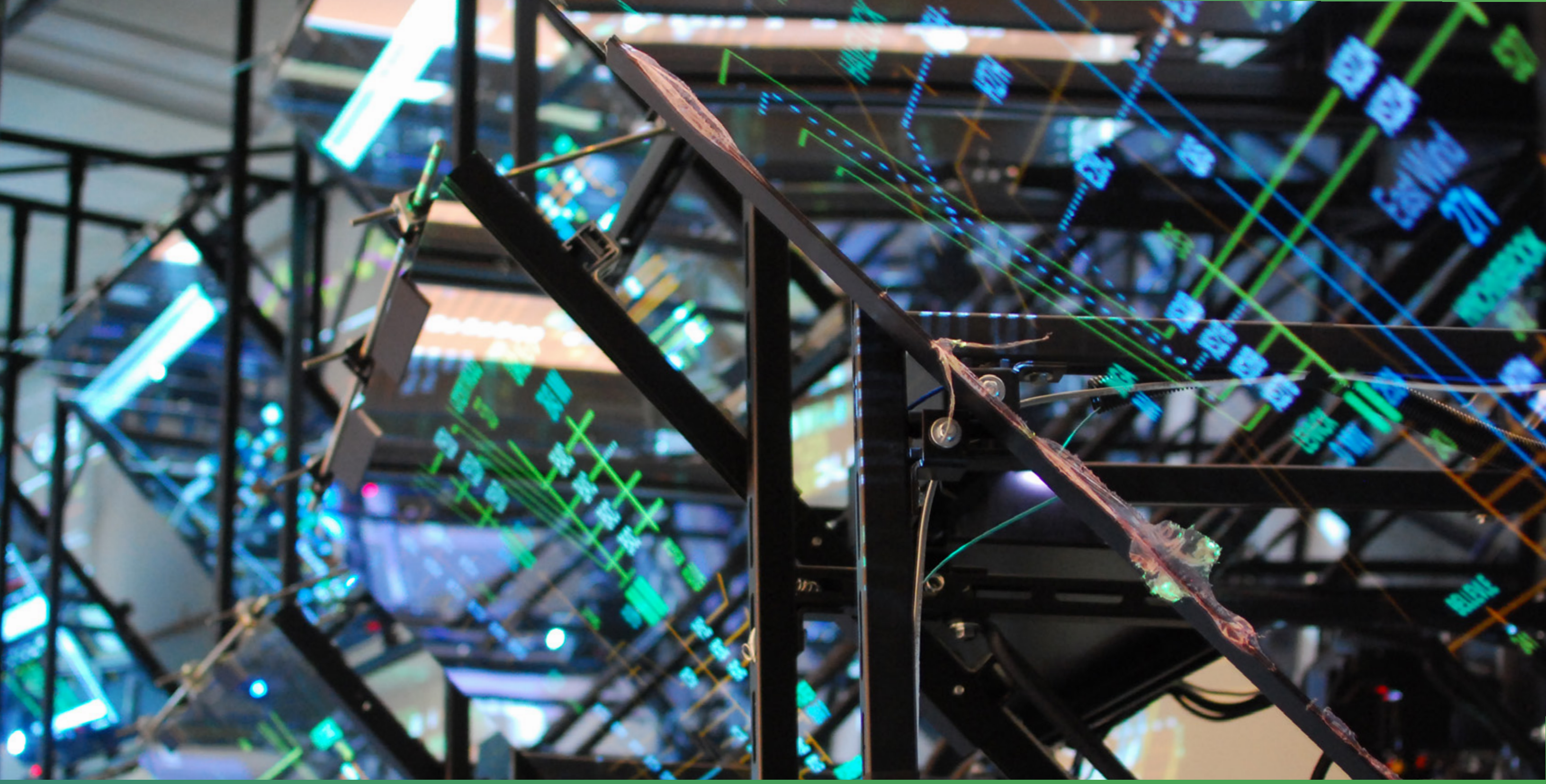

Single Schedule Market High-Level Design

Independent Electricity System Operator

SEPTEMBER 2018

ieso
Connecting Today.
Powering Tomorrow.

Contents

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LIST OF ABBREVIATIONS

Abbreviation	Description
BCA	Broad Constrained Area
CMSC	Congestion Management Settlement Credits
DAM	Day-Ahead Market
ERUC	Enhanced Real-Time Unit Commitment
ICP	Intertie Congestion Price
IESO	Independent Electricity System Operator
ISP	Intertie Settlement Price
LMP	Locational Marginal Price
MCP	Market Clearing Price
MIO	Multi-Interval Optimization
MLP	Minimum Loading Point
MRP	Market Renewal Program
MW	Megawatt
IOG	Import Offer Guarantee
NCA	Narrowly Constrained Areas
NERC	North American Electric Reliability Corporation
NISL	Net Intertie Scheduling Limit
OR	Operating Reserve
PD	Pre-Dispatch
RT	Real-Time
SSM	Single Schedule Market
TR	Transmission Rights
TS	Transformer Station

Description of Core Concepts

Short-run marginal cost

The additional cost that is incurred if a supply resource produces one more unit of electricity.

Marginal incentives for loads

The incentive for price sensitive loads, if they are able, to reduce consumption in response to relatively high locational prices.

Binding constraint

To ensure safe, reliable operation of the grid, transmission lines have constraints on the amount of electricity they can carry. A binding constraint occurs when the flow of electricity on a transmission line is equal to a constraint.

Intertie congestion constraints

The transmission lines that connect Ontario to other jurisdictions (i.e., interties) have constraints on the amount of electricity they can carry. "Intertie congestion" results when demand to flow electricity to or from Ontario is greater than can be accommodated.

Out-of-merit

At times, to maintain safe, reliable and efficient operations, the IESO directs a supply resource to produce more or less electricity. When a resource may not appear to be the most economic unit, based on the bids and offers submitted, it is said to be dispatched "out-of-merit." Such results are the lowest-cost way to satisfy reliability or to achieve the most efficient dispatch.

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.

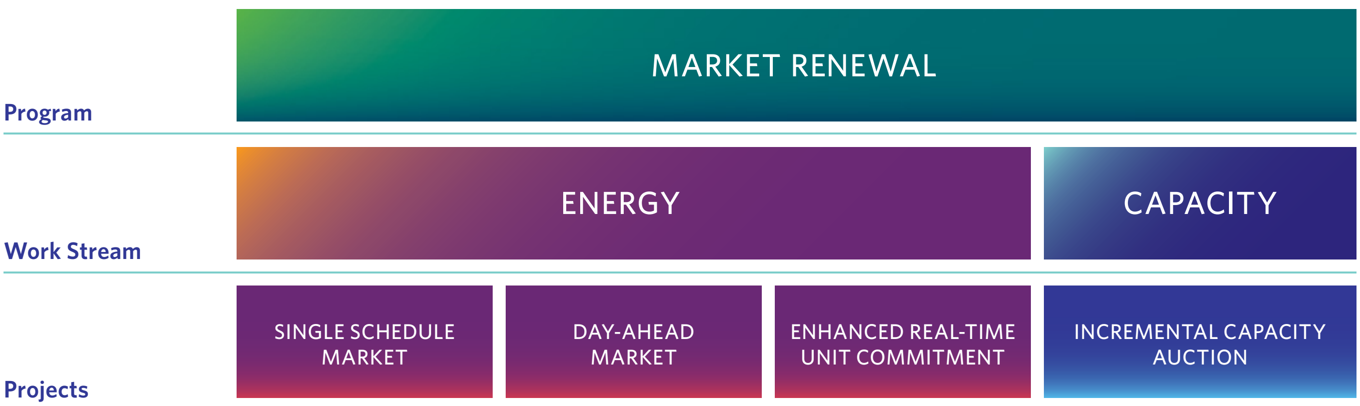
Market renewal initiatives

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 only 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 an **incremental capacity auction** (ICA) that will drive down costs by encouraging greater competition in acquiring the resources to meet system needs

Together, these projects are expected to deliver $3.4 billion in savings over a 10-year period, with the potential to reach as high as $5.2 billion.

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

FIGURE 2: PROJECT DESIGN PROCESS

The single-schedule market

Laying the foundation

When the province's wholesale electricity markets were introduced in 2002, the Market Design Committee at the time recommended a two-schedule market as a way to simplify the transition from a regulated system to fully-fledged markets. This decision has endured and Ontario is now the only jurisdiction in North America with a two-schedule market for energy.

Currently, the pricing schedule ("unconstrained schedule") is used to set a single price across the province every five minutes. This uniform market clearing price (MCP) is then used to establish the province-wide hourly Ontario energy price (HOEP) for electricity. Because this price doesn't take into account actual system conditions or operational constraints, it doesn't reflect the real cost of generating or consuming electricity at different locations.

However, in order to maintain reliability, the dispatch schedule ("constrained schedule"), which determines the physical dispatch instructions, has to take all system and operational limitations into account.

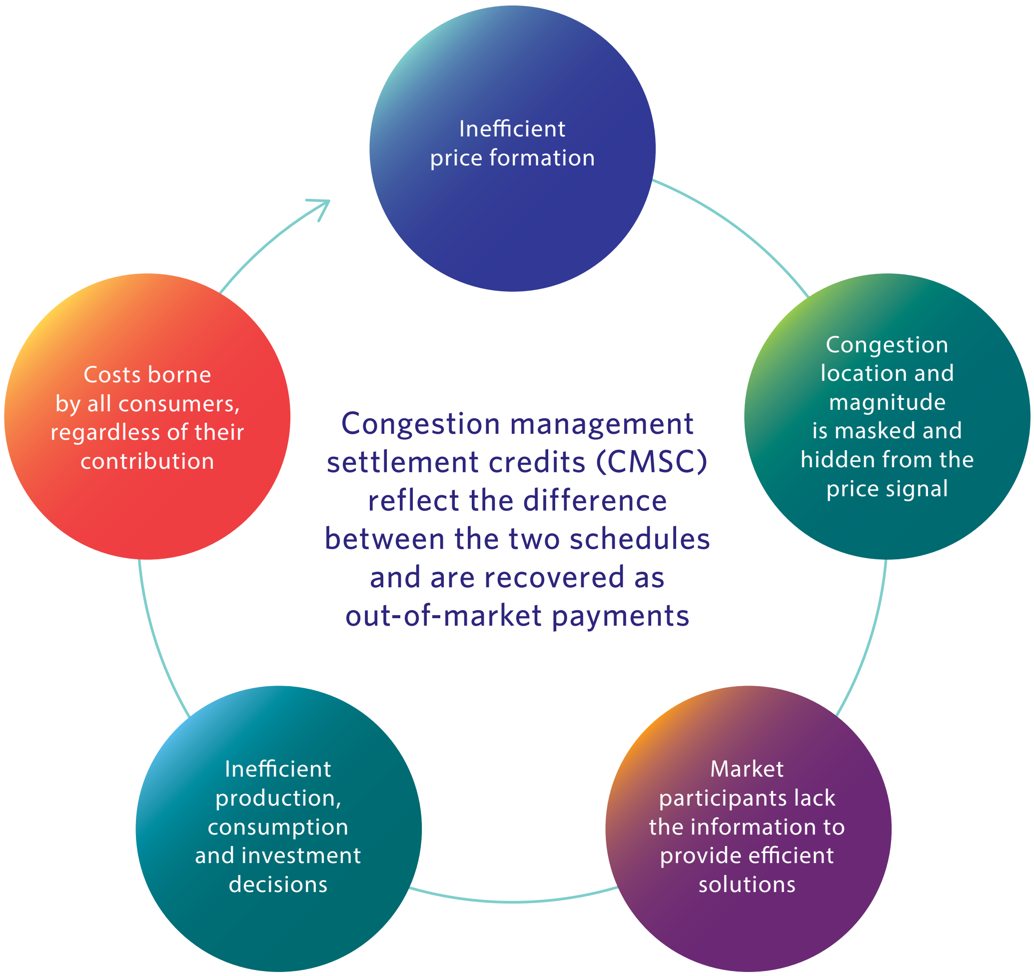
This system results in two key challenges for Ontario. First, when price and dispatch are not aligned, decisions that make financial sense to market participants may not be efficient or reliable for the markets as a whole. Second, the differences between price and dispatch require a complex series of out-of-market payments – or congestion management settlement credits (CMSC) – to ensure all market participants follow dispatch instructions to maintain reliability.

The larger the divergences between those two schedules, the more out-of-market payments in the form of CMSC are required to reconcile the difference. Greater divergences also increase the probability of inefficient outcomes, such as higher costs, complex settlements and opportunities for market participants to game the system (see Figure 3). CMSC payments are not transparent and as such not subject to the scrutiny of transparent markets or the pressures of open competition.

With the proposed SSM design, market prices will reflect the true costs of producing or consuming electricity at a given place and time. Transparent price signals will support more open competition between market participants and lead to more efficient outcomes without the need for the CMSC payments that are a necessary feature of the current design. In addition, the introduction of a single market schedule will allow the IESO to implement important changes to the energy markets, such as the establishment of a day-ahead market and enhanced real-time unit commitment.

Finally, as technology changes empower a larger range of consumers, more granular pricing will help consumers connect their actions to needs on the system, and maximize the economic benefit for both.

FIGURE 3: EFFECTS OF CMSC PAYMENTS



Since May 2017, when we hosted the first SSM stakeholder meeting, consultation has taken place on all aspects of the SSM design, including in-depth discussions of the applicability for Ontario of different options for each of the proposed design elements. Throughout this process, we have taken into account how the choices we considered would affect stakeholders, doing our best to ensure decisions reflect their collective feedback, adhere to our guiding principles and address and anticipate unintended outcomes.

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 the new single-schedule model.

To manage the scope and complexity of the SSM, the IESO focused the design work and engagement with stakeholders, separating the project into 19 design elements. These elements were then grouped into one of four categories: Price Formation, Market Power Mitigation, Load Pricing and Settlement Topics.[1] The following sections focus on the most material design elements in each category.

[1] See Appendix 1.

Price formation at a glance

Improving the way electricity is priced – and ensuring as many of the underlying costs as possible are reflected transparently in the energy price – is one of the goals of market renewal. With more granular prices, resources will be better able to make decisions that will improve efficiencies and reduce total system costs. For this reason, locational marginal prices – commonly referred to as LMPs – are a key element of single schedule markets.

In an SSM, locational prices will align with dispatch by accounting for congestion and losses – power loss from "distance travelled" from the supply resource – on the system.

Paying supply resources a locational energy price that reflects system conditions where they are connected to the grid will help ensure they present offers that accurately reflect their short-run marginal costs. This, in turn, will result in efficient dispatch, reducing the long-run cost of operating the system.

Under the new structure, operating reserves or standby capacity that allows the IESO to respond to short-term unexpected changes, such as downed transmission lines or generators, will also vary by region to reflect locational constraints.

The move will minimize the need for out-of-market or make-whole payments, which compensate generators when they face a shortfall between their offer price and the revenue earned through market clearing prices. While the cost of make-whole payments will drop dramatically with an SSM in place, these payments will still be required occasionally to ensure market participants will not lose money as a result of following IESO instructions to maintain system reliability.

Market power mitigation at a glance

A market thrives when there is open and fair competition among many resources. Competition becomes unfair when market participants 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 prevent participants from exercising market power and protect consumers from higher costs. Under the current system, however, market power mitigation is carried out after it occurs, and so is based on actual values rather than estimates. With the alignment of price and dispatch under the SSM, after-the-fact mitigation will no longer be viable.

