Enhanced Real-Time Unit Commitment High-Level Design

Independent Electricity System Operator

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Contents

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LIST OF ABBREVIATIONS

Abbreviation	Description
ADE	Availability Declaration Envelope
DACP	Day-Ahead Commitment Process
DAM	Day-Ahead Market
DGD	Daily Generator Data
DSO	Dispatch Scheduling and Optimization
ERUC	Enhanced Real-Time Unit Commitment
HE	Hour Ending
IESO	Independent Electricity System Operator
LAP	Look-Ahead Period
MGBDT	Minimum Generation Block Down-Time
MGBRT	Minimum Generation Block Run-Time
MLP	Minimum Loading Point
MRP	Market Renewal Program
MWh	Megawatt-Hour
NQS	Non-Quick Start
OR	Operating Reserve
PD	Pre-Dispatch
RT	Real-Time
RT-GCG	Real-Time Generation Cost Guarantee
SSM	Single Schedule Market

Description of Core Concepts

Pre-Dispatch

The timeframe between clearing of the day-ahead market until real-time operations, during which optimization of bids and offers is performed to address changes in system conditions.

Multi-Hour Optimization

The evaluation of all bids/offers and operating restrictions over multiple hours, optimizing all hours at the same time, in order to determine the lowest-cost resources to meet demand.

Minimum Loading Point

The minimum output of energy that can be produced by a generator under stable conditions without ignition support.

Minimum Generation Block Run-Time

The number of hours that a generator must be operating at or above its minimum loading point, in accordance with the technical requirements of the facility.

Lead Time

The amount of time between the initiation of the start-up sequence and the time at which a generator is able to reach its minimum loading point, which depends on the technical requirements of the facility. Lead time determines the amount of notice a generator needs to respond to a start-up instruction.

Non-Quick Start Resource

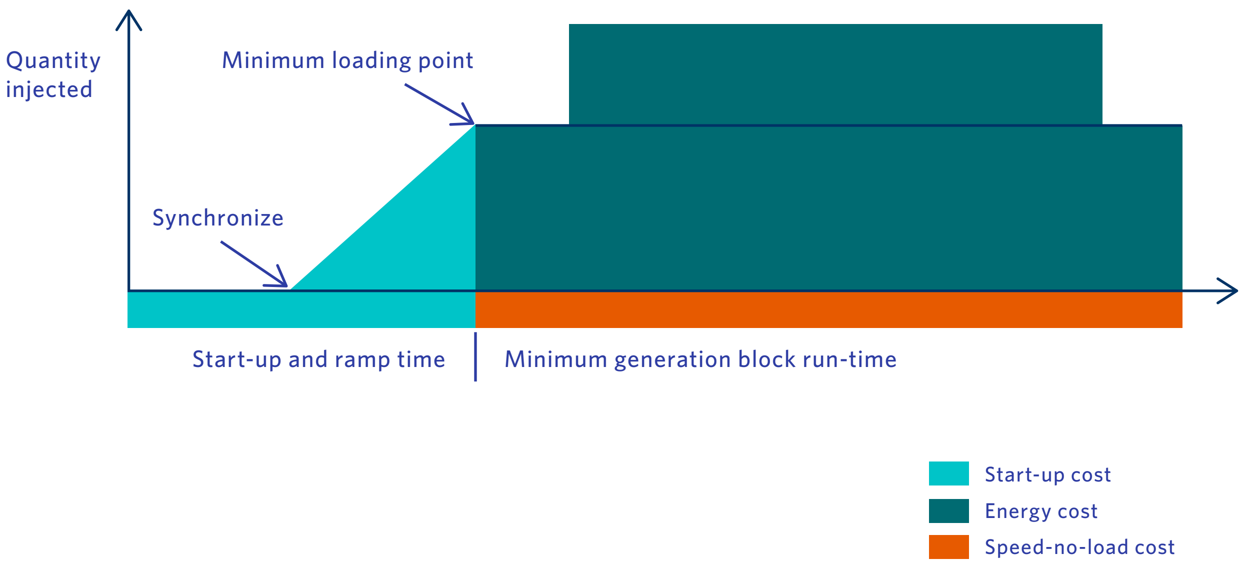
A generator with a lead time of at least one hour, and that must remain operating at its minimum loading point for its minimum generation block run-time.

Commitment

The process of deciding when and which non-quick start resources should come online in order to maintain reliability and meet demand at lowest overall cost. Operational constraints are applied such that a non-quick start resource will not be required to operate below its minimum loading point or to come offline before its minimum generation block run-time has been completed, and the non-quick start resource will be guaranteed to recover its as-offered costs.

Three-Part Offer

A resource offer into the energy market that comprises three parts: start-up cost, speed-no-load cost and energy cost. Start-up cost is the cost for a generator to come online and reach MLP. Speed-no-load cost is the cost to maintain a generator synchronized with zero net energy injected into the system. Energy cost is the cost to generate energy.



1. Executive Summary

Designing the Electricity Market of the Future

Every minute of every day, the Independent Electricity System Operator (IESO) is responsible for ensuring the reliability of the province's electricity grid, administering Ontario's electricity markets, and providing businesses, communities and consumers with the power they count on to meet their needs. Achieving these objectives is complicated by the fact that our existing electricity markets have not kept pace with the dramatic sector-wide developments – technological advances, an evolving operating and regulatory environment and a more diverse supply mix – that are continuing to transform the energy landscape.

Market Renewal: The Rationale For Change

In May 2002, the opening of transparent, wholesale competitive electricity markets in Ontario marked a shift from large, centralized and publicly owned bodies providing services to passive customers to one where buyers and sellers connect to cost effectively supply more engaged consumers with the electricity they need.

While the IESO has made incremental changes to market design to ensure system reliability, the consensus has been clear for some time: the markets require foundational and wide-reaching reforms. That is where the IESO's market renewal program (MRP) comes into play.

Part of our broader efforts to continually rethink the way we do business, this redesign will address persistent, costly design flaws in the current system, and prepare us to more effectively manage future change. In the end, the IESO will deliver more efficient markets, ensuring that all Ontarians have a stable and reliable supply of electricity at the lowest cost.

To lay the groundwork for market renewal, in 2016 the IESO committed to a made-in-Ontario approach by establishing an internal market renewal team supported by an external Market Renewal Working Group, a representative stakeholder forum to advise and inform the IESO on important strategic, policy and design issues affecting the program's success.

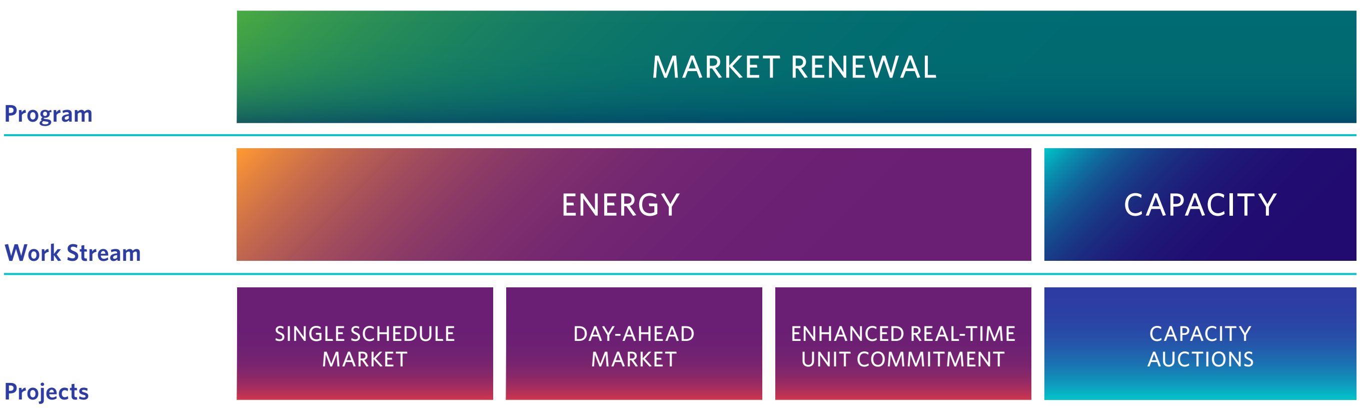
In the two years since, this collaborative effort has delivered a compelling benefits case study, a comprehensive market renewal engagement framework founded on agreed-upon principles, and general consensus on important high-level design decisions that will shape Ontario's new marketplace.

Market Renewal Initiatives

To deliver on its mission to enhance the efficiency of Ontario's wholesale electricity markets, the MRP will:

- Replace the two-schedule market with a **single schedule market** (SSM) that will address current misalignments between price and dispatch, eliminating the need for unnecessary out-of-market payments
- Introduce a **day-ahead market** (DAM) that will provide greater operational certainty to the IESO and greater financial certainty to market participants, which lowers the cost of producing electricity and ensures we commit the resources required to meet system needs
- Reduce the cost of scheduling and dispatching resources to meet demand as it changes from the day-ahead to real-time through the **enhanced real-time unit commitment** (ERUC) project
- Improve the way Ontario acquires the resources to meet longer-term supply needs by implementing capacity auctions that will drive down costs by encouraging greater competition and reducing barriers to ensure we have an efficient way to acquire the resources to meet system needs and customer demands at the lowest cost

FIGURE 1: MARKET RENEWAL PROGRAM WORK STREAMS



Developing a Balanced Market Design: Incorporating Stakeholder Input

At the outset, we recognized that our success in creating a market that better meets the needs of suppliers and consumers would depend, in part, on the broad support of stakeholders who were prepared to invest time and effort in developing solutions that will work for the sector and the IESO.

With this in mind, the IESO committed to designing the new energy markets collaboratively and established a comprehensive consultation framework. Built on agreed-upon principles –efficiency, competition, implementability, certainty and transparency – this framework reinforces the importance of giving interested parties an opportunity to provide feedback.

While each of the MRP initiatives addresses specific needs, they all follow the same design process shown in Figure 2.

FIGURE 2: PROJECT DESIGN PROCESS

Enhanced Real-Time Unit Commitment

An Efficient Transition from Day-Ahead to Real-Time

Electricity markets require a mechanism to cost-effectively transition from day-ahead scheduling to real-time operations. While a day-ahead market can efficiently schedule resources to meet the following day's expected demand, conditions can and typically do change after the day-ahead scheduling process is complete. There may be changes in Ontario demand due to weather conditions or changes in supply from variable generators, such as wind. Electricity markets evaluate bids and offers from all resources between the clearing of the day-ahead market until real-time operations, known as the pre-dispatch timeframe. This evaluation addresses deviations between day-ahead and real-time in order to reliably meet real-time demand at the lowest possible cost. For most resources, the pre-dispatch process does not produce any form of financial guarantee. Instead it provides information on how they are likely to be dispatched, so they can prepare for real-time operation.

However, certain generators – like non-quick start (NQS) resources – require unique treatment in the pre-dispatch process. NQS resources incur three types of costs: the cost of providing energy (energy costs), the cost of starting up to be available to provide energy (start-up costs), and the cost of operating at a minimum level required to inject power to the grid without generating any output (speed-no-load costs). Further, once started, these NQS facilities must remain online and provide a certain amount of power for a minimum period of time prior to shutting down, to avoid damaging their equipment. Without the appropriate market design, these resources may not make themselves available until they are certain they will be able to recover their costs in the real-time market.

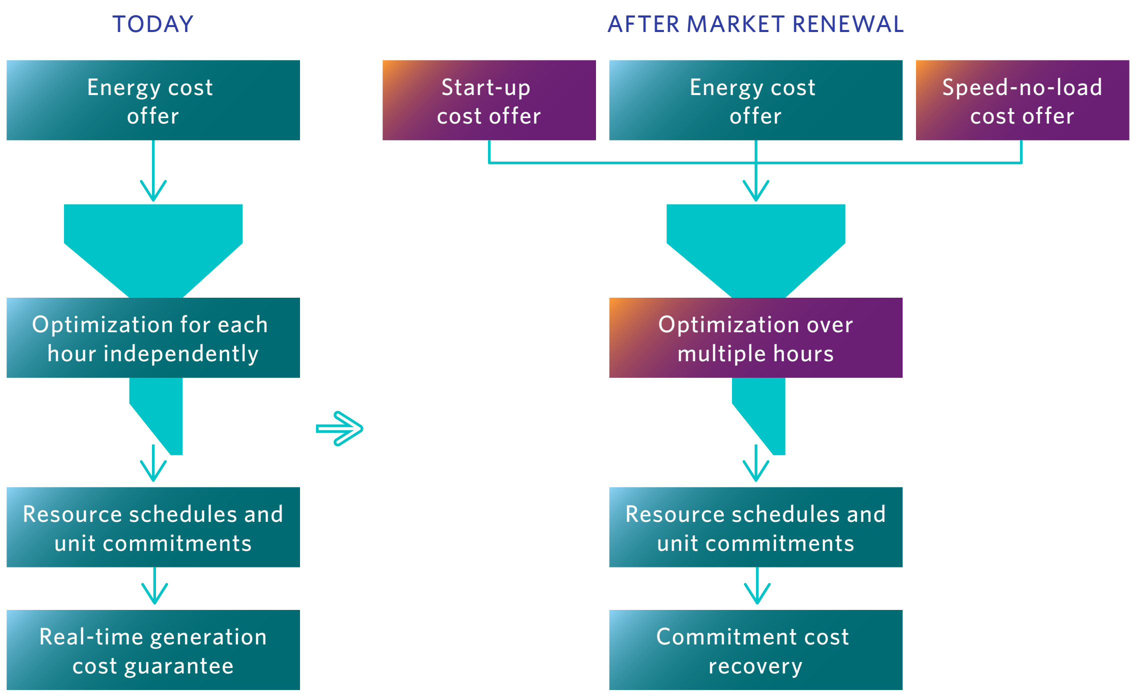
Unit commitment is an important element of the pre-dispatch process. It is the mechanism through which electricity markets ensure that cost-effective NQS resources are available in real-time. Once committed, an NQS resource is guaranteed to be scheduled in accordance with its physical requirements (including the minimum amount of time it must remain online and the minimum amount of energy it must produce). Typically, the unit commitment process is accompanied by a financial guarantee, which ensures the resource will not have to operate at a loss, even if conditions change in real-time.

A unit commitment process in pre-dispatch was not included in the province's electricity markets at opening because real-time energy prices were expected to offer sufficient incentive to ensure that resources would be online when needed. However, as Ontario's generation mix evolved to include more NQS resources, it became apparent that this approach would no longer suffice. To better integrate NQS resources, the IESO introduced a unit commitment process and accompanying financial guarantee in 2003. The program has evolved over time and is known today as the Real-Time Generation Cost Guarantee (RT-GCG) program.

While the RT-GCG program is an important tool for meeting reliability needs, market renewal provides opportunities to improve both the program and the pre-dispatch scheduling process it supports. That is why the IESO is engaging with stakeholders on the ERUC initiative, which will replace both the current pre-dispatch process and the RT-GCG program.

In particular, ERUC will result in pre-dispatch schedules and unit commitments that better reflect the total cost of NQS supply and that are based on a longer, more efficient optimization timeframe. When implemented, ERUC will help to ensure that when changes in system needs arise in the pre-dispatch time frame, the most cost- effective set of resources will still be available to meet demand in real-time.

FIGURE 3: CHANGES TO UNIT COMMITMENT PROCESS



Today, unit commitment decisions are made based on energy costs alone, while start-up and speed-no-load costs are not taken into account. This means a resource with lower energy costs but higher overall costs may be committed instead of a resource with lower total costs. In other words, because RT-GCG decisions do not account for all costs, they may result in inefficient outcomes.

ERUC will address this issue by introducing three-part offers into the unit commitment process. NQS resources will have to submit offers for their energy, start-up and speed-no-load costs. Considering all these costs in making commitment decisions will increase transparency and competition within the commitment process, resulting in lower costs for consumers.

In today's unit commitment process, costs are evaluated separately for each hour, without taking into consideration the minimum level of output that NQS resources must provide and the minimum amount of time they must remain online. This results in inefficient scheduling decisions as only the following hour is considered. For example, a resource that has lower costs over a particular hour may get dispatched, though it has a higher cost overall because it must remain online for a longer period of time.

ERUC will improve the efficiency of commitment decisions by optimizing over multiple hours rather than solving for each hour independently.

In addition to addressing issues with the existing pre-dispatch unit commitment process, ERUC will also work effectively alongside the other the energy work stream initiatives. The SSM will enable the IESO to improve scheduling decisions by laying the foundations for DAM and ERUC.

The DAM will produce financially binding day-ahead schedules for all participants, including NQS resources based on three-part-offers. If an NQS resource is scheduled in the DAM, the resulting day-ahead commitments will be transferred to ERUC. ERUC will then make additional scheduling and unit commitment decisions to address deviations between DAM and real-time, ensuring reliability is maintained cost-effectively. However, ERUC will not "de-commit" an NQS resource with a DAM financially binding schedule.

Since the first ERUC stakeholder meeting in October 2017, in-depth consultation has taken place on all aspects of ERUC design, including the applicability for Ontario of different options for each of the proposed design elements. The process has considered how design decisions may affect stakeholders and reflects the collective stakeholder feedback received. While collaboration does not necessarily signal agreement on every detail, the design decisions have been extensively discussed, and provide a strong foundation for the detailed work required to implement ERUC.

To manage the scope and complexity of the ERUC initiative, the IESO focused the design work and engagement with stakeholders, separating the project into 13 design elements. These elements were grouped into four categories: Engine Parameters and Output, Market Power Mitigation, Participation and Input Data, and Settlement. The following sections focus on the most material design elements in each category.

Engine Parameters and Output at a Glance

The design elements in this category focus on the internal workings of the optimization engine used to produce schedules and determine dispatch, including unit commitment decisions.

The optimization engine will run on an hourly basis using multi-hour optimization to make improved scheduling, dispatch and commitment decisions. During each hourly run, the optimization engine will assess offers to sell energy, bids to buy energy and hourly forecasts (e.g., for demand) for all remaining hours of the operating day. By taking a longer view, ERUC will deliver more efficient schedules for all resources.

Improved modelling of both NQS resources and hydroelectric resources will be incorporated into the optimization engine for the pre-dispatch timeframe, and this will be consistent across all timeframes, day-ahead to real-time. NQS resources have scheduling dependencies between units within the same facility, resulting in operational restrictions. These dependencies can be recognized by using “pseudo-units” that model the relationships between resources, as currently done in the Day-Ahead Commitment Process (DACP). The IESO is also committed to modelling additional hydroelectric operating characteristics to the extent feasible within the DAM and pre-dispatch engines, as outlined in the DAM high-level design document. Hydroelectric resources have operational restrictions, including but not limited to must-run requirements, a limited number of daily starts, and scheduling dependencies with upstream or downstream hydroelectric resources. Improved modelling in the pre-dispatch timeframe will recognize that NQS and hydroelectric resources have operational restrictions that limit their ability to generate, and will optimize the scheduling of these resources in all timeframes.

