSU is in service when pre-dispatch is run or it has a future minimum constraint to bring it in service before the end of Day 0 (Figure 8-8), pre-dispatch will:

- Use the single cycle flag of day 0 (which indicates combined cycle mode) for the pre-dispatch look-ahead period in day 0 and use the single cycle flag of day 1 (indicating single cycle operations) for the pre-dispatch look-ahead period in day 1; and
- Schedule the PSU to 0 MW in HE1 of day 1. This is because the unit must be offline for the change in single cycle flag to be implemented.

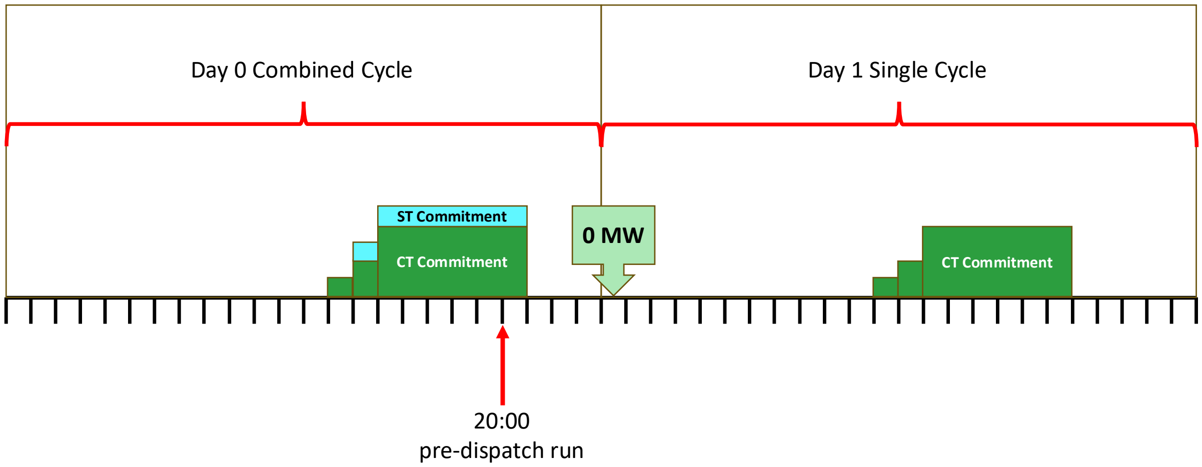


Figure 8-7 Single cycle flag across two dispatch days – Special case logic 1

If the PSU has a minimum constraint to keep it in service across the two days (Figure 8-9), pre-dispatch will:

- Use the single cycle flag of day 0 (single cycle mode) for the pre-dispatch look-ahead period in day 0 and the beginning hours of day 1 to meet the minimum constraint;
- Use the single cycle flag of day 1 (combined cycle mode) for the pre-dispatch look-ahead period in day 1 after the minimum constraint for the PSU has completed; and
- Schedule the PSU to 0 MW in the immediate following hour of day 1 for which no commitment or reliability constraint applies.