Instead, the IESO will move to an approach that mitigates "before-the-fact" for economic withholding – a shift that prevents offers that are too high from affecting dispatch schedules and market prices. This approach is in keeping with the one used by other North American system operators.

This means that, where possible, the IESO will adjust offer prices for market participants that fail the tests for market power to their respective, pre-determined reference levels ahead of dispatch. In general, the test thresholds that determine what offer level and price impact trigger mitigation will be higher in areas with significant competition and lower in areas where competition is restricted.

As part of its market power mitigation strategy, the IESO will also address a number of scenarios that may create opportunities for the exercise of market power. These include situations where suppliers could set the LMP at their location or lower their office price to profit from the congestion caused by a transmission constraint, when interties are deemed to be uncompetitive – for example, because the majority of the trade comes from a single market participant – and when import congestion could drive price increases in Ontario.

Load pricing at a glance

While an SSM introduces locational pricing for those that supply electricity directly to the wholesale market, the prices sent to different classes of consumers merit a separate group of design elements. The high-level design deals with the pricing for loads (also known as electricity consumers) that are market participants[2] and typically directly connected to the IESO-controlled grid. This group represents about 14 per cent of total load in Ontario and includes the largest industrial and commercial facilities in the province.

Locational pricing is not just a cornerstone of a more dynamic and active marketplace; it also help ensure that consumers' energy consumption decisions are linked to actual system needs, leading to greater operational and economic efficiencies. For example, accurate price signals can encourage price-sensitive loads to reduce consumption when local prices are high, reducing demand and putting downward pressure on prices in a relatively high-priced region and, ultimately, enabling cost reductions for the responding loads and other loads in the region.

The IESO has examined best practices from other jurisdictions and has decided on a zonal pricing design – a weighted average of nodal prices within the zone[3] – as the right choice for Ontario. Loads will also have the option to move to nodal pricing depending on their preference. By moving to zonal prices, loads that are connected to the IESO-controlled grid or are market participants with limited or no ability to respond to price signals will still see benefits in the form of overall price reductions.

As a consequence of transitioning some loads from a uniform price to a locational one, congestion rents and loss residuals will be collected as part of the energy settlement. Congestion rents are the difference in the price paid by consumers and the price paid to suppliers when there is congestion on the system. Similarly, loss residuals result from the difference between the amount paid for losses by loads and the amount paid for losses to generators.

Money collected as a result of congestion rents and losses will be returned to Ontario consumers according to the degree to which they are impacted by congestion on the system. In practical terms, this means consumers who are exposed to higher LMPs in zones where there is congestion will see their prices reduced toward the provincial average.

The high-level design decisions on load pricing primarily apply to larger consumers who are market participants. While this is not within our jurisdiction, the IESO is not aware of any plans to move residential and low-volume consumers from the province-wide uniform commodity cost set through the Ontario Energy Board's Regulated Price Plan (RPP). However, these consumers will still benefit from the move to LMP, as the actions of suppliers and larger loads will result in more efficient operational outcomes for the system and, ultimately, help lower costs for all consumers in Ontario.

Settlement topics at a glance

These design elements deal with situations when offer prices do not align with dispatch – for example during unexpected events, which can lead to reliability concerns for the IESO.

In instances where a resource is dispatched to produce more or less energy than that implied by the LMP, the resulting "operating cost loss" or "opportunity cost" is addressed through make-whole

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[2] As market participants, local distribution companies (LDCs) will be charged zonal prices. However, Ontario's current regulated price plan (RPP) is legislatively mandated and requires LDCs to charge uniform RPP prices to their RPP customers (low-volume consumers).

[3] Pricing zones, which correspond to Ontario's existing 10 electricity zones, usefully segment the Ontario grid according to congestion and expected price separation.

payments and uplift recovery payments. In both cases, these payments incent market participants to adhere to dispatch instructions, providing the IESO with greater operational certainty.

Under the SSM, the IESO will continue to assign make-whole uplift charges on an hourly basis to all loads and exports to recuperate the cost of services that are not otherwise recovered through other charges.

Conclusion

Our goal, at the IESO, has always been to operate markets that provide clear signals for the value of needed services, and ensure prices accurately reflect system conditions, permitting both suppliers and consumers to make more informed decisions. In providing a blueprint to achieve this goal, the single schedule market high-level design addresses longstanding concerns with the current two-schedule market structure.

Collectively, the decisions included in the document – starting with the replacement of uniform pricing across the province with pricing that reflects the true costs of producing and consuming electricity – resolve the costly misalignment between price and dispatch. Once implemented, the high-level design will also dramatically reduce existing complexities, paying the way for other cost-saving initiatives, including the day-ahead market.

The culmination of 18 months of extensive consultation with stakeholders, this document is both a comprehensive summary of the decisions that will enable us to move to an SSM, and a stepping-off point for engagement on the detailed decisions that will need to be addressed before implementation.

As the initial high-level design, it also represents the first in a series of reforms that will fundamentally transform the province's electricity markets, and which, taken together, will enable us to deliver electricity to consumers at lowest cost and better prepare the IESO and market participants for whatever the future may hold.

2. Price Formation

The single schedule market (SSM) is one of three initiatives in the Market Renewal Program's energy work stream. The SSM will align system dispatch and market prices using locational marginal prices (LMPs). This will improve price formation resulting in LMPs that reflect the value of electric energy at different locations on the IESO-controlled grid ("grid" or "system"). LMPs may vary by location[4] as a result of changes in congestion and losses across the system. The alignment of prices and dispatch will also increase the incentives for market participants to offer at competitive prices and reduce out-of-market uplift payments. Competitive offers from suppliers reflect the short-run marginal cost of supplying electricity.

Offers based on short-run marginal cost result in resources being dispatched more efficiently and, therefore, minimize the long-term cost of operating the system. The LMP is calculated at each supplier and load location on the grid as follows:

LMP = Energy Reference Price + Energy Price Congestion Component + Energy Price Loss Component

[4] A location on the IESO-controlled grid is typically the connection point of a market participant supplier, load or interconnection with other jurisdictions. The SSM will have an LMP associated with each location on the grid.

2.1 Energy Reference Price

2.1.1 Design Element Description

The energy reference price is the cost of increasing the demand for electricity by one megawatt (MW) more than actual demand at a specific location on the transmission system known as the "reference location." The reference location is used as a starting point to determine all LMPs on the transmission system. Differences in LMPs at different locations are the result of congestion and losses relative to the reference location.

The energy reference price is a necessary component in the calculation of an LMP. Once computed for a specific time interval, it is then applied to all locations on the transmission system. The congestion and loss components of the energy price are both zero[5] at the reference location, resulting in the LMP at the reference location being equal to the energy reference price. If a different reference location is used, the LMP components at each location on the grid would change, but the LMP at each location would remain the same.

The energy reference price in Ontario is currently established at the Richview Transformer Station (TS) located in the Greater Toronto Area.

2.1.2 Decisions

The Independent Electricity System Operator (IESO) has determined that it will continue to use Richview TS as the energy reference price because it is located in the Greater Toronto Area load centre; has strong connections to the rest of the transmission system; and has served this function for many years without adversely impacting dispatch solutions.

2.1.3 Detailed Design Considerations

The IESO will need to consider how best to determine an energy reference price for scenarios when the Richview TS is unavailable. The IESO will also consider a proper calculation of LMPs for atypical situations where islands[6] form on the grid. Islands can disconnect a portion of the Ontario grid from the Richview TS, making congestion and losses between the "islanded" nodes and Richview TS impossible to determine. In the current market, nodal prices are not calculated for islanded locations, making the status quo untenable in an SSM.

2.1.4 Linkages

Linkages highlighted in this document are limited to those between SSM project design elements. Potential linkages between SSM design elements and design elements in the day-ahead market, enhanced real-time unit commitment and incremental capacity auction projects are not listed. The linkages identified and listed in this document include design decisions that directly impact the choices and outcomes of other design elements.

The Energy Reference Price design element is linked to SSM design elements 2 ("Energy Price - Congestion Component") and 3 ("Energy Price - Loss Component"). Collectively these three components form the LMP.

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[5] This is because the location of injection and withdrawal are the same.

[6] In a power system, an island is an area that has become disconnected from the rest of the grid.

2.2 Energy Price - Congestion Component

2.2.1 Design Element Description

The energy price - congestion component ("congestion component") is the incremental cost at any location on the grid due to transmission congestion between that location and the reference location. The congestion component can be positive, negative or zero, depending on whether the direction of the transmission constrained flow of energy is toward or away from the reference location.

On a specific transmission line, the change in incremental cost due to congestion is:
- *Positive*, when transmission flows are limited away from the reference location into a specific location
- *Negative*, when transmission flows are limited toward the reference location from a specific location, or
- *Zero*, when there are no binding transmission constraints.

The congestion component represents the cost of dispatching resources once transmission constraints are taken into account. It affects system costs whenever transmission congestion causes a higher-cost resource to be dispatched locally, instead of a lower-cost resource behind the transmission bottleneck.

The congestion component transparently identifies the cost of energy congestion at specific locations on the grid. This information can signal the need for and value of:
- Transmission system expansion and upgrades, and
- Additional sources of supply and/or demand management at specific locations.

2.2.2 Decisions

The IESO will include the congestion component when determining LMPs; this is a foundational aspect of SSM design. The congestion component will be calculated concurrently with dispatch to align pricing and dispatch. Prices that align with dispatch encourage offers that reflect short-run marginal costs.

2.2.3 Detailed Design Considerations

The IESO will need to calculate congestion components as discrete variables and determine how they should be reported from day-ahead, pre-dispatch and real-time results.

2.2.4 Linkages

The Energy Price - Congestion Component design element is linked to SSM design elements 1 ("Energy Reference Price") and 3 ("Energy Price - Loss Component"). Collectively, these three components form the LMP.

2.3 Energy Price - Loss Component

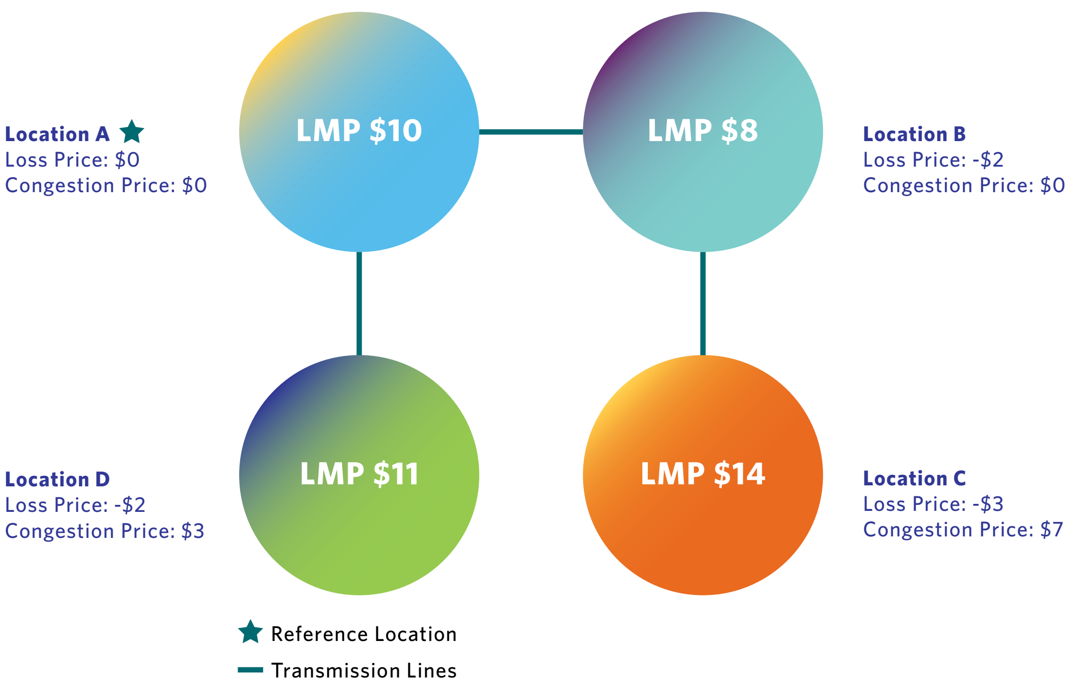
2.3.1 Design Element Description

Transmission losses occur when power is transmitted from the location of a supply resource to the location of a load. The energy price - loss component ("loss component"), which reflects the cost of marginal transmission losses at a given location relative to the reference location, is one of three price components that make up an LMP.

The loss component is a function of the marginal loss factor at a given location and the price at the reference location (i.e., the energy reference price). The marginal loss factor at a given location is derived from the transmission losses incurred from meeting one additional MW of load at that location with one additional MW of supply from the reference location.

FIGURE 4: CONGESTION AND LOSS COMPONENTS AT EACH NODE

Location A is the reference location. This means that the loss price at Location A is $0 and the loss prices for all other locations are set in relation to Location A. Location C has a loss price value of -$3 and a congestion price of $7, indicating losses and congestion associated with generating an additional MW and transmitting it to Location A.



Loss factors for specific resources are typically greater the further they are from the reference location.[7] The cost of losses also increases as the price increases at the reference location. If all else is equal, the greater the cost of marginal transmission losses to a particular location relative to the reference location, the lower the LMP will be at that location.

Loss factors are also dependent on generation and load schedules, as well as on power flow. These can be modeled in a number of ways. Static loss factors reflect the cost of losses within a historical

[7] In general, the loss factor for a resource is a function of its electrical distance from the reference location and the prevailing transmission system flows. When two resources are transmitting power over the same transmission corridor in the same direction as the prevailing flows, the loss factor is greater for the one further away from the reference location.

sample set used to calculate the factors. Dynamic loss factors, determined for each dispatch interval, most accurately represent the cost of losses for the schedule and power flow outcome. Quasi-dynamic loss factors are calculated much more frequently (e.g., daily or hourly) than static loss factors, but are not determined for each dispatch interval. They, therefore, reflect some of the near-term system conditions in the cost of losses, but are less accurate than dynamic loss factors.

Historically, the IESO has used static loss factors to determine the cost of losses. This is satisfactory in the current market as the uniform market clearing price (MCP) does not include the cost of losses,[8] so any imprecision associated with using them does not affect the MCP. However, in an SSM, the cost of losses can directly impact the LMPs for energy. Using more dynamic loss factors will produce prices that better reflect the cost of meeting demand at a given location.

2.3.2 Decisions

The IESO will include the loss component when calculating LMPs as this is a foundational aspect of SSM design. The loss component will be calculated concurrently with dispatch to align pricing and dispatch. Prices that align with dispatch encourage offers from market participants that reflect their short-run marginal costs.

The IESO has also determined that dynamic loss factors will be used, where technically feasible, to more accurately calculate losses.

2.3.3 Detailed Design Considerations

The IESO will need to calculate the loss component as a discrete variable. It will also need to determine if, and in what form, a report will be created to record the loss component at each location during each interval.

Dispatch volatility issues that were previously an issue with implementing dynamic loss factors will also need to be considered.[9]

2.3.4 Linkages

The Energy Price - Loss Component design element is linked to SSM design elements 1 (“Energy Reference Price”) and 2 (“Energy Price - Congestion Component”). Collectively these three components form the LMP.

[8] The IESO currently accounts for the cost of marginal transmission losses when it dispatches resources, but does not directly account for the cost of those same losses when determining the market clearing price.

[9] Quasi-dynamic loss factors will be considered if using fully dynamic loss factors is not technically feasible.