After the DAM, the ERUC optimization engine will produce additional binding start-up instructions for NQS resources, as required. Advisory schedules, which indicate if, when and to what extent resources are likely to be required to meet system needs in future hours, will be produced for all other resources.

Market Power Mitigation at a Glance

Market power mitigation is an important element of deregulated wholesale electricity markets. A market thrives when there is effective competition among many resources. When competition is restricted, market participants can exercise their “market power” by either economically or physically withholding energy from the market to increase the price.

The IESO has always had a framework to address the potential exercise of market power. Under the current system, however, market power mitigation is carried out after it occurs, and so is based on actual values rather than estimates.

While the approach to market power mitigation will be consistent across the three initiatives within the energy work stream, there are some specific market power mitigation considerations for commitment of NQS resources in the pre-dispatch and DAM timeframes.

In pre-dispatch, as in other timeframes, to address economic withholding, energy offers from all resources will be tested to see if they deviate from expected costs based on pre-defined levels known as conduct thresholds. In cases where energy offers violate a conduct threshold, resulting in a material impact on price that could distort market outcomes, offers will be adjusted to pre-determined reference levels before schedules are produced. In cases where a cost guarantee is impacted, the guarantee payment may be adjusted after-the-fact.

Restrictions to offer changes will also be placed on NQS resources that are committed in DAM and pre-dispatch, in order to maintain a level playing field. For example, once committed in pre-dispatch, NQS resources will not be allowed to increase their offer prices. These limitations will help to ensure that committed resources are not able to use their commitment to influence market prices.

Participation and Input Data at a Glance

Broad participation in the IESO's electricity markets drives competitive behaviour which typically results in efficient market outcomes. Participation and input data design elements focus on what data will be required and evaluated by the optimization engine, when they will be submitted, and under what circumstances they may be revised. These design elements also explore the physical characteristics required for a resource to be eligible for a cost guarantee.

To be eligible for cost guarantee payments, resources will have to qualify as NQS resources. Then they will need to have registered values for: the minimum loading point (MLP), the minimum generation block run-time (MGBRT), and a registered elapsed time to dispatch, i.e., minimum lead time, that is greater than one hour.

Market participant data will either be generally static or subject to relatively frequent variation. For example, MLP and MGBRT data, which are connected to the physical attributes of a resource, are relatively static but may change on occasion. Other data such as three-part offers which are driven by fuel costs will change more frequently. Market participants will provide operating parameter data during the market registration process and, since this data can change, generators will also have the opportunity to make updates on a daily basis.

Settlement Topics at a Glance

In its settlement processes, the IESO will determine the cost guarantee payments for NQS resources. The IESO will evaluate all as-offered energy, start-up, speed-no-load and operating reserve (OR) costs up to maximum offered quantity against all revenues earned in the energy and OR markets during the commitment period.[1] Cost guarantee payments will typically be made if revenues earned are less than the costs incurred. In making this determination, the IESO will examine other factors, such as whether resources synchronize on schedule and inject energy for the expected length of time. The calculation of the cost guarantee payment for pre-dispatch NQS commitments will not overlap with the financially binding DAM schedule for that resource. During the DAM scheduled hours, the NQS resource will receive a DAM make-whole payment, if applicable.

Unit commitment is about ensuring reliability can be met effectively. In cases when an NQS resource fails to meet its pre-dispatch commitment for reasons that are within its control or influence, system reliability might be impacted, and the IESO will apply a failure charge. The magnitude of this charge will depend on how much energy the resource failed to deliver and whether any additional costs have been incurred to secure a replacement resource.

[1] The commitment period begins at synchronization and includes all hours that the NQS resource is operationally constrained at minimum load point.

Conclusion

The ERUC high-level design addresses existing issues with the current pre-dispatch and unit commitment processes. ERUC will improve competition and produce more efficient market outcomes by taking all relevant costs into account when making commitment decisions. Further, costs will be optimized over multiple hours and the physical constraints of NQS resources, such as minimum output and run-time, will be factored into the pre-dispatch optimization process. With these enhancements, the IESO will be better positioned to schedule the lowest-cost resources to satisfy reliability needs in real-time.

Building on months of extensive consultation with stakeholders, this document is both a comprehensive summary of the decisions that will enable the introduction of an enhanced pre-dispatch model, and a stepping-off point for engagement on the detailed design decisions that will need to be addressed before implementation.

This high-level design is part of a series of changes intended to fundamentally transform the province's electricity markets to deliver electricity to consumers at lowest cost and to better prepare the IESO and market participants for future market evolution.

2. Engine Parameters and Engine Output

The enhanced real-time unit commitment (ERUC) project will implement a new pre-dispatch (PD) optimization engine to replace the IESO's current PD engine. The PD timeframe is the period between clearing of the day-ahead market (DAM) and real-time dispatch. The IESO is also implementing a DAM in order to provide the appropriate incentives for resource operation in real-time, resulting in improved operational certainty for the next day.

The ERUC initiative seeks to improve efficiency and competition by optimizing during the PD timeframe, while providing technically feasible schedules and maintaining reliability. The new Pre-Dispatch plus ERUC optimization engine, referred to as "PD + ERUC" in this document, will re-optimize resources closer to real-time in order to address changes in system conditions.

PD + ERUC will use multi-hour optimization, which optimizes all bids/offers and resource costs over multiple hours at the same time. PD + ERUC will also recognize and respect resource operating restrictions for all applicable resources. In addition, DAM financially binding schedules for non-quick start (NQS) resources will be provided with an initial commitment for their minimum generation block run-time (MGBRT) and minimum loading point (MLP) operational restrictions in all runs of PD + ERUC. The NQS resource with a DAM schedule will not be required to operate below its MLP or to come offline before completing MGBRT. This will be accomplished by applying an "operational constraint" during the NQS resource commitment.

NQS resources have scheduling dependencies between units within the same facility, known as a combined cycle plant. Dependencies between resources within the same NQS facility can be recognized by using "pseudo-units" that model the relationships between resources, as currently done in the day-ahead commitment process (DACP). Hydroelectric resources have operational restrictions, including must run requirements, limited number of daily starts, and scheduling dependencies with upstream or downstream hydroelectric resources on the same cascade river system operated by the same market participant.[2] Improved modelling of NQS resources will be incorporated into PD + ERUC, and this will be consistent across all timeframes, day-ahead to real-time. Improved modelling of hydroelectric resources will also be incorporated in day-ahead and PD timeframes. This will recognize that NQS resources and hydroelectric resources have operational restrictions that limit their ability to generate, and will optimize the scheduling of these resources in all timeframes.

For example, an NQS resource with a combustion turbine must operate in tandem with the associated steam turbine in order to produce electricity at lowest cost. The fuel-fired combustion turbine routes waste heat to the steam turbine, generating additional electricity through conversion of water to steam, and producing up to 50% more electricity from the same fuel compared to a combustion turbine on its own. Combined cycle plant modelling allows generators to offer their dependent units into the market as one "pseudo-unit", reflecting actual operation for each combustion turbine with the associated portion of the steam turbine capacity.

[2] Improved modelling of hydroelectric resources is described under the DAM High-Level Design, Optimization of Hydroelectric Resources.

For hydroelectric resources, a downstream resource may need to generate in one hour in order to pass the water being received from an upstream resource generating in the hour prior. The current pre-dispatch engine optimizes the dependent resources separately, but they cannot operate separately.

The current pre-dispatch engine can generate infeasible schedules, requiring IESO out of market actions or requiring participants to use very high or very low offer prices to economically create feasible schedules. This may also result in inefficiency, where the lowest cost resource is not scheduled. Modelling improvements will recognize dependencies between these resources, providing more feasible schedules that result in less change to be managed. These improvements will be carried from DAM through PD + ERUC and into real-time dispatch.

As in the current market, PD + ERUC will continue to jointly optimize energy and operating reserves to determine the lowest cost resources to meet system requirements and market demand. Also consistent with the current market, security-constrained advisory schedules and prices will be produced by PD + ERUC for resources that bid and offer into the market. A security-constrained optimization engine considers key system operational constraints in order to optimize and maintain system security. These constraints include reserve requirements, transmission security constraints and generation limitations.

PD advisory schedules and advisory prices are currently produced on an hourly basis, and this will continue in PD + ERUC. This information provides an indication of future real-time dispatch schedules and real-time prices. Participants use this advisory information to make decisions about how they wish to bid/offer into the market in future hours. In PD + ERUC, the advisory schedule for an NQS resource will recognize operational restrictions for MLP and MGBRT. Advisory schedules are used to determine when to provide an additional commitment to an eligible NQS resource. Once the commitment is provided, the schedule is no longer advisory for that resource. A commitment means that the NQS resource is operationally constrained to respect its operational restrictions, and will therefore not be required to operate below MLP or come offline before completing MGBRT. A committed resource may receive a cost guarantee payment if market revenues are not adequate to recover its costs. An NQS resource is committed if it is the lowest cost resource to reliably meet demand.

The current PD engine advisory schedules are used to determine NQS resource commitments under a program known as the real-time generator cost guarantee (RT-GCG) program. Through the remainder of this document, the current PD engine will be referred to as "PD + RT-GCG". Under the RT-GCG program, NQS resources may self-commit and receive a guarantee of cost recovery if they have an advisory schedule at MLP or greater for at least half of MGBRT hours based on their energy offers (start-up costs are not competitively assessed). Currently, the advisory schedule for an NQS resource does not recognize operational restrictions for MLP or MGBRT. In the future, PD + ERUC will be able to use advisory schedules to determine when to provide an additional commitment to an NQS resource. At the time of commitment, PD + ERUC will provide a binding start-up instruction based on three-part offers, considering operational restrictions over multiple hours.

Following the PD timeframe, real-time dispatch schedules and prices will continue to be determined by the IESO's dispatch scheduling & optimization software, known as the dispatch scheduling and optimization (DSO). Dispatch instructions that specify required injection and withdrawal quantities will still be issued every five (5) minutes for the next five-minute interval.

The PD engine parameter and output design elements explore key aspects of the PD + ERUC optimization engine and the resulting outputs. These design elements include decisions regarding the timeframe over which the multi-hour optimization will be performed, known as the look-ahead period, as well as the timing, frequency and outputs of the optimization.

2.1 Functional Passes

2.1.1 Design Element Description

Functional passes describe how PD + ERUC will determine NQS resource commitments, advisory schedules and advisory prices. The number of functional passes required to generate commitments, schedules and prices, as well as the key features that will be taken into account in each functional pass, must be determined for PD + ERUC. There can be one or more functional passes, and each pass would have a different objective (e.g., cost minimization, reliability).

The current PD + RT-GCG has one functional pass with the objective to minimize cost. It uses security constrained unit commitment and dispatch scheduling to jointly optimize energy and operating reserves (OR). The following are some of the key features of the PD + RT-GCG functional pass:

- Each hour is independently evaluated. Independent evaluation of each hour means that the evaluation considers all bids and offers for an individual hour, stacking up the supply and demand, in order to determine advisory schedules and advisory prices for that hour. The evaluation does not consider what resources were scheduled for in the hours before the hour under consideration, or what resources will be scheduled for in the hours after.
- Only energy cost offers are evaluated. Other costs such as start-up costs are not competitively evaluated.
- A two-schedule solution is produced, comprising an advisory unconstrained/market schedule and an advisory constrained/dispatch schedule.[3] The unconstrained schedule determines the advisory uniform market clearing price, which does not take into account system constraints. The constrained schedule is the advisory schedule for real-time dispatch scheduling and operation, which takes into account all system constraints.

PD + RT-GCG is not able to take into account operating restrictions of resources because it is evaluating each hour independently. As a result, the lowest cost resources may not be scheduled. For example, PD + RT-GCG does not take into account the MGBRT of the NQS resources. It could schedule a low cost NQS resource with a MGBRT of several hours for as little as one hour, instead of a quick start resource that can operate for one hour or less, but has a higher energy cost. The PD + RT-GCG does not competitively evaluate the start-up cost for the NQS resource, and is unable to evaluate whether offers reflect actual costs.

The results of the functional pass of PD + RT-GCG are used to determine the eligibility of NQS resources for commitment under the RT-GCG program. In the future, PD + ERUC will consider all the relevant information in its functional pass, over multiple hours, to ensure efficient decisions for NQS resource commitment and for scheduling of all other resources.

[3] The IESO is also implementing a Single Schedule Market (SSM) in all timeframes, which will eliminate the unconstrained schedule.

2.1.2 Decisions

Similar to PD + RT-GCG, PD + ERUC will have one functional pass that will use security constrained unit commitment and dispatch scheduling to jointly optimize energy and operating reserves. The objective of the single functional pass is minimization of overall production costs. This means that the functional pass will optimize all bid/offers and resource costs over multiple hours at the same time, while respecting resource operating restrictions. It will competitively evaluate three-part offers. In this way, the functional pass will be able to more accurately determine the lowest cost resources to meet demand.

PD + ERUC will respect the operational restrictions of NQS resources with a DAM schedule, providing advisory schedules that may be higher or lower than the DAM schedule, while respecting MLP and MGBRT. Additional NQS resources will only be committed if they are required to address changes in system conditions after the DAM, and if they are the lowest cost resource to meet forecasted demand during the period under evaluation.

Similar to PD + RT-GCG, once PD + ERUC commits an additional NQS resource, it will respect all operational restrictions in subsequent hourly PD runs, producing technically feasible schedules. It will also respect operational restrictions for any reliability commitments applied by IESO operators.

PD + ERUC will identify new commitments as well as extensions to existing commitments of NQS resources, whether committed in DAM or in a previous pre-dispatch run. It will perform intertie scheduling. It will provide advisory schedules, and advisory locational prices as outlined in the Single Schedule Market (SSM) project.

The functional pass of PD + ERUC will take into account various inputs,[4] including:

- Non-dispatchable load quantity for each hour by zone, using the forecasted hourly peak quantity or forecasted hourly average quantity;
- Dispatchable load bids;
- Hourly demand response offers;
- Variable generation forecast;
- Intertie bids and offers (subject to ERUC design element 5);
- Dispatchable generator offers;
- Self-scheduled generator quantities;
- Registered and offered generator operating parameters, such as MGBRT & MLP, including data for modelling of NQS and hydroelectric resources; and
- DAM schedules for NQS resources (operational constraint for MLP and MGBRT).

Similar to the DAM optimization, PD + ERUC's functional pass to minimize overall production costs, will apply market power mitigation, consistent with the SSM market power mitigation guiding principles. Resources that have market power will be limited in their ability to impact market price or the overall cost to meet demand. However, PD + ERUC does not require a reliability functional pass, as is the case for DAM pass 2, which will use the peak zonal load forecast. The single functional pass of PD + ERUC will use the forecasted hourly peak quantity for any hour where there is a significant difference between forecasted peak quantity and forecasted average quantity. This is consistent with the current PD + RT-GCG.

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[4] Dispatch data and operational data inputs are described fully under ERUC design element Market Participant Data. In detailed design, decisions will be made regarding whether or not bids/offers will be carried forward from DAM into PD + ERUC.

2.1.3 Detailed Design Considerations

At this time, the IESO has not identified any detailed design considerations.

2.1.4 Linkages

The Functional Passes design element is linked to ERUC design elements 2 (Look-Ahead Period), 3 (Frequency and Timing of Run) and 4 (Time Step). The ERUC design elements 2, 3 and 4 directly impact the solution time for the functional pass, as well as the tasks to be accomplished by the functional pass. PD + ERUC must generate results within a specific timeframe in order to produce commitments, schedules and prices that achieve the lowest cost outcome and maintain reliability. The linked design elements must be designed in a way that allows them to effectively work together.

In addition, this design element is linked to the DAM High Level Design, Optimization of Hydroelectric Resources.

2.2 Look-Ahead Period

2.2.1 Design Element Description

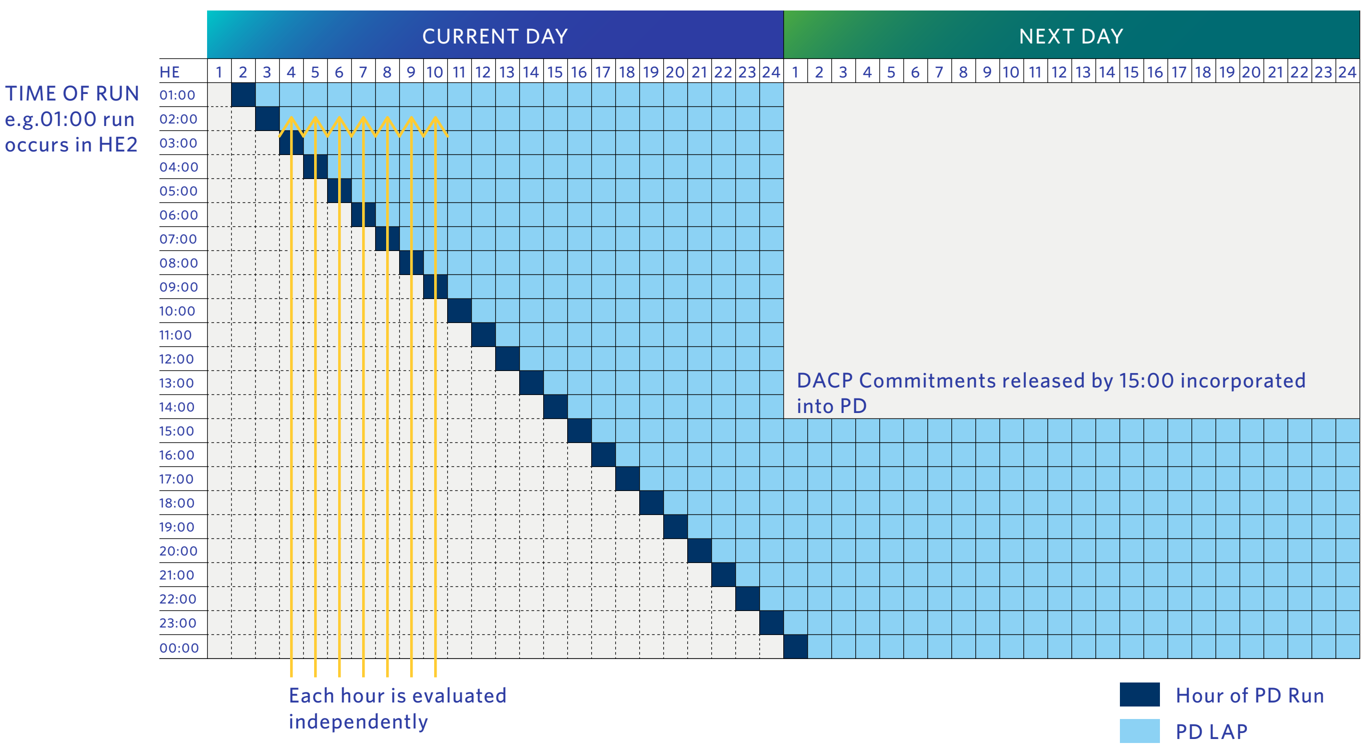
The look-ahead period (LAP) is the timeframe over which the optimization of PD + ERUC will be performed.

