ONTARIO ENERGY BOARD

Market Surveillance Panel

LOCATIONAL PRICING IN THE RENEWED MARKETS

For the period of May 2025 to April 2026

July 2026

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Ontario Energy Board

List of Figures

Ontario Energy Board

List of Tables

Ontario Energy Board

1 PREAMBLE

The Market Surveillance Panel (MSP) is a statute-based panel of the Ontario Energy Board (OEB). It serves as the market monitor for the Ontario wholesale electricity markets, which are administered by the Independent Electricity System Operator (IESO). The MSP's mandate is set out in the *Electricity Act, 1998*, and the OEB's By-law #2. The work of the MSP is supported by the Market Assessment Unit (MAU) within the IESO, in accordance with a Protocol between the IESO and the OEB.

In August 2025, the MSP issued a public report, *The Market Surveillance Panel in the Renewed IESO-Administered Markets*, detailing its approach for monitoring, investigating, reviewing and reporting on wholesale electricity market activities under the renewed markets.

The MSP is evolving its approach to reporting for the renewed markets, aiming to improve the effectiveness and timeliness of its public reports. This involves providing more frequent, shorter reports, on an ad hoc basis, that focus on specific monitoring issues, to supplement the MSP's annual *State of the Market* reports. Key content can include insights into the design of the markets, observations on market performance, analysis of factors affecting market results, and the efficiency characteristics of the markets. In addition to these key insights, these reports will provide recommendations where warranted. Conclusions or recommendations may be developed over multiple reports and will be summarized annually in the *State of the Market* report.

This report, *Locational Pricing in the Renewed Markets*, is the first in this new series.

2 INTRODUCTION

On May 1, 2025, the IESO implemented a set of market design reforms which included, but were not limited to, the introduction of a single-schedule, real-time market with locational marginal pricing. Historically, the Ontario two-schedule system produced an unconstrained schedule to determine a uniform market clearing price for settlement and a constrained schedule for dispatch instructions, both calculated every 5 minutes. The unconstrained schedule was calculated after the fact (ex-post) using actual demand and losses, but assumed no internal transmission constraints and a ramp rate multiplier of 3 times (earlier 12-times) the actual ramping capability of dispatchable resources.[1] In contrast, the constrained schedule was a forward looking (ex-ante) calculation that used forecast demand, transmission constraints and (static) marginal losses, and the actual as-offered resource ramp rates.

The use of different assumptions and data inputs into the two schedules created a misalignment between price signals and dispatch instructions, resulting in significant out-of-market payments in the form of congestion management settlement credit (CMSC) payments. At times, the two-schedule and CMSC design created incentives for market participants to submit offers/bids that did not reflect the cost/value of their resources, which induced inefficient market outcomes and transfers of wealth to the offering/bidding participant from Ontario consumers and other participants. The misalignment obscured short-term locational price signals that drive efficient consumption and generation decisions, as well as long-term signals for new investment in generation, load and transmission facilities. Moving to an ex-ante single-schedule model aims to improve both short- and long-run market efficiency by better aligning prices and dispatch schedules and reducing the need for some of the historical out-of-market payments.

This report presents the MSP's initial observations on locational marginal prices (LMPs) over the first twelve months of the renewed markets. While the

[1] The 12-times ramp rate assumption was implemented as a "temporary solution to address extreme price excursions that were experienced during testing prior to opening of the wholesale market." See Ontario Energy Board, EB-2007-0040, Decision and Order, April 12, 2007, page 3. In 2007, the IESO moved to a 3-times ramp rate multiplier "to improve the quality of market signals to all consumers and producers," and "address some concerns expressed by the Ontario Energy Board's Market Surveillance Panel about market inefficiencies." See IESO Market Rule Amendment Proposal, MR-00331-R00, page 2. Also note the unconstrained run considered total losses by dispatching to a demand level that accounted for system losses.

renewed markets include a day-ahead market with a two-settlement system, this report focuses on the real-time LMPs across Ontario's electrical zones and the likely causes for differences in LMPs[2]. Most notably, congestion is most consequential in northern Ontario, driving the highest price divergence from the reference location (reference bus). Infrequent but extreme congestion has also been observed in the Niagara, West and Ottawa zones, due, at least in part, to unique supply and demand characteristics in the respective zones and a single interface with the rest of the province. The MSP will continue its analysis and routine monitoring of the locational marginal pricing design and, where warranted, report observations and make recommendations.[3]

3 PAST MSP RECOMMENDATIONS

The MSP has advocated for locational marginal pricing since market opening in May 2002. In its first monitoring report, the MSP stated that Ontario should pursue implementation of locational marginal pricing.[4]

In its December 2003 report, the MSP stated, "the most effective way to attract efficient investment in generation and transmission is to eliminate sources of distortion in the market price and eliminate the present approach to congestion management. In this regard, we continue to favour the introduction of locational marginal pricing as was contemplated in the original market design." [5]

[2] Although most energy is procured in the day-ahead market, this report focuses on real-time LMPs because they directly reflect the operational impacts of transmission congestion and system constraints as they occur. day-ahead LMPs are based on forecasted conditions and schedules. Real-time LMPs are calculated from the actual dispatch of resources in each dispatch interval and provide the clearest indication of how congestion affects the marginal cost of serving load at different locations on the grid. While day-ahead LMPs are no less important than real-time LMPs the latter provides an opportunity for this report to inform both the MSP and the reader on the dynamics of locational marginal pricing as it has been implemented in the market.

[3] The MSP is aware of several defects first reported as part of the August 21, 2025 *Renewed Market Update – Performance and Operational Overview* stakeholder presentation. Specifically, 5-minute interval Ontario demand values reported in real-time were overstated in certain limited circumstances. The IESO indicated at the November 26, 2025 *Renewed Market Update – Market Performance and Common Questions* stakeholder presentation that a fix for the defect was implemented on November 16, 2025. In that presentation, the IESO identified 38 intervals where the incorrect demand input had an impact on price formation, requiring prices to be administered. Based on the materiality of the issue reported by the IESO, the defect does not alter the general observations contained in this report.

[4] *Monitoring Report on the IMO-Administered Electricity Markets for May to August 2002*, (released Oct 7-02), page 141.

[5] *Monitoring Report on the IMO-Administered Electricity Markets for the First Eighteen Months (May 2002 – October 2003)*, page 116.

Ontario Energy Board

In 2006, the MSP raised additional concerns with the two-schedule design specifically related to intertie trades and the ability to profit from two directly opposite arbitrage opportunities (i.e., import offer and export bid) at the same time. This strategy was contemplated to be most beneficial in the Northwest, where the MSP reported the largest gaps between the constrained and unconstrained pricing schedules.[6] In late 2006, the MSP undertook an assessment of the potential allocative and dynamic efficiency benefits of locational pricing and recommended that the IESO conduct their own assessment to provide a sound analytic basis for the consideration of future policy decisions.[7]

In 2010, the MSP put forward alternative approaches to a full locational marginal pricing model, whereby loads would continue to be settled at a uniform price, while directly compensating dispatchable resources based on LMPs consistent with the constrained schedule. This would "*eliminate the non-transparent CMSC payments and provide a better mechanism for market participants with dispatchable resources to respond to market signals, thereby improving market efficiency.*"[8]

In 2011, the MSP repeated its position for market redesign as the IESO developed its "market roadmap" and held Electricity Market Forum consultations, recommending that "*the IESO should work with stakeholders to examine the feasibility of replacing the two-sequence design with locational pricing, variable pricing for dispatchable resources or other alternatives.*" [9]

The MSP reiterated this position in 2012, recommending that "the IESO proceed with development work on those recommendations of the Electricity Market Forum that are directed at improving market efficiency, including the

[6] *Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2005 to April 2006*, page 81.