2.4 Pre- or Post-Interval Pricing

2.4.1 Design Element Description

LMPs can be determined at the beginning or the end of each five-minute dispatch interval. The pre-interval (ex-ante) pricing or post-interval (ex-post) pricing consideration under the SSM aims to align LMPs with the underlying cost of dispatch related to:

- Producing or consuming energy at a given location and time
- Providing operating reserve at a given location and time.

The current markets determine the real-time physical dispatch in advance (ex-ante) of each five-minute dispatch interval[10] and calculate the prices for energy and operating reserve (OR) following the interval (ex-post). Under the current market structure, the dispatch instructions are determined using inputs, such as planned outages, transmission constraints and forecasted Ontario demand.

An ex-post pricing run uses actual, rather than forecasted Ontario demand. These two demand determinations may differ, changing the demand curve between the dispatch and pricing run, and resulting in the use of two different market clearing points to set price. Applying the ex-post approach to the determination of LMPs could cause misalignment of prices and dispatch. In such cases, the market price would not reflect the cost of dispatching the marginal resource and could result in out-of-market uplift payments to ensure dispatch instructions are followed.

For an SSM, the better approach is to determine prices ex-ante. Under ex-ante pricing, both the dispatch and the pricing run take place prior to the interval and use the same set of inputs, including forecasted Ontario demand. In ensuring alignment between dispatch and pricing, this timing reduces the need for out-of-market payments.

2.4.2 Decisions

The IESO has determined that ex-ante pricing will be used to calculate LMPs. In improving alignment between dispatch and price, and encouraging offers based on short-run marginal cost, ex-ante pricing will minimize the long-term cost of operating the system.

2.4.3 Detailed Design Considerations

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

2.4.4 Linkages

There are no identified linkages for this design element.

[10] Every five minutes, a market clearing price (MCP) is set based on the bids and offers that are settled in the wholesale electricity markets. For each five-minute interval, dispatch instructions specify the required amount of energy to be injected into or withdrawn from the IESO-controlled grid by sellers and buyers, based on their accepted offers and bids.

2.5 Intertie Congestion Pricing

2.5.1 Design Element Description

Interties are transmission lines that allow energy to move between adjacent balancing authorities or jurisdictions. Ontario is connected with five other jurisdictions: Manitoba, Minnesota, Michigan, New York and Quebec. Each of Ontario's interties has a maximum allowable import and export transmission capability that relates to its power flow limit. These limits are used to ensure system stability and acceptable thermal loading levels.

When an intertie's maximum capability is reached, the intertie is either import- or export- congested. When congested, the price on the intertie is set by the offer or bid price of the resource that can most economically satisfy the next MW of demand at the intertie. When congested, the price on the intertie will differ from the nearest internal LMP by the amount of the intertie congestion price (ICP). By definition, the ICP identifies the incremental change in marginal costs associated with intertie congestion constraints at the intertie location. The ICP can be negative, positive, or zero, depending on the type of intertie transactions bound by an intertie constraint.

The change in marginal cost due to congestion caused by intertie constraints is:

- *Negative*, when the intertie is import-constrained (i.e., the intertie price is lower than the Ontario price). This negative congestion reflects a decrease in marginal costs at the intertie location as a result of offers that express importer willingness to be paid less than the clearing price at internal locations.
- *Positive*, when the intertie is export-constrained (i.e., the intertie price is higher than the Ontario price). This positive congestion reflects an increase in marginal costs at the intertie location as a result of bids that express exporter willingness to pay a premium relative to the clearing price at internal locations.
- *Zero*, when there are no binding transmission constraints on the intertie (i.e., the intertie price is equal to the Ontario price).

Current Market

Intertie transactions can currently be scheduled in day-ahead and in the last hour of pre-dispatch. However, the ICP is only calculated in the pre-dispatch timeframe. It is in this timeframe when intertie schedules can be changed in response to an incremental amount of load. As a result, intertie transactions determine the ICP at the time that intertie constraints become binding in pre-dispatch. Intertie transactions are then able to set pre-dispatch hourly prices.

In real-time, intertie transactions are not eligible to set price because their quantities are fixed for the hour to the amount scheduled in pre-dispatch.[11] As a result, interties can neither set the price[12] in real-time, nor can they contribute to the congestion cost component of LMPs and set the ICP at that time.

As a result, interties can neither set the price in real-time, nor can they contribute to the congestion cost component of LMPs and set the ICP at that time.

[11] Intertie schedules are fixed in the dispatch hour to reflect scheduling in pre-dispatch and the agreement between neighbouring jurisdictions to exchange a fixed amount of MWs between the two markets (e.g., Ontario and New York).

[12] To set price in real-time, offers or bids need to be able to respond to dispatch instructions in real-time.

In the current market, when intertie transactions are scheduled in the pre-dispatch (PD) unconstrained sequence, a “static” ICP is generated. The ICP is meant to describe the change in the marginal cost at the intertie location relative to the pre-dispatch MCP. The current ICP calculation in the pre-dispatch formula is:[13]

Equation 1 – Intertie Congestion Price (ICP)

PD ICP = PD Intertie Price – PD Ontario MCP

The static ICP is then added to the real-time (RT) Ontario MCP for the applicable intertie location(s), setting the RT intertie settlement price (ISP). The current RT intertie settlement price calculation is:

Equation 2 – Real-Time Intertie Settlement Price

RT ISP = RT Ontario MCP + PD ICP

Future Market

While the current application of a static ICP in real time is reasonable and has been used for some time in Ontario, there are drawbacks to this approach. Adding the real-time MCP (which can differ from the pre-dispatch MCP) to the static ICP determined in pre-dispatch can result in a settlement price that fails to reflect the incremental cost of exports or the incremental value of imports as determined by the bids and offers of traders at specific interties. This is because the current system allows exporters to pay lower prices and importers to be paid higher prices than the pre-dispatch prices for which they were scheduled.

To the extent that exporters are able to predict price decreases (and importers price increases) between pre-dispatch and real-time, the current system encourages bids or offers that may target scheduling outcomes in pursuit of better real-time prices, instead of the expected marginal value of the transaction. When bids/offers are not reflective of expected marginal value, market efficiency is reduced and costs to Ontario consumers may increase. Incentives that encourage bid or offer submissions to deviate from their marginal value[14] can result in:

- Inefficient scheduling and commitment outcomes,
- Increased uplift payments to the market place, and
- Distorted prices when such bids or offers are used to set price.

1. Import Congestion

As a result of the above design considerations, the IESO has developed an approach to determine the intertie settlement price at import-congested interties. The IESO will use a settlement price with a “dynamic” ICP to better reflect changing intertie congestion conditions. This approach only applies to imports settled in the real-time market.

The import-congested intertie settlement price will be equal to the lower of the real-time intertie price and the final pre-dispatch intertie price. Better alignment between the price received by an importer and its offer price – its stated willingness to sell – will encourage the importer to offer in line with the expected marginal value of its transaction. Offers reflecting marginal value will ensure efficient scheduling of internal resources and reduce the cost of meeting Ontario demand. Importers will still be eligible for the real-time import offer guarantee (IOG),[15] which promotes reliability by protecting importers from down-side price risks associated with hourly pre-dispatch scheduling.

[13] For more information on how the IESO currently prices intertie congestion, refer to the IESO’s training or Interjurisdictional Energy Trading.

[14] Marginal value is the price at which a market participant is willing to be settled.

[15] The real-time 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 materially decrease between pre-dispatch and real-time.

In summary, when the intertie is import-congested, the intertie settlement price will be based on the lower of the nodal price in real-time or pre-dispatch at the intertie. This dynamic settlement approach is set out in Equation 3:

Equation 3 – Intertie Settlement Price

RT ISP = Minimum of {RT Internal Node LMP, Final PD Intertie LMP}

The "effective" (i.e., not required to be calculated for the real-time intertie settlement) dynamic ICP can be calculated in real-time as the difference between the intertie settlement price and the real-time internal nodal price near the intertie. The effective real-time ICP is set out in Equation 4:

Equation 4 – Intertie Congestion Price

Effective RT ICP = RT ISP – RT Internal Node LMP

2. Export Congestion

The issues with the current intertie congestion methodology described above are also applicable to export-congested interties. Exports have the incentive to bid at prices higher than their actual willingness to pay in the expectation of being charged a lower price in real-time. Pricing export-congested interties in a similar manner to how import-congested interties will be priced would better encourage efficient bids from exporters than the current methodology.

However, the IESO recognizes that this pricing methodology could lead to unscheduled export capacity, which would be detrimental to market efficiency.

Currently, pre-dispatch prices are persistently higher than prices at the same location in real-time. Causes of this difference include the use of peak demand forecasts in some hours, the ability to schedule control action operating reserve in real-time and the inability for exports and imports to set prices in real-time. Exporters may need to bid higher than the pre-dispatch price to ensure that the transaction, which is often efficient in real-time, is scheduled.

The current pricing rules let exporters receive price improvement between pre-dispatch and real-time, allowing the efficient export to be economically viable for the exporter. A dynamic ICP, for the reasons outlined above, would not allow exports to see price improvement between pre-dispatch and real-time when a given intertie was export-congested.

This pricing logic encourages exporters to bid at the expected marginal value of the transaction. However, because pre-dispatch prices tend to be higher than those in real-time, a dynamic ICP could also lead to some efficient real-time exports going unscheduled because the dynamic ICP pricing rules would make the trade uneconomic. Given the potential for this inefficient outcome, the IESO will continue to use the current static ICP methodology for interties that are export-congested.

In summary, if export-congested, the intertie settlement price will be consistent with the current static ICP methodology, which adds the pre-dispatch ICP to the RT internal node LMP near the intertie. The ICP pricing approach for exports will apply only to transactions settled in the real-time market. The approach is described in equations 5 and 6:

Equation 5 – Intertie Congestion Price

PD ICP = PD Intertie LMP – PD Internal Node LMP

Equation 6 – Intertie Settlement Price

RT ISP = RT Internal Node LMP + PD ICP

3. No Congestion

When there is no congestion, the intertie congestion price is zero and the real-time intertie price will be used as the settlement price. In encouraging efficient bids and offers from market participants, this will minimize the long-term cost of operating the system.

2.5.2 Decisions

The IESO has determined that it will adopt the following intertie settlement pricing approach based on design considerations for intertie congestion:

- For ***import-congested interties***, a dynamic ICP that varies with pricing at the intertie between pre-dispatch and real-time will be used. The dynamic settlement approach will select the lesser of the pre-dispatch and real-time price as the intertie settlement price. The effective real-time ICP can be calculated as the difference between the intertie settlement price and the real-time price at the internal node. Note that import transactions will continue to be eligible for IOG protection when the intertie settlement price is less than the import offer price. This approach will improve efficiency and the price signal, while maintaining competition.
- For ***export-congested interties***, the intertie settlement price will remain consistent with the existing approach of adding the static ICP determined in pre-dispatch to the real-time LMP at the internal node. This approach will allow export transactions to be scheduled in hours with elevated pre-dispatch prices in comparison to real-time, preserving efficiency and competition.
- For ***interties with no congestion***, the ICP is zero and settlement prices will be equal to the real-time LMP at the internal node near the intertie.

2.5.3 Detailed Design Considerations

The IESO will review the following considerations during the detail design:

- A single intertie with a neighbouring jurisdiction can be composed of multiple transmission lines that connect to different locations on the grid. Each of these connection points could be subject to a different LMP. For example, Ontario has multiple connection points with New York, but only one New York intertie price. When LMPs across the connection points of an intertie vary, a methodology for the determination of prices for the intertie location will be required.
- When an intertie location has been scheduled to its limit, the ICP changes the marginal cost for both energy and operating reserve (OR) transactions at the intertie location. For import-congested interties, the IESO will need to consider whether the dynamic ICP derived in the calculation of the real-time intertie settlement price for energy is transferrable to intertie reserve prices, or whether a separate ICP needs to be derived for OR.
- Transmission rights (TRs)[16] that are available in the current market provide a hedge against intertie congestion in real-time and pay out the ICP when congestion matches the location and direction of the TR. In other jurisdictions, similar products are settled in the DAM and are not offered in real-time. The IESO is planning to review further design changes and the impacts of TR market development, such as TR clearing account funding, disbursement and settlement changes.

[16] On a monthly basis, the IESO sells TRs through an auction process. TRs entitle the owner to a payment if the price of energy in Ontario is different from the price in an intertie zone. The TR market allows market participants to reduce price risks associated with transmission congestion and price volatility. This, in turn, can improve market liquidity. TRs are sold for specific intertie paths through an auction process accessible through the IESO's web portal. Both short-term (one month) and long-term (one year) TRs are available. A price differential is paid to TR owners when the intertie zone price is different from the Ontario market clearing price.

- Wheel-through intertie transactions are currently settled with one intertie settlement price. Detailed design will investigate the implications of having two different settlement prices for different intertie zones.
- Incremental requirements and dependencies for moving to LMP at intertie locations will be considered for modeling of the external network.

2.5.4 Linkages

The Intertie Congestion Price design element is linked with to SSM design element 2 ("Energy Price - Congestion Component"), which provides for including congestion costs from transmission congestion in LMPs. The ICP design element complements that decision by also including any congestion costs as a result of intertie constraints for LMPs at intertie locations.

2.6 Supplier Pricing

2.6.1 Design Element Description

Through LMPs, the SSM will align the prices paid to suppliers[17] with their dispatch instructions. These instructions are based on locational considerations, such as the cost of congestion and losses. Aligning prices with dispatch encourages suppliers to offer at their short-run marginal cost without the need for a complex set of out-of-market uplift payments. Short-run marginal cost offers allow the IESO to dispatch resources more efficiently and, therefore, minimize the long-term cost of operating the system.

In an SSM, both dispatchable and non-dispatchable suppliers sell to the market and receive the LMP corresponding to their location on the grid. Under the IESO's current two-schedule market, the unconstrained schedule (which ignores system constraints) determines the uniform market clearing price (MCP) that all suppliers receive, while actual dispatch instructions are determined by a constrained schedule, which takes into account all system constraints.

As a result, the two-schedule market results in a settlement price that does not reflect actual dispatch instructions. Because of this inconsistency, suppliers that are dispatched even when their short-run marginal cost is higher than the MCP are compensated via congestion management settlement credits (CMSC). The current disconnect between prices and dispatch can lead to market inefficiencies and higher overall system costs.[18]

In addition to aligning market prices with dispatch instructions, paying suppliers the LMP associated with their location:

- Encourages short-run marginal cost offers, which improves the efficiency of the dispatch and, therefore, minimizes the long-run cost of operating the system
- Decreases administrative complexity by reducing the need for make-whole payments
- Informs investment decisions by encouraging resources to provide energy in relatively high-priced areas.

2.6.2 Decisions

The IESO has determined that it will use LMPs for energy and OR settlement in the SSM. Both dispatchable and non-dispatchable supply resources will participate in the SSM in the same manner as they do with the current market, but they will be settled on their output at their specific LMP.[19]

2.6.3 Detailed Design Considerations

Negative prices

At times, some supplier nodes in the province can experience negative LMPs. Often such prices are the result of transmission congestion and negatively priced offers in a given region. The IESO will evaluate

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[17] Refer to SSM design element 16 ("Pricing for Loads").

[18] For more information on this issue, see the Market Surveillance Panel's report on congestion payments, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_CMSC_Report_201612.pdf.