The current PD + RT-GCG has a LAP of one hour. This means that each hour is optimized independent of all other hours. For example, at 01:00, PD + RT-GCG evaluates hour ending (HE) 3 independently, then HE4, HE5, up to HE24.[5] This is followed by the next evaluation at 02:00 for each independent hour from HE4 to HE24. The PD + GCG engine looks only at bids and offers for an individual hour to determine the schedules and prices for that hour. It does not consider schedules for any other hours in making decisions.

As a consequence of evaluating each hour independently, PD + RT-GCG is not able to consider operating restrictions of resources. This means that the schedules may not be efficient. If multiple hours were optimized at the same time, a different schedule would result, which would be more efficient than a schedule based on independent evaluation of each hour.

Starting with the run at 15:00, PD + RT-GCG also evaluates the hours of the following day, again with each hour independently evaluated. The number of hours in the LAP varies across the day. The following figure illustrates the hours that are being independently evaluated each time PD + RT-GCG is run.

FIGURE 4: CURRENT PD + RT-GCG LOOK-AHEAD PERIOD



[5] The "Hour Ending" convention is a standard way of numbering each hour in a day, from HE1 to HE24. For example, HE2 runs from 01:01 to 02:00 (i.e., it is the hour that ends at 02:00). The PD run that starts at 01:00, is being run during HE2.

In order to determine the optimum length of the LAP for PD + ERUC, consideration must be given to ensuring reliability of the system, given the Ontario generation resource mix. Unlike other jurisdictions, Ontario is not able to use a short LAP. Other jurisdictions have many flexible generator resources that can come online in under one hour. Ontario has few flexible generators and relies on NQS resources for flexibility and reliability. At critical times in the day, the LAP must be longer, to allow for evaluation of the start-up and MGBRT time required for the majority of NQS resources. In order to meet demand for the morning ramp period, the LAP must start in the previous day. However, it is important to evaluate a similar timeframe to the DAM (HE1-24) during the initial run of PD + ERUC that considers hours of the next day, in order to produce consistent results across all timeframes. Therefore, the initial run should not occur earlier than necessary to meet morning ramp requirements.

In addition, the LAP must consider all hours until end of the operating day to correctly evaluate remaining available energy based on the daily energy limits of hydroelectric resources. This ensures that limited energy is used at the optimal time during the day and that the limits are not exceeded. Ontario has significantly more hydroelectric generation than other jurisdictions.

Finally, the LAP must be long enough to consider the morning and evening demand peaks in one optimization early in the day. A longer LAP at this time will avoid the potential inefficiency of starting an NQS resource twice in one day, instead of keeping it online throughout the day.

2.2.2 Decisions

PD + ERUC will use multi-hour optimization. By evaluating all bids/offers and operating restrictions over multiple hours, the optimization will determine the lowest cost resources to meet demand. For example, a quick start resource that has a higher energy cost offer price, but can operate for a shorter period may be scheduled instead of committing an NQS resource with a MGBRT of several hours. A hydroelectric resource that has limited energy will be used in the hours that result in the lowest overall cost. An NQS resource will be scheduled to start once during the day rather than twice, if that is lowest cost.

Similar to PD + RT-GCG, the number of hours in the LAP will vary across the day. The LAP will always start with the hour immediately following the hour of the evaluation. It will include specific hours that depend on the time that the evaluation occurs. For example, the PD + ERUC evaluation at 01:00 (HE2) will consider HE3 to HE24, evaluation at 02:00 (HE3) will consider HE4 to HE24. The LAP will always include all hours until the end of the day, allowing evaluation of the daily energy limits of hydroelectric resources.

Given that the PD timeframe is the period between clearing of the DAM and real-time operation, it is appropriate to begin discussion of the LAP at the time that DAM clears. The DAM financially binding schedule for the next day will be provided daily at 13:30 Eastern Prevailing Time.[6]

A shorter LAP is acceptable after DAM clears because any additional NQS resources needed to ensure reliability for the rest of the current day have likely already been committed during earlier runs of PD + ERUC. Further, the DAM ensures that the NQS resources needed for reliability for the following day are already committed, unless there have been significant changes in system conditions following the DAM.[7] Evaluation of NQS resources that have a MGBRT extending over midnight will be considered for DAM and PD + ERUC. The shortest LAP will be for the 19:00 run, with a 4-hour LAP for HE21 to HE24 (inclusive) of that day.

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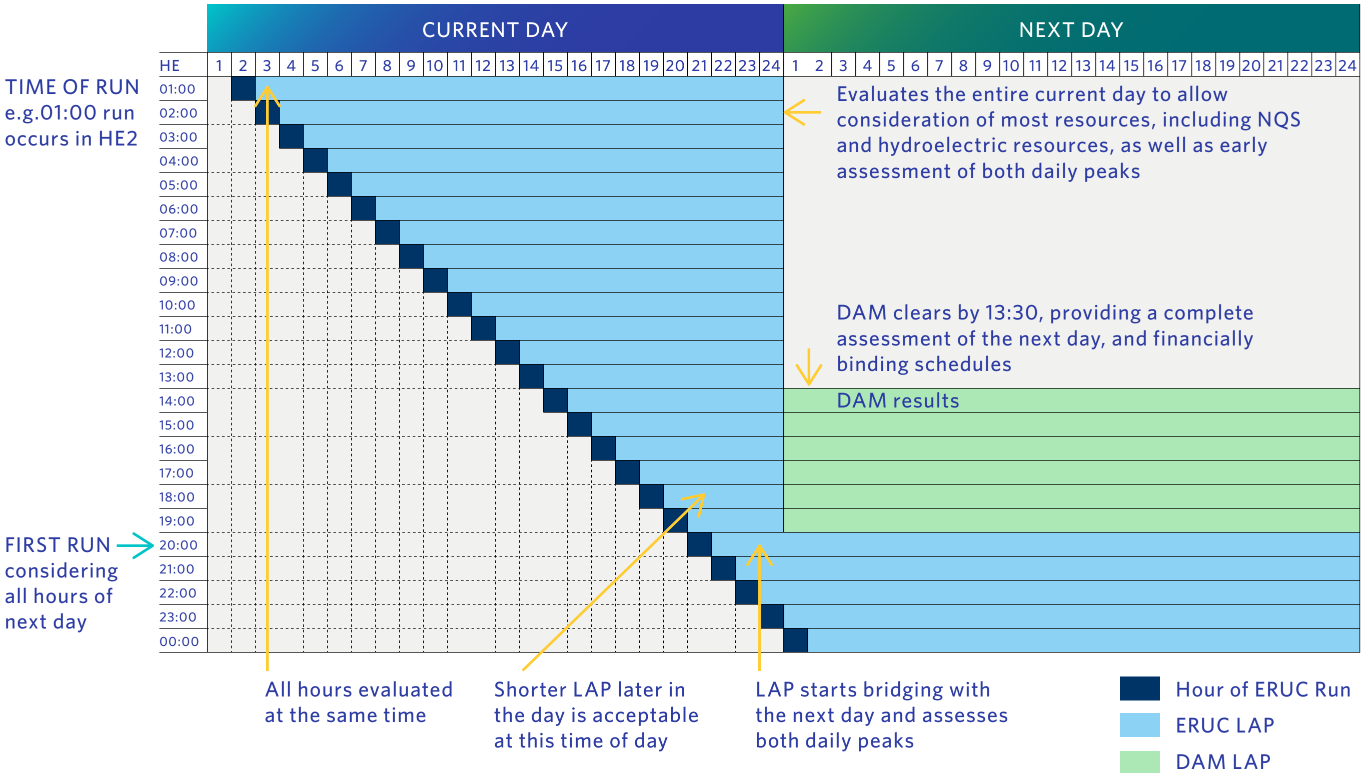
[6] PD + ERUC will use Eastern Standard Time, the same as PD + RT-GCG. Participants will need to consider that the DAM financially binding schedule for the next day will be provided daily at 13:30 Eastern Prevailing Time, and adjust accordingly.

[7] In the case of significant changes in system conditions for next day needs between 13:30 and the first run that considers all hours of the next day, the IESO will determine if additional commitment of NQS resources is required earlier. This is discussed under the ERUC design element for Frequency and Timing.

FIGURE 5: PD + ERUC LOOK-AHEAD PERIOD



There will be improved operational certainty for the following day due to the DAM,[8] so there is no need to begin re-optimizing for hours of the next day until later, when required for reliability reasons. In fact, as previously noted, re-optimizing too soon after the DAM clears would result in an evaluation of a significantly different timeframe than the HE1-HE24 period evaluated by DAM. This would produce results that might be inconsistent with DAM financially binding schedules. The results of the PD + ERUC optimization should be based on the same information as the DAM optimization to the extent possible. In jurisdictions that have a very short LAP, alignment between PD and DAM is less of a concern; however, given the current resource mix, the LAP for Ontario must be lengthy at certain times of day.

For reliability reasons, it is necessary to run the initial PD + ERUC considering all hours of the next day must be run earlier than the ideal timing at 23:00, which would like the DAM, evaluate HE1 to HE24. The initial PD + ERUC for the next day will be run at 20:00 in the day-ahead, to ensure that the required additional NQS resources can be online in time to meet demand for the morning ramp period. An NQS resource that is required for reliability at 06:00 may need notice of commitment as early as 20:30, due to its start-up and ramp time. The 20:00 evaluation has the longest LAP, optimizing over 27 hours, from HE22 of the current day until HE24 of the next day, inclusive.

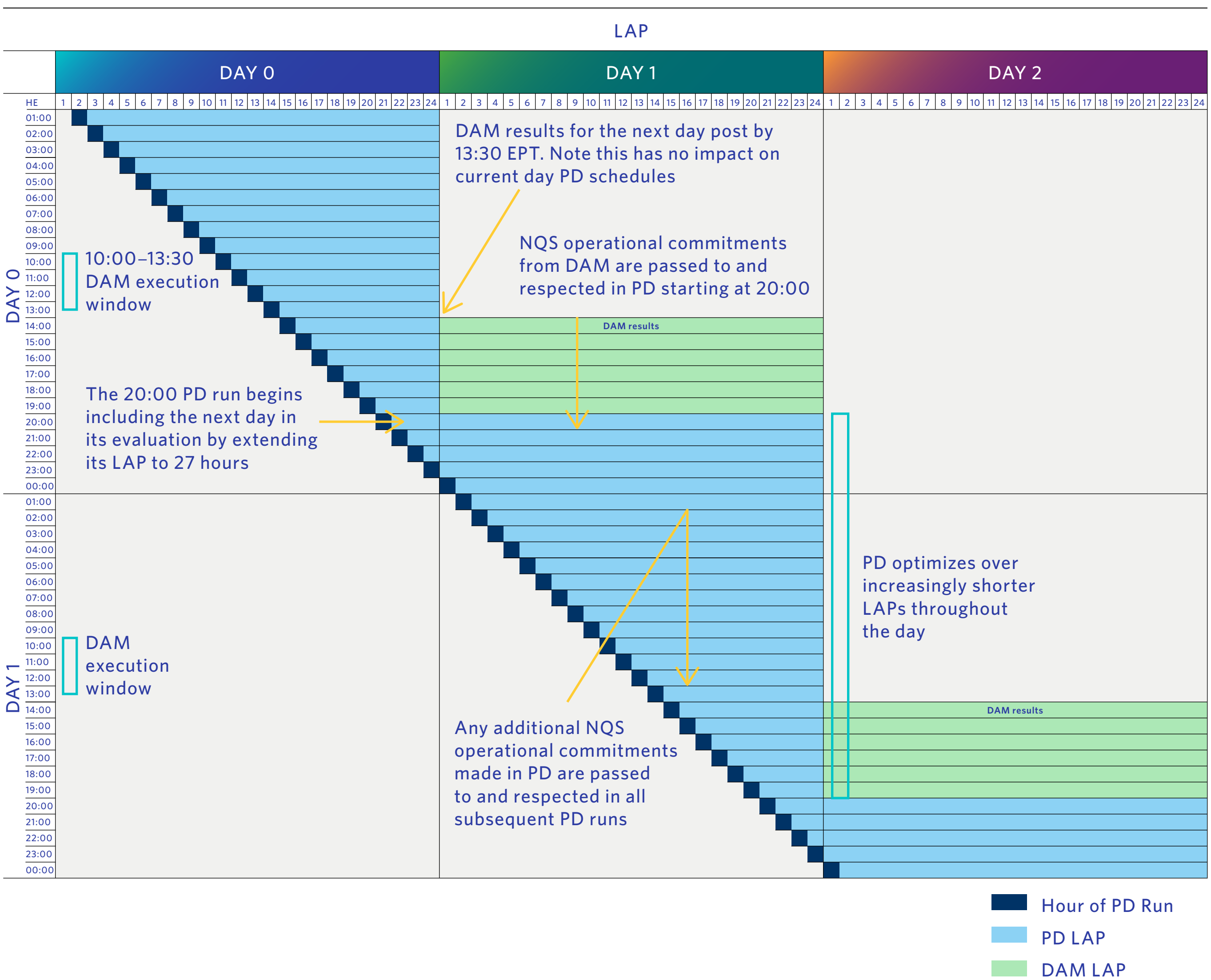
[8] Resources will be settled based on bids/offers into the DAM. Real-time deviations from DAM schedules will be bought or sold back at real-time prices. This provides appropriate incentives for operation in real-time resulting in operational certainty.

The PD + ERUC evaluations starting at 20:00 (in HE21), will incorporate the minimum operational constraints resulting from DAM financially binding schedules for NQS resources, for the applicable hours of the next day. The PD + ERUC evaluation at 20:00 is the first run to address any inconsistencies between a current day's schedules and the DAM schedules for next day. The PD + ERUC runs at 20:00, 21:00 and 22:00 will bridge current and next day, recognizing any operational restrictions and responding with the most efficient schedule.

The PD + ERUC run at 23:00 is the first run that, like the DAM, considers only the hours next day, HE1 to HE24. The LAP in the first part of the day, e.g., 01:00, 02:00, will continue to provide an assessment of both daily demand peaks, and still have a lengthy LAP for consideration of additional NQS resource commitments. The LAP for each evaluation will continue to be reduced by one hour as the day progresses.

The figure below provides an overview of the interaction between DAM and PD + ERUC over a three-day period. Note that DAM results for the next day have no impact on current day PD + ERUC schedules. The evaluations that include all hours of the next day start at 20:00, and incorporate the NQS resource MLP and MGBRT operational constraints for hours of the next day, as per DAM financially binding schedules provided earlier at 13:30.

FIGURE 6: INTEGRATION OF DAM AND PD + ERUC



2.2.3 Detailed Design Considerations

The IESO will consider any interface issues in the interaction between the PD + ERUC evaluation and DAM financially binding schedules in the detailed design phase. Specifically, the PD + ERUC evaluation must consider operational restrictions including constraints resulting from the DAM in order to deliver feasible scheduling. A PD + ERUC evaluation that does not consider all hours of the next day (which includes all PD + ERUC evaluations up to the run at 20:00) may indicate that a resource scheduled in the DAM for the next day should ramp down. Taking into account a DAM financially binding schedule in the early hours of the next day may result in a different decision. The management of inconsistencies between PD + ERUC and DAM will be addressed with stakeholders in the detailed design phase.

Evaluation of NQS resources that have a MGBRT extending over midnight will be considered for both the DAM and PD + ERUC during detailed design. The current DACP allows escalating start-up cost offers during the hours prior to midnight. Any decision would need to consider market power mitigation and reference levels for start-up costs.

2.2.4 Linkages

The LAP design element is linked to ERUC design elements 1 (Functional Passes), 3 (Frequency and Timing of Run) and 4 (Time Step). The ERUC design elements 1, 3 and 4 directly impact the solution time, as does the length of the LAP. The more that is being accomplished by the functional pass of the PD + ERUC engine, e.g., market power mitigation, the longer the solution time relative to the time available.

2.3 Frequency and Timing of Run

2.3.1 Design Element Description

This design element describes:

- *Frequency*: how often the PD + ERUC engine must be run; and
- *Timing*: when results of the PD + ERUC engine must be provided.

The current PD + RT-GCG engine runs hourly and provides advisory prices and schedules, including binding intertie schedules for the next dispatch hour by 15 minutes past the hour. The hourly run frequency and notification time facilitate the coordination of intertie transaction schedules between the IESO and neighbouring jurisdictions.[9] The timing also provides an opportunity for market participants to review advisory schedules and prices, and respond by revising bids or offers before the next pre-dispatch run, if desired. Finally, the timely provision of advisory schedules and prices inform NQS resources to self-commit under the existing RT-GCG program.

Frequency

The frequency of the PD + ERUC run will affect the efficiency of the economic evaluation that optimizes resources. More frequent evaluation considers more current input data, which will generally improve efficiency of the evaluation. Frequency of the run will also impact reliability because a more frequent run will address changes in system conditions in a more timely fashion. These efficiency and reliability improvements are only realized if data inputs used in the evaluation (e.g., forecasts) are updated at least as frequently as the PD + ERUC process is run. Demand and variable generation forecasts that look out over the forecast period are currently updated hourly because of diminishing returns to forecast accuracy improvements associated with more frequent updates. Forecasts that look out only 2-3 hours may benefit from more frequent updates, but do not satisfy the requirements of the PD + ERUC LAP (up to 27 hours).

Since frequency will also determine how often advisory prices and schedules are updated, and how often intertie transactions are scheduled, it must be adequate to address hourly intertie scheduling and provide informational benefits for the IESO and participants. A PD + ERUC evaluation that is less frequent than hourly may lead to decreased efficiency and increased production costs due to the use of potentially out-of-date information. Less frequent evaluation may also adversely impact reliability if system conditions change between runs.