[7] *Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2006 to April 2007*, Recommendation 3-6, page 153.

[8] *Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2009 to October 2009*, page 122.

[9] *Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2010 to October 2010*, Recommendation 3-3, page 86.

consideration of options to replace the two-schedule structure of the current market design."[10]

In 2016, the IESO launched the Market Renewal Program engagement and committed to replacing the two-schedule and CMSC payment system with a single-schedule and locational pricing system. The IESO has frequently cited the MSP's reports to support the merits of a single-schedule, locational pricing system.[11]

4 BACKGROUND ON LOCATIONAL MARGINAL PRICING DESIGN

Locational marginal pricing is designed to reflect the incremental cost of producing and consuming electricity at each pricing location on the IESO-controlled grid by accounting for actual as offered/bid resource capability, marginal congestion costs, and marginal losses relative to a reference location. In a competitive market, persistent and significant price differences between pricing locations (also called "delivery points" or "nodes") provide a signal for the entry and exit of generation and load resources, or the buildout of transmission infrastructure. While historically in Ontario, investment decisions in both generation and transmission assets are largely influenced by central planning and government procurement directives, persistent price differences between pricing locations can inform planning decisions.

Across all wholesale electricity markets with locational marginal pricing, LMPs are determined based on three components:

1. The **energy reference price** represents the marginal as-offered[12] cost of energy delivered to the reference location (or "reference bus"), which in Ontario is the Richview Transformer Station located in the

[10] *Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2011 to October 2011, Recommendation 4-1, page 92*.

[11] References to various MSP reports can be found in the IESO's two business case studies on the benefits of market renewal: *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project*, The Brattle Group, 2017, and *Market Renewal Program: Energy Stream Business Case*, IESO, 2019, and in other supporting documentation.

[12] With the introduction of an ex-ante Market Power Mitigation regime, as-offered costs can also be mitigated prior to entering the pricing algorithm.

Greater Toronto Area.[13] Since LMPs are relative prices, the reference bus serves as a notional delivery point against which all other prices are calculated based on how much more (or less) it costs to deliver an incremental unit of electricity to a given location compared to the reference bus.

2. The **loss component** represents the cost of marginal transmission losses to/from a given location relative to the reference location. Electricity is lost as it moves from one point on a transmission system to another, meaning that at any moment sufficient supply must be included in the schedule to replace losses in addition to meeting demand.
3. The **congestion component** represents the sum of marginal costs at a pricing location for each constraint affected by flow to the reference bus. Congestion occurs when the ability of the most economic energy to serve demand is restricted due to the need to manage transmission limits. Congestion is positive at a pricing location when flows are limited toward the pricing location. The positive congestion component increases the LMP, signaling a potential need for higher-cost resources to be dispatched at that location to manage transmission limits. Congestion is negative at a pricing location when flows are limited away from the pricing location. The negative congestion component lowers the LMP, signaling a potential need for a reduction in generation at the location to keep transmission limits within acceptable thresholds. Congestion is zero when there are no binding constraints limiting the flow of economically scheduled energy.[14]

The congestion component of an LMP can be a small or large percentage of the total price, depending on operating conditions (i.e., the relative cost difference between generation available at the pricing location and generation available on the reference bus side of a binding constraint). In contrast, the

[13] It is worth noting that the LMP at each location stays the same regardless of where the reference bus is located. When the location of the reference bus is changed, all three components change so that the LMP at each location remains the same.

[14] A given pricing location may be subject to multiple constraints which could potentially contribute to congestion at any given moment in time. A constraint is “binding” when its physical capacity (like power flow limit) is fully utilized, acting as a crucial constraint that dictates system operation. For example, a 150 MW transmission constraint is not “binding” if only 110 MW of generation is economical to flow across that transmission path to achieve an optimal solution for the next dispatch interval. The constraint is “binding” if 170 MW of *potential* generation is economical to flow across that transmission path for the next dispatch interval, but due the physical capacity limit, only 150 MW of *actual* generation is allowed to flow to achieve an optimal solution.

loss component of an LMP tends to make up a relatively small percentage of the total price and is predictable under most operating conditions.

In the renewed markets, real-time pricing and scheduling are determined through a specific computational process known as the real-time calculation engine.[15] This ex-ante engine schedules resources to maximize gain from trade while meeting the forecast reliability requirements of the grid (known as the scheduling algorithm) while setting locational marginal prices (known as the pricing algorithm). Dispatch schedules are calculated for each dispatchable resource and LMPs are calculated for each consumer and supplier connection point to the IESO-controlled grid.

- Ontario-based resources[16] that participate directly in the market are settled using LMPs, while virtual transactions[17] are settled using zonal prices which are the load-weighted average LMPs in the applicable zone.
- The Ontario zonal price applicable to non-dispatchable loads is calculated in a similar manner but is the day-ahead load-weighted average LMPs for all pricing locations across the province.[18]
- Intertie transactions are settled for each intertie zone reflecting LMPs calculated on the Ontario side of the interconnection and accounting for any external and net interchange scheduling limit (NISL) congestion, calculated during the one-hour ahead pre-dispatch scheduling process.

[15] The IESO’s real-time calculation engine uses two algorithms - a scheduling algorithm to determine feasible dispatch subject to system constraints and a pricing algorithm which establishes LMPs based on the marginal cost of serving demand under those same constraints. This distinction exists to ensure both reliable system operation and economically efficient price formation. The real-time calculation engine runs continuously to produce LMPs and schedules for the current dispatch interval and the subsequent 10 5-minute intervals (a "real-time look-ahead period"). LMPs and schedules are calculated ex-ante within the look-ahead period to provide forward-looking signals for price and dispatch.

[16] These resources include dispatchable resources, self-scheduling and intermittent suppliers and price-responsive loads.

[17] In the renewed markets, virtual traders submit day-ahead bids/offers, get financially settled at the day-ahead price, and then receive the opposite settlement at the real-time price, all without moving physical power, which helps align day-ahead and real-time prices.

[18] Under the two-settlement system, non-dispatchable loads will be settled on the day-ahead Ontario zonal price to capture costs associated with serving demand in the day-ahead timeframe. Since non-dispatchable loads do not submit bids, a load forecast deviation adjustment within the settlement process accounts for real-time deviations from day-ahead schedules. The load forecast deviation adjustment is calculated and added to the day-ahead Ontario zonal price within the settlement process to account for the financial impact of forecast deviations.

Constraint violation penalty curves are used in both the scheduling and pricing algorithms to ensure they continue to produce schedules and prices when constraint violations occur.[19] The penalty violation curves are different for the scheduling and pricing algorithms (see Table 5 in the Appendix for a comparison of penalty prices in each schedule). For example, the penalty price for transmission security limit violations in the pricing algorithm is $2,300/MWh for minor violations (at or below 2% of the transmission limit) and $8,000/MWh for major violations (greater than 2% of the transmission limit)[20]. In contrast the penalty price for transmission security violations in the scheduling algorithm is $60,000/MWh for all exceedances above zero percent.[21] These differences could contribute to situations where LMPs from the pricing algorithm do not have complete economic parity with the dispatch instructions from the scheduling algorithm. Such differences can result in make-whole payments.[22]

It is important to note that the pre-set penalty costs do not signify an actual breach of physical security limits. Rather, they are tools used by the real-time calculation engine to simulate the economic "cost" of violating constraints and to establish a prioritization order for which constraints might be relaxed if no feasible market solution can be found otherwise. The pricing algorithm does not impact schedules and therefore the use of constraint violation price curves doesn't impact reliability. Should the need arise where the calculation engine utilizes a penalty violation curve in the scheduling algorithm, the applicable reliability requirement is handled manually through real-time operations.