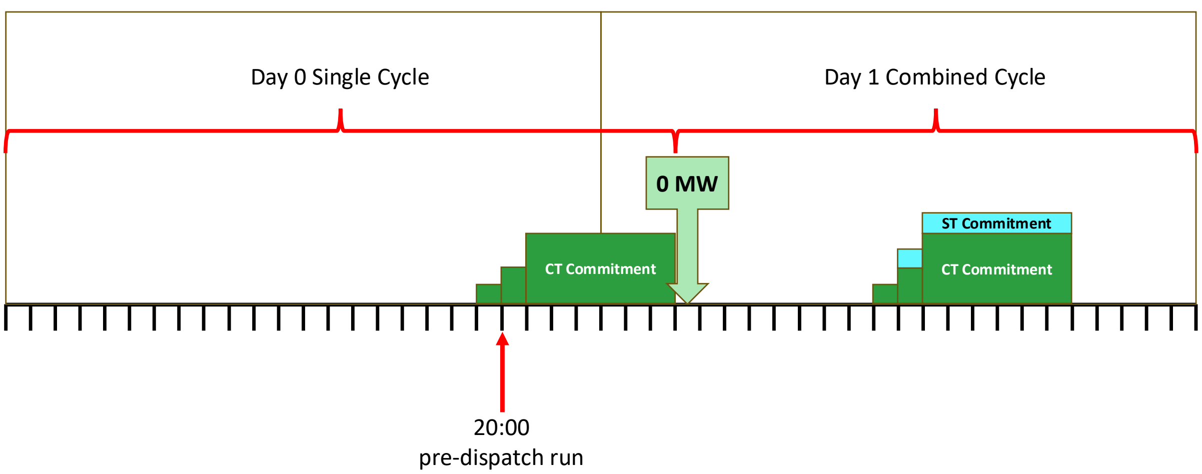


Figure 8-8 Single cycle flag across two dispatch days – Special case logic 2

– End of Section –

9. Hydroelectric Resources Scheduling

Hydroelectric resources have unique operating constraints that can impact their energy and operating reserve schedules. Some operating constraints are physical limitations, while others are for safety, regulatory or environmental requirements. These constraints are considered in DAM and pre-dispatch. Only some, however, are applied in real-time through minimum generation constraints.

This section provides examples of hydroelectric operating constraints.

9.1 Minimum Hourly Output

Minimum hourly output (MHO) is an hourly dispatch parameter used in DAM and pre-dispatch, representing the minimum amount of energy a resource must be producing, if economically scheduled. The DAM and pre-dispatch will not schedule a hydroelectric resource between 0 MW and the MHO value. MHO is not modelled in real-time as a minimum constraint. Market participants, though, can declare their availability through their offers, request the IESO to impose minimum/must-run constraints, or submit an outage to manage MHO.

As illustrated in Figure 9-1, DAM and pre-dispatch schedule a hydroelectric resource to at least its MHO if it is economic. For example, the resource is scheduled to 0MW in HE 10 and 11. The calculation engines also schedule additional MWs up to the maximum offered quantity when it is economic.

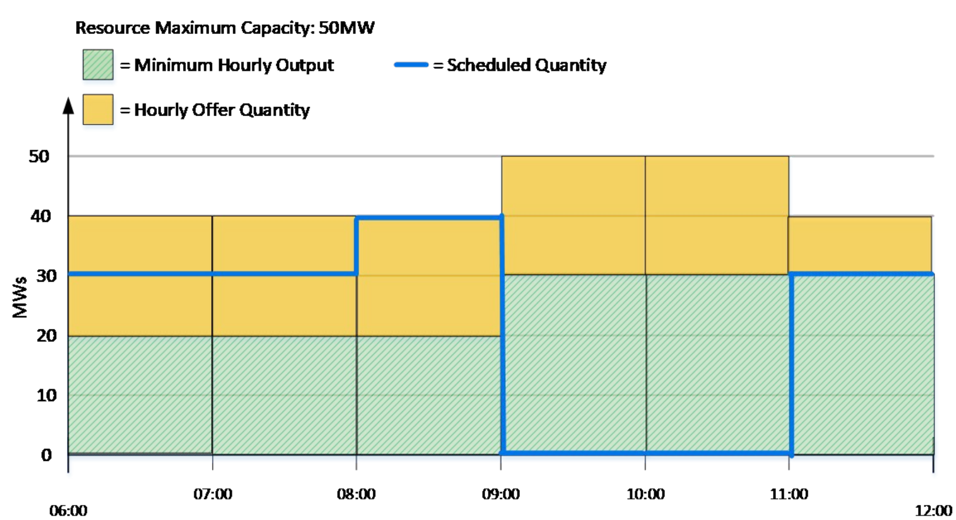


Figure 9-1 Example on minimum hourly output

9.2 Hourly Must Run

Hourly must-run (HMR) is an hourly dispatch data parameter to represent the minimum amount of energy that a dispatchable hydroelectric resource must produce regardless of economics.

As illustrated in Figure 9-2, DAM and pre-dispatch schedule a hydroelectric resource to MWs up to the maximum offered quantity when it is economic. However, it does not schedule it below the HMR level.