[9] To ensure fair and efficient use of interties, the IESO has established checkout processes to ensure intertie transactions scheduled in the Ontario market have corresponding schedules in neighbouring jurisdictions. In order to complete checkout, binding intertie schedules produced by PD + RT-GCG are required no later than 15 minutes past each hour.

Timing

The PD + ERUC engine will need to provide the advisory prices and schedules at a specific time, including binding intertie schedules for the next dispatch hour and NQS resource commitments.

The timing must ensure that the "checkout" processes and protocols for scheduling intertie transactions can be performed, respecting agreements between the IESO and neighbouring jurisdictions. The IESO has a checkout process that addresses intertie scheduling protocols with neighbouring jurisdictions, ensuring fair and efficient use of interties. For NYISO, the IESO determines projected real-time intertie schedules based on the two-hour ahead forecast. Real-time intertie schedules for other neighbouring jurisdictions are based on the one-hour ahead forecast. Based on established checkout processes, intertie schedules for the next two hours are required no later than 15 minutes past the hour.

The notification time must allow adequate time for an offline NQS resource to acknowledge and confirm[10] a new commitment, and prepare to begin their start-up processes. An NQS resource will receive hourly advisory schedules indicating that it may be required in future hours. The time needed by the generator to actually perform the start-up process and ramp to MLP will already be considered by the PD + ERUC evaluation. However, the notification time for the PD + ERUC commitment, including the start of an NQS resource before its DAM financially binding schedule, should allow at least 30 minutes for their confirmation prior to start of the next PD + ERUC run at the top of the hour.

Finally, the publishing notification time for extensions to commitments must provide adequate notice for NQS resources to either stay online or prepare to shut down. The initial operational constraint for a DAM schedule or a new PD + ERUC commitment will be limited to the MLP and MGBRT, and extensions to the commitment may be provided. An NQS resource that is already online for its MGBRT hours will receive hourly advisory schedules indicating that it may be required/extended beyond its MGBRT hours. However, it is not until the hour before it completes its MGBRT that the generator will know if the PD + ERUC commitment is be extended by one hour, or not. The publishing notification time for the extension of commitment should allow at least 30 minutes to facilitate continued operation, or preparation to begin ramping down. An NQS resource may continue to be extended on an hour by hour basis.

2.3.2 Decisions

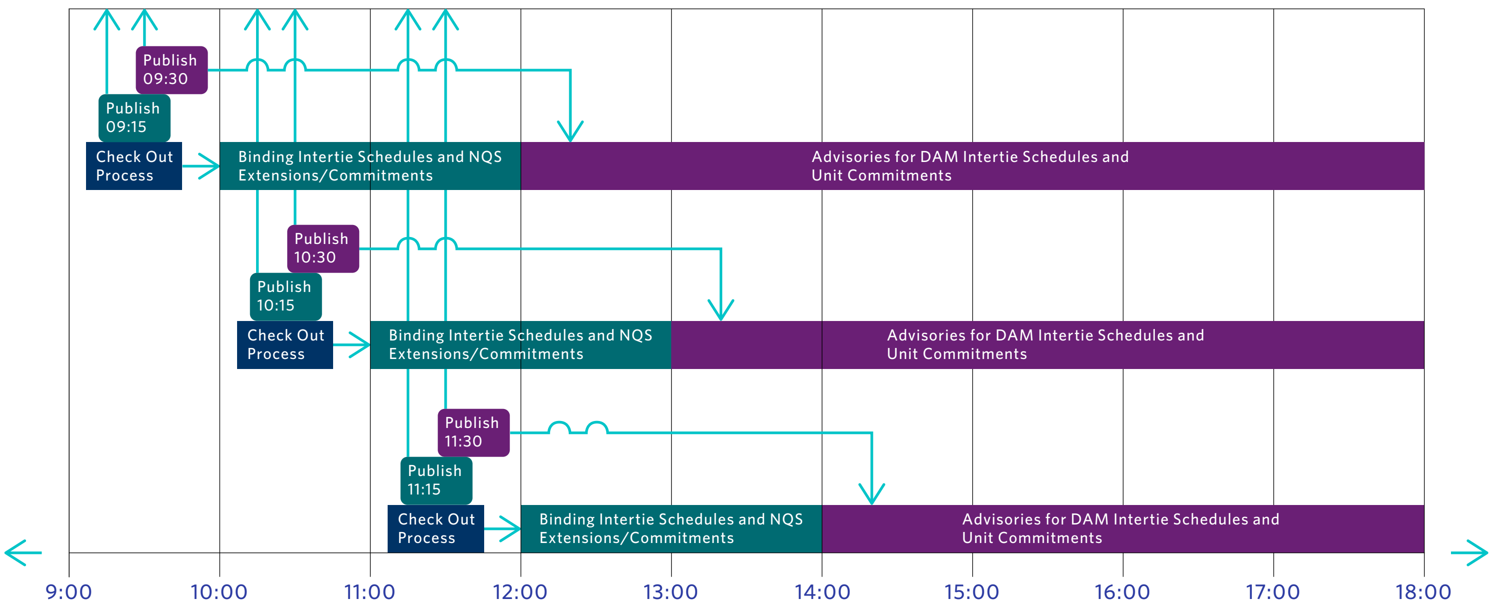
In summary, PD + ERUC will be run every hour. The results of the next two hours will be provided every hour by 15 minutes past the hour for intertie transactions and NQS resource extensions, and then the results for all hours will be provided by 30 minutes past the hour[11] for all resources, including notification of new NQS resource commitments.

In the example below, the 09:00 run provides results for the mandatory window hours by 09:15, facilitating the intertie checkout process and extension of NQS resource commitment. Results for all hours are provided by 9:30 am. Information is passed to the next hourly run at 10:00.

[10] The process for IESO notification and NQS resource confirmation will be developed during detailed design, as described under Binding Start-up Instruction and Operational Constraint in section 2.5.2.

[11] It may be possible to provide all results by 15 minutes past the hour, to be determined during implementation.

FIGURE 7: FREQUENCY AND TIMING



Frequency

As with the current PD + RT-GCG, PD + ERUC runs will occur hourly to allow efficient scheduling and minimize overall production costs. This frequency allows efficient scheduling and minimization of overall production costs. Hourly frequency provides intertie transaction schedules that allow effective management of the interties and respect agreements between the IESO and neighbouring jurisdictions, as well as facilitating reliability by regularly evaluating and addressing any changes in system conditions.

Timing

By 15 minutes past each hour, extensions of NQS resource commitments will be provided for the next hour. At the same time, intertie schedules for real-time operation will be provided for next hour, and advisory intertie schedules will be provided for the hour after.

By 30 minutes past each hour, the following additional information will be provided for all hours of the LAP at the same time, starting with the next hour and continuing until the end of the LAP:

- Advisory schedules and advisory prices for all resources; and
- New NQS resource commitments (i.e., binding start-up instruction and operational constraint).[12]

The information provided at 30 minutes past the hour will not change information already provided at 15 minutes past the hour. The 15-minute and 30-minute notification timing requirements described above meet the needs for certain information, specifically intertie schedules and NQS resource extensions, to be provided earlier regardless of processing limitations. Unlike the current PD + RT-GCG, the PD + ERUC will use multi-hour optimization over a lengthy look-ahead period, considering three-part offers, resource operational restrictions, and market power mitigation. This additional complexity will increase processing time, as a result, there will be limited time available to produce data on an hourly basis.

[12] The operational constraint for a new NQS resource commitment will be respected in all future runs of PD + ERUC.

The timing of the PD + ERUC run will ensure that existing timelines for intertie transaction checkout processes are respected. Timing of providing extensions to NQS resource commitments should allow adequate notice for resources to either stay online or prepare to shut down. The timing should also provide adequate time for market participants to review their advisory schedules in order to revise offers before the mandatory window, or to confirm a new commitment.

Evaluation During Between 13:30 and 20:00

Under normal conditions, all NQS resources required for reliability will already be committed either by PD + ERUC or DAM by 13:30. However, the IESO may need to evaluate whether additional NQS resource commitments are needed for next day reliability in the case of significant changes in system conditions after the DAM clears. Under these rare circumstances where an additional commitment is needed in advance of the 20:00 PD + ERUC run in order to bring an NQS resource on in time to meet the need, such a commitment will be issued manually by IESO operators. Additional commitment notifications will only be issued through manual intervention if required to meet Ontario demand or reserve requirements.

2.3.3 Detailed Design Considerations

The IESO will need to determine the exact start time of the PD + ERUC in each hour by considering factors such as availability of information regarding the latest system conditions, the latest demand/ variable generation forecast, and ramping requirements at top of the hour.

The IESO will need to consider the processing time required for running PD + ERUC. The look-ahead period will be lengthy and significant data processing is required to perform the optimization over multiple hours at the same time. Unlike the current PD + RT-GCG, this optimization will also need to include market power mitigation, and consider three-part offers and resource operational restrictions. Give the limited time available to produce data on an hourly basis. The same functional pass may need to be run more than once, but for different hours (e.g., one run for the near-term hours and another run for the rest of the look-ahead period). There will still be only one functional pass, and each run would perform the same optimization with the objective of cost minimization. Multiple runs would require information to be passed between runs.

In the case of significant changes in system conditions between 13:30 and 20:00 for next day needs, the IESO must be able to commit additional NQS resources for reliability.[13] The IESO will develop objective and transparent criteria to determine if additional commitment of NQS resources is required prior to the 20:00 PD + ERUC run in order to bring the resources on in time to meet the need.

2.3.4 Linkages

The timing and frequency design element is linked to ERUC design elements 1 (Functional Passes), 2 (Look-Ahead Period) and 4 (Time Step). ERUC design elements 1, 2 and 4 directly impact the solution time and may impact the determination for the timing and frequency of the PD + ERUC runs.

[13] In a scenario where there are exceptional reliability concerns and there are no internal resources remaining to commit, the IESO may solicit non-DAM import offers for hours beyond the next two forecast hours. This is outlined under ERUC design element Intertie Transactions.

2.4 Time Step

2.4.1 Design Element Description

The time step is the duration of the interval used for optimization and scheduling of resources. The time step in the current PD + RT-GCG model is hourly. Each interval is evaluated and optimized over one hour, resulting in advisory schedules and advisory prices for each hour in the optimization. This hourly time step also aligns with intertie transactions that are currently scheduled hourly.

Optimized schedules could be produced in increments of five minutes, 15 minutes, 30 minutes, one hour, two hours, and so on. Real-time dispatch produces schedules with a relatively short time step of five minutes based primarily on system input data (e.g., forecasts) that also have a five minute granularity. Similarly, the hourly time step used by PD + RT-GCG is based on forecasts that have an hourly granularity. Because forecast accuracy significantly diminishes further out along the PD + RT-GCG forecast period (24 hours or more), there is little benefit to having a (five-minute) granular forecast looking out over the PD + RT-GCG forecast period.

Other factors that influence the determination of an appropriate time step include: efficiency of the optimization, co-ordination with intertie scheduling, and processing time.

The time step will affect the efficiency and precision with which resources are scheduled and NQS resources are committed. Scheduling and committing with shorter time steps mean that the resource is more likely to produce a more efficient solution. However, shorter time steps mean more schedules need to be produced, impacting on submission of bids/offers, demand forecasts, variable generation forecasts, and reporting, and increasing the complexity and processing time associated with optimization.

A time step longer than one hour would also introduce imprecision in the timing of operational constraints for NQS resources. These resources may not be required for multiple hours once the MGBRT is complete, and the extended commitment could be inefficient. Further, a time step longer than one hour would not facilitate the necessary hourly intertie scheduling to meet the IESO's agreements with other jurisdictions.

2.4.2 Decisions

Under the new PD + ERUC model, the time step for all advisory schedules and prices will continue to be hourly. Because inputs used in the optimization of the pre-dispatch timeframe are hourly, like demand forecasts and variable generation forecasts, a more granular time step would be unlikely to generate an efficiency improvement. Using an hourly time step will allow the optimization to solve in a timely manner.

An hourly time step is suitable for evaluating all resources, including NQS resources that have longer start-up times and require an operational constraint. An hourly time step enables a longer look-ahead period and meets the requirements for intertie scheduling.

2.4.3 Detailed Design Considerations

The IESO has not identified any mandatory considerations for detailed design. However, the IESO may consider the future capability of shorter-term time steps in the near-term hours to facilitate future market improvements such as more frequent intertie scheduling.

2.4.4 Linkages

The time step design element is linked to ERUC design elements 1 (Functional Passes), 2 (Look-Ahead Period) and 3 (Frequency and Timing of Run). The ERUC design elements 1, 2, and 3 directly impact the solution time for the functional pass, as well as the tasks to be accomplished by the functional pass.

2.5 Binding Start-Up Instruction and Operational Constraint

2.5.1 Design Element Description

NQS resources are eligible for a commitment because they must prepare to start-up well in advance of real-time, when the ability to recover their costs from the real-time market is uncertain. Once online, they need to remain operating at a minimum level of injection (i.e., their MLP) for a minimum time period (i.e., their MGBRT) for technical equipment reasons. This design element reviews how a resource initiates its commitment and how this commitment is carried through pre-dispatch.

Currently, NQS resources self-commit under the RT-GCG program by calling the IESO and indicating they are eligible. This "invoking" is a participant-driven process that will initiate commitment if the resource sees itself meeting the cost guarantee eligibility criteria. The NQS resource must have a PD + RT-GCG advisory schedule at its MLP or greater, for at least half of its MGBRT hours in order to be eligible. Provided this criteria is met, it is up to the resource to identify which hour it intends to begin its commitment.

The NQS resource is then manually constrained by the IESO to its MLP for its MGBRT; this is the operational constraint that is manually respected in all future runs of PD + RT-GCG. For the duration of the operational constraint, the resource follows dispatch, injecting at or above MLP. After the MGBRT is completed, the resource continues to follow dispatch. It may continue to be dispatched at or above MLP if economic, or may be dispatched offline.

2.5.2 Decisions

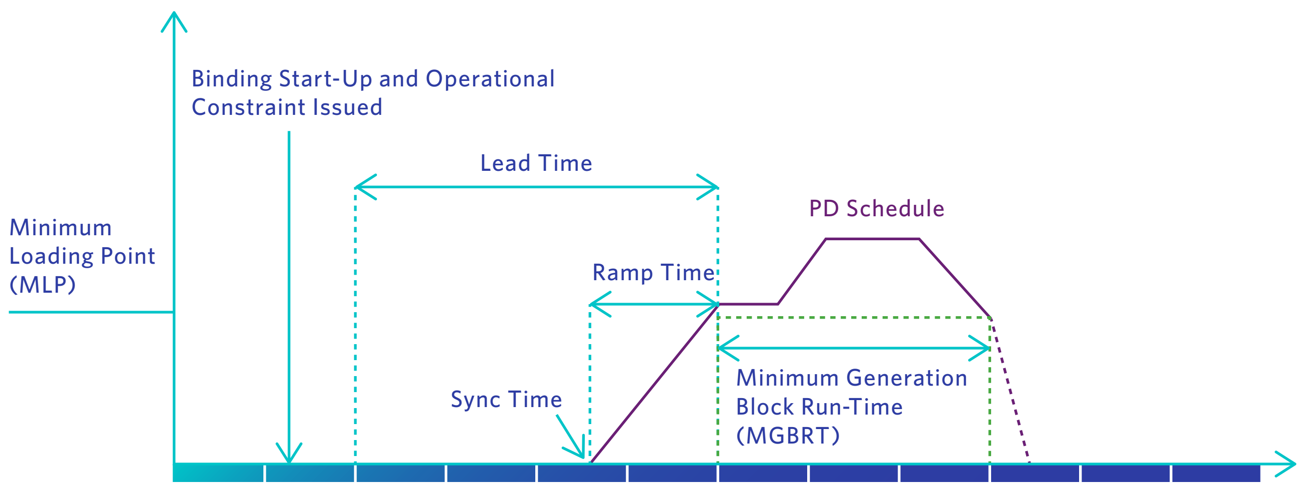
Binding Start-Up Instruction and Operational Constraint

With PD + ERUC, NQS resources will not self-commit outside of the DSO. PD + ERUC will schedule and commit NQS resources, directing the market participants to come online and reach MLP at a certain time, based on offer data. The initiation of this commitment process is the binding start-up instruction. Unlike the self-commitment process under the PD + RT-GCG, this should result in generators coming online exactly when they are most efficient.

The binding start-up instruction obligates the resource to begin the process of getting online to provide energy to the grid. The binding start-up instruction to commit an NQS resource will be provided at the latest possible PD + ERUC run for the resource to physically reach its economic schedule. All other PD + ERUC schedules provided prior to receiving a binding start-up instruction should be considered advisory.

For example, a resource may require four hours' notice to reach the MLP. PD + ERUC will run every hour and provide an advisory schedule for the resource. PD + ERUC will not commit this resource until the last possible run that respects the resource's lead time, recognizing that system conditions can change such that the resource is no longer needed. Following that run, the NQS resource will be issued a binding start-up instruction advising them of the time of their commitment to reach MLP, including assumptions for synchronization and ramp time.

FIGURE 8: BINDING START-UP INSTRUCTION BASED ON LEAD TIME



The new PD + ERUC engine will also optimize all resources over its entire LAP to ensure scheduling consistency while respecting operational restrictions. As a result of the new multi-hour optimization capability, NQS resources will be directly scheduled within PD + ERUC while respecting their lead time, MLP and MGBRT. This means manual constraints to be applied outside of the DSO to respect these characteristics are no longer required. Instead these operational constraints are passed automatically through subsequent PD + ERUC runs over the day. Application of an operational constraint at the time of the binding start-up instruction means that the resource will be dispatched to at least the MLP for the duration of MGBRT.