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[19] Details on constraint violation penalty curves can be found in Market Manual 4.3: Operation of the Real-Time Market, Appendix A. The IESO's current penalty price curves in the renewed markets were set through a detailed design process that involved stakeholder engagement, historical data analysis, and the establishment of a clear pricing hierarchy based on the reliability impact of violating specific system constraints. The IESO may adjust penalty prices from time to time where the IESO determines that constraint violation price signals may either overstate or understate the cost of managing the constraint violation given prevailing market conditions.

[20] The IESO's Quick Take: Update on Constraint Violation Prices in the Pricing Algorithms.

[21] Market Manual 4: Market Operations. Part 4.3: Operation of the Real-Time Market.

[22] Make-whole payments are settlement credits designed to ensure that a market participant is not financially disadvantaged when the IESO schedules a resource in a manner that deviates from its calculated economic operating point. They compensate eligible costs including lost opportunity costs that arise when a resource's actual schedule differs from the output or consumption level implied by its bids, offers, LMPs and applicable operating constraints. See IESO Market Manual 5: Part 5.5.

5 ASSESSMENT

The following assessment captures the MSP's general observations on real-time locational prices in the renewed markets from May 1, 2025, to April 30, 2026, with a specific focus on the transparency benefits of locational marginal pricing.[23]

5.1 Transparency Benefits of Locational Marginal Pricing versus Pricing in the Legacy Markets

The MSP has noted in previous reports[24] that locational marginal pricing can improve market efficiency by better aligning prices with actual system conditions. This alignment should, in principle, produce more efficient price signals, enhance transparency, promote efficient dispatch, inform investment decisions, and ultimately strengthen overall market competition.

The introduction of locational marginal pricing has improved price transparency compared to the legacy two-schedule market design. The two-schedule market design calculated a single, uniform price for the province, that ignored the costs of congestion and losses present in real-time at different locations within the province. These costs were reflected imperfectly in uplift charges such as CMSC payments, that were available post real-time. This made it difficult for participants to identify locational cost differences and to respond efficiently to the cost differences. The use of a fictitious 3-times ramp rate assumption in the uniform price calculation also obscured the costs of short-term, periodic constraints on ramping capacity.

[23] With the renewed markets, the IESO introduced a financially binding day-ahead market, which also uses locational marginal pricing. According to the IESO, as stated in its Update on Renewed Market Performance and Operations issued August 21, 2025 (page 33), over 95% of load is being scheduled at day-ahead prices and as such is not subject to real-time price volatility. Routine MSP monitoring reviews the day-ahead LMPs, including the review of day-ahead to real-time price convergence, as well as other aspects of the performance of the day-ahead market. The MSP will report on these market features where warranted.

[24] See for example, *The Market Surveillance Panel in the Renewed IESO Administered Markets* (Ontario Energy Board, August 2025), Section 3.1.1, pp. 26–27; Section 3.2.1, pp. 30–31; and Appendix (LMP benefits), p. 40. Also see section 3 of this report.

The locational marginal pricing design directly embeds congestion components[25] and losses into marginal prices at each location, revealing both the magnitude and direction of transmission constraints in real-time. The locational marginal pricing design also better reflects those instances when there is limited ramping capacity, and associated cost of the limited ramping capacity. This provides a clearer signal of underlying system conditions, allowing congestion patterns, price divergence, and localized system constraints to be more explicitly observed and acted on by all market participants.

5.2 Summary of Key Findings

Table 1 presents the average monthly LMPs by Zone for May 2025 to April 2026. The average monthly LMPs that were at least 5% below the average reference price for the month are highlighted in blue and average monthly LMPs that were at least 5% above the average reference price for the month are highlighted in red. As the loss component typically represents less than 5% of the total LMP, the 5% threshold is intended to highlight material differences from the reference price attributable to congestion.

The first year of locational marginal pricing operation highlights strong spatial differences in congestion and prices across Ontario zones. Positive and negative congestion affected prices in the Northeast, Northwest, Ottawa and West zones in at least half the months of the first year of locational marginal pricing operation. Negative congestion was a factor in the Niagara zone in four consecutive months starting in August, while negative congestion affected the East and Southwest in only one month during the first year of the renewed markets. In the ESSA and Toronto zones, congestion was not a significant factor affecting zonal prices.

[25] The term “congestion” in this report refers specifically to congestion reflected in LMPs. LMPs reflect the marginal impact of transmission constraints incorporated into the market dispatch and pricing process. However, not all congestion-related costs are included in LMPs. The IESO's settlement framework also includes internal congestion and loss residuals (ICLRs) and external congestion and NISL residuals, which arise from market settlement processes and intertie constraints and are recovered through separate settlement mechanisms rather than being reflected in LMPs. See [IESO Market Manual 5: Part 5.5](#).

Table 1 — Average Monthly LMPs by Zone, May 2025 to April 2026

ZONE	May	June	July	August	September	October	November	December	January	February	March	April
REFERENCE BUS	$ 28.73	$ 56.79	$ 73.26	$ 53.89	$ 45.03	$ 57.59	$ 84.07	$ 99.18	$ 122.51	$ 118.36	$ 48.37	$ 36.63
EAST	$ 28.92	$ 56.38	$ 73.03	$ 55.60	$ 45.75	$ 58.86	$ 86.86	$ 103.07	$ 126.27	$ 122.82	$ 49.02	$ 33.32
ESSA	$ 28.38	$ 56.69	$ 73.37	$ 54.36	$ 46.05	$ 58.54	$ 86.03	$ 101.35	$ 124.55	$ 120.22	$ 49.16	$ 36.78
NIAGARA	$ 28.03	$ 58.76	$ 71.37	$ 50.25	$ 42.44	$ 54.39	$ 67.34	$ 96.01	$ 122.08	$ 115.80	$ 47.42	$ 36.05
NORTHEAST	$ 16.03	$ 46.48	$ 53.55	$ 48.62	$ 46.23	$ 58.52	$ 87.03	$ 100.93	$ 114.33	$ 83.47	$ 39.91	$ 31.75
NORTHWEST	$ 16.08	$ 35.07	-$ 14.85	$ 43.04	$ 49.89	$ 67.17	$ 87.58	$ 101.33	$ 109.33	$ 83.57	$ 64.35	-$ 12.98
OTTAWA	$ 29.71	$ 57.07	$ 73.33	$ 58.69	$ 46.58	$ 60.53	$ 95.68	$ 114.85	$ 128.44	$ 125.53	$ 50.34	$ 45.83
SOUTHWEST	$ 28.83	$ 56.74	$ 73.31	$ 53.58	$ 45.20	$ 57.08	$ 72.25	$ 98.79	$ 122.40	$ 117.04	$ 48.46	$ 36.46
TORONTO	$ 28.68	$ 56.84	$ 73.14	$ 53.79	$ 44.94	$ 57.48	$ 83.98	$ 99.08	$ 122.40	$ 119.10	$ 48.30	$ 36.74
WEST	$ 34.95	$ 55.42	$ 69.57	$ 51.07	$ 44.51	$ 56.05	$ 66.42	$ 79.74	$ 99.17	$ 86.54	$ 47.86	$ 41.64

Table 2 shows congestion frequencies by zone as well as the median real-time LMPs for energy, congestion and losses.[26]

The analysis shows that congestion frequency and magnitude are not uniformly distributed across zones. For example, the Northwest and Northeast zones exhibit relatively high congestion frequency, reflecting structural transmission constraints and regionally driven supply-demand dynamics.