[19] For greater clarity, a supplier's settlement will be a function of the value of supply sold in the day-ahead market and the value of incremental supply sold in the real-time market.

potential drivers for and issues resulting from negatively priced offers and LMPs. Negative offer prices that are not reflective of the short-run marginal costs of suppliers can result in distorted price signals in the market. If negative pricing is determined to be an issue, the IESO will assess appropriate options to address it.

2.6.4 Linkages

There are no identified linkages for this design element.

2.7 Operating Reserve Reference Price

2.7.1 Design Element Description

In the current market, the energy and operating reserve (OR) markets are co-optimized by the IESO. The constrained sequence co-optimization produces nodal prices for energy and for each class of OR.

OR is the standby power or demand reduction that the IESO can call on with short notice to deal with an unexpected mismatch between supply and demand. Ontario's OR requirements are based on mandatory North American Electric Reliability Corporation (NERC) reliability standards and the reliability criteria established by the Northeast Power Coordinating Council (NPCC). The IESO currently administers three different OR products: 10-minute spinning (referred to as "10S"), 10-minute non-spinning ("10N") and 30-minute reserves ("30R").[20]

The IESO is mandated by regional authorities such as NERC and NPCC to schedule enough of each type of OR to maintain system reliability. OR is generally activated when supply from a generator or the transfer capability of a transmission line is unexpectedly reduced or unavailable.[21] Transmission constraints may impact the ability to transmit OR from one area to another. Like the energy reference price, the OR reference price for each OR product is needed to calculate prices for each type of OR.

The energy and OR markets currently form the core of the IESO-administered markets and are co-optimized by the IESO. This means that they are simultaneously scheduled in a manner that optimizes the value of all energy and OR products. Co-optimization is considered best practice for single schedule markets.

2.7.2 Decisions

The IESO will continue to calculate the OR reference price by jointly optimizing energy and the three categories of OR.

2.7.3 Detailed Design Considerations

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

2.7.4 Linkages

There are no identified linkages for this design element.

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[20] For system reliability and flexibility, the IESO is, at times, able to schedule more OR than is required by the NERC and NPCC.

[21] Richview TS is also the reference location for operating reserve.

2.8 Operating Reserve Price - Congestion Component

2.8.1 Design Element Description

Eligible market participants can offer to provide OR to the IESO-administered markets. A MW of capacity can be scheduled to provide only one product at any given time, i.e., one of energy, 10S, 10N or 30R.

The IESO defines operating reserve areas to ensure that OR is distributed appropriately across the system and can be activated[23] when called upon. The boundaries for these reserve areas in the IESO-controlled grid are usually defined by transmission interfaces and their associated system operating limits.

The IESO currently accounts for system constraints when it schedules OR, but not when determining the uniform market clearing price for OR. The inclusion of the cost of congestion in OR prices would:

- Provide a more accurate and transparent signal to the market regarding the cost of incremental OR
- Encourage efficient OR offer behaviour from market participants
- Limit the need for OR make-whole payments
- Help resources make informed investment decisions by encouraging them to provide OR in higher-priced areas.

System constraints can be taken into account in determining OR prices by considering binding constraints associated with reserve areas, i.e., transmission limitations that prevent the delivery of the activated OR into or out of a reserve area. When such constraints are binding, the cost of that congestion can be reflected in the OR price - congestion component ("OR congestion component"). Absent any binding system constraints, the OR congestion component would be equal to zero and the prices of 10S, 10N and 30R would be identical to the corresponding OR reference prices. When congestion is taken into account in determining OR prices, the OR price[24] is calculated as follows:

OR Price = OR Reference Price + OR Congestion Component

2.8.2 Decisions

The IESO has determined that the calculation of OR prices will be based on the OR reference price and should take into account the OR congestion component. This will help align prices with schedules, encourage OR offers based on short-run marginal cost and, therefore, minimize the long-term cost of operating the system.

2.8.3 Detailed Design Considerations

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

2.8.4 Linkages

There are no identified linkages for this design element.

[23] When the operating reserve is activated, the suppliers are paid for the energy provided.

[24] OR prices are derived as a result of area operating reserve requirements. Area OR requirements specify a minimum quantity of OR required to be located in an area or a maximum quantity allowed to be scheduled in an area.

2.9 Constraint Violations

2.9.1 Design Element Description

The IESO dispatches resources and determines market prices by optimizing the system to most efficiently meet energy and OR requirements. However, the optimization may at times be unable to resolve all of the system constraints that are used to reliably dispatch and operate the system. In the absence of a feasible solution that can respect all modeled constraints, the optimization can attempt to achieve a solution by allowing for constraints to be violated. This design element dictates how constraint violations are resolved in dispatch and how these outcomes are reflected in market prices.

Under the IESO's current market, constraint violations are handled differently in the constrained dispatch and unconstrained pricing schedules.

The existing constraint violations rule mechanisms are described as follows:

1. *High penalty prices* are used in the constrained dispatch schedule to value the cost of incurring a particular violation. High penalty prices ensure that all market options have been exhausted before violating constraints that are needed to maintain reliability. These prices have been determined with enough separation to ensure that a clear priority of constraint violations is established. The priority is important, as it signals the order in which the IESO will violate system constraints when no market outcomes would otherwise be found.

TABLE 1: CURRENT IESO PENALTY PRICES

Table 1 identifies constraint violations and accompanying penalty prices currently used by the IESO in its constrained ("dispatch") schedule. The magnitudes of penalty prices determine the priority for observing the different constraints. It is important to note that the values in Table 1 are used for dispatch only and not for settlement purposes.

Violation	Penalty Price
Total Reserve Requirement	\$6,000/MW
10-Minute Total Reserve Requirement	\$10,000/MW
10-Minute Spinning Reserve Requirement	\$12,000/MW
Energy Balance	\$30,000/MW
Import/Export Scheduling Limit or Net Interchange Scheduling Limit	\$40,000/MW
Security Transmission Limit (Base case or Contingency)	\$60,000/MW

2. *Relaxation* is often used in the current unconstrained schedule to determine market pricing when a violation is incurred. Its purpose is to "relax" the constraint according to the size of the incurred violation, thereby eliminating the violation. By relieving the constraint, prices are not set by the high penalty prices (above). They are instead based on the marginal cost of the last resource dispatched before the violation would have been incurred following the relaxation.

3. *Specific pricing rules* are also used by the current unconstrained schedule to calculate the energy price based on the outcomes of the relaxation and violation runs. For example, operating reserve (OR) prices are based on the higher of the energy price or the highest-cost OR offer scheduled.

A shortcoming of using relaxation to resolve constraint violations is that it often results in an over- or under-relaxation of constraints. Accurately identifying exactly how much a constraint needs to be relaxed can be challenging – and lead to inaccurate market prices.

Instead the use of high penalty prices for both dispatch and pricing can limit the cost of re-dispatch and produce a more accurate price signal when violations occur.

While the intent of an SSM is to align dispatch with market prices, penalty prices that are the same in both the dispatch and pricing run can result in challenges:

- A high penalty price can help mitigate the violation of a given constraint by allowing relatively expensive resources to be used to resolve the violation. However, the resultant market prices may be higher than the market is willing to pay to resolve specific constraints.
- A low penalty price may result in market prices that more appropriately reflect the market value of the violation, but may allow a violation to persist by not dispatching higher-cost units to resolve it. This could require operator intervention to manually resolve the violation through potentially inefficient out-of-market actions.

Allowing for different sets of penalty prices for the same type of violation in the dispatch and pricing run can potentially alleviate these concerns. For constraints related to a reliability standard obligation,[25] adherence is not discretionary.[26] Therefore, applying a high penalty price for at least the dispatch run is justified. However, for some types of constraints not directly linked to a reliability standard obligation (such as the net intertie scheduling limit), a high penalty price may not be appropriate.

A more advanced form of penalty pricing for constraint violations is "graduated penalty pricing." This approach varies the magnitude of the penalty price in proportion with the magnitude of the violation. For example, an OR violation of 10 MW would incur a lower penalty price than an OR violation of 500 MW. Graduated penalty pricing allows the market to distinguish violations of all magnitudes and prevents unnecessary price volatility. This approach can also reduce the need for different sets of penalty prices to be applied between dispatch and pricing.

2.9.2 Decisions

The IESO has determined that the pricing rules for constraint violations will be broken into two categories:

- For reliability-based constraints, apply the current penalty prices in dispatch, but use a new set in pricing
- For non-reliability based constraints, apply a new set of penalty prices that are the same in both dispatch and pricing.

In addition to the two categories above, the IESO has determined that market prices will be capped at the current maximum market clearing price ($2,000/MWh). This approach will help address situations where multiple violations occur and the total of the corresponding penalty prices exceeds the maximum market clearing price.

[25] These types of reliability standard obligations represent a requirement to assess, identify, resolve and mitigate transmission violations, capacity or emergency deficiencies and procure a sufficient amount of OR.

[26] Where operational buffers exist in the definition of the reliability constraint, the violation amount corresponding to the buffer can be treated as discretionary in terms of penalty prices.

2.9.3 Detailed Design Considerations

The IESO will need to create a new set of penalty prices for pricing reliability-based constraints and for dispatching and pricing non-reliability based constraints. This will involve exploring the different methods, references and considerations applicable to Ontario that can be used when determining penalty prices. This will also include setting a review frequency to ensure penalty prices are current (e.g., reflect changes in fuel costs).

When developing methodologies for setting constraint violation pricing, the IESO will use graduated pricing when appropriate. Graduated pricing can improve price signals provided under varying magnitudes of constraint violations.

The IESO will need to develop a process to define NISL limits and corresponding violation magnitudes that are applicable to a given timeframe. The IESO's ability to accommodate large changes in intertie schedules will vary by time of day, types of resource online and the direction of the schedule change. These considerations should be included when defining the violation prices in order to ensure that violation pricing reflects the system costs incurred, while preventing violations that might affect reliability.

2.9.4 Linkages

The Constraint Violations design element is linked to SSM design element 18 ("Make-Whole Payments"). That design element establishes that make-whole payments apply to scenarios where resources were dispatched-up or dispatched-down with respect to their locational marginal price and the economics of their bids or offer costs. Where penalty prices differ between the dispatch and the pricing run, these differences can create scenarios requiring make-whole payments.

2.10 Out-of-Market Operator Actions

2.10.1 Design Element Description

The IESO-administered markets are, in general, dispatched and settled in an automated fashion. The algorithms responsible for the reliable and efficient dispatch of the system are constantly fed information that enables the determination of reliable and efficient dispatches. Such information includes market participant bids and offers, supply and demand forecasts and important system constraints, such as transmission line limits. Overseeing this process are the IESO's control room operators who monitor the system, including forecasts and constraints, to reliably match supply and demand.

While the majority of the time automation reliably operates the system, control room operators may, at times, have to take out-of-market operator actions ("control actions") to maintain system reliability. These can involve changes to reflect the real-time operating characteristics of generation resources and updates to transmission system capability and dispatch instructions. Such changes can affect supply and demand and, therefore, impact market prices. If those changes result in counterintuitive price signals, specific pricing rules should be implemented to prevent that from occurring.

When determining how control actions should impact price, if at all, the IESO currently applies the principle that control actions should not lead to counterintuitive prices that may mask prevailing system conditions. Control actions taken to reflect prevailing system conditions and transmission limits help to inform the correct dispatch and, therefore, should impact price.

On the other hand, control actions taken to address reliability concerns during scarcity conditions should impact dispatch, but be prevented from impacting price. For example, during a supply scarcity condition inside Ontario, the control room operator may use load shedding, voltage reductions, emergency imports or curtailment of exports to ensure system reliability. Such control actions will reduce demand (or increase supply) and, if unimpeded, reduce the market price, resulting in counterintuitive pricing. Failing to properly signal a scarcity situation to the market could discourage imports and suppliers from providing scarce energy and encourage exports, which might further exacerbate the issue.

In the current two-schedule market, in order to send correct price signals that reflect the underlying scarcity condition, the impact of the control actions taken to address scarcity is prevented from providing counterintuitive prices. The MW impact (amount of relief) of the control action is added back into market demand for the purpose of price determination. This has the effect of creating prices that are reflective of the scarcity condition prior to initiating the control action.

In order to maintain the current price determination logic as a result of control actions in an SSM, the IESO re-examined how it currently treats pricing during a number of different control actions. In particular, the IESO examined whether the current pricing treatment was appropriate and how similar pricing rules should be applied to LMPs in an SSM.

2.10.2 Decisions

Table 2 provides a list of control actions the IESO may take to ensure reliability, and indicates those that may permitted to impact prices and those that will be prevented from impacting price.

TABLE 2: SUMMARY OF SSM DESIGN ELEMENT 10 DECISIONS

Control Actions Prevented from Impacting Price	Control Actions Permitted to Impact Price
Scarcity or Surplus within Ontario: Load shedding Voltage reduction Emergency imports Export curtailments during scarcity inside Ontario Import curtailments during surplus inside Ontario	Emergency exports Adjustment of reserve requirement Derating of CAOR resources Recall outages Adjust NISL limit Adjust intertie scheduling limit
Imposing Operating Restrictions on Resources: Constraining of resources Activation of operating reserve Increase in amount of regulation service	Curtail imports or exports due to issues outside Ontario or because of importer or exporter failure Adjust demand requirement Adjust reserve area limits Adjust operating security limits
Ex-post Dispatch: One-time dispatch Blocked dispatch	Adjust for prevailing loop flow Utilize special protection systems Reconfigure transmission system

The IESO has determined that:

- When control actions are taken to address a scarcity condition inside Ontario, the prices should show the scarcity condition inside Ontario that triggered the control action. The pricing pass should, therefore, differ from the dispatch run and reflect scarcity conditions prior to the control action.
  - This is consistent with the status quo for scarcity control actions.
- When imports are curtailed to address surplus conditions within Ontario, the prices should show the surplus condition inside Ontario that triggered the control action. The pricing pass should, therefore, differ from the dispatch run and reflect surplus conditions prior to the control action.
  - This a change from the status quo as the pricing pass will reflect conditions prior to the control action. The impact of the control action should be prevented from providing counterintuitive prices.
- Control actions reflective of prevailing system conditions or transmission system capability should be consistently modeled in pricing and dispatch runs.
  - This is a change from the status quo for control actions related to either prevailing system conditions, such as adjustments to area limits for operating reserve, or to transmission system capability (which are ignored in the current market's pricing run).
- Control actions imposing operational restrictions on a resource (e.g., modifying minimum or maximum MW generation) should be prevented from setting price. This is consistent with the decision for SSM design element 12 ("Price-Setting Eligibility/Operating Restrictions").
  - This is a change from the status quo, as the current pricing run does not account for most operating restrictions.
- Control actions taken following dispatch instructions, such as one-time dispatch and blocked dispatch, should not impact prices as they would not be known at the time of the ex-ante pricing run.
  - This is consistent with the status quo for control actions that override dispatch instruction. The current pricing run does not factor in the physical dispatch of resources or any subsequent changes to dispatch.

These decisions will minimize the amount that market prices are distorted by control actions during supply scarcity or surplus conditions. Under otherwise normal operating conditions, market prices will align with dispatch.

2.10.3 Detailed Design Considerations

The IESO will need to determine whether control actions taken to address local reliability issues[27] need to be prevented from impacting prices.

2.10.4 Linkages

The Out-of-Market Operator Actions design element is linked to SSM design elements 18 ("Make-Whole Payments") and 12 ("Price-Setting Eligibility/Operating Restrictions") as follows:

- *Make-Whole Payments*: market prices that may not align with dispatch instructions can result in make-whole payments; and
- *Price-Setting Eligibility/Operating Restrictions*: the approach for control actions that involve imposing operating restrictions on resources is consistent with the approach for this design element.