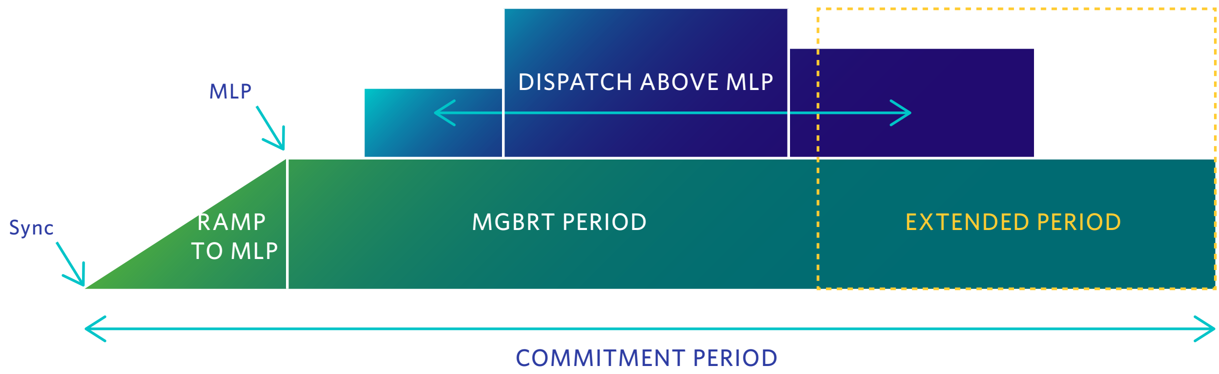
Extension of Operational Constraints

After the initial operational constraint for MGBRT, PD + ERUC may extend the MLP operational constraint of an NQS resource that is already online on an hour-by-hour basis if it is the lowest-cost resource to meet the need. As a result, NQS resources may be kept online to meet demand in future hours, avoiding use of higher-price resources. The extension, if applicable, will be applied by PD + ERUC during the resource's final MGBRT hour.

Similar to the current market, the resource follows real-time dispatch, injecting at or above MLP. Once the operational constraint is no longer extended, the resource will continue to follow its dispatch instructions.

The commitment period starts when the resource synchronizes to the grid and includes the entire period of time that the resource is constrained at its MLP, which may extend beyond the MGBRT. The following figure illustrates an extended commitment period for an NQS resource, including its dispatch during the commitment period.

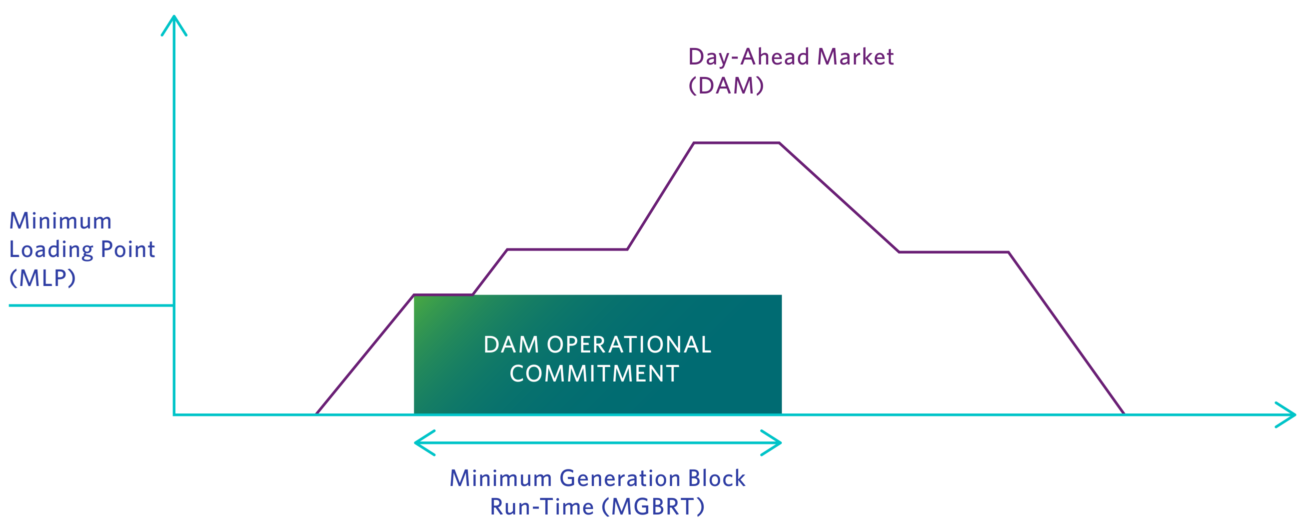
FIGURE 9: EXTENDED COMMITMENT PERIOD



Interaction with DAM Schedule

The DAM design element for "Initiation of Operational Commitments" provides for operational constraints for NQS resources. As with PD+ERUC, operational commitments can also be initiated in DAM. These constraints will be used as inputs to PD + ERUC, which will not change the MGBRT operational constraint set by DAM. This will provide operational certainty for the IESO and market participants. The following figure illustrates an example of a DAM financially binding schedule for an NQS resource, showing its DAM operational commitment for MGBRT.

FIGURE 10: DAM SCHEDULE WITH A DAM OPERATIONAL CONSTRAINT



PD + ERUC may, however, add to the MGBRT operational constraint set by DAM in order to economically respond to changes in real-time conditions. This may include issuing a binding start-up instruction to the resource earlier than its DAM schedule. In this instance, the hours with a DAM operational constraint would continue to be respected and remain unchanged. PD + ERUC would add to the operational constraint by committing the resource to its MLP for hours preceding the original DAM operating constraint.

PD + ERUC could also extend the operational constraint beyond the hours established in DAM. The NQS resource may receive advisory schedules of MLP or greater that indicate a potential extension past the original operating constraint. This could extend the commitment beyond the original DAM schedule.

2.5.3 Detailed Design Considerations

The IESO will need to consider the following in detailed design:

- *Notification*: the process and timing for notifying market participants of a binding start-up instruction and operational constraints;
- *Confirmation*: the process and timing of the confirmation the IESO will need to receive from market participants in response to any notification of commitment, in order to ensure operational certainty; and
- *Reporting*: any public reporting of information relating to binding start-up instructions and operational constraints.

2.5.4 Linkages

The binding start-up instruction and operational constraint design element is linked to ERUC design elements 3 (Frequency and Timing of Run) and 10 (Market Participant Data). The linkages are as follows:

- *Frequency and Timing*: PD + ERUC results for the next hour will be provided by 15 minutes past each hour, which should allow sufficient notice to NQS resources of an extension of the commitment into the next hour.
- *Market Participant Data*: NQS resources will provide the IESO with the operating parameters (such as MLP, MGBRT and lead time) needed to evaluate and schedule these resources.

3. Market Power Mitigation

In order to achieve efficient scheduling and commitment, the wholesale markets seek to encourage participants to offer their resources at their short-run marginal costs. This is achieved by subjecting resources to competitive forces – offering at short-run marginal cost is an efficient strategy in a competitive market.

Market power mitigation refers to the actions necessary to prevent market participants from taking advantage of market power they may have in a local area. This can occur when lack of competition creates incentives for participants to raise their offer prices above their short-run marginal cost and inappropriately profit as a result. Currently, market power mitigation is performed ex-post or "after the fact," which allows the IESO to use actual energy cost data for the period in which market power is being reviewed.

A market participant can exercise market power by either economically or physically withholding supply from the market. Economic withholding occurs when a portion or all of a resource's available supply is offered at prices that are too high. Physical withholding occurs when a portion of or all available capacity is not offered into the market, increasing the price at which the remaining supply is sold. Both economic and physical withholding should be evaluated in all timeframes, including in pre-dispatch.

The impact of the exercise of market power from economic withholding can be addressed by identifying offers that materially depart from estimated short-run marginal costs (including opportunity costs). These offers are replaced with an estimate of a cost-based offer, referred to as a "reference level."

Typically, exercise of market power is more easily thought of in the context of energy offers. However resources submitting three-part offers and operational restrictions must be also tested for the exercise of market power via these other parameters. Confirmed conduct violations must be assessed to measure price and cost impacts.

Once an NQS resource is committed in PD + ERUC or scheduled in DAM, restrictions to offer changes must be considered due to inherent competitive advantages resulting from a commitment.

The design elements in this section include discussion of:

- Mitigation of commitment costs; and
- Offer obligations and offer change restrictions.

3.1 Commitment Cost Mitigation

3.1.1 Design Element Description

A methodology must be established to determine when to mitigate commitment costs[14] in order to address the potential exercise of market power.[15] The exercise of market power reduces economic efficiency because prices impacted by market power do not reflect short-run marginal costs, resulting in inefficient outcomes in both the short- and long-run. Higher consumer costs from the exercise of market power are inconsistent with the premise of a competitive electricity market.

Currently, the IESO indirectly prevents the exercise of market power for an NQS resource's commitment costs by pre-approving the amounts allowed for submission. Any time a resource comes online under the RT-GCG program, it submits these pre-approved costs which are not considered in the optimization and do not impact dispatch or market clearing prices. Market participants are, therefore, currently unable to exercise market power via the submission of their commitment costs.

The new market design with PD + ERUC relies on competition rather than pre-approvals to instill market discipline on commitment costs. Participants will submit commitment costs as part of their three-part offers, no longer bound by the pre-approved framework. It is expected competition between NQS resources vying to receive a schedule, will keep commitment costs close to marginal costs. This competition did not previously exist, as commitment costs were only known after-the-fact at settlement, well after the actual scheduling.

There may be instances where insufficient competition occurs, resulting in the potential exercise of market power. Additionally, the operational constraints respecting MLP and MGBRT may create conditions where a scheduled resource possesses market power. For these reasons, a market power mitigation framework that considers the impact of commitment is required in the pre-dispatch timeframe.

The IESO has conducted a detailed analysis on how market power mitigation is conducted in other jurisdictions.[16] The following are two approaches that are broadly used for mitigation of market power:

1. *Pivotal Supplier Test*: this process helps to determine whether a resource impacting a binding transmission constraint is also essential to resolving the constraint. This is a structural test that assesses the potential for the exercise of market power.
2. *Conduct and Impact Test*: this process helps to determine whether market participants offered above competitive levels,[17] raising prices or uplifts above the competitive outcome. This process includes an implicit structural test. Under the structural test, if prices were not affected, then market power will not be considered to have been exercised. The impact test portion of this process is further broken down into two tests: whether energy or operating reserve prices were impacted and whether uplifts resulting from guarantee payments were impacted.

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[14] Commitment costs are start-up costs, speed-no-load costs and energy costs up to MLP. These costs, along with incremental energy costs (above MLP, up to maximum offered quantity), form the components of the 3-part offers that are used to optimize production decisions for NQS resources.

[15] Market power is discussed in detail in the SSM High-Level Design document, section 3.

[16] See slide deck: Market Power Mitigation and Load Pricing, November 13, 2017

[17] The competitive level that will prevent mitigation is offering at some price which does not fail the conduct test. The competitive level will reflect the reference level plus some allowed margin (the conduct threshold).

3.1.2 Decisions

The decisions presented in this section build on the market power mitigation decisions outlined in the SSM High-Level Design document, which are applied across all timeframes. Decisions directly related to resources that have commitment costs are presented below.

The IESO has determined that a ***conduct and impact test*** will be used for market power mitigation relating to commitment costs and other parameters. The conduct and impact test is further discussed in SSM design elements 13 (Mitigation Process), 14 (Timing of Mitigation Application) and 15 (Reference Levels). If both the conduct and the impact tests are failed, then the offer will be mitigated. The rationale behind this determination is the same as the rationale under the SSM design element 13 (Mitigation Process).

Conduct Test

The conduct test will be carried out on an ex-ante basis. It will consider a number of parameters to determine if any were offered outside of their conduct thresholds. The conduct threshold will specify the threshold departure from established reference levels that will trigger mitigation. If any parameters were offered outside their conduct thresholds, then the price and uplift impact tests will be triggered. The following list sets out a number of the parameters that will be tested.

Price Parameters:
- Energy cost offer ($/MWh)
- Start-up cost offer ($)
- Speed-no-load cost offer ($/hour)

Non-Price Parameters/Operational Restrictions:
- MLP (MW)
- MGBRT (hours)
- MGBDT (hours)
- Lead time (hours)
- Ramp rates (MW/minute)
- Maximum or minimum number of starts per day (#)

Currently, the only non-price parameter offered into PD + RT-GCG is ramp rates. The remaining items are provided as registered data only. However, all non-price parameters are allowed to be offered into the DACP as daily generator data (DGD). In PD + ERUC, resources will still register all applicable operational restrictions, but also be allowed to offer non-price parameters into the market as DGD.[18] This will also be allowed in the DAM. All offered data is subject to mitigation.

The conduct test is failed if offer prices for energy, start-up or speed-no-load costs are too high relative to the reference level, considering the allowed conduct threshold. The conduct test is also failed if non-price offer parameters (e.g., ramp rates, MGBRT, MLP) are too restrictive relative to the reference level.

[18] This is fully described under the ERUC design element for Market Participant Data.

Impact Tests

There are two separate impact tests: the price impact test and the uplift impact test.

The price impact test will be carried out on an ex-ante basis. This test will determine if energy offers that violated the conduct threshold resulted in higher pre-dispatch advisory prices for energy or operating reserve. If the price is higher by more than a specified threshold (called the price impact threshold), the exercise of market power is determined to have occurred, and the energy offer will be adjusted to the reference level, mitigating the advisory schedule and advisory price. The same process will be carried out in the DAM, mitigating the DAM financially binding schedules and prices, as well as in real-time in order to mitigate dispatch and price.

The uplift impact test will be carried out on an ex-post or "after-the-fact" basis. Uplifts applicable to this test include any cost guarantees or make-whole payments. The test cannot be done ex-ante because it requires the calculation of the uplifts associated with the commitment, which can only be done once the commitment has concluded, and actual revenues and costs are known.

This test will determine if the start-up offer, speed-no-load offer or non-price offer parameter(s) that violated the conduct threshold resulted in an increase to uplift payments. The uplift impact test will compare the uplift payment using the unmitigated offers to the payment using mitigated values for offers that violated the conduct thresholds. The exercise of market power will have occurred if the unmitigated payment is larger than the mitigated payment by more than a specified threshold (called the uplift impact threshold). As a result, the uplift payment would be mitigated.

In the event that a market participant does not fail the price impact test, but fails the uplift impact test, only the uplift payment will be mitigated.

3.1.3 Detailed Design Considerations

The IESO will need to consider the following in detailed design:

- Reference levels[19] that will be used for start-up and speed-no-load costs;
- The set of non-price offer parameters that will be tested and the reference levels for each of these parameters for each resource;
- Conduct thresholds for all offered costs and non-price offer parameters; and
- Uplift impact thresholds[20] for all offered costs and non-price offer parameters.

3.1.4 Linkages

- The commitment cost design element is linked to ERUC design elements 12 (Calculation of Cost Guarantee) and 13 (Failure Charge).

[19] Reference levels are discussed in detail under SSM design element 15.

[20] Price (i.e., energy offer) impact thresholds will be determined under the SSM design element 13 detailed design considerations.

3.2 Offer Obligations and Offer Changes

3.2.1 Design Element Description

Offer Obligations

The IESO must determine whether market participation in the PD timeframe will be voluntary or mandatory in the context of a financially binding DAM.

The current PD + RT-GCG does not have any offer requirements for the energy or OR markets. However, under the DACP, all internal dispatchable resources must offer the amount of capacity up to which they wish to be dispatched in the real-time market. This is referred to as the availability declaration envelope (ADE). In lieu of a financially binding DAM, this requirement incentivizes resources to participate in the DACP, and provides the IESO with a dependable view of the next day.

In other jurisdictions, participation in the DAM through to real-time is only mandatory for resources that have capacity obligations from clearing a capacity auction. Other jurisdictions also monitor for physical withholding through after-the-fact processes, adjusting settlement amounts if market power has been exercised.

Offer Changes

This design element is specific to NQS resources that have a DAM or PD + ERUC commitment. Restrictions on changes to offers made by resources with a commitment are necessary during the period after the DAM results are provided until real-time dispatch. Once a resource receives an operational constraint, parameters like MLP and MGBRT are respected in subsequent PD runs. At the time the commitment is made, the resource is economic and will be held online no matter how uneconomic it becomes. In this case, there is insufficient competition. A resource that changes its offers during this period could therefore influence the size of uplift payments it receives. The conduct and impact tests under the market power mitigation framework will not prevent offer changes unless the offer is outside of the conduct threshold and there is a price impact.

In the current RT-GCG program, energy offer prices for the MLP quantity during MGBRT are not allowed to be increased after NQS resource commitment. This design in in place because the cost guarantee payment could be inappropriately increased.

Similarly, restrictions must be applied to offer changes when an NQS resource receives an operational constraint from DAM or through PD + ERUC. With an operational constraint, the resource is locked in for its MGBRT at its MLP, and will not be dispatched below MLP. This could increase the amount of the make-whole or cost guarantee payment.

Offer change restrictions will be considered for the following:

- Commitment cost offer prices, which include offers for start-up costs, speed-no-load costs and energy costs up to MLP;
- Incremental energy offer prices, which include offers for energy costs above MLP;
- OR offer prices; and
- Non-price offer parameters, which include hourly offered ramp rates, MLP, MGBRT, MGBDT, maximum number of starts per day and lead time.

3.2.2 Decisions

Offer Obligations

Participation requirements in DAM and PD + ERUC should be consistent for ease of market participant operations under a coherent set of market obligations. Under the DAM, it has been determined[21] that:

- An explicit obligation for resources to participate in the DAM is not required as long as contracted and rate-regulated resources have the correct incentives to participate;[22]
- The exercise of market power through physical withholding will be managed through after-the-fact processes; and
- The availability declaration envelope will only be required as a transitionary measure if the correct incentives for contracted and rate-regulated resources to participate in the DAM are not in place in time for implementation of the renewed market.

The IESO has determined that participation in PD + ERUC will be consistent with DAM participation. Any exercise of market power in PD through physical withholding will be effectively managed by implementing after-the-fact assessment and response processes.

Offer Changes

Offer change restrictions will apply to NQS resource offers for commitment costs, incremental energy costs, OR costs and non-price parameters.

Each restriction is described below. Offer changes will be automatically prevented in accordance with the rules set out in this design element to ensure PD + ERUC uses the appropriate values in its hourly run.

Commitment Cost Offer Prices

After a commitment is made, committed resources are not subject to competition for energy up to the MLP because the system must schedule this energy. As a result, NQS resources with a DAM or PD + ERUC commitment will not be allowed to increase offer prices for their commitment costs.

Since the DAM and PD + ERUC evaluations will jointly optimize energy offers and OR offers,[23] the offer price restriction will also apply to OR offers up to the MLP for both DAM and PD + ERUC committed resources.

Incremental Energy Offer Prices for PD + ERUC Commitments

Offer price increases for incremental energy above MLP could result in the exercise of market power. Committed resources have a competitive advantage up to their full capacity once they are online. Their start-up and speed-no-load costs no longer need to be considered by PD + ERUC as they are already committed (sunk) costs. Compared to offline NQS resources, energy from the committed NQS resource is significantly cheaper up to its full offered capacity. This competitive advantage would allow the resource to increase its offer price for quantities up to full capacity, and continue to be dispatched.