In contrast, the Ottawa zone demonstrates low congestion frequency but very high impacts, with large energy price spikes occurring when the Flow Into Ottawa (FIO) interface becomes a binding constraint. Zones such as ESSA and Southwest show moderate congestion frequency and low congestion magnitudes relative to other zones. Additional details on the duration, magnitude and persistence of congestion are reported in the Appendix.

Table 2 — Congestion Frequency and Median Price Impacts (May 2025 to April 2026)

Zone	Congestion Frequency	Median LMP	Median Congestion	Median Loss
NORTHWEST	46.8%	$36.12	$-0.75	$-0.69
NORTHEAST	21.7%	$39.32	$-5.77	$-2.31
SOUTHWEST	13.2%	$70.89	$-0.16	$0.00
WEST	10.6%	$62.30	$-22.88	$-5.73

[26] Prices for Table 1 are uncapped LMPs, which reflect the prices produced by the calculation engine that are not capped at the settlement ceiling of $2,000/MWh or settlement floor of -$100/MWh.

Ontario Energy Board

NIAGARA	8.9%	$43.30	$-1.85	$-1.75
ESSA	6.9%	$53.47	$-0.03	$-0.03
TORONTO	3.6%	$112.53	$0.66	$-0.04
EAST	1.5%	$75.66	$6.50	$1.45
OTTAWA	1.4%	$210.01	$117.92	$3.37

Figure 1 — Ontario's Major Transmission Interfaces, Electrical Zones and Interties

Source: IESO 2025 Annual Planning Outlook, page 37.

The following sections provide a brief overview of the factors that may contribute to differences in LMPs in the various zones.[27]

[27] Within each zone there are many other smaller transmission lines and limits that can drive congestion prices within the zone and impact the average zonal price. For the purposes of this report, discussion will focus broadly on the major transmission interfaces between zones.

Ontario Energy Board

5.2.1 Ottawa Transmission Zone Observations

The Ottawa zone experienced infrequent but severe congestion spikes, making it the most volatile zone in Ontario (see Table 4 in Appendix). Two possible factors may explain this observation. First, the Ottawa zone is constrained by a single internal transmission interface, FIO, and one intertie connection with Quebec. During periods of elevated demand, both internal Ontario supply and imports from Quebec are limited by these transmission constraints, restricting the ability to meet load increases efficiently.

Second, Ottawa represents the second largest demand pocket in Ontario but has limited local generation capacity (a 75 MW combined cycle gas generation unit and a 100 MW wind facility). As a result, even small increases in demand can require dispatching higher-cost resources along a steep supply curve, leading to disproportionately large increases in LMPs.

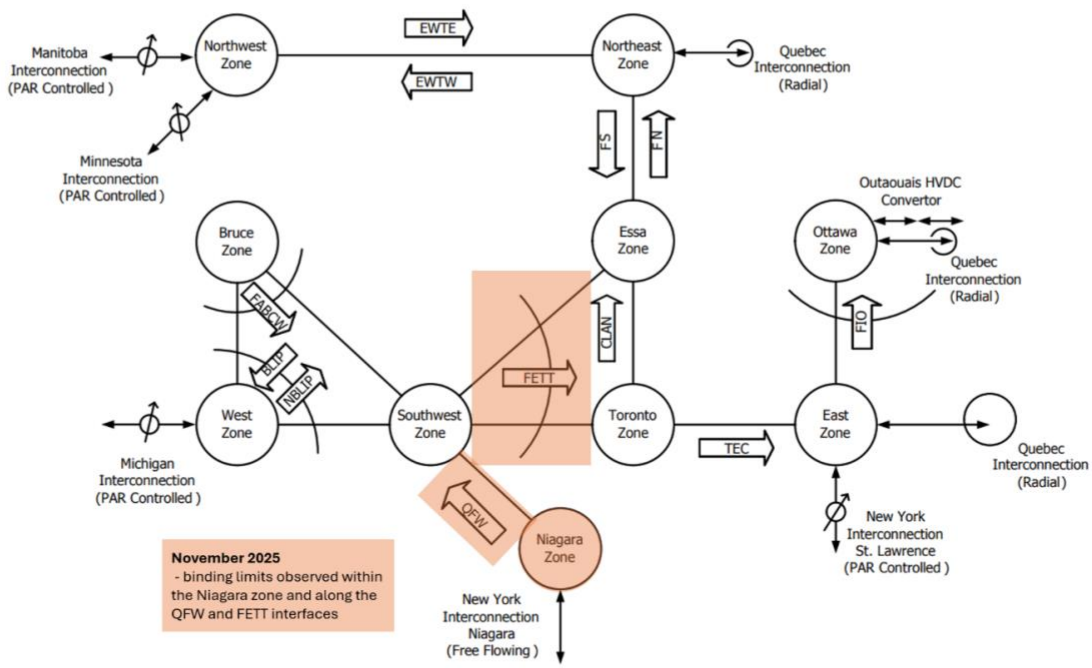
5.2.2 Niagara Transmission Zone Observations

Between August and November 2025, the Niagara zone consistently traded at a discount to the Richview reference bus. In November 2025, this congestion differential was among the largest observed during the reporting period (see Figure 2). Several factors likely contributed to this significant price separation.

First, excess supply in the Niagara zone relative to local demand places downward pressure on prices when transmission lines are congested. The Niagara zone has substantial hydroelectric generation capacity, including the 2,400 MW Sir Adam Beck complex, which can result in oversupply conditions, particularly during periods of moderate demand.

Second, the MSP notes that various equipment outages during this period occurred within the Niagara zone, some of which coincided with binding constraints on the Flow East Towards Toronto (FETT) interface (see Figure 2). These circumstances, whether individually or in combination, could have further contributed to congestion both within the Niagara zone and on exports from the zone.

Figure 2 — Locations of Select, Binding Limits Concurrent with Negative Congestion in the Niagara Zone, November 2025



(Base image source: IESO, Transfer Capability Assessment Methodology For transmission planning studies MAN-2, VERSION 4.1 PUBLISHED APRIL 8, 2019)

And lastly, this surplus generation cannot always be exported to serve load in other Ontario zones due to transmission constraints on the Queenston Flow West (QFW) interface,[28] which has a 2,025 MW transfer capability and serves as a critical pathway for moving Niagara generation and imports from New York into the broader Ontario market. When this interface becomes constrained, excess supply remains trapped within the Niagara Zone.

Together, these conditions contribute to negative congestion pricing and sustained downward pressure on locational marginal prices in the Niagara zone.

[28] Source: IESO 2025 Annual Planning Outlook: Ontario's Transmission Interfaces and Interties, April 2025. Transfer capabilities are based on the forecast system in 2027 and are based on summer ratings assuming all transmission elements in-service.

5.2.3 West Transmission Zone Observations

The West zone recorded the second-largest congestion magnitude in absolute terms (see Table 2) and ranked as the third most volatile zone (see Table 4 in Appendix), indicating significant transmission constraints affecting LMPs. Several factors contributed to this outcome.