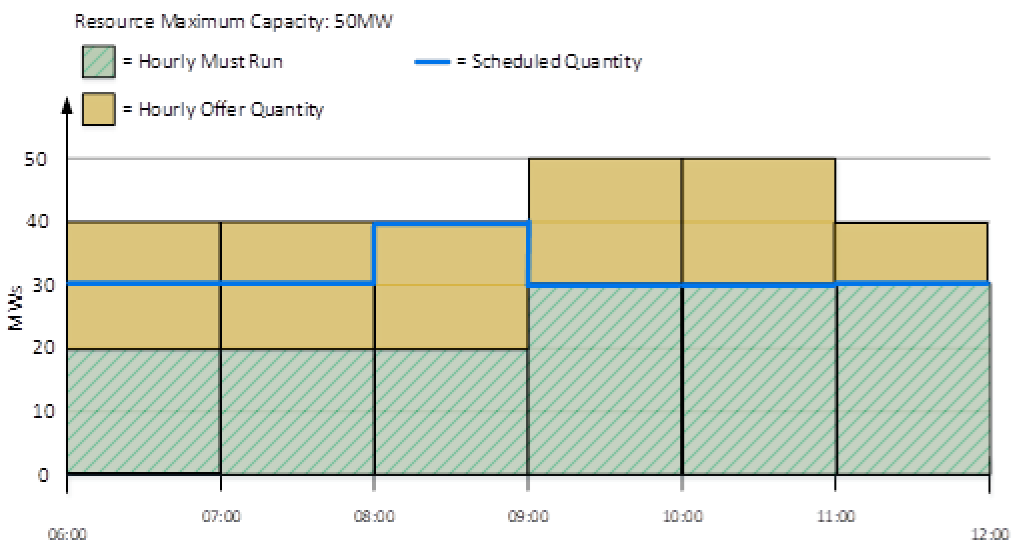


Figure 9-2 Example on hourly must run

9.3 Maximum Number of Starts Per Day

The parameter of Maximum Number of Starts Per Day (MNSPD) is the maximum number of times a dispatchable hydroelectric resource can be started within a dispatch day. This parameter has associated start indication values, above which a start is deemed to have occurred.

More than one hydroelectric physical units may be aggregated into a single resource, with each unit having a limited number of starts. Because different stages of generation within an aggregated resource may represent different unit starts, an aggregated resource may have multiple start indication values.

As illustrated in Figure 9-3, hydroelectric resource 'Resource AB' represents an aggregated resource with two generation units, each with a maximum capacity of 100 MW. Start indication values of 1 MW and 101 MW have been registered. Assume that each generation unit has a maximum number of three starts per day. Then the aggregated resource has a combined maximum of six starts per day.

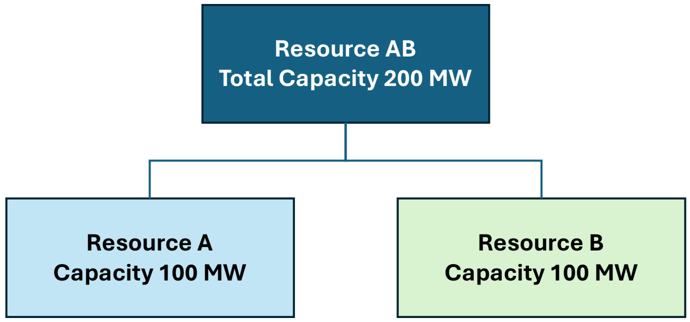


Figure 9-3 Example on aggregated hydroelectric resource

As part of the scheduling considerations for Resource AB, DAM and pre-dispatch count the number of starts that have or will occur based the number of times the resource schedule crosses the registered start indication value. An example is in Figure 9-4 below.