[27] When scarcity is only a concern in a local area, control actions could be taken to affect only that local area. For example, a small amount of local load shedding could be used to alleviate the issue. In this case, the IESO will consider whether the control action should be prevented from counterintuitively impacting prices.

2.11 Multi-Interval Optimization

2.11.1 Design Element Description

Multi-interval optimization (MIO)[28] is used to improve the efficiency of operating the IESO-controlled grid by considering energy balancing requirements over a timeframe longer than a single five-minute interval.

The IESO currently uses a real-time schedule that looks ahead over the next 11 intervals in order to dispatch resources for energy and OR. This optimization allows the dispatch algorithm to evaluate all inputs over the 11-interval period and consider dispatch decisions that result in the most efficient solution over the evaluation timeframe. These may include dispatching resources out-of-merit in relation to their offer prices for the immediate interval in order to realize greater savings in future intervals. Such decisions may be used to manage a number of different types of technical limitations and restrictions, such as limited ramping capability, and changes in supply or demand conditions, operating reserve requirements or transmission limits.

An SSM aims to produce LMPs that are aligned with dispatch. As a result, it is beneficial to have any limitation or constraints that may influence the dispatch over the multi-interval lookout also influence LMPs. The use of MIO for determining both LMPs and schedules would continue to encourage short-run marginal cost offers and minimize the long-run cost of operating the system.

The use of MIO can, however, send dispatch instructions to resources that may make them uneconomic in the short-term in order to gain overall market efficiency in future intervals. Currently, when resources are dispatched out-of-merit because of MIO, they are not eligible to set the price. Instead, the lowest-cost resource that is able to respond to an increase in demand will be the price-setting resource. Under such circumstances in an SSM, LMPs may not align with the dispatch instructions for the uneconomically dispatched unit. The resulting difference between LMP and dispatch would need to be accounted for with a make-whole payment (discussed below in section 2.11.4).

2.11.2 Decisions

The IESO will continue to use MIO to determine dispatch schedules in all timeframes and to set LMPs. The implementation of this approach will align dispatch and pricing and:

- Ensure that prices reflect prevailing system conditions, resource limitations and needs in the immediate and subsequent intervals; and
- Reduce the frequency of required make-whole payments given the expected improvement in alignment between dispatch and pricing.

2.11.3 Detailed Design Considerations

There are no further considerations for detailed design.

[28] MIO is a feature of the software the IESO uses to determine dispatch instructions. With MIO, the dispatch scheduling optimizer software considers a number of future intervals to determine optimal dispatch instructions for the current interval, rather than considering just a single interval.

2.11.4 Linkages

The Multi-interval Optimization design element is linked to SSM design element 18 ("Make-Whole Payments"). The use of MIO to determine LMPs and dispatch schedules can create scenarios where resources are uneconomically dispatched-up or dispatched-down due to MIO. For example, MIO may dispatch a slow-ramping resource out-of-merit in order to satisfy a need in subsequent intervals. To the extent that its costs are not covered by its LMP during that MIO dispatch, the resource will be eligible to receive a make-whole payment.

2.12 Price-Setting Eligibility/Operating Restrictions

2.12.1 Design Element Description

The SSM will align system dispatch and market prices using LMPs. An LMP represents the cost of a marginal increase in energy or operating reserve (OR) at a location for a specific schedule of generating units ("units"). Currently, in order for a resource in Ontario to be eligible to set an LMP[29], the resource must be both economically marginal, and capable of producing an incremental unit of energy or OR.

If facility-specific operating restrictions require a resource to be scheduled – for example, to produce a minimum amount of output or prevent a resource from producing incremental energy – the resource is not permitted to set the LMP. The SSM price-setting eligibility design element considers whether some restrictions recognized in determining the schedule should be relaxed for the purpose of setting price.

Many resources that participate in the IESO-administered markets have restrictions on how they can be operated. A common technical restriction related to price setting on units is the minimum loading point (MLP).[30] Units that have an MLP must generate at or above their MLP in order to be able to follow dispatch instructions. When a unit is scheduled to its MLP but only a portion of its MLP quantity is required to meet demand, another less expensive resource must be backed down to accommodate the additional output due to the unit's MLP.

In determining price under such a scenario, the question arises of whether the LMP should be set by the offer price of the MLP output or by the less expensive unit which was backed down to accommodate its MLP. The IESO's constrained solution in the existing market respects operating restrictions such as the MLP and does not let the MLP offer price set the LMP. The unconstrained solution, however, treats the MLP output as flexible and, therefore, allows it to set price.

2.12.2 Decisions

The Ontario market does not have the types of fully block-loaded[31] intra-hour units[32] that have caused most of the pricing concerns in other jurisdictions. Ontario's current intra-hour units have significant dispatchable ranges above their MLP, allowing them to set the LMP. Additionally, in 2016 the IESO found that Ontario's intra-hour units were scheduled for more than 200 MW, but not setting price, in only 1% of intervals – information that confirms the materiality and frequency of this issue is not currently significant.

Based on this assessment of frequency and materiality, the IESO has determined that it will not allow the MLP output (or other operating range restrictions) of a resource to set LMPs. This is consistent with the way the current constrained solution produces prices.

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[29] In today's market, the shadow prices from the constrained schedule are a proxy for the current LMP.

[30] The MLP is the minimum output of energy that a resource can provide. This type of restriction is common to gas-fired generators.

[31] A unit that is fully block-loaded has an MLP that is equal to its entire capacity. When such a resource is producing electricity it tends not to have any dispatchable range. The resource can, therefore, be brought online to full output and never be eligible to set price.

[32] The term "intra-hour units" is used here to refer to a unit that can start and reach MLP within a relatively short time, such as 10 or 30 minutes.

The IESO will continue to monitor developments in other jurisdictions related to how the MLP output of intra-hour units are allowed to set the price with the intent of adopting any best practices that fit Ontario's current and future supply mix.

2.12.3 Detailed Design Considerations

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

2.12.4 Linkages

The Price-Setting Eligibility/Operating Restrictions design element is linked to SSM design element 18 ("Make-Whole Payments"). This is because the LMP may be less than the offer price of a unit that was scheduled to its MLP because of the reasons described in section 2.12.1.

3. Market Power Mitigation

In order to achieve efficient dispatch and pricing, an SSM seeks to encourage participants to offer at their short-run marginal costs. As discussed earlier, this is achieved by aligning dispatch and LMPs and also by subjecting resources to competitive forces – offering at short-run marginal cost is the optimal 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 market. This can occur when lack of competition in an area enables participants to profit by raising their offers significantly above their short-run marginal costs.[33] 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 of, or all, available capacity is offered at prices significantly higher than short-run marginal cost. 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.

A financially binding DAM will introduce the risk of participants exercising market power to maximize their settlement outcome. This can lead to higher costs to loads in the form of unnecessary uplifts. 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.

To ensure that electricity markets are not significantly impacted by the exercise of market power, market power mitigation can address the potential for economic withholding[34] by replacing market participant offers that are identified as materially departing from estimated short-run marginal costs (including opportunity costs) with an estimate of a cost-based offer, referred to as a "reference level."[35]

All North American independent system operators[36] apply some form of market power mitigation in which offer prices and, in some cases, non-price bid parameters can be replaced with the reference level value.

As part of the detailed design phase of the single schedule market initiative, the IESO will also develop new processes, or amend existing ones related to how market participants interact with the mitigation framework. Such interactions may include requesting reviews of reference levels, requesting real-time amendments to fuel or opportunity cost information and the dispute of mitigation decisions.

[33] Market power can also be exercised by raising prices to increase profits or reducing prices to depress the energy price.

[34] Other avenues are discussed under SSM design element 13, "Mitigation Process."

[35] This is discussed in detail under SSM design element 15, "Reference Levels."

[36] Alberta is currently in the process of implementing a series of significant changes to their market structure, including the implementation of a market power mitigation regime. For more information, see: https://www.aeso.ca/assets/Uploads/Proposal-section-10-Formatted.pdf, p. 3-4.

3.1 Timing of Application

3.1.1 Design Element Description

Mitigation of economic withholding can either be carried out ex-ante or ex-post. With ex-post mitigation, actual costs incurred by the participant are known and can form the basis of cost-based reference levels. In addition, offer prices that are too high can affect dispatch and prices. In these situations, mitigation is applied ex-post and the settlement adjustment is restricted to the participant that is the subject of the mitigation.

With ex-ante mitigation, costs and other non-price parameters must be estimated based on competitive benchmarks, rather than actual incurred costs. However, ex-ante mitigation prevents offer prices that are too high from affecting dispatch and prices.

Under the IESO's current uniform price regime, market power mitigation is carried out ex-post by setting limits on energy market clearing prices. Exercises of market power in the current system primarily impact CMSC payments for the resources concerned. However, the impact on the uniform price used by the IESO to settle the market is limited, since the uniform price is not strongly related to the cost of meeting demand, specifically because:

- Most transmission and resource constraints are not taken into account when calculating prices
- Actual generation ramp capability is not used in calculating prices
- The MLP output of resources is treated as dispatchable for the purpose of determining the uniform price.

The ex-post mitigation approach is, therefore, tenable under the current two-schedule market as offers reflecting the exercise of market power impact uplift payments (which can be recovered) and have minimal impact on settlement prices.

In an SSM, dispatch and LMPs are significantly impacted by offer prices. Since ex-post mitigation requires resettlement of the entire market when a resource is found to have exercised market power, the ex-post approach is too burdensome, costly and disruptive to be viable.

3.1.2 Decisions

The IESO has determined that, where possible,[37] mitigation will be applied using the ex-ante approach. Offer prices and other parameters that fail the tests for market power will be mitigated prior to the determination of dispatch schedules and market prices. This will ensure dispatch and prices are not significantly inconsistent with competitive outcomes.

In particular, the IESO has determined that mitigation for economic withholding and uneconomic transactions (offer prices that are too low) will be applied on an ex-ante basis. Offer prices and other parameters that vary significantly from their competitive benchmarks will be mitigated when determining dispatch and prices.

3.1.3 Secondary Decisions

There are no secondary design element decisions.

[37] Mitigation of physical withholding will be conducted ex-post. It is not possible for the IESO to accurately assess each facility's production and capability before-the-fact.

3.1.4 Detailed Design Considerations

The IESO will need to determine whether mitigation can be applied in the real-time timeframe[38] or whether it will need to carry forward decisions to mitigate from the pre-dispatch timeframe.[39]

3.1.5 Linkages

The Timing of Application design element is linked to SSM design elements 13 ("Mitigation Process") and 15 ("Reference Levels"). These design elements describe the methodology and inputs into the automated mitigation test that will be applied for economic withholding in all timeframes. The mitigation test will be applied using the ex-ante approach discussed under section 3.1.1.

[38] The real-time timeframe is the hour-at-hand or dispatch hour.

[39] This information will be known following completion of the procurement processes, which will determine the capabilities of the optimization engine for the Market Renewal Program.

3.2 Mitigation Process

3.2.1 Design Element Description

The mitigation process design element describes the methodology that will be applied to determine when to mitigate offers from market participants in order to prevent the exercise of market power. There are a number of different types of mitigation processes that can be used to address the potential for economic withholding in markets with LMPs.

The IESO has conducted a detailed analysis[40] on how market power mitigation is conducted in other jurisdictions. The following are two approaches that are broadly used for mitigation of market power in an SSM:

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, raising prices or uplifts above the competitive outcome.[41] This process includes an implicit structural test. Under this test, if prices were not affected, then market power will not be considered to have been exercised.

The IESO's current market power regime incorporates a hybrid of both approaches in making ex-post[42] evaluations of the exercise of market power through economic withholding.

As discussed in section 3.2.2, this approach is not viable under an SSM. As loads have limited incentives to use market power to raise price, they will generally not be subject to mitigation for economic or physical withholding in the SSM. However, the IESO will explore the extent to which they have incentives to exercise market power in order to maximize their settlement outcomes (discussed in section 3.2.3 under "Uneconomic Production").

3.2.2 Decision

The IESO has determined that a ***conduct and impact test*** will be used for market power mitigation. Mitigation under a conduct and impact test will be more directly tied to actual exercises of market power than under the pivotal supplier test, which only assesses the potential to exercise market power.

[40] See slide deck: Market Power Mitigation and Load Pricing http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ssm/ssm-20171113-load-pricing.pdf?la=en, November 13, 2017.

[41] The conduct and impact test includes a test for price impact, which is applied ex-ante, and a test for impact to uplift (guarantee payments), which is applied ex-post. A resource could be mitigated as a result of failing either the price or uplift impact test. If a resource is mitigated ex-post for failing the uplift impact test, then only the guarantee payment is affected – and the dispatch of the resource is not modified.

[42] An ex-post approach is generally based on actual values rather than estimates. Ex-post and ex-ante terms as they pertain to interval pricing are also discussed in detail under SSM design element 4, "Pre- or Post-Interval Pricing."

3.2.3 Secondary Decisions

Secondary design element decisions have been made by the IESO with respect to the following:

- Conduct and impact thresholds
- Constrained zone designation
- Uneconomic production
- Uncompetitive interties
- Global market power.

Conduct and Impact Thresholds

The IESO will designate conduct and impact thresholds that determine what level of offer price and what price impact will trigger mitigation. Represented by percentage or fixed dollar per megawatt-hour values, these thresholds will be added to the reference levels (the proxies for competitive offers) to determine when to mitigate ex-ante. In general, the conduct and impact thresholds will be higher in areas with significant competition and lower in areas where competition is restricted.

The IESO will use the following guidelines to develop specific conduct and impact thresholds during detailed design. The conduct and impact thresholds will:

1. Promote market outcomes that are consistent with those that would result under competitive participation;
2. Consider and account for relevant Ontario-specific issues that could otherwise significantly impact the efficiency of the mitigation regime;
3. Result in intervention in the market that is no greater than needed to constrain the material exercise of market power;
4. Not unnecessarily distort efficient incentives for market participation;
5. Balance the administrative burden of maintaining the mitigation regime against the effectiveness of that regime; and
6. Become less permissive as competition is more restricted.

Constrained Zone Designation

The IESO will designate areas of the transmission grid that are expected to be frequently constrained – known as narrowly constrained areas (NCAs) – on an annual basis. Designations will be based on the number of hours annually that these areas of the grid are constrained.

The IESO will also designate dynamic constrained areas (DCAs), or areas that are expected to be congested on a persistent basis for shorter periods of time, i.e., less than a year. These regions can be created by outages or deratings of grid components that may alter congestion patterns on the grid. Such circumstances may create opportunities for market participants to exercise market power even though the constraints may not be sustained over the length of time necessary to result in an NCA designation.

Transmission constraints that bind infrequently will result in the designation of broad constrained areas (BCAs). Resources that are "inside" the BCAs are those that can prevent the violation of a transmission constraint.

Uneconomic Production

A financially binding DAM introduces the potential risk of market participants exercising market power in order to maximize their settlement outcome. When a resource is scheduled in the DAM, but a transmission constraint binds before the real-time dispatch, that resource may be unable to deliver its DAM schedule. The resource may then be able to set the LMP at its location in order to profit from the congestion caused by the transmission constraint. This market participant behaviour increases costs to loads. The conduct and impact thresholds described above will not address this exercise of market power, as it does not increase prices and involve offers above reference levels.