First, the West zone has a high penetration of wind generation, which introduces variability in supply. Sudden declines in wind output can create shortfalls, particularly when replacement generation cannot ramp up quickly. Conversely, unexpected increases in wind generation can result in excess supply that must be exported from that zone to maintain local supply/demand balance. Both scenarios can contribute to exceedances on the Buchanan Longwood Input (BLIP) interface, affecting power flows into and out of the West zone.

Second, cross-border trades are scheduled on an hourly basis and cannot adjust to intra-hour changes in system conditions. As wind output fluctuates within the hour, export schedules may become misaligned with real-time supply-demand conditions. This mismatch can force additional flows onto constrained transmission paths such as the BLIP interface either by maintaining exports when local supply has declined or by restricting exports when supply has increased, thereby intensifying congestion.

Third, the BLIP transmission, which connects the West zone and Southwest zone, plays a critical role in supplying local demand and facilitating intertie trade between Ontario and Michigan.[29] When the BLIP limit is binding, the system's ability to efficiently rebalance supply and demand across zones is restricted, which can lead to counter-intuitive pricing outcomes, including negative congestion in the West zone.

Finally, forecast errors in variable generation resources can amplify these impacts. Inaccurate wind forecasts require real-time rebalancing under existing transmission constraints, contributing to more pronounced and volatile congestion outcomes.

[29] The West zone and Southwest zone are also connected by the Negative Buchanan Longwood Input (NBLIP), but the power transfer is measured in the opposite direction. NBLIP transfer capability is important for delivering supply to the Southwest Zone and power imported from Michigan to the rest of the province.

Overall, the interaction of variable generation, inflexible intertie scheduling, and binding transmission constraints produced significant congestion volatility. While these price signals are consistent with real-time system conditions under locational marginal pricing, the complexity of the underlying drivers warrants further examination.

5.2.4 Northeast and Northwest transmission zone observations

The Northeast and Northwest zones exhibit a range of outcomes that provide valuable insights while also raising important questions requiring further assessment. This section examines two key themes: intertemporal and intrazonal price volatility and seasonality of hydroelectric production.

5.2.4.1 Intertemporal and Interzonal Price Volatility

In May 2025, congestion prices were negative in both the Northeast and Northwest zones during morning peak (hour ending 7 to hour ending 9; see Table 3), indicating that low-cost supply, primarily hydroelectric generation (see Figure 5 — Average Monthly Hydroelectric Dispatch Schedules, Northern Ontario), exceeded the capacity available to transmit power southward. In contrast, during overnight hours in the Northwest zone (hour ending 22 to hour ending 24, hour ending 2 to hour ending 3), congestion prices were large and positive, reflecting periods of limited available supply within the zone and restricted import capability from the rest of the province.

Table 3 — Real-Time Congestion Price by Hour and Month, Northeast and Northwest Zones ($/MWh) - May 1, 2025 to April 30, 2026

ZONE	Hour	May 2025	June 2025	July 2025	August 2025	September 2..	October 2025	November 2..	December 2..	January 2026	February 20..	March 2026	April 2026
NORTHEAST	1	0.0	0.0	-0.5	0.0	0.0	0.5	5.1	0.0	0.6	-15.9	-0.2	0.0
	2	0.0	0.0	-0.6	0.0	3.8	0.5	2.9	0.0	0.7	-0.9	-0.2	0.0
	3	0.0	0.0	-0.9	0.0	6.1	0.4	2.6	0.0	1.6	-12.9	-21.5	0.0
	4	-0.4	0.0	-0.5	0.0	2.1	0.2	0.2	0.0	1.1	-38.2	-7.3	0.0
	5	-0.4	0.0	-0.5	0.0	0.0	0.1	0.0	-0.4	-0.5	-1.3	-46.2	-0.1
	6	-0.4	0.0	-0.8	0.0	0.0	0.1	0.0	-0.5	0.1	-19.1	-12.8	-0.5
	7	-26.9	-1.1	-1.4	-4.2	-0.2	0.0	0.0	-0.1	-2.3	-6.3	-0.3	-2.9
	8	-28.0	-1.2	-3.4	-7.0	0.0	-0.8	0.0	-0.4	-34.1	-80.5	-0.9	-5.0
	9	-17.2	-3.1	-7.6	-7.1	0.0	0.0	4.3	-4.7	-17.6	-148.0	-3.8	-11.6
	10	-1.9	-3.4	-9.2	-6.9	0.0	0.0	3.1	-3.1	-8.7	-57.5	0.9	-19.1
	11	-3.6	-2.9	-7.4	-6.4	0.0	0.0	0.8	-2.7	-4.3	-58.1	-17.6	-14.7
	12	-2.8	-2.0	-7.2	-1.8	0.0	0.0	1.3	0.0	0.1	-23.5	1.1	-1.2
	13	-7.9	-3.8	-17.6	-8.1	0.0	-0.1	3.7	0.0	0.7	-137.0	-59.0	-2.2
	14	-4.0	-5.8	-13.3	-7.9	-0.1	0.0	2.3	0.0	-0.4	-87.4	-3.1	-4.5
	15	-4.3	-18.5	-18.7	-4.5	0.0	0.0	1.3	0.0	-0.9	-40.3	-0.6	0.7
	16	-3.2	-27.5	-47.4	-4.5	-0.2	0.0	0.0	0.0	-58.9	-63.9	-23.7	5.6
	17	-11.6	-19.5	-63.7	-11.5	-0.4	-0.1	-0.1	0.0	-44.7	-78.9	-1.1	-7.9
	18	-22.7	-24.5	-66.6	-11.9	-0.6	-0.9	-0.2	-0.5	-50.4	23.6	-2.3	-7.1
	19	-25.7	-31.3	-42.5	-9.1	-1.0	0.0	0.1	-0.4	-46.1	24.7	-1.9	-6.6
	20	-17.3	-12.2	-32.2	-4.2	-0.2	-0.4	0.1	0.0	5.0	38.9	-0.4	-9.6
	21	-39.9	-5.3	-11.1	-3.0	0.0	-0.1	0.1	-0.1	64.8	-6.7	-0.3	-1.4
	22	-16.2	-1.1	-7.5	-2.7	0.0	0.0	0.0	0.0	-1.5	-5.5	-0.2	0.2
	23	-12.8	-0.2	-4.4	-0.4	0.0	0.1	0.1	1.9	-0.9	-4.7	-0.6	-0.7
	24	-0.2	0.0	-1.2	0.0	0.0	0.2	0.0	1.4	0.3	-4.9	-0.2	-0.3
NORTHWEST	1	0.5	30.5	-4.6	17.9	7.9	4.7	4.9	0.5	2.3	-9.3	4.2	-51.2
	2	12.6	-0.3	9.8	-0.3	5.1	8.4	4.7	0.3	1.3	-10.2	0.2	-72.8
	3	10.7	-1.0	-45.0	1.4	6.1	3.4	6.3	2.9	3.0	-3.4	-1.9	-38.1
	4	0.5	1.1	-63.5	1.7	2.1	2.3	5.4	2.0	0.2	-8.4	4.9	-37.4
	5	-3.7	0.0	-49.0	-1.1	0.0	5.0	5.4	0.9	-6.6	-9.8	0.7	-39.5
	6	0.9	-2.0	-36.7	-1.4	0.0	-0.2	3.6	0.7	-2.3	-24.4	-2.0	-40.9
	7	-104.5	-5.8	-83.4	-10.1	10.7	27.6	1.6	-0.2	-13.2	-36.7	-8.5	-49.8
	8	-88.6	-3.5	-46.7	-3.5	1.6	2.1	0.3	-2.2	-27.9	-61.6	10.4	-16.9
	9	-70.4	-10.1	-47.0	-9.9	4.0	2.6	4.5	-0.1	-13.4	-50.3	61.4	-38.9
	10	-6.0	-10.1	-41.6	0.5	1.0	3.1	4.3	-0.1	7.0	-37.7	48.0	-66.3
	11	-8.2	-14.3	-34.2	-1.8	0.2	8.2	17.0	-0.5	-30.7	-27.8	46.2	-36.7
	12	-1.3	-14.5	-50.0	-1.7	3.1	8.2	1.3	0.0	-1.2	-24.2	11.5	-27.9
	13	-29.7	-14.0	-49.5	-3.0	1.1	1.3	3.4	0.0	0.0	-30.8	-1.4	-23.1
	14	-18.4	-15.6	-51.8	-30.1	2.6	2.1	2.6	0.1	-1.9	-10.9	6.5	-25.2
	15	-22.3	-40.6	-106.6	-26.5	0.7	3.7	-0.8	-0.1	-8.9	-13.1	2.4	-23.8
	16	19.4	-63.0	-260.8	-43.4	-2.3	3.1	-3.0	-0.1	-9.3	-18.6	3.5	9.4
	17	-28.2	-51.1	-304.2	-51.9	-3.9	-2.1	-2.7	-0.5	-27.5	-47.7	4.5	-55.8
	18	-33.0	-65.3	-309.4	-38.1	-3.5	-7.7	-6.6	-4.3	-43.5	-71.2	-2.6	-57.0
	19	-16.8	-65.0	-175.4	-35.0	36.0	-1.1	-1.5	-3.1	-55.9	-50.3	-4.1	-81.1
	20	18.6	-33.2	-99.1	-10.6	2.8	-0.5	-0.5	-0.2	-34.3	-24.4	-1.1	-72.7
	21	-30.5	-31.7	-25.2	-2.2	0.4	81.6	-2.1	-1.5	-13.0	-29.7	94.8	-37.5
	22	42.3	-10.4	-20.3	3.0	4.5	10.2	-0.7	0.1	-7.5	-30.1	82.1	-102.4
	23	60.4	-2.3	-22.0	6.7	5.4	15.2	-0.4	1.2	22.7	-33.1	11.6	-101.0
	24	44.0	-2.7	-50.2	35.7	4.2	10.3	0.0	2.0	2.8	-20.7	2.7	-89.3