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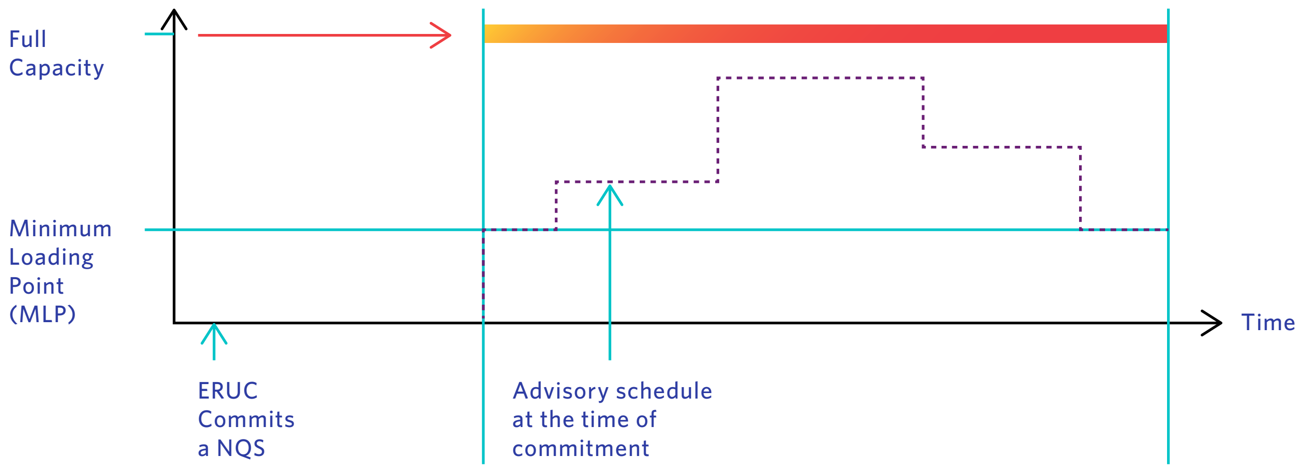
[21] The reasons for this decision are fully outlined under the DAM design element Offer Obligations.

[22] Contracted and rate-regulated constructs are currently tied only to real-time market participation.

[23] Joint optimization means that the bids and offers in the energy market and offers in the OR market are evaluated at the same time, satisfying both the total electricity demand and the OR requirements with the solution that provides the overall lowest cost.

A committed resource that sets the locational marginal price will know that they set the marginal price and may be able to increase their offer price and remain the marginal resource. Without offer change restrictions, this information could otherwise allow them to influence price and increase their cost guarantee payment. Therefore, NQS resources will not be allowed to increase their offer prices for energy above MLP up to their full capacity, i.e., maximum offered quantity, during the hours of the advisory schedule provided at the time of commitment. This advisory schedule may include hours beyond MGBRT. Since PD + ERUC will jointly optimize energy offers and OR offers, the offer price restriction will also apply to OR offers up to the maximum offered quantity.

FIGURE 11: BINDING PD + ERUC SCHEDULE AND FULL CAPACITY



This restriction can be lifted by the IESO under exceptional circumstances. Resources may require offer flexibility during unusual circumstances, such as significant changes in pre-dispatch conditions (e.g., gas prices). In this case, the IESO will consider offer price increases for quantities above the advisory schedule at the time of PD + ERUC commitment (the binding PD + ERUC schedule).

Incremental Energy Offer Prices for DAM Commitments

NQS resources with a DAM financial binding schedule will be allowed to increase their offer prices for megawatts above MLP during their DAM scheduled hours. Two-settlement provides the appropriate incentives for operation in real-time. The resource is subject to a balancing settlement at real-time prices for differences between the DAM and real-time schedules. If the resource increases its offer for DAM scheduled energy making it uneconomic, it will need to buy back that energy if it is not scheduled in real-time. Therefore, the appropriate incentives are already in place up to the DAM scheduled quantity, and offer price increases do not need to be restricted for DAM scheduled NQS resources for quantities above MLP.

Non-Price Offer Parameters

Changes to non-price offer parameters after receiving a DAM or PD commitment must also be covered under the market power mitigation framework. For example, if a committed resource was allowed to increase its MGBRT after it was committed, the resource would be constrained to its MLP for additional hours. This would create an opportunity for the participant to increase their cost guarantee payment. Accordingly, market participants with DAM or PD + ERUC commitments will not be allowed to make changes that make non-price offer parameters more restrictive.

3.2.3 Detailed Design Considerations

The IESO will establish pre-defined criteria to allow it to identify conditions that warrant offer changes for energy above the advisory schedule, when the NQS resource was initially committed by PD + ERUC. If an NQS resource increases its offer price under this exception, the process provides evidence to facilitate ex-post IESO audit and compliance will need to be developed.

3.2.4 Linkages

The offer changes design element is linked to ERUC design elements 10 (Market Participant Data) and 12 (Calculation of Cost Guarantee). The linkages are as follows:

- *Market Participant Data*: defines non-price offer parameters for NQS resources and the time window in which participants can update those parameters; and
- *Calculation of Cost Guarantee*: establishes the basis for determining the payments based on offers. Any offer changes following the receipt of an operational constraint will be subject to offer change restrictions, which will impact how it affects make-whole payment calculations.

4. Participation and Input Data

Participation and input data design elements address:

- Treatment of intertie transactions in PD that do not have a DAM schedule;
- The types of data that are required by the PD model to perform its optimization; and
- The characteristics of resources that should be eligible for a cost guarantee.

4.1 Intertie Transactions

4.1.1 Design Element Description

The DAM will provide price certainty for all market participants, including intertie transactions that receive a DAM financially binding schedule for the next day. However, conditions can change in the hours after DAM clears, requiring evaluation in the PD + ERUC timeframe for imports, exports and other resources to balance the system. In this context, it is important to establish how intertie bids and offers that did not receive a DAM schedule should be evaluated in PD + ERUC to ensure efficiency and reliability.

In today's market, DACP evaluates intertie bids and offers along with other resources as part of a multi-hour optimization. Scheduled import transactions are provided a day-ahead import offer guarantee[24] to support reliability, while export transactions do not receive a guarantee. As a result, few exports bid into the DACP. Instead, most traders prefer to participate with export bids in the PD + RT-GCG timeframe when the price may be more predictable and when they know their DAM schedule. Following DACP, all intertie bids and offers are evaluated in all runs of PD + RT-GCG. For all dispatch hours, the binding real-time hourly intertie schedule is established in the PD + RT-GCG run that immediately precedes it.

Additional NQS resources often become eligible for the RT-GCG program, in part, to meet the increased export demand in the PD + RT-GCG timeframe. However, since export schedules do not become binding until the hour before real-time dispatch, NQS resources may be operationally constrained in PD + RT-GCG in response to advisory export schedules that may not actually flow in real-time. As a result, costs may be incurred to provide a guarantee payment to an NQS resource that was not required to meet market demand.

In the future, the DAM will evaluate intertie bids and offers along with other resources as part of a multi-hour optimization. The DAM will issue financially binding schedules to all market participants, including imports and exports.. Market participants will be settled and made whole based on bids and offers into the DAM, providing price certainty. Price certainty through DAM schedules provides the incentive for both imports and exports to participate in the DAM. The real-time balancing market provides the incentive for resources scheduled in the DAM to participate appropriately in real-time.

Given that the appropriate incentives will be in place for real-time operation due to DAM financially binding schedules, consideration must be given to which intertie bids and offers should be evaluated in PD + ERUC runs. If intertie transactions that do not have a DAM schedule are evaluated by PD + ERUC and later withdrawn, there may be impacts on efficiency and reliability. Efficiency may be impacted if an NQS resource is committed to meet export demand that does not appear in real-time. Reliability may be impacted if the IESO relies upon an import that does not appear in real-time to meet system needs. This is especially true if an advisory import schedule in PD + ERUC displaces or prevents an NQS resource commitment that is required to meet system needs in real-time. Intertie transactions that do not have a DAM schedule should be considered only if they are relatively certain to be available in real-time. If they can be withdrawn by the participant, they are less certain.

[24] The import offer guarantee is a mechanism that ensures eligible imports are settled at no worse than their offer price. It supports reliability by reducing the incentive for imports to fail transactions that may otherwise become uneconomic if prices decrease between the time they are scheduled and real-time.

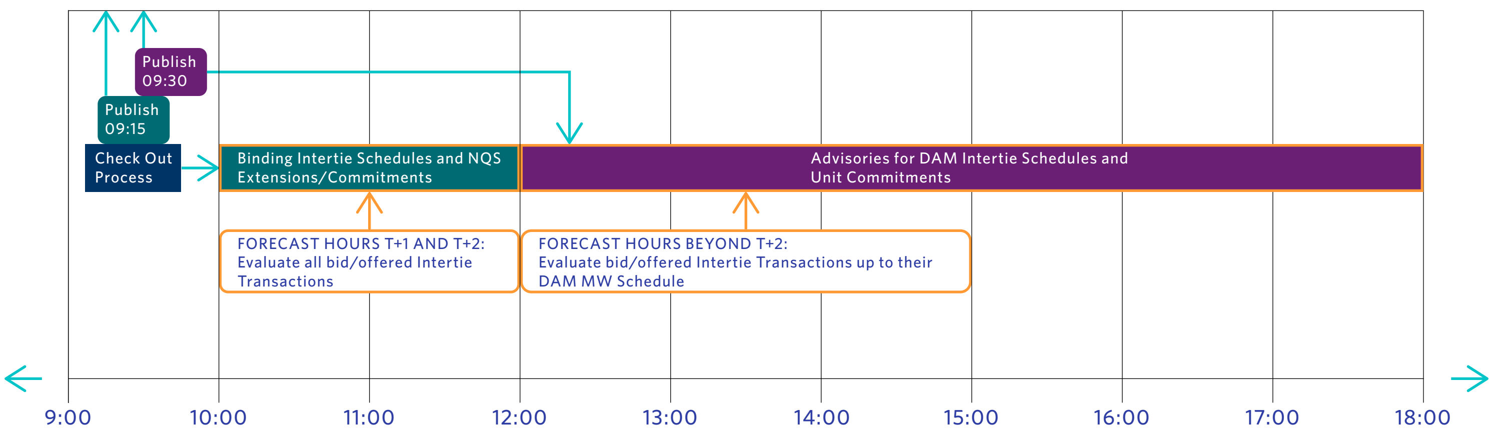
4.1.2 Decisions

The evaluation of both DAM and non-DAM intertie transactions will occur in the two forecast hours immediately following the PD + ERUC run. This timeframe is illustrated in figure 12 as "Forecast Hours T+1 and T+2." Evaluation of all intertie bids and offers during this timeframe is appropriate because other jurisdictions begin scheduling their real-time intertie schedules at this time as well. As a result, intertie transactions are much more certain to flow in real-time. Further, changes to bids and offers are normally not allowed by the IESO during the two-hour mandatory window, providing additional certainty that intertie bids/offers will flow in real-time.

Outside of the two forecast hours immediately following the PD + ERUC run, only DAM-scheduled intertie bids and offers will be evaluated to determine if they are still economic. This timeframe is illustrated in figure 12 as "Forecast hours beyond T+2." This evaluation will ensure that additional commitments are based on transactions that are more certain to occur in real-time because they have a DAM financially binding schedule. It will further ensure that commitments are primarily used to satisfy Ontario demand and reserve requirements rather than exports.

The following figure illustrates, for the PD + ERUC run in hour "T" (run at 09:00 i.e., HE10 in the figure below), those intertie bids and offers that will be taken into account in PD + ERUC.

FIGURE 12: SAMPLE TIMELINE FOR INTERTIE BID/OFFER EVALUATION



Secondary Considerations

Emergency Transactions

Emergency transactions are out-of-market intertie schedule arrangements between neighbouring jurisdictions that are used only in system emergency situations that cannot be resolved under normal timelines. Although usually scheduled only for the next one or two hours, emergency transactions may be extended beyond those hours. If so, these transactions will be included in the PD + ERUC evaluation to allow efficient commitment and scheduling.

Emergency transactions must be accommodated to maintain the reliability of the grid. They are not scheduled in the day-ahead timeframe, but are likely to flow in real-time. These transactions are subject to cross-jurisdictional procedures and agreements.

Capacity-Backed Transactions

Capacity-backed transactions are a form of intertie transaction that is scheduled through bids and offers in the market. They are the product of capacity markets and/or formal agreements between jurisdictions; and as such are subject to additional obligations and guarantees that maximize the likelihood that scheduled transactions will flow in real-time. Because of these additional obligations and guarantees, capacity-backed transactions should be given special consideration in the PD + ERUC evaluation over all hours of the look-ahead period.

4.1.3 Detailed Design Considerations

The IESO has identified potential scenarios in which PD + ERUC results for hours beyond the next two forecast hours may show that system requirements will not be satisfied, even with all internal resources scheduled. To ensure reliability under these exceptional circumstances, the IESO may accept non-DAM import offers beyond the next two forecast hours. To this end, the IESO will develop criteria that allow PD + ERUC to accept non-DAM import offers beyond the next two forecast hours under exceptional reliability conditions.

4.1.4 Linkages

The intertie transactions design element is linked to ERUC design elements 2 (Look Ahead Period), 3 (Frequency and Timing of Run) and 4 (Time Step). Changes to these design elements may impact how intertie transactions should be handled by the IESO. Intertie scheduling and notification, particularly for the two forecast hours immediately following the PD + ERUC run, must provide adequate timing to support coordination with external jurisdictions.

4.2 Market Participant Data

4.2.1 Design Element Description

This design element will specify the market participant data necessary for PD + ERUC to economically evaluate and optimize the scheduling of resources. Market participant data consists of dispatch data and operational data.

Dispatch Data includes hourly bids and offers from all resources for energy, speed-no-load and start-up costs. Each energy offer or energy bid may contain ramp rate data, if applicable.[25] Dispatch data also includes hourly offers from resources that provide operating reserves.

Operational Data consists of the registered operational restrictions of a resource provided to the IESO during the market registration process. Operational data may also be offered into the market on a daily basis as daily generator data (DGD). Operational data includes MGBRT, MGBDT, MLP, minimum run-time (MRT) and max/min number of starts per day.

Under the current PD + RT-GCG, market participant data is required to determine PD advisory schedules and prices, and eligibility for the RT-GCG program.

- *Dispatch Data*: All resources provide hourly single part energy bids or offers, and associated ramp rate data. Speed-no-load and start-up cost offers are not accepted under the PD + RT-GCG.[26] All resources that are able to provide OR may submit hourly OR offers.
- *Operational Data*: NQS resources must register MGBRT, MRT, and MLP for the RT-GCG program. Other registered operational data is not required to be eligible for the RT-GCG cost guarantee. No operational data is offered into the market as DGD at this time.

4.2.2 Decisions

Dispatch Data

Similar to the current market, PD + ERUC will require market participants to submit dispatch data. New dispatch data will now be required for NQS resources in pre-dispatch; participants will submit hourly three-part offers consisting of energy, speed-no-load and start-up.[27] Three-part offers will allow optimization of all resources based on complete cost information. All other dispatch data requirements will remain the same.

[25] For example, intertie transactions do not submit ramp rates as part of their bids/offers.

[26] Unlike in the current PD + RT-GCG, three-part offers are considered under DACP.

[27] Other resources may also submit start-up costs, if applicable, but only NQS resources are eligible for a PD + ERUC commitment and cost guarantee based on three-part offers.

Operational Data

PD + ERUC will continue to require market participants to register operational data through market registration. This data is needed as standing inputs to PD + ERUC in the absence of offered data for a given day.

DGD is currently used in the DACP, and will be similarly used in the DAM. Generators may choose to make regular changes to this data, subject to market power mitigation. This is allowed because operating parameters may change day-to-day. DGD offers must be submitted prior to the DAM being run for the next day. The DGD offered for DAM will be used by PD + ERUC, and no changes to DGD used in clearing DAM can be made in pre-dispatch. This is a new aspect of operational data as PD + ERUC will now consider DGD in scheduling. With multi-hour optimization, these constraints are key inputs and should be accurately reflected in the PD + ERUC optimization.

DGD used in PD + ERUC will include MGBRT, MGBDT, MLP, maximum/minimum number of starts per day, and a new parameter "lead time." Lead time is the amount of notice a generator needs in order to reach its MLP from an offline state. Lead time curve data is necessary in order to correctly evaluate and optimize all available resources, and to establish the timing required to provide a start-up instruction.[28] Lead time is impacted by the operating state of the resource (e.g., cold, warm or hot). Generally, the longer a generator has been offline, the longer the lead time. Each NQS resource will be required to register data that identifies the resource lead time, depending on how long the resource has been offline, producing a lead time curve.

PD + ERUC will have information regarding the number of hours an NQS resource has been offline. This information can be used in conjunction with the lead time curve to establish the applicable lead time to provide a binding start-up instruction in an efficient and timely manner. It is acceptable for generators to update lead time DGD for the next day prior to the initial PD + ERUC run including all hours of the next day, which occurs at 20:00 of the day-ahead.

4.2.3 Detailed Design Considerations

The IESO will determine whether bids/offers will be passed from DAM to PD + ERUC, or if new bids/offers are required for PD + ERUC.[29] The IESO will also determine whether lead time data is utilized in the DAM.

4.2.4 Linkages

Market Participant Data is linked to ERUC design elements 5 (Binding Start-Up Instruction and Operational Constraint), 11 (Eligibility for Cost Guarantee), and 12 (Calculation of Cost Guarantee). Market participant data, including physical characteristics, must be provided and updated in order for the PD evaluation to determine if an NQS resource should receive a binding start-up instruction or operational constraint and be assessed for a cost guarantee.

[28] This is discussed under ERUC design element Binding Start-up Instruction and Operational Constraint.

[29] Changes to offer prices for committed NQS resources are restricted, as described under ERUC design element Offer Changes.

4.3 Eligibility for Cost Guarantee

4.3.1 Design Element Description

This design element considers whether there should be any change in the types of resources eligible for a PD + ERUC cost guarantee.

Under PD + RT-GCG, a resource is eligible for a guarantee of certain costs provided that it is a dispatchable resource with a registered MLP and MGBRT, and is not a quick-start resource. A quick-start resource is a generator whose electrical energy output can be provided to the IESO-controlled grid within five minutes of the IESO's request, where the generator is not synchronized at the time the request is made. An eligible resource must have an elapsed time to dispatch[30] greater than one hour. Cost guarantee payments mitigate the possibility that resources that meet the criteria above will not come online when there is a risk that real-time market revenues will not cover their costs.