For example, suppose a supplier was scheduled in the DAM to produce 100 MW (offered at $10) at a price of $10 but was unable to provide that supply in real-time because of a transmission constraint. Assuming its offer price remained unchanged between day-ahead and real-time, the supplier's settlement outcome would be $1,000-$1,000 = $0.[43]

The presence of the transmission constraint means that the supplier's LMP will be set by its real-time offer price. This gives the supplier the incentive to lower its offer price to affect its LMP and settlement outcome. If instead of maintaining its original offer, the supplier offered and set the LMP at -$1,000, its settlement amount would become $1,000 – (-$100,000) = $101,000. The transmission constraint allows the supplier to profitably affect its settlement outcome simply by lowering its real-time offer price.

The IESO will determine when resources are contributing to congestion and if their offers meet criteria specific to uneconomic production. In this case, mitigation will result in offers being increased to their reference levels.

The IESO will also consider whether a corollary of this concern with respect to dispatchable loads needs to be addressed in a similar manner.

In addition to the above treatment, the IESO will need to determine whether to define a specific prohibition and sanction for this type of behaviour in the Market Rules.

Uncompetitive Interties

The IESO will only apply mitigation on the interties when competition is restricted or the intertie is deemed and designated to be uncompetitive. Interties will be designated as uncompetitive when they meet a set of criteria that tests whether a majority of the trade on the intertie comes from one market participant or there are reasonable grounds to believe that a market participant controls the level of transactions on the intertie.

Interties will not be subject to ex-ante mitigation for economic withholding — the reasons for this are twofold. First, interties are generally competitive with many market participants who can freely access the markets in both jurisdictions and who do not enjoy a significant competitive advantage. Second, it is not practical to determine a reference level or proxy for a competitive offer ex-ante, as the data that would inform this proxy is not available until ex-post.

The designation of an uncompetitive intertie will:

1. Require that the IESO has a reasonable expectation that significant restrictions to competition exist. These could include situations where:
   a. the bulk of trade is controlled by one market participant
   b. regulatory barriers to competition exist
   c. there is the potential for collective behaviour.
2. Apply across all timeframes (i.e., day-ahead, pre-dispatch and real-time).
3. Require public notification before coming into force.

After an intertie is designated as uncompetitive, the mitigation applied will take the form of pricing rules to modify pricing on that intertie. Pricing rules will be used for mitigation, as it is not possible to determine reference levels for an intertie.

[43] This is a simplified example of DAM to real-time settlement outcome. In general, the result is value of energy sold in DAM +/- the value of incremental production in real-time.

Pricing rules for uncompetitive interties will address circumstances in which a congested intertie is de-rated:

a) Prior to the DAM and the IESO would otherwise pay significantly more to financial transmission right holders than it collects from intertie traders; or
b) After the DAM clears and the IESO pays intertie traders significant amounts to buy them out of their day-ahead positions.

During detailed design, the IESO will use the following guidelines to develop the pricing rules that will apply to designated uncompetitive interties:

1. Specific pricing rules will address issues particular to the DAM and to the day-at-hand
2. Pricing rules are intended to improve price fidelity on uncompetitive interties
3. When activated, pricing rules will result in intertie prices that better reflect local conditions in Ontario
4. Pricing rules are intended to reduce the potential impact on uplift and on the financial transmission rights account than would otherwise have been the case
5. Pricing rules will account for potential issues regarding both import and export transactions.

In addition to the above treatment, the IESO will need to determine whether to define a specific prohibition and sanction for this type of behaviour in the Market Rules.

Global Market Power

One of the foundational assumptions of the market power mitigation regime under development is that the market will generally be competitive, as this will discipline behaviour and limit the need for mitigation to situations when competition is restricted.

Under the ex-ante mitigation regime, a binding transmission constraint will be one precondition to mitigating market participants in situations of economic withholding.[44] A binding transmission constraint is an example of a situation in which competition is potentially restricted.

However, without a mitigation regime that contemplates other ways in which competition could be restricted, market participants could avoid mitigation if there is no binding transmission constraint. To address this, the IESO will test for global market power when competition in the province may be restricted. Such situations can arise when Ontario is import-congested and when there is an overall scarcity in flexible capacity.

When the Michigan and New York interfaces[45] are both import-congested, the marginal market participant could unilaterally increase prices in Ontario by increasing their own offer price. When these interfaces are both import-congested, the IESO will test the entire market for mitigation.

When there is scarcity in flexible capacity, the limited set of resources that can supply flexible capacity could increase their offer price without significant competitive constraints. Accordingly, the IESO will also test the entire market for mitigation in this situation.

[44] As described in the Mitigation Process decision (section 3.2.2), economic withholding will be mitigated using a conduct and impact methodology.

[45] Other interties are not considered to be of sufficient size or are not connected to a sufficiently liquid market to discipline competition.

3.2.4 Detailed Design Considerations

As part of a new framework for mitigating the exercise of market power on an ex-ante basis, the IESO will need to consider the following items under detailed design:

Conduct and Impact Thresholds

The IESO will need to determine the conduct and impact thresholds for BCAs, NCAs, DCAs and reliability dispatches. These thresholds will be consistent with the guidelines laid out above.

Constrained Zone Designation

The IESO will need to determine the criteria used to designate NCAs and DCAs based on the frequency in terms of hours per year these areas on the grid are constrained. For the purposes of market power mitigation, the IESO will also need to determine what constitutes a reliability constraint. The IESO will assess and designate NCAs and DCAs for "Day 1" of the post-market renewal markets.

Uneconomic Production

The IESO will need to determine the conduct and impact thresholds that will be applied to test when to mitigate for uneconomic production and also under what circumstances resources are considered to contribute to congestion. The process for mitigating uneconomic production will attempt to avoid mitigation of resources that may be trying to achieve feasible scheduling. The IESO will also need to determine under what circumstances (if any) dispatchable loads are subject to similar mitigation to address a corollary market power concern.

Uncompetitive Interties

Consistent with the guidelines laid out above, the IESO will need to determine both the designation criteria used to assess which interties should be designated as uncompetitive and the pricing rules that will affect pricing on these interties.

Global Market Power

The IESO will need to determine the specific criteria for when to test for global market power. These criteria will include measuring when the New York and Michigan interfaces are both import-constrained, when the net intertie scheduling limit is binding for imports, and when flexible capacity is scarce within the province.

3.2.5 Linkages

The Mitigation Process design element is linked to the SSM design elements 13 ("Timing of Application") and 15 ("Reference Levels"). Reference levels will be a key element of the mitigation process as they impact the extent to which offers must be mitigated. Timing of application will determine when the mitigation process is applied.

3.3 Reference Levels

3.3.1 Design Element Description

Reference levels are prices that reflect the approximate cost of dispatch and are calculated for each resource during the market power mitigation process. Reference levels, therefore, represent proxies for the price a resource would have offered had they been subject to unrestricted competition. All ex-ante mitigation processes employ reference levels to form proxies for the competitive cost level.

In determining reference levels, other jurisdictions use a variety of methods, including:

- Gas price indexes
- Prior fuel-adjusted offer prices
- Prior fuel-adjusted market prices
- Agreed-upon reference prices representing opportunity costs, formulas or models to estimate commitment costs
- Opportunity costs and reviews of market participant models used to estimate opportunity costs (such as for complex hydro systems).

Gas market volatility has been a significant issue with market designs in other jurisdictions, especially during winter months when natural gas infrastructure is more likely to be under stress, leading to price volatility. Another issue has been accounting for the opportunity costs of energy-limited resources, including hydroelectric reservoirs and pumped storage.

The IESO's current mitigation process uses historical offer prices or the concurrent energy market price to inform whether to mitigate ex-post. This allows the IESO to use actual energy cost data for the period in which market power is being reviewed. Determination of the mitigation amount is based on reference levels, operating characteristics and actual short-run marginal costs (including opportunity costs).

In determining reference levels, the IESO currently follows these principles:

1. Reference levels are informed by short-run marginal costs
2. Short-run marginal costs are generally determined on the basis of:
   a. Fuel costs
   b. Variable operating and maintenance costs
   c. Opportunity costs
   d. Any other appropriate costs.

Using the above principles, the IESO explored the following two high-level options:

1. Apply the principles used in the current market to determine reference levels in an SSM
2. Develop new principles to apply when determining some or all reference levels in an SSM.

Under an SSM, ex-ante mitigation will require changes to the reference level calculation methodology. Estimates of fuel and opportunity costs will need to be available prior to clearing the DAM and prior to the real-time dispatch.

3.3.2 Decisions

The IESO has determined that current principles should continue to be used to establish reference levels for market power mitigation in the SSM. These principles, which govern how the current regime determines reference levels and settlement adjustments, are consistent with those underpinning reference levels under ex-ante mitigation regimes.

Moving to an ex-ante mitigation regime does not mean that the general approach adopted by the current market is unviable. However, ex-ante mitigation will require a change in the methodology for determining reference levels, as not all of the information relied upon in the current market to determine reference levels is available on an ex-ante basis.

3.3.3 Secondary Decisions

Secondary design decisions have been made by the IESO with respect to reference levels. They will be based on one of the following data sets:

- Recent offers
- Recent LMPs at the resource
- Estimates of a resource's short-run marginal cost (cost-based reference levels).

The IESO will determine cost-based reference levels daily on the basis of short-run marginal cost, and make reference levels known to market participants ahead of time.

This approach will ensure the cost-based reference levels used in the market power mitigation framework are consistent with the methodology for determining the short-run marginal costs that will be established during detailed design.

After the market renewal program has been implemented, cost-based reference levels will be used to calibrate the process. Following the calibration period, cost-based reference levels will be applicable only when resources are infrequently scheduled. Reference levels will more frequently be determined by recent offers or LMPs at specific resources. Such information provides useful proxies for competitive outcomes.

3.3.4 Detailed Design Considerations

Cost-based reference levels will need to be determined in a manner that is consistent with the methodology developed by the IESO with input from market participants. The methodology will show how cost-based reference levels will be determined according to the fuel type and technology at the facility.

In consultation with stakeholders, the IESO will develop mechanisms for participants to:

- Request review of cost-based reference levels
- Dispute decisions to mitigate offer prices
- Provide fuel-cost data for the purpose of adjusting cost-based reference levels on a timely basis.

3.3.5 Linkages

The Reference Levels design element is linked to SSM design element 13 ("Mitigation Process"). Mitigation Process will be impacted by this design element's detailed design considerations. The reference level is a key input to the conduct and impact test discussed in section 3.2.

4. Load Pricing

4.1 Pricing for Loads

For clarity, this high-level design only discusses pricing for loads that are IESO market participants.[46] The decisions discussed in this section will not directly affect how the majority of loads in the province, including residential consumers, are billed for electricity. However, all Ontario consumers will be better off than they would have been without implementing the SSM and the initiatives it enables.

4.1.1 Design Element Description

As discussed in the Supplier Pricing section (2.6), locational pricing results in a more accurate price signal and can drive efficiencies and system cost savings not available through a market with a uniform price.[47] A better price signal encourages efficient responses from both suppliers and from market participant loads. Prices that vary by location better align settlement prices with the incremental cost of consumption in a given location or region.

An accurate price signal can encourage market participant loads that are price-sensitive – and able to respond – to reduce consumption from the IESO-controlled grid when local prices are relatively high. Such responses will reduce demand and put downward pressure on prices in a relatively high-priced region. This is an efficient way to lower prices and enable cost reductions for the responding load and other loads in the region. In the long-term, locational pricing for loads better enables more active demand-side participation and energy efficiency and can help to inform investment decisions.

In other jurisdictions with an SSM, the approach to load pricing is typically zonal[48] prices, sometimes complemented by the option to choose a nodal price.[49] This election process allows loads to select their preferred choice of pricing granularity (zonal or nodal), which is then applied to their settlement over a fixed period of time before a new election can be made.

Under both zonal pricing and nodal pricing, load prices will be calculated based on the LMPs at load nodes[50] and will include the cost of congestion and losses.[51] This ensures that settlement prices applicable to loads include the incremental system costs associated with supplying load locations – a practice that is consistent with other jurisdictions.

A nodal/zonal load pricing regime will allow prices to accurately reflect local system conditions, such as shortages or surpluses. Zonal prices are able to encourage efficient responses from market participant loads, enabling cost reductions that are generally unavailable with uniform pricing.

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[46] IESO market participants represent approximately 14% of Ontario consumption.

[47] A uniform price does not signal high prices in a given location or zone and, therefore, does not encourage local load response.

[48] A zonal price is the load-weighted average of a group of nodal/locational prices in a zone. A zone is a region of the power system that incorporates many individual nodes.

[49] A nodal price is the price at an individual node.

[50] Load pricing based on LMPs at supply nodes would reflect the average cost of congestion and losses. While the average cost of congestion and losses recovers enough from the loads to compensate supply, the price signal is weakened, as this approach does not capture the full impact of an increment in consumption (e.g., the associated increment in system cost).

[51] This is discussed further under SSM design elements 1-3 ("Energy Reference Price," "Energy Price - Congestion Component" and "Energy Price - Loss Component").

The election process for nodal pricing requires limitations as to how frequently the load pricing option can be changed. An election period of one year will eliminate the ability for a non-dispatchable load to elect to pay a nodal price during months when its nodal price is expected to be lower than the zonal price, and then elect a zonal price when its nodal price is expected to exceed the zonal price. This will ensure that a given load is settled on one level of granularity (nodal or zonal) for an entire year – and prevent loads from electing a nodal price to follow a seasonal pattern of price changes. The specific time when the election must be made will be defined during detailed design.

4.1.2 Decisions

The IESO has determined:

- Prices for non-dispatchable market participant loads will be zonal, with the price zones corresponding to the province's 10 existing electrical zones.[52] In delineating patterns in historical and expected transmission congestion across Ontario, these electrical zones usefully segment the Ontario grid according to congestion and expected price separation. This zonal pricing approach will support efficiency by providing more accurate price signals which, in turn, will enable more active demand-side participation, energy efficiency and better investment decisions.

[52] The site provides a map to view zonal boundaries by postal code or street address. http://www.ieso.ca/localContent/zonal.map/index.htm.

- Prices for market participant loads that are dispatchable[53] will be nodal to better align their settlement prices with their dispatch instructions. This will encourage efficient bids and support efficient dispatch outcomes. If such resources were zonally priced, misalignment between zonal prices and nodal dispatch outcomes would require an additional set of out-of-market payments to ensure efficient outcomes, increasing system costs.
- Non-dispatchable loads may elect to have their settlement price determined on a nodal basis. Any such election will be effective for a period of no less than one year. Allowing nodal prices for these resources will better align their prices with the IESO's nodal dispatch.
- Through the DAM, non-dispatchable loads may also elect to become price-responsive loads.[54] Such an election will be effective for a minimum one-year period. Price-responsive loads will be settled on the basis of a nodal price.

4.1.3 Detailed Design Considerations

At times, some load nodes/zones in the province can experience negative LMPs. Often such prices are the result of transmission congestion and negatively priced offers in a given region. The IESO will evaluate potential drivers for and issues resulting from negatively priced offers and LMPs. Negative offer prices that are not reflective of the short-run marginal costs of suppliers can result in distorted price signals in the market. If negative pricing is determined to be an issue, the IESO will assess appropriate options to address it.

4.1.4 Linkages

The Pricing for Loads design element is linked to SSM design element 17 ("Congestion Rents and Loss Residuals"), which discusses how the residual created as part of consumer and supplier settlement in an SSM (when more money is collected from consumers than is paid to suppliers) will be disbursed.

[53] Market participant loads that are dispatchable include: dispatchable loads (DL), storage and price-responsive loads (see next footnote).