This intraday price volatility can be partly attributed to the intertemporal nature of hydroelectric generation. Water may be dispatched to meet morning peak demand, reducing available supply for later periods such as the evening or overnight peaks due to storage limitations. As a result, the timing of water usage contributes to significant swings in supply availability within the day.

In addition, the operational flexibility of hydroelectric resources allows generators to optimize the timing of production in response to expected market conditions. While such behavior may reflect efficient intertemporal optimization, it can also contribute to outcomes that resemble the withholding of supply during certain periods, followed by increased production in others, thereby amplifying intraday price volatility. Further detailed analysis is required to disentangle these effects.

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Transmission constraints further amplify these dynamics. The northern transmission system is connected to the ESSA zone via Flow North (FN) and Flow South (FS) internal transfer interfaces, which include two major 500 kilovolt circuits – X503E and X504E. Transfer capability on these interfaces can be reduced when one or both circuits are out of service or under high or low water conditions, when hydroelectric production is insufficient to meet northern demand, limiting imports into the region. Conversely, FS constraints may bind under high-water conditions, when excess hydroelectric generation cannot be fully exported southward to load centers via the ESSA zone.

In addition, the East-West Transfer East (EWTE) and East-West Transfer West (EWTW) internal interfaces connect the Northeast and Northwest zones. The EWTE has a transfer capability of 475 MW and is critical for exporting Northwest supply and imports from Manitoba and Minnesota to the rest of the province.[30] The EWTW has a transfer capability of 490 MW and supports the reliable supply of demand within the Northwest zone.[31]

When these transmission constraints limit the ability to move power between zones, localized supply-demand imbalances emerge. In particular, when supply cannot flow into northern Ontario, the Northwest zone can experience scarcity conditions, resulting in positive congestion prices. Under locational marginal pricing, these constraints lead to price separation across zones, reflecting the physical limits of the transmission system and the cost of serving demand locally.

In July 2025, both the Northeast and Northwest zones experienced significant negative congestion prices, with the effect most pronounced in the Northwest. Congestion remained negative for most of the day (hour ending 3 to hour ending 24) reaching an average of -$309.40/MWh in Hour Ending 18.

Figure 3 highlights several days (July 15, July 16, July 24) where congestion prices were large and negative during evening peak hours (hour ending 16 to hour ending 20), as indicated by the dark blue cells. These intraday and seasonal patterns are further illustrated in Figure 3, which shows frequent negative congestion prices during summer months (blue cells) and increased

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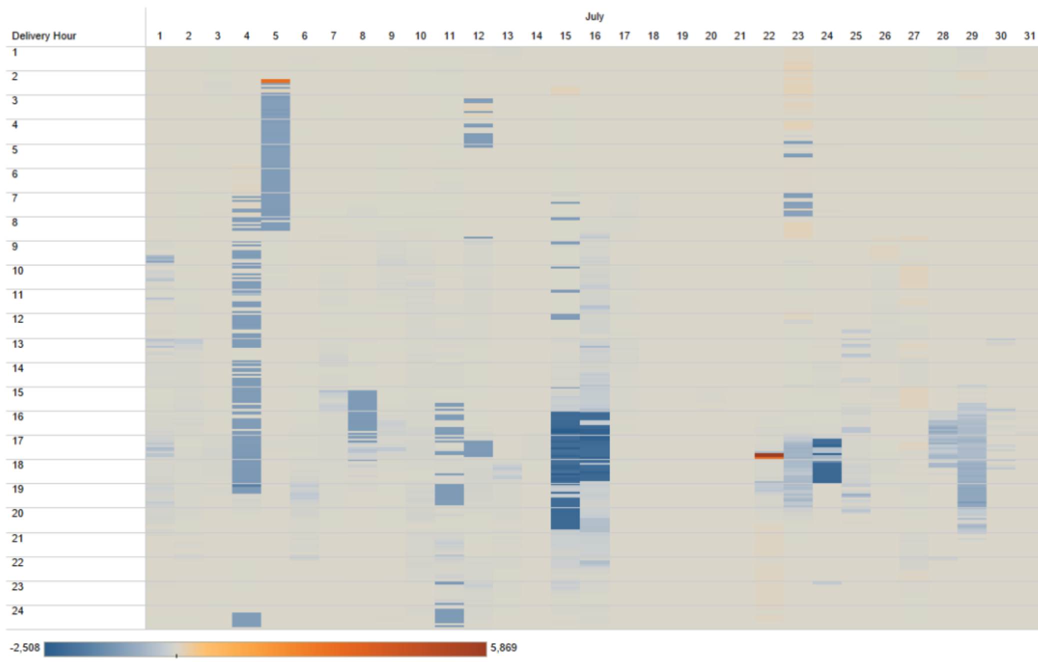
[30]The IESO's Annual Planning Outlook Overview of Ontario's Transmission Interfaces April 2025, Table 1. Note that the IESO's most recent Reliability Outlook, published on May 7, 2026, after the end of this assessment period, now puts this interface transfer limit at 500 MW in each direction.