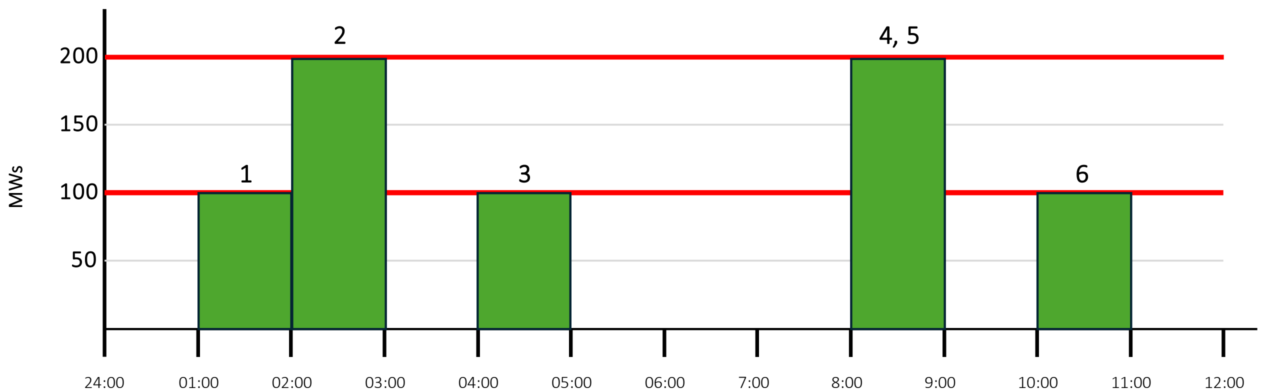


Figure 9-4 Scheduled starts example for aggregated hydroelectric resource

9.4 Forbidden Regions

Forbidden regions represent one or more operating ranges within which a hydroelectric generation unit cannot maintain steady state operation without causing equipment damage. Forbidden regions are submitted as dispatch data consisting of upper and lower limit values. DAM and pre-dispatch must avoid scheduling the unit within the indicated ranges. The real-time calculation engine ramps the resource through any submitted forbidden region at its maximum ramp rate.

As illustrated in Figure 9-5 below, DAM and pre-dispatch schedule hydroelectric resources to any point outside the forbidden regions in each hour.

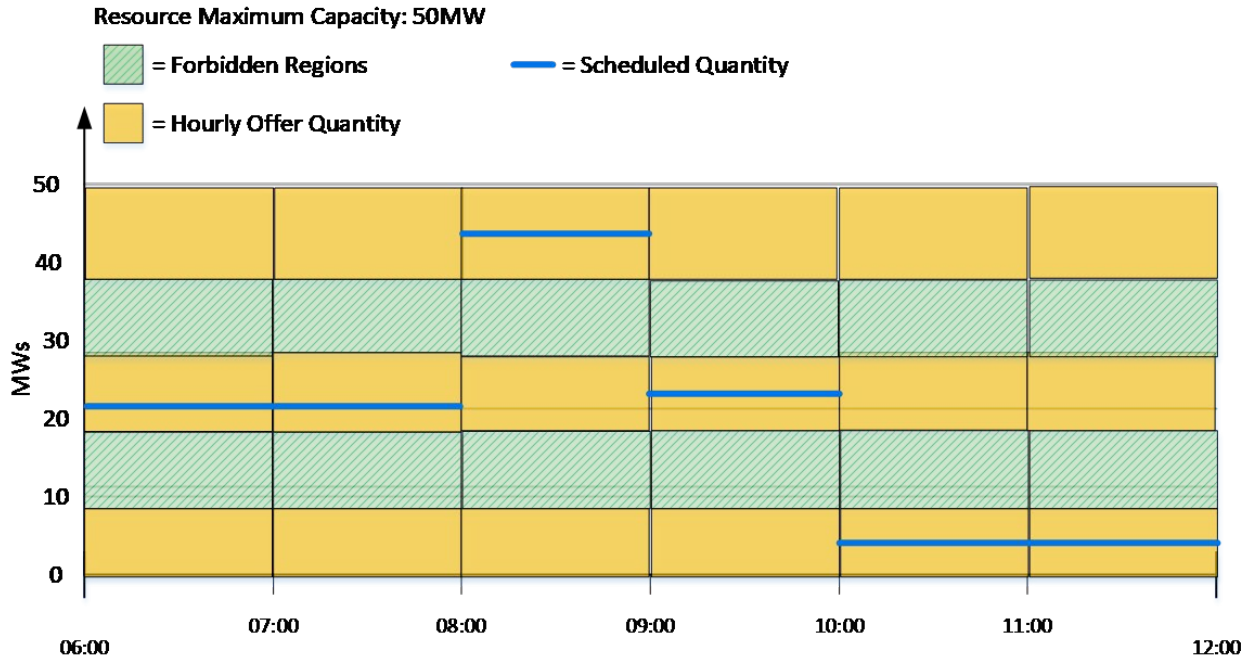


Figure 9-5 Example of forbidden regions

9.5 Maximum and Minimum Daily Energy Limits

DAM and pre-dispatch respect the minimum and maximum daily energy limits.