[54] Price-responsive loads have been introduced as part of the DAM work stream. Non-dispatchable loads can become price-responsive loads and provide bids into the day-ahead market in order to receive financially binding day-ahead schedules. In real-time, these loads would continue to be non-dispatchable. Non-dispatchable loads that can accurately predict their actual consumption can use the price-responsive load options to fix their settlement price based on day-ahead prices and minimize any balancing costs associated with deviations that apply in real-time.

4.2 Congestion Rents and Loss Residuals

4.2.1 Design Element Description

Price Formation and "Residuals"

An SSM aims to align dispatch with market prices using LMPs. As noted in SSM design element 16 ("Pricing for Loads"), this applies to market participant loads as well as suppliers. This goal is achieved by aligning the settlement price for loads with the cost of incremental consumption at their node or zone. As outlined in the previous section, this means settling market participant loads on either a nodal or zonal price, and no longer charging all market participant loads a uniform price for energy. As a result of the decision to move to nodal or zonal pricing for market participant loads:

- Market participant loads will no longer be settled using a uniform price across Ontario
- Congestion rents and loss residuals (the "residuals") will be collected as part of the energy settlement
- Congestion rents and loss residuals will be disbursed to Ontario loads.

The congestion rent and loss residuals design element will discuss how a residual is created as part of an energy settlement in an SSM and how those residual amounts will be returned to Ontario loads.

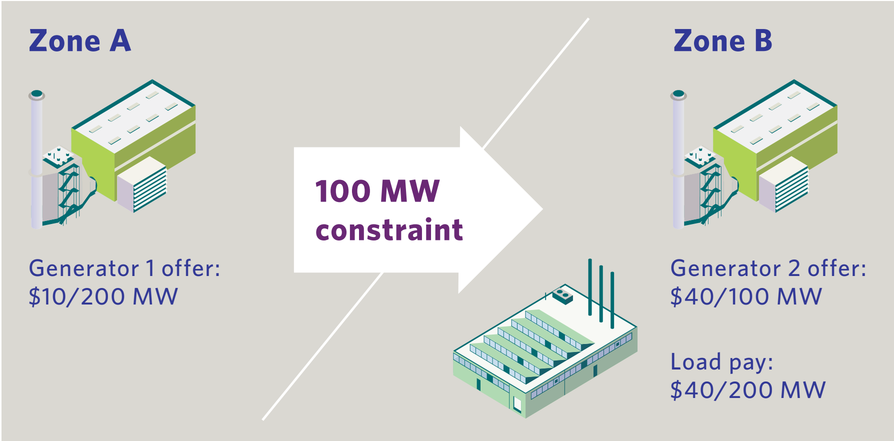
Congestion Rents

A binding transmission constraint will create differences in the congestion component[55] of the LMP across the system that it divides. A part of the system may have binding transmission constraints, which limit the output of low-priced generation. There will be a lower energy price in this constrained area of the system than in the rest of the system, which can no longer receive that low-priced generation. As a result of these transmission constraints, higher-priced resources must be scheduled to satisfy demand.

Low-priced supply resources in the constrained areas of the system will be settled based on the lower prevailing prices at their locations. However, loads outside the constrained area will pay higher prices, based on the marginal cost of an incremental MW of consumption at the load's location. The difference between how much loads pay for a MW and how much the supply resource is paid for a MW can create settlement residuals called "congestion rents." These are based on the difference between the cost of congestion paid to the supply resources that produce the energy and the cost of congestion paid by loads when transmission constraints bind.

[55] This is discussed further under SSM design element 2 ("Energy Price - Congestion Component").

FIGURE 5: EXPLANATION OF CONGESTION RENTS



Simplified residual settlement example

Load pays	$40 × 200 = $8,000
Generator 1 receives	$10 × 100 = $1,000
Generator 2 receives	$40 × 100 = $4,000
Congestion rents	$3,000

In this scenario, the load would like to consume 200 MW and the less-expensive Generator 1 is offering to fully supply the load at $10. However, due to transmission congestion between Zone A and Zone B, the load's demand must be served by 100 MW of supply from each of Generators 1 and 2. Since the price in Zone B is determined by the cost of meeting the next MW of the load's demand, the Zone B price is set at Generator 2's $40 offer price, which becomes the price paid by the load for its consumption. However, because of the transmission constraint, Generator 2 is paid $40 and Generator 1 is paid $10. A settlement residual/congestion rent of $3,000 results from the constraint between the zones.

Loss Residual

The amount of electricity lost when electricity flows across a transmission system is referred to as transmission losses (or "losses").[56] Losses are a function of the amount of current flowing on a wire, the resistance it encounters and the distance it travels. The cost of losses is one component of the LMP (the others are the energy cost and the congestion cost).

There are two broad approaches to determining the cost of losses: average loss pricing and marginal loss pricing. Although average loss pricing has been used in the past by other jurisdictions (e.g., PJM), it has generally not been considered best practice.

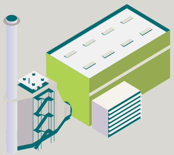
Marginal loss pricing determines the cost of losses based on the cost of an incremental MW of consumption (the "marginal MW"). Prices based on short-run marginal costs and benefits are a cornerstone of efficient outcomes. The total cost of losses at a load is calculated as the total consumption times the marginal cost of losses. The rate at which energy is lost is always increasing as consumption increases, so the absolute value of the marginal cost of losses is always larger than the absolute value of the average cost of losses.

The difference between the amount paid for losses by loads and the amount paid for losses to the generators results in the "loss residual."

[56] Losses are also discussed in detail under SSM design element 3 ("Energy Price - Loss Component") found in section 2.3.1.

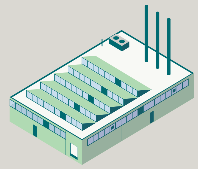
FIGURE 6: EXPLANATION OF LOSS RESIDUALS

Generator Offer:
$10/MW
Schedule: 205 MW



Energy losses = 5 MW
(average losses = 2.5% of 200 MW)

Load pays:
$10.50/200 MW



Marginal cost of losses = $10* 5%
= $0.50
(marginal rate of losses = 5%
@ 200 MW)

Simplified loss residual example

Load pays	$10.50 × 200 = $2,100
Generator receives	$10 × 205 = $2,050
Loss Residual	$50

Loss residuals are created even in a simple system with one load and one generator. Due to transmission losses, the generator in this example is dispatched to 205 MW to meet the demand (200 MW) at the load. The price at the load is higher than the price received by the generator.

Description of Residuals

Residuals are created in all electricity markets that have locational pricing for loads. In other jurisdictions with SSMs, these residuals are typically used to fund internal financial transmission rights. In the absence of internal transmission rights in Ontario, the IESO will return the residuals collected under SSM to Ontario loads, since the residuals are a result of the investments they have made in the transmission system.

The methodology to allocate the residuals to Ontario loads needs to be clear and understandable to market participant loads, as well as practical to solve given the inputs and processing tools available. It must also take into account the relationship between how the residual is allocated and its effect on the incentive for loads to respond to the zonal price signal.

The methodology discussed below avoids significant distortion of price signals to loads in order to preserve the efficient incentives of locational pricing. The potential interaction between marginal incentives (produced by the nodal/zonal price signal) and the allocation methodology is discussed in more detail below. In general, the residual disbursement methodology seeks to obtain and preserve the efficiency and cost-saving benefits associated with nodal/zonal pricing, while still maintaining some insurance against unforeseen locational congestion events that loads currently have through uniform pricing.

Eligibility to Receive Residual Disbursement

The IESO will use a two-step process to determine which Ontario loads are eligible to receive a residual disbursement over a given period of time (an "allocation period"). The first step will determine which of the 10 zones are eligible to receive a portion of the residuals and the second step will determine which loads within each eligible zone will receive an allocation. The eligibility rules are discussed below:

Zonal Eligibility: The IESO will allocate the residuals to market participant loads located in a zone that, based on average expenditure over a defined period[57] of time, pays a higher zonal price than the uniform supplier weighted price across the province ("eligible zones").[58]

[57] As defined in the "Residual Disbursement Frequency" section of this document.

[58] The allocation of residuals to high-priced zones will be limited so that the prices (net of residuals) in these high-priced zones will not be lower than the zones that have not been allocated residuals.

Within-Zone Eligibility: Eligible zones also need a methodology for determining how to allocate those residuals among the loads in the zone. Within these zones, the IESO will compare a load's total cost over the allocation period under nodal/zonal pricing to what its cost would have been under uniform pricing.[59] Loads with a nodal/zonal settlement price that is higher than their average uniform price will receive a portion of the residual.

Marginal Incentive Impacts

As previously discussed, nodal/zonal pricing provides a price signal that when used for settlement encourages efficient energy consumption. Preserving marginal incentives will retain the efficiency benefit and cost-saving potential of nodal/zonal pricing.

Distribution of residuals will lower the average cost of consumption for loads. A key requirement of the methodology used to allocate these residuals is that it should not significantly distort marginal incentives. Any disbursement process that significantly interferes with the marginal incentive will reduce the benefit of settlement using an LMP.

For example, a load currently consuming 10 MW with a marginal cost of $15/MWh (including the marginal cost of losses) faces a decision to consume an incremental MW. The efficient outcome is consumption only if the marginal benefit is greater than $15/MWh. Assume that the marginal cost of losses for that incremental 11th MW is $3/MWh, but the average cost of losses across the consumption of the 11 MW (10 MW currently being consumed and the incremental MW) is only $2/MWh. If the load faces the average cost of losses rather than the marginal cost of losses, it could make an inefficient consumption decision: consuming when the marginal cost of consumption was higher than the marginal benefit of consumption.

The proposed residual disbursement methodology will result in lower average costs to consumers, while helping preserve the marginal incentives. The preservation of marginal incentives is achieved in a number of ways:

- Extending the length of the allocation period. If residuals were allocated on an interval basis, the price signal would be significantly distorted. Assuming that congestion is not easily predictable, the longer the allocation period, the less impact each individual consumption decision over the period has on the residual distribution.
- Assigning the residuals first on the basis of eligible zones reduces the extent to which the actions of each individual consumer impacts the amount of residuals allocated to them.
- Assigning the residuals according to the "within-zone eligibility," which means the allocation of residuals to each individual load is based not only on the consumption decisions of that load, but on those of all other loads in the same zone. This reduces the ability of individual loads to impact the amount of residuals allocated to them.

Residual Allocation Period

Congestion rents and loss residuals will be collected over a three-month allocation period, a timeframe that balances the need to avoid distortion of the price signal with the need to return residuals to eligible loads on a timely basis. In general, the longer the time period for determining residual eligibility, the harder it is to determine how much residual a load can expect to receive in any given consumption interval.

If residuals were returned after each interval of consumption, then it would be relatively simple to determine how much residual a load should expect to receive – it becomes harder to perform such a calculation with uncertain congestion patterns over a three-month period. This uncertainty helps to preserve the marginal price signal. Residuals will be used to fund a residual disbursement available to all domestic loads settled in the wholesale market over the allocation period.

[59] This hypothetical price is solely used as a device to identify high-priced loads. It is the uniform supplier-weighted average price.

The rationale behind this proposed disbursement frequency is that the overall mechanics use a mixture of periodic and interval calculations. The methodology preserves marginal incentives, as no individual load has direct control over the disbursement process. In addition, any act by an individual load to influence the disbursement by increasing their consumption is muted by the varying weights contributed by the consumption of other loads over the allocation period.

Residuals from the DAM and the Real-Time Market Disbursed

The disbursement will be available to metered market participants[60] who were settled in the wholesale market over the allocation period. The congestion rents and loss residuals that make up the residual disbursement will include a total of the residuals following the energy settlement in both the DAM and the balancing settlement in the real-time market. The total residual over the allocation period is calculated as follows:

$$\begin{array}{c}\text{Total Residual}\\ \text{over the}\\ \text{Allocation Period}\end{array} = \sum_{\substack{\text{(All Hours in the}\\ \text{Allocation Period)}}} \begin{array}{c}\textit{Congestion Rent}\\ \textit{and Loss Residual}\\ \textit{from DAM}\end{array} + \sum_{\substack{\text{(All intervals in the}\\ \text{Allocation Period)}}} \begin{array}{c}\textit{Congestion Rent}\\ \textit{and Loss Residual}\\ \textit{from RTM}\end{array}$$

Calculation of Residual Disbursement - Two-Step Approach

The residual disbursement will be calculated in two steps. The first step (the "zonal disbursement") will determine how the residual disbursement is divided among the province's load zones.

The second step (the "in-zone disbursement") will divide any disbursement to the zone among individual wholesale loads. A load's overall residual disbursement will be tied to the combined effect of the zonal disbursement and the in-zone disbursement. The two-step disbursement is calculated as follows:

$$\begin{array}{c}\text{Load Allocation}\\ \text{Period Residual}\\ \text{Disbursement}\end{array} = \begin{array}{c}\text{Total Residual}\\ \text{over the}\\ \text{Allocation Period}\end{array} \times \begin{array}{c}\text{Loads Zonal}\\ \text{Residual}\\ \text{Disbursement}\\ \text{Coefficient}\end{array} \times \begin{array}{c}\text{Loads In-Zone}\\ \text{Residual}\\ \text{Disbursement}\\ \text{Coefficient}\end{array}$$

Step 1: Zonal Disbursement

The zonal disbursement will be based on relative differences in zonal expenditure using the load-weighted price for the zone averaged over the allocation period[61] and the uniform supplier-weighted price averaged over the allocation period.

Eligible zones will receive a portion of the total residual collected over the allocation period.[62] As shown in the equation below, the amount that is allocated to each eligible zone will be proportional to the difference in over-expenditure relative to other zones. The zonal disbursement will be calculated as follows over the allocation period:[63]

$$\begin{array}{c}\text{Loads Zonal}\\ \text{Residual}\\ \text{Disbursement}\\ \text{Coefficient}\end{array} = \frac{\displaystyle\sum_{\substack{\text{(All Loads}\\ \text{in the Zone)}}} Max\left(0, \sum_{\substack{\text{All intervals}\\ \text{in Allocation}\\ \text{Period}}} (Settle\_Price\$ \times Load\_Consum) - Uniform\$ \times \sum Load\_Consum\right)}{\displaystyle\sum_{\text{All Zones}} \sum_{\substack{\text{(All Loads}\\ \text{in the Zone)}}} Max\left(0, \sum_{\substack{\text{All intervals}\\ \text{in Allocation}\\ \text{Period}}} (Settle\_Price\$ \times Load\_Consum) - Uniform\$ \times \sum Load\_Consum\right)}$$

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[60] This includes IESO market participants and LDCs.

[61] Load-weighted prices for the zone will include loads priced on both a nodal and zonal basis.

[62] Zones that are not classified as "eligible zones" will not receive a portion of the residual.

[63] Where:
- "Settle_Price" is settlement price per load for each interval within the allocation period;
- "Load_Consum" is load consumption; and
- "Uniform$" is the uniform supplier-weighted price averaged over the allocation period.