[31] Ibid.

positive spikes during winter months (orange cells), alongside clear variation across hours of the day.

Figure 3 — Average Real-Time Congestion Price by Hour and Day, Northwest Zone, July 2025



One key factor contributing to these outcomes is excess electricity supply within the Northwest zone-specifically, supply that exceeds both local demand and the transmission capability required to move power out of the transmission zone (see Figure 4 and Figure 5). Under such conditions, surplus generation becomes constrained within the zone, exerting strong downward pressure on prices and leading to negative congestion outcomes.

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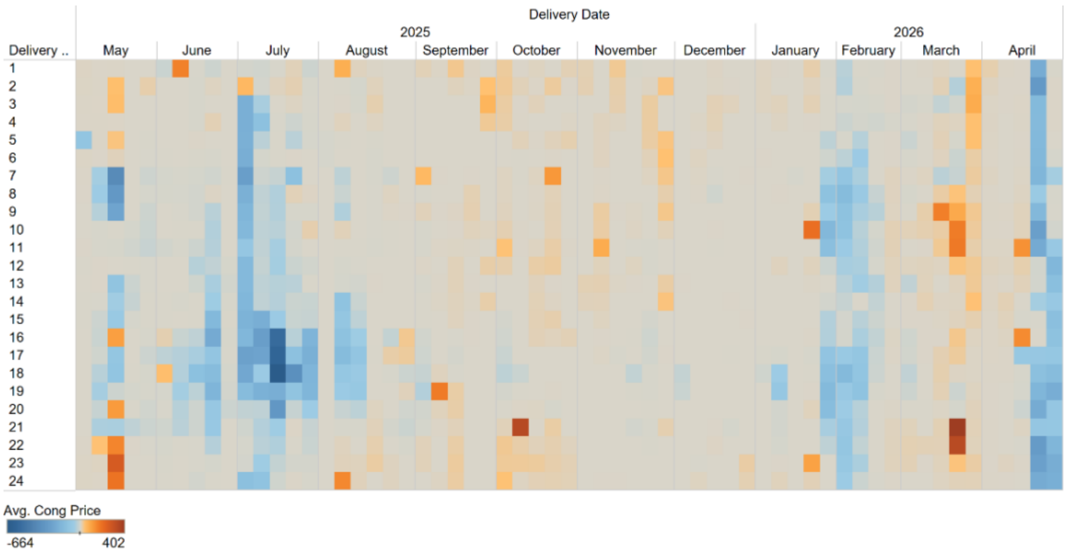
Figure 4 — Average Real-Time LMPs by Hour and Month, Northwest Zone, May 1, 2025 to April 30, 2026



Overall, the observed intertemporal and interzonal volatility in congestion prices in the Northeast and Northwest zones is more transparent under a locational marginal pricing framework than it would be otherwise. These patterns point to complex and interrelated dynamics involving zonal supply, demand, and transmission constraints, suggesting the need for further detailed assessment.

5.2.4.2 Seasonality Effects and Hydroelectric Production

In contrast to the conditions observed in May and July, positive congestion prices in the Northeast and Northwest zones during September and October were partly driven by lower hydroelectric supply availability. This is reflected in the reduced dispatch levels shown in Figure 5 and the corresponding increase in LMPs in Figure 6.

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Figure 5 — Average Monthly Hydroelectric Dispatch Schedules, Northern Ontario

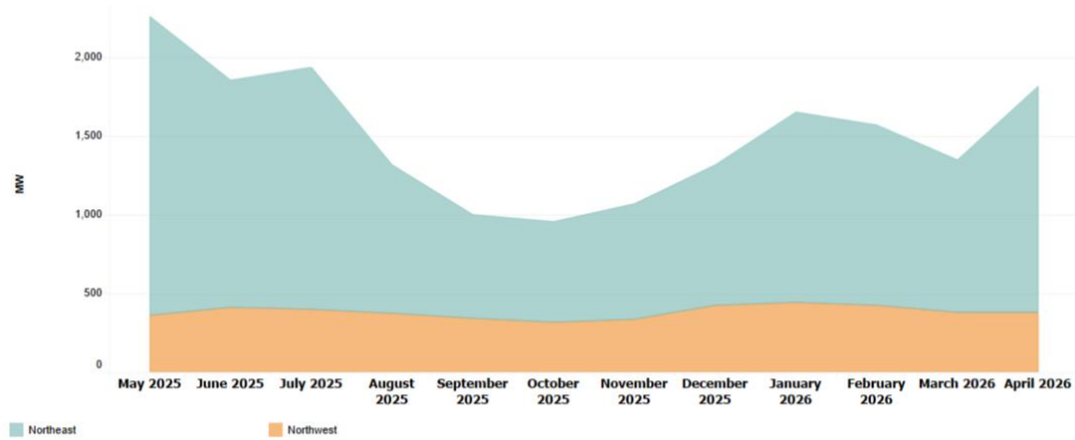


Figure 5 overlays average hourly LMPs with hydroelectric dispatch schedules, providing further insights into these seasonal dynamics.

In the Northeast, locational prices generally track both the hydroelectric dispatch profile and the reference bus price, indicating that hydro availability is a primary driver for price formation in the zone.

In contrast, the Northwest zone displays more complex behaviour. While hydroelectric output in May and July contributed to lower zonal prices relative to the rest of the province, this relationship does not consistently hold. The gap between the green line (Northwest) and red line (reference bus) in the bottom panel of Figure 5 clearly illustrates periods of significant price separation, particularly when excess supply cannot be exported.