A cost guarantee is not required for resources without a MLP and MGBRT, because this type of resource can, at any time, come offline within the hour if system conditions change and it is no longer economic. A quick-start resource does not require a guarantee since it does not have to begin coming online until very close to real-time, greatly reducing the risk its start is no longer economic.

4.3.2 Decisions

Eligibility for a cost guarantee under PD + ERUC will be the same as under the current PD + RT-GCG. An eligible resource must be a dispatchable resource with a registered MLP and MGBRT, and must not be a quick-start resource. The resource must also have an elapsed time to dispatch greater than one hour to be eligible for the cost guarantee.

It is appropriate that cost guarantee payments are provided for resources with these specific characteristics to ensure they will come online when needed to improve efficiency and to maintain reliability. Changing eligibility requirements to provide a cost guarantee for resources who are not exposed to these economic risks would only increase uplift costs without a corresponding improvement to efficiency or reliability.

4.3.3 Detailed Design Considerations

At this time, the IESO has not identified any further considerations for detailed design.

4.3.4 Linkages

This design element is linked to ERUC design elements 5 (Binding Start-Up Instructions and Operational Constraint), 11 (Market Participant Data), and 12 (Cost Guarantee Payment). Market participant data, including physical characteristics, must be provided and updated in order for the PD evaluation to determine if a resource should receive a binding start-up instruction and operational constraint, and should be assessed for a cost guarantee payment.

[30] Elapsed time to dispatch is the registered minimum amount of time between the initiation of the start-up sequence and the time the resource becomes dispatchable by reaching its MLP. This registered data is the same as lead time but represents the minimum lead time allowed in order to be eligible for the cost guarantee. Lead time data is further described in ERUC design element Market Participant Data.

5. Settlement

The Settlement design elements establish what payments and charges are necessary in the PD + ERUC timeframe to ensure efficient scheduling and reliability. PD + ERUC will produce advisory schedules and advisory prices, but this output is not used for settlement. Resources are settled based on DAM prices and financially binding DAM schedules, with real-time deviations from DAM schedules bought or sold back at real-time prices. An NQS resource receiving a commitment through PD + ERUC is settled no differently than other resources, for the purpose of two-settlement. For example, an NQS that did not receive a DAM schedule but was committed in PD would be paid for RT output at RT prices.

Additionally, if the PD + ERUC issued an NQS resource commitment based on the advisory schedules, these resources will be assessed for a cost guarantee payment. While at the time the binding start-up instruction was issued the resource was economic, market conditions may have changed over the course of the commitment. The cost guarantee is intended to keep the committed resource whole if it satisfies its obligation. It is necessary to consider how the calculation of the cost guarantee will be performed in the future if these conditions are met. It also necessary to establish what failure charge is appropriate if the NQS resource fails to deliver as committed.

The payments and charges for intertie transactions, including Intertie Offer Guarantee, Real-Time Import Failure Charge, and Real-Time Export Failure Charge, are not discussed in the ERUC High-Level Design. There are no decisions specific to these payments/charges, although the calculations will be reviewed in detailed design in order to make any changes required for consistency with the new market design.

The design elements in this section apply only to NQS resources, establishing the:

- High-level calculation methodology for the cost guarantee; and
- Application and high-level calculation methodology for a failure charge.

5.1 Calculation of Cost Guarantee

5.1.1 Design Element Description

The calculation of cost guarantee payments for NQS resources that are committed via PD + ERUC requires the determination of applicable costs and revenues, and the period over which these are assessed. PD + ERUC produces schedules that have been optimized for least cost and maintaining reliability. The design of the cost guarantee calculation should maintain adequate incentive for committed resources to follow these pre-dispatch schedules, even with the risk that real-time prices may not materialize as anticipated.

Under the current market, the RT-GCG program provides a payment if market revenues are insufficient to cover generation costs during the period from synchronization until the end of MGBRT. Market revenues include energy revenues and congestion management settlement credit revenues for injections up to the MLP during MGBRT. Costs include submitted start-up costs and as-offered energy costs up to the MLP during MGBRT. Since PD + RT-GCG includes offers for energy only, start-up costs are submitted by the NQS resource based on amounts pre-approved by the IESO. Revenues and costs for injections above MLP and beyond MGBRT are not included in the RT-GCG calculation. Revenues and costs for OR are also not included.

Settlement must also consider various scenarios where the committed resource fails to perform exactly as originally scheduled by PD + ERUC at the time a binding start-up instruction is issued. This schedule is referred to as the "binding PD + ERUC schedule." Situations where a resource fails to meet its binding PD + ERUC schedule include where the unit does not synchronize before the start of its MLP and MGBRT period, fails to complete its MGBRT, or reaches MLP later than committed. In these cases, the design must consider impact the calculation of the cost guarantee and if a failure charge[31] may be applied where the resource fails to meet its binding PD + ERUC schedule.

Under the current PD + RTGCG, the calculation of the cost guarantee is limited by the resource's minimum run-time. If a resource takes longer to ramp than expected, the cost guarantee calculation may not cover its entire MGBRT period and the resource may not recover all their costs. Further, a resource that does not complete its MGBRT does not receive a cost guarantee payment. If a committed resource is dispatched on the basis of a revised, lower energy offer, the lower offer is used to calculate costs.

Decisions are also required to determine the calculation of the cost guarantee if a resource is committed multiple times in one day, or is committed by the IESO outside of PD + ERUC for reliability reasons. Under the current PD + RT-GCG, the guarantee is calculated separately for multiple starts in one day, and generators are eligible for the RT-GCG if committed by the IESO for reliability reasons.

[31] This is fully described under the ERUC design element Failure Charge.

5.1.2 Decisions

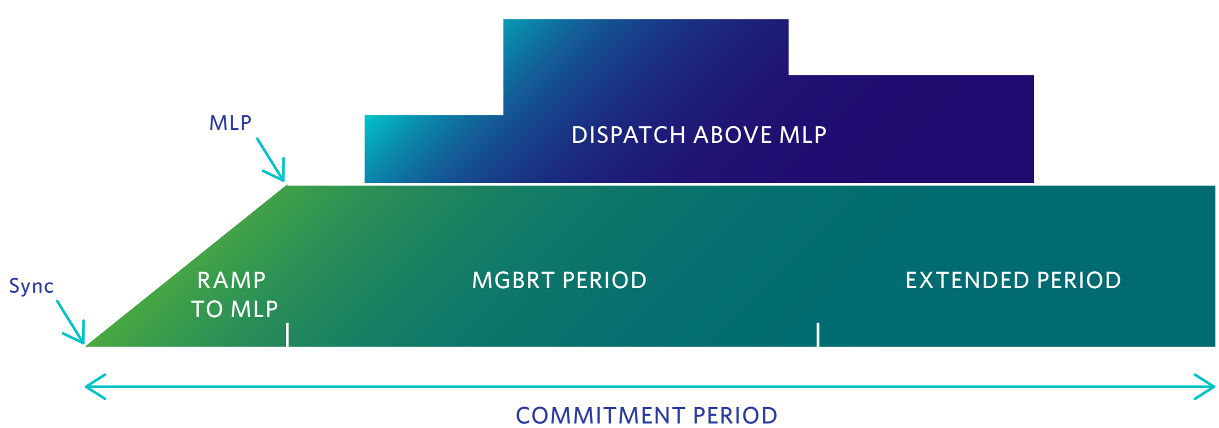
The PD + ERUC cost guarantee calculation will consider all energy market and OR market revenues over the commitment period for the total delivered quantity, net of costs incurred. Market revenues are determined by the real-time settlement. Costs will be determined based on NQS resource three-part offers for start-up costs, speed-no-load costs, energy costs and OR costs. These offers are used in determining whether to make a commitment to the resource as the lowest cost option to satisfy demand. If a committed resource lowers its offer price to achieve a different real-time schedule, the guarantee payment will be based upon that price, and not the original higher offer price. If market revenues are greater than the costs over the commitment, no cost guarantee payment will be required. In this instance, the participant is entitled to retain the net profit over the commitment period.

Unlike the RT-GCG, the PD + ERUC cost guarantee will consider OR revenues and costs in the calculation. This is appropriate because the optimization done by PD + ERUC includes efficiency attributable to the provision of operating reserve. In fact, a resource may receive a commitment primarily driven by how economic their reserve offers are, with slightly uneconomic energy offers. Therefore, it is appropriate to consider net revenues earned in both energy and reserves.

The commitment period over which the PD + ERUC cost guarantee is calculated will begin at synchronization, and includes the ramp period to MLP and all hours the resource is constrained at its MLP. If the commitment is extended on an hour-by-hour basis, the costs and revenues for the extended period will be included in the calculation. Any time period after the last extension hour, including the ramp-down period, is not part of the commitment period and will not be included in the calculation of the cost guarantee. Cost recovery for the ramp-down period will be addressed in detailed design.

The following figure illustrates the commitment period over which the guarantee payment is calculated.

FIGURE 13: COMMITMENT PERIOD



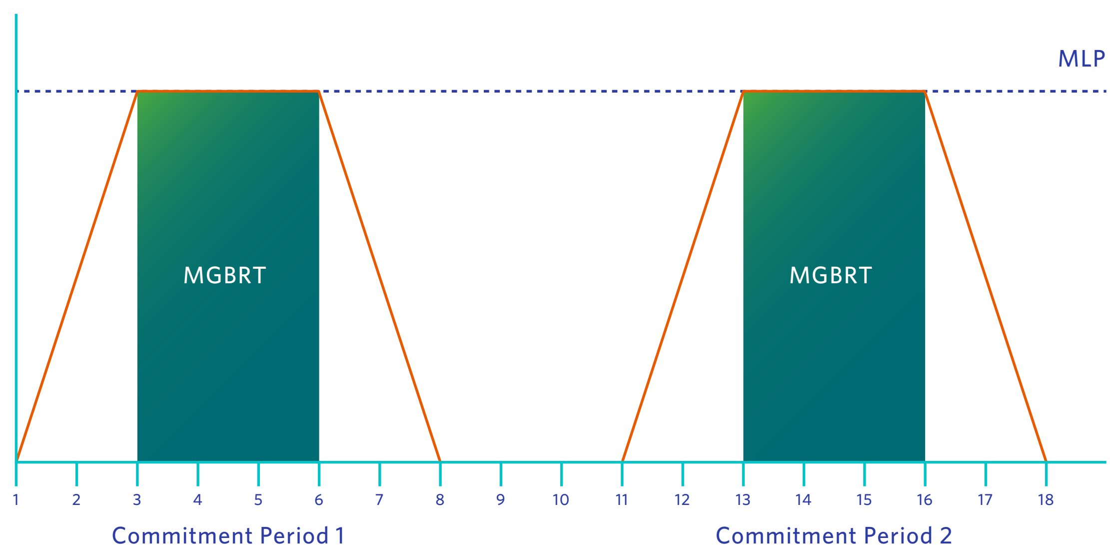
Unlike the RT-GCG, the PD + ERUC cost guarantee will include costs and revenues for quantities delivered above MLP and beyond MGBRT hours. This is appropriate as the economic evaluation done by the PD +ERUC optimization will consider all of the resource's energy over the commitment, not just quantities associated with MLP. In order for the resource to receive a cost guarantee, the overall efficiency for the entire binding PD + ERUC schedule will be evaluated, and not just the MLP and MGBRT portions.

When a commitment is not extended through PD + ERUC, an NQS resource will see it is no longer anticipated to be economic. At this point, it may begin to plan to bring itself offline. However, after the most recent PD + ERUC schedule is produced, system conditions continue to change. As a result, the resource may still receive a dispatch in real-time if they now become economic. If the NQS resource continues to be dispatched after the commitment has ended, net revenues earned from that point will not be considered in the cost guarantee calculation.

The intent is to preserve the incentive to operate and respond to real-time changes after the commitment period has technically ended. Had these net revenues instead been included in the cost guarantee calculation, this would diminish any incentive to maintain flexible operation in response to unanticipated intra-hour events.

Similar to the current PD + RT-GCG, generators will be eligible for a cost guarantee if committed outside of PD + ERUC by the IESO for reliability reasons, which will ensure that generators have the correct incentive to respond to these requests. The cost guarantee for a reliability commitment will be calculated separately from a PD + ERUC commitment. Also similar to PD + RT-GCG, the cost guarantee payment will be calculated separately for each of multiple commitments in a given day when the resource has followed dispatch instructions to come offline between commitments (as illustrated below). Separate calculation of the cost guarantee for each commitment ensures that potential profits from one commitment will not reduce the cost guarantee payment for another commitment, and the incentive for the resource to operate when needed by the system is preserved.

FIGURE 14: TWO COMMITMENT PERIODS IN A SINGLE DAY



Finally, if an NQS resource is committed under both DAM and PD + ERUC, the cost guarantee and DAM make-whole payment will be calculated separately. The DAM make-whole payment will consider all DAM as-offered costs, including start-up, energy and speed-no-load costs, compared to DAM revenues over hours where there is a DAM financially binding schedule. For any other hours where the NQS resource was additionally committed and operationally constrained at MLP by PD + ERUC, the cost guarantee will be calculated using energy and speed-no-load as-offered costs and energy/OR market revenues.

Scenarios Impacting Cost Guarantee Calculation

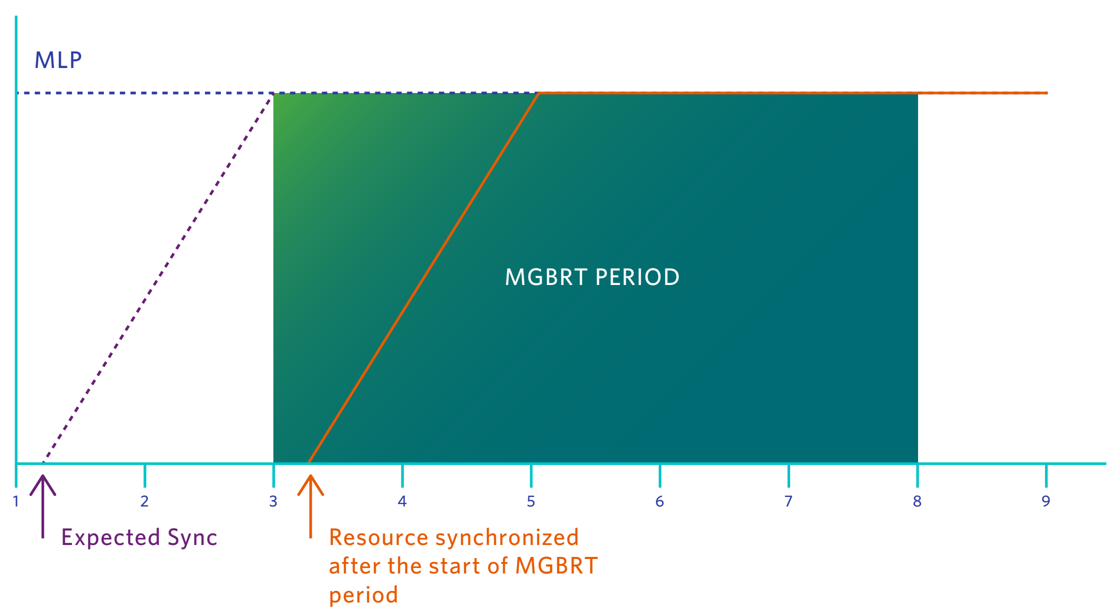
The following sections indicate the impact on cost guarantee payments in scenarios where the resource does not operate exactly as scheduled at the time of the binding start-up instruction.

Scenario one: The resource fails to synchronize (start injecting) before the start of its MGBRT period, or fails to complete its MGBRT.

A cost guarantee payment will not be made if a resource fails to synchronize before the start of its MGBRT period (as illustrated in Figure 15). Similarly, a cost guarantee payment will also not be made if a resource does not complete its MGBRT (as illustrated in Figure 16).

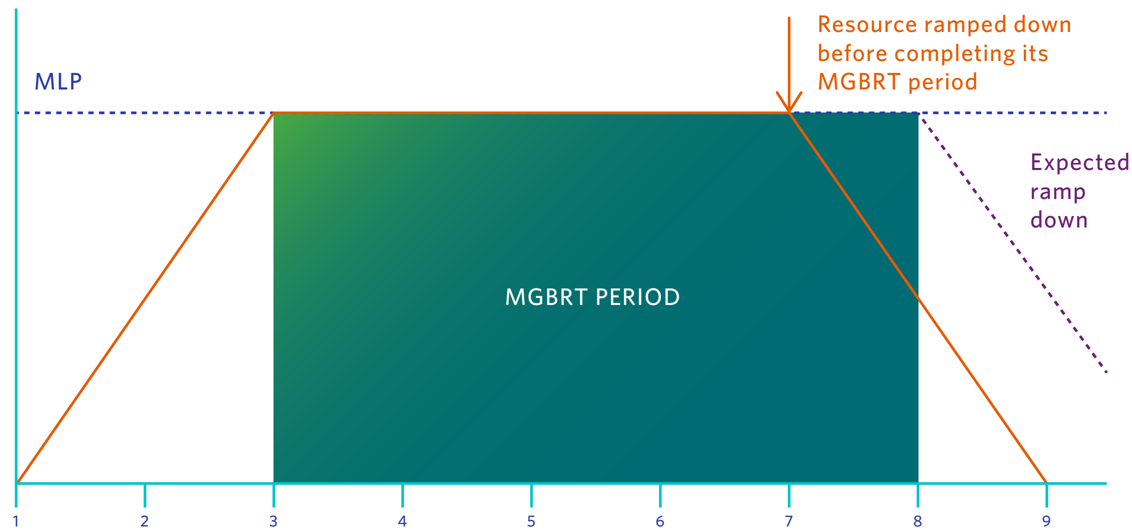
In each case, as a result of the failure, the IESO could be forced to schedule or commit replacement resources with significantly less notice. This has the potential to materially impact system costs and reliability. Therefore, no cost guarantee will be provided, even if costs were incurred. In addition, a failure charge will be assessed for the period that the resource failed to meet its commitment. The IESO may also review whether there has been a failure to comply with dispatch instructions.[32]

FIGURE 15: LATE SYNCHRONIZATION



[32] Compliance with dispatch instructions for all dispatchable resources is required under the market rules. It is necessary to maintain the reliable operation of the IESO-controlled grid and the effective and efficient operation of the IESO-administered markets. The IESO monitors compliance with dispatch instructions and may impose sanctions, including financial penalties, if material non-compliance is found without an acceptable reason.