Step 2: In-Zone Disbursement

The in-zone disbursement will be based on the relative difference between a load's expenditure across the allocation period using their applicable settlement price[64] and the uniform supplier-weighted average price in each interval across the allocation period. A given load's allocation will be based on the extent to which their actual settlement price was higher than what their settlement price would have been under a uniform price over the allocation period. It will also be based on the relative expenditure of other loads in the zone, with loads in the zone that faced relatively higher prices receiving a larger share of the zonal allocation.[65] The in-zone disbursement will be calculated as follows over the allocation period:

$$\text{Loads In-Zone Residual Disbursement Coefficient} = \frac{Max\left(0, \sum_{\substack{\text{All intervals} \\ \text{in Allocation} \\ \text{Period}}} (Settle\_Price\$ - Interval\_Uniform\$) \times Load\_Consumption\right)}{\sum_{\substack{\text{(All Loads} \\ \text{in the Zone)}}} Max\left(0, \sum_{\substack{\text{All intervals} \\ \text{in Allocation} \\ \text{Period}}} (Settle\_Price\$ - Interval\_Uniform\$) \times Load\_Consumption\right)}$$

Disbursement Floor

In-zone disbursements will not reduce a load's overall cost of energy to a level lower than would have been the case under a uniform price supplier-weighted average price. Any balance in residual that is unallocated as a result of applying this limit will be transferred to the following allocation period's residual for disbursement.

4.2.2 Decisions

The IESO has determined:

- The residual from congestion rents and marginal losses from both the DAM and RT balancing market will be distributed using the residual disbursement process.
- The total disbursement of residuals to each zone will be based on relative differences in zonal expenditure using load-weighted price for the zone averaged over the allocation period and uniform supplier-weighted price averaged over the allocation period. Load-weighted average price for the zone will include loads priced on both a nodal and zonal basis. Eligible zones will receive a portion of the total residual collected over the allocation period.[66] The amount that is allocated to each eligible zone will be proportional to the difference in over-expenditure relative to other zones.
- The in-zone disbursement will be based on the relative difference between a load's expenditure across the allocation period using its applicable settlement price[67] and the uniform supplier-weighted average price in each interval across the allocation period. A given load's allocation will be based on the extent to which its settlement price was higher than the uniform price over the allocation period. It will also depend on the relative over-expenditure of other loads in the zone, with loads in the zone that faced relatively higher prices receiving a larger share of the zonal allocation.

[64] A load in an SSM can be settled based on either a nodal or zonal LMP. See SSM design element 16, "Pricing for Loads," for more details.

[65] Loads in the zone that faced a lower settlement price relative to the uniform price over the allocation period will not receive a portion of the residual allocated to the zone.

[66] Zones that are not "eligible zones" will not receive a portion of the residual.

[67] A dispatchable load in an SSM can be settled based on either a nodal or zonal LMP. For more details, refer to SSM design element 16, "Pricing for Loads."

- In-zone disbursements will not reduce a load's overall cost of energy to a level lower than would have been the case under a uniform price supplier-weighted average price. Any balance in residual that is unallocated as a result of applying this limit will be transferred to the following allocation period's residual for disbursement.

4.2.3 Detailed Design Considerations

The IESO will need to finalize the methodology for carrying over any balances from one allocation period to the next allocation period.

The IESO will continue to evaluate the interaction between the residual disbursement methodology and nodal/zonal load pricing to ensure the correct incentives are in place.

4.2.4 Linkages

The Congestion Rents and Loss Residuals design element is linked to SSM design elements 2 ("Energy Price - Congestion Component"), 3 ("Energy Price - Loss Component"), 6 ("Supplier Pricing"), 16 ("Pricing for Loads") and 19 ("Uplift Recovery"). The linkages are as follows:

- *Energy Price - Congestion Component:* Establishes that LMPs will include a congestion component that will reflect the marginal cost of congestion. As prices will vary by location, loads will be settled at different prices and settlement residuals will be distributed to Ontario loads according to the above methodology.
- *Energy Price - Loss Component:* Establishes that LMPs will include a loss component that will reflect the marginal cost of losses. As prices will vary by location, loads will be settled at different prices and settlement residuals will be distributed to Ontario loads according to the above methodology.
- *Supplier Pricing:* Establishes that suppliers use nodal LMPs for settlement. In conjunction with the Pricing for Loads, Energy Price - Congestion Component and Energy Price - Loss Component design elements, this will result in settlement residuals being distributed to Ontario loads according to the above methodology.
- *Pricing for Loads:* Establishes that load resources will be settled based on a nodal or zonal basis. In conjunction with the Supplier Pricing, Energy Price - Congestion Component and Energy Price - Loss Component design elements, this will result in settlement residuals being distributed to Ontario loads according to the above methodology.
- *Uplift Recovery:* Describes other mechanisms to disburse or recover other costs in the market.

5. Settlement Topics

5.1 Make-Whole Payments

5.1.1 Design Element Description

Compared to the current two-schedule market, the need for make-whole payments in an SSM is expected to be infrequent and immaterial. That's because the most significant causes of divergence between dispatch and price, namely congestion and losses, will no longer result in out-of-market payments. LMPs will generally be:

- Greater than or equal to the offer price of the amount of energy a generator at that location was dispatched to produce; and
- Less than or equal to the bid price of the amount of energy a dispatchable load at that location was dispatched to consume.

However, there may be a limited set of conditions where LMPs are not always able to reflect the cost of balancing the system. In these circumstances, which are common to all organized electricity markets, even those with an SSM, resources may need to be dispatched out-of-merit to maintain system reliability (e.g., failure of a generator[68] to follow dispatch instructions can result in reliability issues, such as the violation of transmission line limits).

Conditions that could trigger the need for special instructions include constraint violations, multi-interval optimization,[69] co-optimization with operating reserve or emergency control actions.[70] These dispatch instructions may be generated automatically by the IESO's optimized dispatch, or manually by the control room based on real-time system operation.

If a resource is asked to change their output at a loss, their willingness to follow this instruction is likely to be low in the absence of a make-whole payment. Make-whole payments apply to circumstances where a resource is either "dispatched-up" to produce more energy than is economic at the LMP, and incurs an operating cost loss, or is "dispatched down" to produce less energy than is economic at the LMP, and incurs an opportunity cost.

Make-whole payments are typically subject to eligibility rules related to how well a market participant has followed dispatch. For example, a market participant that deviates from dispatch instructions may not be eligible for make-whole payments. Make-whole payments also commonly take into account the total revenues received by the market participant. For example, a participant who received an instruction to dispatch-down for energy may have earned additional net revenues for operating reserve (OR) – and this additional revenue would be considered when calculating the make-whole payment.

[68] Dispatchable loads will also be eligible for make-whole payments under similar dispatch-up and dispatch-down circumstances.

[69] For more information on multi-interval optimization, see the section on SSM design element 11.

[70] The IESO presented materials showing potential settlement scenarios regarding the make-whole payment for non-quick start units - May 2018 (slides 26-50): http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/dam/dam-eruc-ssm-20180523-settlement-scenarios.pdf?la=en

5.1.2 Decisions

The IESO has determined that it will provide make-whole payments for dispatch-up and dispatch-down instructions for energy and OR. Both are required to incent resources to follow the out-of-merit dispatch instructions required to manage the reliability needs of the grid.

5.1.3 Detailed Design Considerations

When assessing make-whole payments, other jurisdictions have eligibility requirements that typically require the resource to be operating in accordance with its dispatch. The IESO will explore these eligibility requirements during the detailed design phase.

5.1.4 Linkages

The Make-Whole Payments design element is also linked to SSM design element 19 ("Uplift Recovery"), which is a type of uplift charge. As discussed in this section, the IESO tracks uplift charges and applies them to relevant participants.

This design element neither includes nor addresses make-whole payments that cover the commitment costs of non-quick start units[71] or commitments in the DAM. These topics are discussed in the ERUC and DAM Make-Whole Payments design elements 12 and 16 respectively.

[71] The term ***non-quick start unit*** refers to a generation facility that does not meet the definition of a ***quick start unit***. A quick start unit is a generation facility whose electrical energy output can be supplied to the grid within five minutes of the IESO's request and is provided by equipment not synchronized to the grid when the request is made. The IESO presented materials showing potential settlement scenarios regarding the make-whole payment for non-quick start units: May 2018: http://www.ieso.ca/-/media/files/ieso/document-library/engage/dam/dam-eruc-ssm-20180523-settlement-scenarios.pdf?la=en slides 26 – 50.

5.2 Uplift Recovery

5.2.1 Design Element Description

An uplift is a mechanism to recover revenue from either loads or exporters if the IESO has determined that they have been undercharged or to provide credits if they have been overcharged. Uplift charges are assigned to loads and exports to recover the cost of services not otherwise captured through two-settlement energy charges and other charges.

Types of uplift charges include:

- Make-whole payments
- Penalties or failure charges
- Congestion rents
- Marginal losses residual
- Cost guarantees
- Ancillary service cost recovery (e.g., OR costs)
- Under-collection (e.g., due to default).

The IESO currently assigns make-whole uplift charges on an hourly basis to all loads and exports. This methodology will continue under an SSM.

This design element describes how to allocate uplift costs associated with intra-hour make-whole payments.[72] Such payments are assessed on an interval-by-interval basis. They generally result because of a discrepancy between a resource's LMP and its schedule based on its offer or bid price.

Additional types of uplifts are not covered in this design element, either because they are not changing as a result of market renewal or are associated with changes to be communicated through the day-ahead market (DAM) or enhanced real-time unit commitment (ERUC) projects. Such uplifts include:

- Real-time commitment costs (associated with DAM and ERUC)
- Day-ahead commitment costs (associated with DAM and ERUC)
- Failure charges (associated with DAM and ERUC)
- Ancillary services
- Demand response products
- Under-collection.

5.2.2 Decisions

The IESO has determined that uplift costs associated with intra-hour make-whole payments will be allocated hourly proportionate to each load's and export's actual withdrawal as a percentage of the total consumption in that hour by all Ontario loads and exports. This is the current approach to uplift allocation and does not change with an SSM.

[72] Make-whole payments are described in detail under section 5.1.

5.2.3 Detailed Design Considerations

The IESO will review new and current make-whole payments and related uplifts to ensure no over- or under-collection of funds is required to pay the various make-whole and residual payments. A review will also ensure that implementation details are correct and compatible with a new market environment.

5.2.4 Linkages

The Uplift Recovery design element is linked to SSM design element 18 ("Make-Whole Payments") that defines how the costs are to be recovered. Other mechanisms to disburse or recover costs in the market are covered under additional linkages to SSM design element 17 ("Congestion Rents and Loss Residuals") and 18 ("Make-Whole Payments").

Appendix 1 – Single Schedule Market Design Elements

Price Formation

1 Energy Price - Congestion Component

2 Energy Reference Price

3 Energy Price - Loss Component

4 Pre- or Post-Interval Pricing

5 Intertie Congestion Pricing

6 Supplier Pricing

7 Operating Reserve Reference Price

8 Operating Reserve Price - Congestion Component

9 Constraint Violations

10 Out-of-Market Operator Actions

11 Multi-Interval Optimization

12 Price-Setting Eligibility/Operating Restrictions

Market Power Mitigation

13 Mitigation Process

14 Timing of Application

15 Reference Levels

Load Pricing

16 Pricing for Loads

17 Congestion Rents and Loss Residuals

Settlement Topics

18 Make-Whole Payments

19 Uplift Recovery

Appendix 2 – Interim Engagement Summary Report

Engagement:
Single Schedule Market - Market Renewal Project

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 single schedule market (SSM) stakeholder engagement activities and outlines how stakeholder feedback has helped shape the high-level design (HLD).

Engagement description/background

Since May 2017, when the SSM engagement was launched, the IESO has been working with stakeholders to design and develop a replacement for Ontario's existing two-schedule system. The SSM is a foundational element of the market renewal program (MRP) and a key driver 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 SSM 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 SSM design elements. Input from stakeholders has informed the decisions reflected in the SSM HLD and has helped lay the foundation for the upcoming detailed design phase.

Engagement objective

The primary objective of this engagement has been to provide a forum for stakeholders to contribute to the development of the overall SSM design. Active engagement from interested stakeholders 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 is to provide information and education to assist stakeholders in understanding the purpose and scope of the SSM initiative and contributing to engagement discussions.

Engagement approach

The stakeholder engagement framework for the MRP was 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

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

Stakeholder participation

At the introduction of the SSM engagement, stakeholders participated in three education sessions designed to facilitate their participation in engagements across the MRP. Throughout 2017 and 2018, stakeholders took part in a series of meetings led by the IESO and its external consultant (FTI). These included presentations on SSM design elements, design options and preliminary decisions. During 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 and Ontario Energy Board
- Academics

In 2018, the IESO hosted eight engagement meetings on the SSM design with an average of 60 stakeholders in attendance per session.

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 SSM 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 May 23/24, 2018 Meeting
- Response to Feedback from the March 29, 2018 Meeting
- Response to Feedback from the January 30, 2018 Meeting
- Response to Feedback from the December 11, 2017 Meeting
- Response to Feedback from the August 17, 2017 Meeting
- Response to Feedback from the June 2, 2017 Meeting
- Response to Feedback from the May 4, 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 SSM. 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 SSM design tracker also provides a history of how design decisions were discussed and developed.

Design Element	Discussion Points
Intertie Congestion Pricing	Feedback from stakeholders on the proposed mechanics of settling real-time intertie transactions included requests for rationale for both the existing and proposed methods of calculating the intertie congestion price (ICP). In response, the IESO developed additional calculation methodology options for stakeholders to review during the course of the engagement. To address concerns with the current ICP methodology, the IESO made a preliminary decision that supported more efficient scheduling of resources to minimize the cost of meeting Ontario demand. After reviewing stakeholder feedback on the preliminary decision, the IESO developed a subsequent option that reflected stakeholder input. After reviewing stakeholder feedback on the new option, the IESO revised its decision on intertie congestion pricing.
Load Pricing (Residuals)	The IESO received stakeholder feedback questioning how congestion rents and loss residuals will be allocated and if disbursement will be temporary. As a result, the IESO performed a sensitivity analysis of the proposed zonal pricing under various scenarios and demonstrated that the benefits to customers of zonal pricing are robust under a range of system conditions. Feedback from stakeholders, in particular from the load community, resulted in changes to the preliminary decision on load pricing with respect to the distribution of residuals. The amended decision will return residuals to eligible loads on a quarterly basis while not distorting the incentives of the Locational Marginal Pricing signal. The zonal pricing decision made on load pricing incorporates feedback, and is aligned with the agreed-upon mission and principles of market renewal. However, the IESO recognizes that additional dialogue with affected market participants and stakeholders will be needed throughout the HLD engagement period.
Supplier Pricing	The IESO received multiple requests for more detailed information and noted that developments in this area may impact existing contracts. In response to stakeholder feedback, on October 31, 2017, the IESO held a contracts webinar to discuss preliminary issues. Stakeholders who provided feedback on the supplier pricing design element were generally supportive of the position and rationale that was being proposed.
Market Power Mitigation Process	Feedback on the Market Power Mitigation (MPM) design element included requests for clarifications and opinions for consideration regarding the mitigation criteria. With respect to the process, stakeholders asked the IESO to clarify the region that a conduct and impact test would apply if mitigation was triggered. The IESO clarified that the regions will likely correspond to the electrical zones; however, in areas where the exercise of market power is a concern, sub-regions may be defined within these zones. Stakeholders submitted feedback advocating for public notification of an uncompetitive intertie. The IESO confirmed that this requirement will be included in the design. Other feedback suggested that market power mitigation should apply to capacity imports. The IESO clarified that pricing rules will be applied in day-ahead and real-time on interties that have been designated uncompetitive to prevent the exercise of market power.
Design Tracker/ Issues Log	In addition to the 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 SSM Design Tracker for SSM.

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, which will include a new engagement approach, will be published on the engagement webpage later this year.

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