- A MinDEL (minimum daily energy limit) represents the minimum amount of energy that a hydroelectric resource must be scheduled within a day.
- A MaxDEL (maximum daily energy limit) represents the maximum amount of energy that a hydroelectric resource can be scheduled in a day. A MaxDEL constraint in the DAM and pre-dispatch calculation engines ensures that the resource will not be scheduled to produce more energy than the submitted limit.

If a group of hydroelectric resources shares the same forebay, shared MinDEL and shared MaxDEL constraints can be used:

- A Shared MaxDEL represents the maximum daily energy that hydroelectric resources are collectively limited to provide during each day; and
- A Shared MinDEL represents the minimum daily energy that hydroelectric resources collectively must provide during each day.

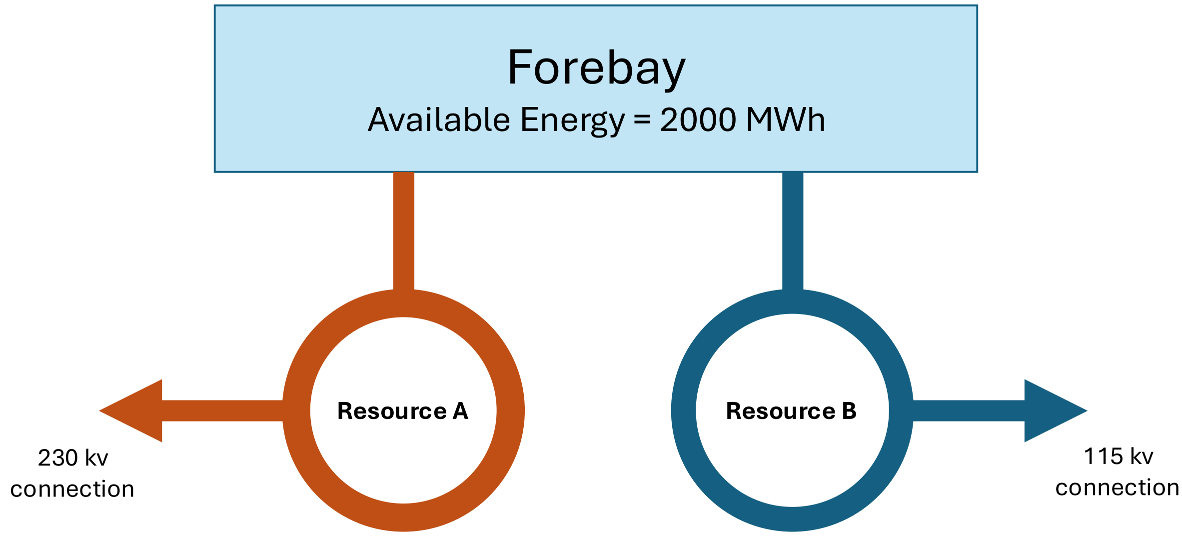


Figure 9-6 Example of hydroelectric resources with a shared MaxDEL

As shown in Figure 9-6, two hydroelectric generating units are located at the dam (i.e. they share the same forebay), but have with two different connection points. The two resources share the same total available energy of 2,000 MWh. The DAM and pre-dispatch calculation engines will respect the shared MaxDEL when scheduling the resources so the total scheduled energy for both resources will not exceed the 2000 MWh limit (Figure 9-7).