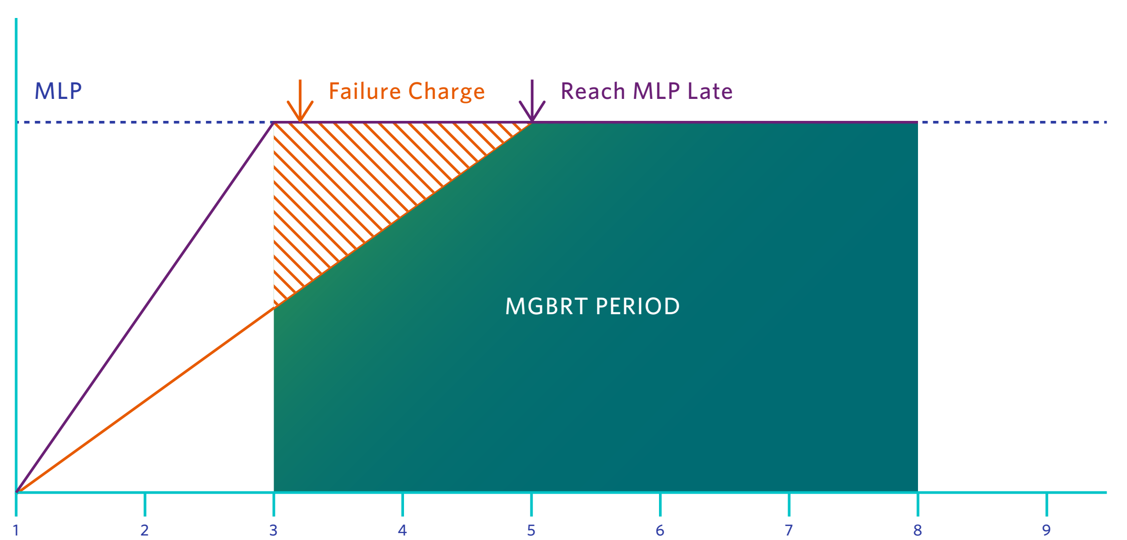
FIGURE 16: FAILURE TO COMPLETE MGBRT



Scenario two: The resource reaches MLP after start of its MGBRT period.

Where the resource synchronizes before the start of its MGBRT period, the cost guarantee payment will be calculated. A resource may reach its MLP later than its binding PD + ERUC schedule (for example, due to a slower than anticipated ramp rate as illustrated in Figure 17), but must keep the IESO informed. This will not impact the eligibility for assessment of a cost guarantee. However, a failure charge (see following design element 5.2 Failure Charge) will be assessed for the period that a resource was late to reach MLP. The IESO may also review whether there has been a failure to comply with dispatch instructions. A resource that reaches MLP *earlier* than its scheduled MGBRT would not have a failure penalty assessed, but must still keep the IESO informed.

FIGURE 17: LATE ACHIEVEMENT OF MLP



5.1.3 Detailed Design Considerations

The following design considerations will be determined in detailed design:

- The specific formula for the calculation of the cost guarantee payment;
- Recovery of costs during the ramp down period after the commitment has ended; and
- How manual out-of-market commitments made for reliability, impact the calculation of the cost guarantee payment.

5.1.4 Linkages

This design element is linked to ERUC design element 11 (Eligibility for Cost Guarantee), 6 (Commitment Cost Mitigation), 8 (Offer Changes), 5 (Binding Start-up Instructions and Operational Constraint), and 13 (Failure Charge).

- *Eligibility for Cost Guarantee*: identifies NQS resources as eligible for PD commitment and cost guarantee payments;
- *Commitment Cost Mitigation*: describes the methodology to mitigate attempts to exercise market power through commitment cost offers;
- *Offer Changes*: identifies offer change restrictions imposed on committed resources;
- *Binding Start-Up Instruction and Operational Constraint*: identifies the initial operational constraint for committed resources and defines the commitment period for calculation of the cost guarantee payment; and
- *Failure Charge*: describes the method for calculating a failure charge when a resource does not fully meet its commitment.

5.2 Failure Charge

5.2.1 Design Element Description

When an NQS resource fails to deliver energy as committed, it can have a significant adverse impact on system reliability, market efficiency and cost. In this event, the IESO must dispatch replacement resources, either through additional more expensive commitments or available energy from other online units. The failure charge is intended to reduce the risk of system reliability events due to failed commitment, improve efficiency and reduce uplift costs to consumers.

Early notice of a potential failure increases the number of replacement resource options available to the IESO, improving reliability and reducing the price impact of the failure. Regardless of the amount of notice that is provided, the failure charge should apply due to the additional costs incurred by the market as a result of the failure. However, the failure charge should incentivize a resource to provide advance notice of a failure as soon as possible.

In the current market, there is no charge for a failure to meet a commitment. This can be attributed to at least three factors. First, the RT-GCG program is voluntary and not built directly into the PD optimization. Second, eligible resources self-commit and have discretion on when they want to initialize the start. Third, a failed commitment would have a minor impact on the uniform market clearing price and uplift.

Under market renewal, these three factors are very different. Cost guarantees for unit commitment are not voluntary, but directly undertaken as part of the PD + ERUC optimization. The binding PD + ERUC schedule that is issued specifically identifies when start-up should occur; eligible resources no longer self-commit. Finally, impacts to locational market prices due to a failed start can be much more material than those on a uniform clearing price.

It is also worthwhile to note that the generator withdrawal charge is no longer required in the DAM. This is because the financially binding DAM schedule provides adequate incentives to ensure the commitment is met, as failing to meet a day-ahead commitment requires the participant to buy back the position in real-time.

5.2.2 Decisions

A failure charge will be assessed when an NQS resource fails to meet all or part of its PD + ERUC commitment in the real-time market.[33] To provide an incentive for an NQS resource to deliver on its PD + ERUC commitment, the failure charge will be calculated as follows:

(A X B) + C.

A is the $/MWh amount.

B is the quantity of energy not delivered.

C is the incremental uplift cost of the replacement resource, if applicable.

[33] The failure charge will not apply to DAM financially binding schedules, which provide appropriate incentives to participate in the RT market.

Similar to the current DACP generator withdrawal charge, the three components of the failure charge are as follows:

A. *The $/MWh amount is the difference between the resource's offer price and the applicable locational marginal price for each hour of the commitment period. The applicable locational marginal price to be used for the failure charge is the real-time price, if notice is provided after the binding start-up instruction, but less than four hours before the start of the MLP and MGBRT commitment. If notice of the failure is provided to the IESO at least four hours before the start of the MLP and MGBRT commitment, the price used will be the lower of the PD locational marginal price at the time the notice was provided and the real-time locational marginal price.*

B. *The quantity not delivered will be the difference, in MWh during the hours of the failure, between the actual quantity of energy injected and binding PD + ERUC schedule.*

C. *The incremental uplift cost of the replacement resource is the additional cost guarantee amount incurred by the market as a result of the failure.*

A failure charge will not result in a payment to a resource, even if the locational marginal price is lower than the resource's offer price. This is necessary to ensure a resource that fails does not benefit as a result of its failure to meet the PD commitment. While in such an instance the failure *could* have coincided with a lower system cost, this is detrimental to reliable system operation.

The IESO recognizes that failure to meet a PD + ERUC commitment may occur for reasons outside the control of the applicable resource. For example, an unplanned outage could occur on the electrical system beyond a generator's control, causing the generator to be grid incapable. In the case of grid incapability, a failure charge will not be applied. However, a failure charge will be applied if a resource is unable to meet its commitment for any reason that is within its control, such as having insufficient fuel or tripping of the generation unit.

5.2.3 Detailed Design Considerations

The IESO will need to consider the following:

- The detailed formula for calculation of the failure charge;
- The process for a resource to notify the IESO that they will fail to meet the commitment and provide reason for failure, if applicable;
- The process for a reversal of the failure charge when the reason for failure is not under the control of the applicable resource; and
- The method of determining the incremental uplift cost of the replacement resource, if applicable, to be included in the failure charge.

5.2.4 Linkages

This design element is linked to ERUC design element 6 (Commitment Cost Mitigation) and 12 (Calculation of Cost Guarantee).

- *Commitment Cost Mitigation*: describes the methodology to mitigate attempts to exercise market power through commitment cost offers.
- *Calculation of Cost Guarantee*: describes the calculation of cost guarantee payments for NQS generators that are committed during pre-dispatch timeframe.

Appendix 1 – Enhanced Real-Time Unit Commitment Design Elements

The 13 design elements associated with the introduction of ERUC have been grouped into four areas as follows:

Engine Parameters and Engine Output

1 Functional Passes

2 Look-Ahead Period

3 Frequency and Timing of Run

4 Time Step

5 Binding Start-up Instruction and Operational Constraint

Market Power Mitigation

6 Commitment Cost Mitigation

7 Offer Obligations and 8 Offer Changes

Participation and Input Data

9 Intertie Transactions

10 Market Participant Data

11 Eligibility for Cost Guarantee

Settlement Topics

12 Calculation of Cost Guarantee

13 Failure Charge

Appendix 2 – Engagement Summary Report

Engagement: Enhanced Real-time Unit Commitment - Market Renewal Project
Engagement Initiation: September 2017
Interim Summary Report Issue Date: December 2018

Interim summaries are provided for extensive engagements to support stakeholders' understanding of the work already completed and to outline the next steps or phases. This interim engagement summary provides an overview of the Enhanced Real-time Unit Commitment (ERUC) stakeholder engagement activities and outlines how stakeholder feedback has helped shape the high-level design (HLD).

Engagement Description/Background

Since September 2017, when the ERUC engagement was launched, the IESO has been working with stakeholders to design and develop a program that will implement a new pre-dispatch optimization engine to replace the IESO's current pre-dispatch engine. ERUC will improve the efficiency of unit commitments in the pre-dispatch timeframe by taking into account all resource costs in commitment decisions. ERUC will also improve commitment decisions overall by optimizing over multiple hours rather than solving for each hour independently.

The ERUC is a foundational element of the Market Renewal Programs (MRP) and plays an important role in achieving the efficiencies that were outlined in an independent study commissioned to assess the benefits of market renewal. Stakeholder involvement has been essential in this process to ensure that the ERUC HLD reflects the unique characteristics of the Ontario marketplace, and considers the practical implications of design decisions on impacted stakeholders.

The engagement activities listed in this summary have enabled stakeholder views and preferences to be considered in the development of the ERUC design elements. Input from stakeholders has informed the decisions reflected in the ERUC HLD and has helped lay the foundation for the upcoming detailed design phase.

Engagement Objective

The primary objective of this engagement was to provide a forum for stakeholders to contribute to the development of the overall ERUC design. Active participation from interested stakeholders throughout this engagement and in future related engagements is critical to ensure that a wide variety of perspectives are considered, resulting in a robust market design that can meet system and participant needs at lowest cost.

A secondary objective was to provide information and education to assist stakeholders in understanding the purpose and scope of the ERUC initiative and to facilitate their contributions to the engagement discussions.

Stakeholders have helped to shape the design reflected in this HLD through their participation in engagement sessions and through written feedback to the IESO.

Engagement Approach

The overall stakeholder engagement framework for the MRP, of which the ERUC HLD engagement was a component, is designed to facilitate dialogue with market participants and stakeholders to inform decisions that will significantly reshape Ontario's electricity marketplace. The framework is based on the IESO's engagement principles and enables participation from all levels of stakeholders through:

- Engagement forums tailored to each initiative to provide opportunities for in-depth and focused discussions on specific design elements
- Education sessions to support stakeholder participation in engagement forums
- The work of the Market Renewal Working Group (MRWG), which guides, advises and informs the IESO on strategic, policy and design issues that could affect the program's success
- Technical subcommittees that provide a forum for focused discussion on issues identified by the MRWG
- One-on-one meetings as part of ongoing relationship building

Stakeholder Participation

Since October 2017, the IESO hosted 11 engagement meetings on the ERUC design with an average of 58 stakeholders in attendance per session.

Throughout 2017 and 2018, stakeholders took part in a series of meetings led by the IESO and its external consultant (FTI). At the introduction of the ERUC engagement, stakeholders participated in three education sessions designed to facilitate their participation in engagements across the MRP. Following this, stakeholders were involved in discussions concerning the design options and then the preliminary decisions. Throughout these engagement activities, stakeholders provided valuable and constructive feedback that helped to inform the design decisions recorded in this document.

The high-level design reflects the contributions of a diverse set of stakeholders, including:

- Generators representing a broad range of technologies and fuel types
- Consumers (e.g., large industrial and commercial enterprises, low-volume consumers)
- Demand response aggregators
- Emerging technologies/developers
- Intertie traders
- Local distribution companies
- Market Surveillance Panel
- Industry associations
- Consultants
- Government, specifically the Ministry of Energy, Northern Development and Mines (formerly the Ministry of Energy)
- Energy Regulator (Ontario Energy Board)
- Gas utilities

How Stakeholder Input Was Used

The IESO received stakeholder feedback during and after each engagement meeting. All feedback and responses were publicly posted on the ERUC engagement page. The following IESO response documents include a summary of the feedback submissions by stakeholders from the first engagement until the release of the HLD:

- Response to Feedback from the July 18/19, 2018 Meeting
- Response to Feedback from the May 23/24, 2018 Meeting
- Response to Feedback from the March 29, 2018 Meeting
- Response to Feedback from the January 31, 2018 Meeting
- Response to Feedback from the November 27, 2017 Meeting

Below is a summary of some of the key areas of focus for which stakeholders submitted feedback and directly helped inform the design decisions of the ERUC. This is not an exhaustive list, as other design elements also benefited from the input of active stakeholders. The responses to feedback above should be consulted for a detailed record of discussions. The ERUC design tracker also provides a history of how design decisions were discussed and developed.

Design Element	Discussion Points
Offer Changes	The IESO received stakeholder feedback indicating that offer price increases may be warranted under certain circumstances. For example, the costs of a natural gas-fueled facility could be significantly impacted by volatility of the intraday gas market. Stakeholders requested an offer change exception process so participants can avoid operating at significant financial losses. The IESO recognized that changes in intraday fuel prices could cause offer prices to no longer reflect true operating costs. However, the IESO maintained that offer price increases will not be allowed due to the competitive advantage of a committed resource up to its full capacity due to “sunk” start-up costs. The committed resource could offer energy above its actual cost (subject to mitigation) and continue to be dispatched as the lowest cost resource; an uncommitted resource would not be competitive. If the committed resource sets price as the marginal resource, it will have clear information to influence price and increase its guarantee payment. It is expected that the committed resource will acquire sufficient fuel in advance for quantities up to the advisory schedule provided at the time of commitment. However, the IESO recognized that offer flexibility above the advisory schedule may be required. Resources would only require the ability to increase offer price for quantities above the initial advisory schedule during exceptional circumstances that can be identified in advance by the IESO. Any offer price increases would be subject to an after-the-fact audit/compliance process.
Intertie Transactions	The IESO received feedback that the pre-dispatch (PD) evaluation should include all available intertie transactions, indicating that the preliminary decision could have price impacts and lead to inefficient scheduling. The preliminary decision excludes intertie transactions that do not have a financially binding DAM schedule from PD evaluation for hours beyond the near term two hours. The IESO indicated that only DAM-scheduled transactions and bids/offers in the near term two hours will be evaluated because they are more certain to appear in real-time (RT) if needed. The IESO agreed that PD prices and schedules beyond the near term two hours may be impacted by excluding non-DAM transactions, but that the inclusion of transactions that fail in RT could also produce inaccurate prices and schedules. Furthermore, the grid must not rely upon imports that are uncertain to appear in RT and must also not commit internal resources for exports that fail in RT. The IESO did not propose any changes to the decision based on the feedback provided.

Design Element	Discussion Points
Commitment Cost Mitigation	The IESO received multiple requests to clarify the IESO's approach to mitigate commitment costs. In particular, stakeholders asked how the IESO will determine eligible costs for mitigation and process exceptional cases. Stakeholders asked to be included in developing principles for conduct and impact thresholds as well as reference levels. The IESO initiated the development of conduct and impact threshold guidelines that form the basis of these mechanisms. The calculation methodology for daily cost-based reference levels will be determined during the detailed design phase, where stakeholders will have the opportunity to provide specific feedback. To address this further, in consultation with stakeholders during the detailed design phase of the engagement, the IESO will develop mechanisms for participants to: 1) request review of cost-based reference levels; 2) dispute decisions to mitigate offer prices; and 3) provide fuel-cost data for the purpose of adjusting cost-based reference levels on a timely basis.
Market Participant Data - Combined Cycle Modelling in All Timeframes	Stakeholders identified complexity relating to scheduling and financially committing combined cycle plant (CCP) resources, which are a type of non-quick start (NQS) generator. Today, the IESO models physical resource unit relationships through simplified "pseudo units" or "PSUs" in the day-ahead scheduling timeframe only. Stakeholders expressed concerns that the inconsistent use of PSU models from day-ahead into RT could result in undue financial penalties. Under DAM financially binding schedules and binding PD commitments for NQS resources, CCP resources may be exposed to greater financial risk if models are not accurately applied in all timeframes to achieve feasible physical resource schedules. To address these concerns, the IESO determined that combined cycle modelling will be implemented in all timeframes (i.e., day-ahead, PD, and RT) for consistency under Market Renewal to improve schedule feasibility and reduce financial impacts to market participants. The combined cycle modelling approach that will be implemented in all timeframes will be determined in the detailed design phase.
General	The IESO received stakeholder feedback requesting clarification on how the combined ERUC design element changes will impact market participant operations from PD into RT. Stakeholders commented they were not clear on the interactions of design elements. To address this, the IESO presented an overview of the enhanced PD evaluation process as well as RT commitment operational impacts. The IESO discussed how the PD engine will optimize hourly to produce advisory schedules and potential NQS resource commitments for each look-ahead period. The IESO discussed the need to include assumptions for synchronization and ramp in the PD schedules. The IESO will continue to work with stakeholders to understand impacts to market participant processes in PD and RT. For example, following notification of a RT commitment, generators will need to communicate more accurate lead time estimates. For ramp down to come offline, generators will notify the IESO control room of expected de-sync timing when a commitment is no longer extended.
Design Tracker/ Issues Log	In addition to stakeholder feedback and IESO response documents, stakeholders asked the IESO to adopt a design tracker and issues log to provide more clarity and progress updates on ongoing issues or design issues. The IESO agreed with the suggestion and has maintained both an Issues & Actions Log and an ERUC Design Tracker.

Engagement Outcome and Next Steps

The culmination of these engagement activities is the completion of the draft HLD document, which is reflective of the decisions discussed with stakeholders at the engagement meetings.

Engagement activities will continue on the HLD until all three energy work stream HLDs are finalized in early 2019. The engagement plan for the detailed design phase includes a new engagement approach.

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