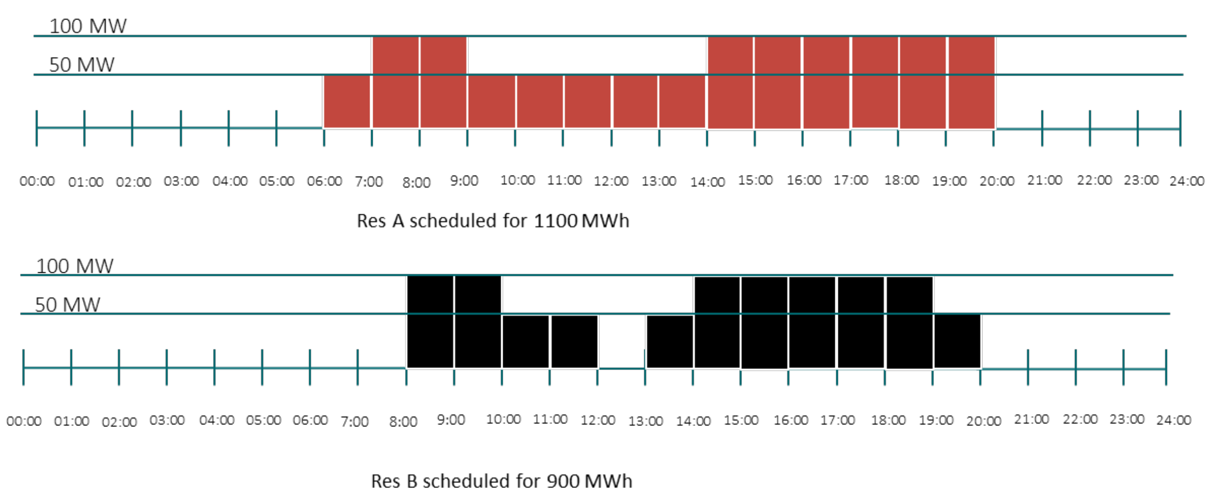


Figure 9-7 Example on scheduling resources with shared MaxDEL

9.6 Linked Forebays, Time Lag and MWh Ratio

Linked hydroelectric forebays, time lag and MWh ratio are daily dispatch data parameters, representing the energy production and time lag relationship between hydroelectric generation resources on a cascade river system. They are used by DAM and pre-dispatch to reflect scheduling dependency among cascade resources with the same registered market participant (RMP).

Time lag is the number of hours it needs for water travel from an upstream forebay to the downstream forebay, while the MWh ratio is the ratio of the output at the upstream forebay to the output at the downstream forebay.

Consider the following cascade hydroelectric resources offered by the same RMP in all 24 hours of a day. Assume there is only one resource per forebay:

- Resource A offered for 50 MW;
- Resource B offered for 120 MW; and
- Resource C offered for 70 MW.

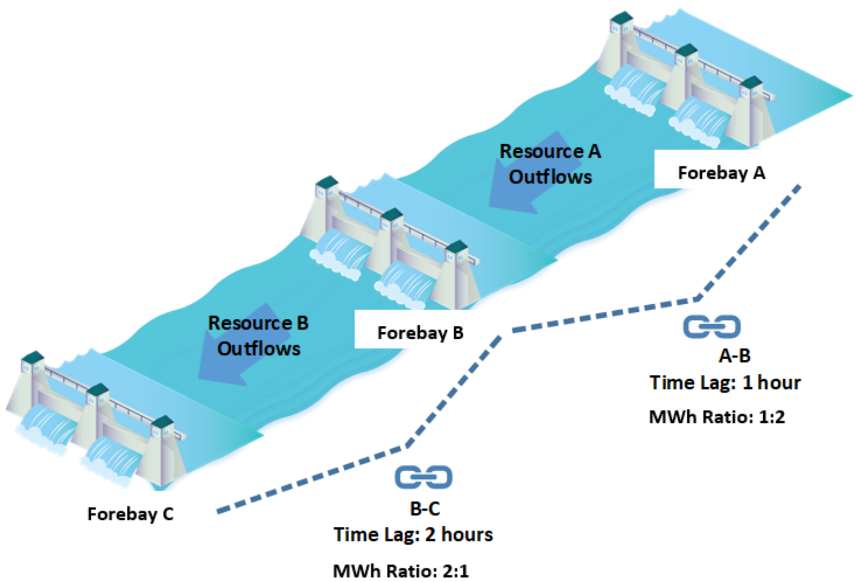


Figure 9-8 Example of hydroelectric cascade of forebays

The market participant links the forebays and submits the following time lags and MWh ratios as dispatch data (illustrated in Figure 9-8):

- Forebay A is linked to Forebay B with a time lag of 1 hour and a 1:2 MWh ratio (i.e., 1 MWh produced at Forebay A leads to 2 MWH of output at Forebay B);
- Forebay B is linked to Forebay C with a time lag of 2 hours and a 2:1 MWh ratio.

As illustrated in Figure 9-9, if DAM or pre-dispatch determine that it is economic to schedule all three resources, all receive energy schedules which respect their time lag and MWh ratios.

In this example, the calculation engine determines that the optimal schedules for resources A, B, and C are 20 MW, 40 MW, and 20 MW, respectively. These schedules respect the MWh ratio and time lag dependency among the linked forebays. If the calculation engine instead determines that the three resources are collectively not economical to schedule in any of the hours across a dispatch day, none of the resources will be scheduled. By linking the forebays, an 'all or none' scheduling dependency is created between the linked forebays.

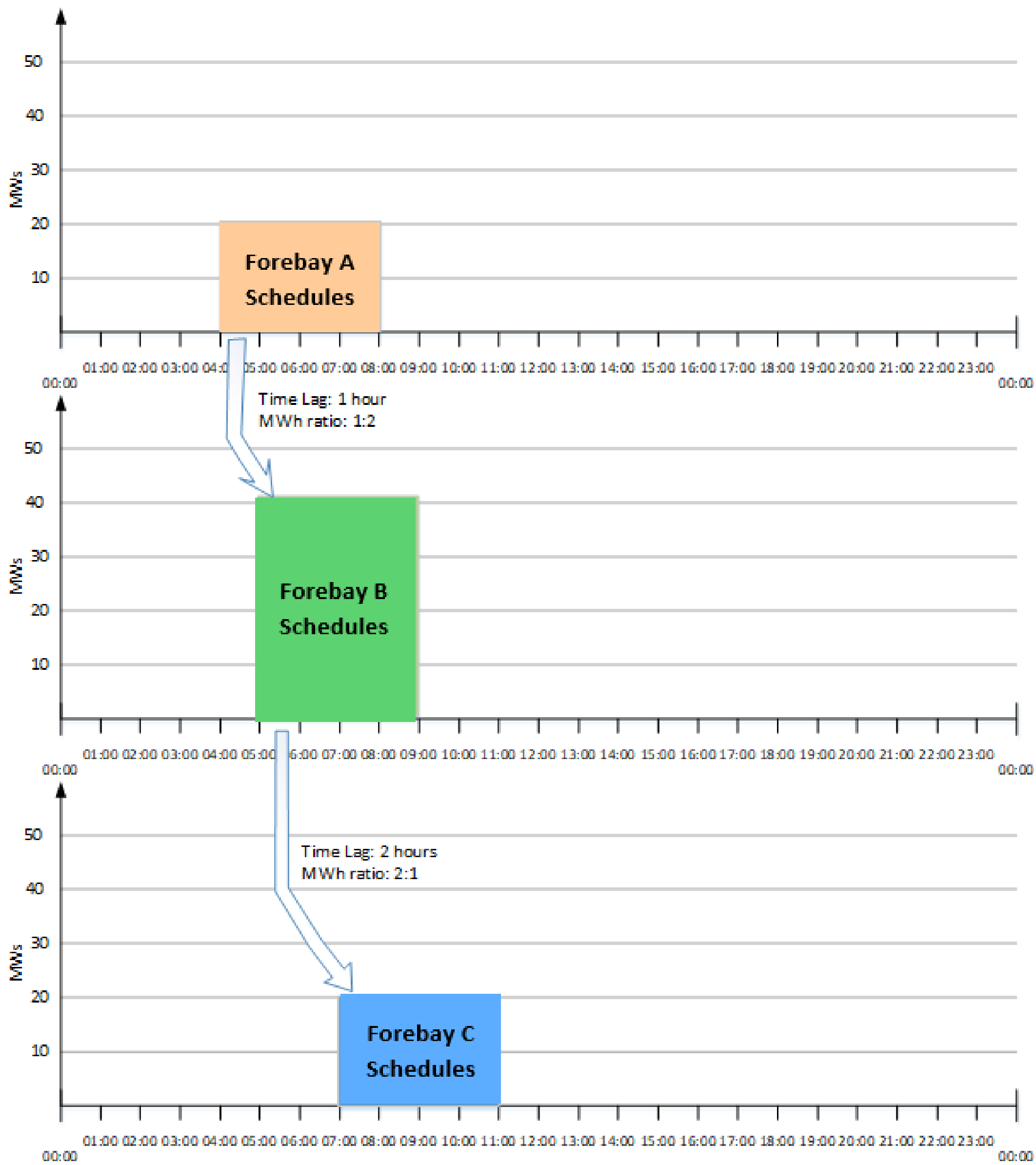


Figure 9-9 Example of hydroelectric Cascade forebay schedules

– End of Section –

10. Glossary

Term	Meaning
Day-Ahead Generator Offer Guarantee	The day-ahead market generator offer guarantee settlement amount provides compensation to market participants with generator offer guarantee-eligible resources that have a day-ahead operational commitment and are unable to recover their as-offered costs based on the revenue earned during the day-ahead commitment period for energy and operating reserve.
Hourly Must Run	The quantity, in MWh, below which a dispatchable hydroelectric generation resource is incapable of responding to dispatch instructions due to specific must run conditions which could reasonably be expected to endanger the safety of any person, damage equipment, or violate any applicable law.
Minimum Generation Block Down Time	For each thermal state (hot, warm, cold), the minimum time, in hours, between the time a generation resource was last at its minimum loading point before de-synchronization and the time the generation resource reaches its minimum loading point again after synchronization.
Minimum Generation Block Run Time	The number of hours that a generation resource must be operating at minimum loading point, in accordance with its technical requirements.
Minimum Loading Point	The minimum output of energy that can be produced by a generation resource under stable conditions without ignition support, in accordance with the technical requirements of the associated facility.
MWh Ratio	The proportional amount of energy that must be scheduled on the resources registered on the downstream linked forebay after the time lag has elapsed for every MWh of energy scheduled on the resources registered on the upstream linked forebay.
Marginal Loss Factors	A location's marginal loss factor reflects the transmission losses incurred on the system from meeting an additional increment of demand at that location with one additional MW of supply from the reference bus.
Marginal Price	A marginal price is the cost to supply one additional increment of demand.
Maximum Daily Energy Limit	For a dispatchable generation resource that is a non-quick start resource and is not a nuclear generation resource, the maximum daily energy limit is a maximum quantity of energy in MWh that may be scheduled for a resource within a dispatch day at or above its minimum loading point excluding the hours scheduled for the ramp up energy to minimum loading point. For any other resource, it is a maximum quantity of energy in MWh that may be scheduled for a resource within a dispatch day.
Minimum Daily Energy Limit	The minimum amount of energy, in MWh, that must be scheduled within a dispatch day for a hydroelectric generation resource.

Term	Meaning
Multi-Interval Optimization	The process whereby a calculation engine determines optimal 5-minute interval resource schedules taking into consideration market and system conditions in a number of future 5-minute intervals.
Multi-Hour Optimization	The process whereby a calculation engine determines optimal hourly resource schedules taking into consideration market and system conditions in a number of future hours.
Net Interchange Scheduling Limit	The total allowable net schedule change (imports plus exports) across all Ontario interties from one hour to the next.
Ramp Up Energy to MLP	The amount of energy, in MWh, a non-quick start generation resource is expected to inject in each hour from the time of synchronization to the time it reaches its minimum loading point.
Real-time Generator Offer Guarantee	The real-time generator offer guarantee settlement amount provides compensation to market participants with generator offer guarantee-eligible resources that are committed during the pre-dispatch scheduling process and are unable to recover their as-offered costs based on the revenue earned during the real-time commitment period or real-time reliability commitment period.
Reference Level	An IESO-determined estimate of a dispatch data parameter that a resource would have submitted if it were subject to unrestricted competition.
Reference Quantity	An IESO-determined estimate for the quantity of energy or operating reserve that a market participant would have submitted for a resource if it were subject to unrestricted competition.
Reserve Area	A localized area of the grid for which minimum or maximum limits for scheduled operating reserve are set due to limitations on the ability to move activated operating reserve into or out of the area.
Time Lag	An amount of time less than 24 hours that it takes for the water discharged from an upstream linked forebay to reach a downstream linked forebay.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.