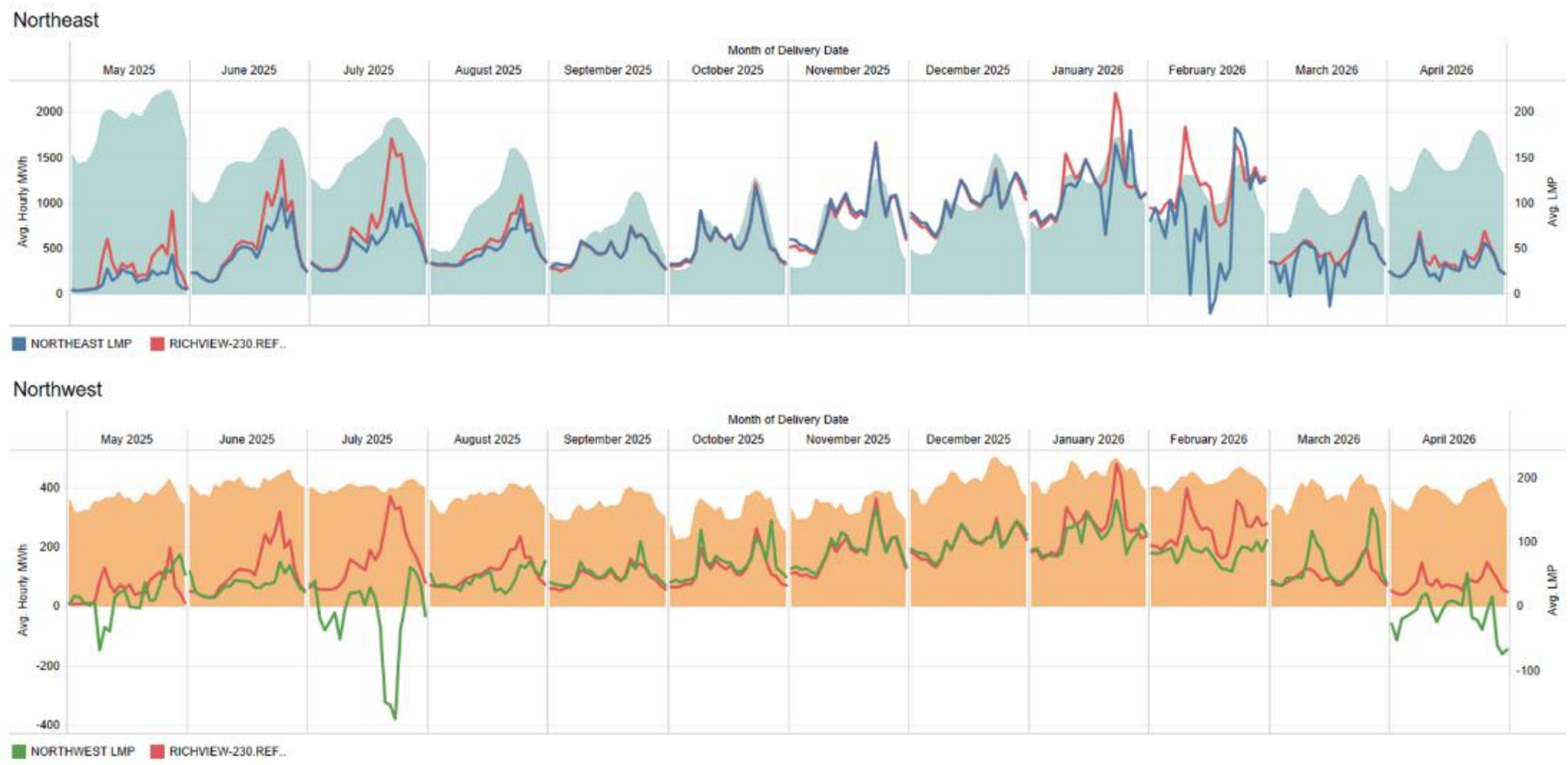
For example, in May, when hydroelectric dispatch in the Northeast reached its highest levels during the period under review, zonal prices were approximately $12/MWh lower than in southern Ontario. Average prices settled at $16.03/MWh in the Northeast compared to $28.73/MWh at the reference bus.

At the same time, the Northwest frequently exhibits divergence from both the hydroelectric dispatch profile and the reference bus price, especially in May and July. These patterns suggest that, in addition to hydroelectric availability, other factors, such as intertie scheduling constraints and limited storage capability and may play a significant role in shaping LMP outcomes in the Northwest zone.

Overall, the seasonal variation in hydroelectric production, combined with transmission constraints and interregional trade limits, drive pronounced intertemporal and interzonal price dynamics in the Northeast and Northwest zones. These findings highlight the complexity of price formation in northern Ontario and point to the need for further detailed analysis.

While seasonal changes in hydroelectric availability explain a significant portion of the observed price variation, some congestion outcomes were driven by temporary operational conditions. This is discussed in the next section.

Figure 6 — Hourly Average Northern Ontario Hydroelectric Schedules vs. LMPs



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5.2.4.3 Operational Factors: Transmission Outages (Winter 2026)

During winter 2026, the management of a major transmission outage may have contributed to a noticeable, though temporary, shift in congestion patterns in the Northeast and Northwest. In particular, the positive congestion prices observed in March 2026 in both zones may be associated with the management of a significant outage involving a 500kV transmission line serving the region.

Under such conditions, system operations can produce counterintuitive outcomes. For example, when the IESO curtails generation within a constrained area to maintain system reliability, power flows may shift toward imports into the affected region. This can result in congestion patterns that differ from typical expectations, including positive congestion in zones that would otherwise be characterized by surplus supply.

These operational practices were evident during the February and March 2026 outage periods highlighted by the pink bars in Figure 6. The figure shows elevated make whole payments[32] in the lower panel, corresponding to large congestion prices reflected by the dark blue cells in the upper table. Such conditions can lead to inefficient pricing outcomes under the locational marginal pricing framework and may contribute to increased uplift payments. These events have prompted the MSP to undertake, in the future, a more detailed assessment of the associated outcomes and operational practices.

[32] Make- whole payments in the Figure 7 include real-time and day-ahead energy and operating reserve payments.

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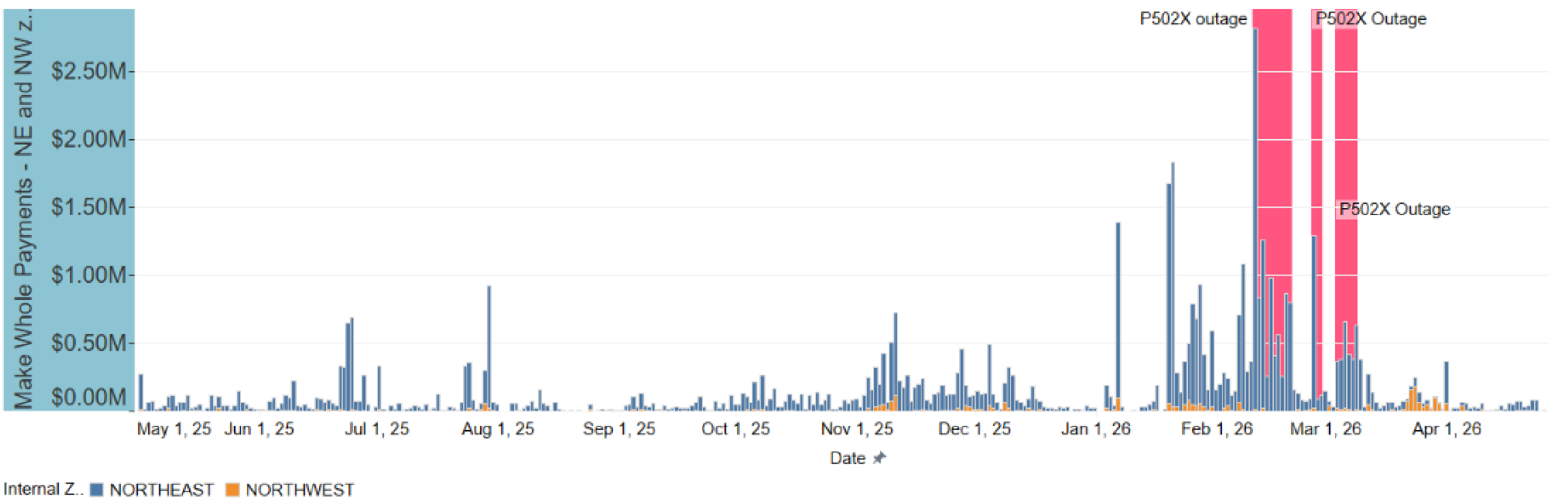
Figure 7 — Make Whole Payments, Real-time LMPs, and the P502X Circuit Outages of February and March 2026

Average Real-Time LMPs ($/MWh), Uncapped, by Zone, by Month - May 1, 2025 to April 30, 2026

	2025								2026			
ZONE	May	June	July	August	Septemb..	October	November	December	January	February	March	April
NORTHEAST	$16.03	$46.48	$53.55	$48.62	$46.23	$58.52	$87.03	$100.93	$114.33	$83.47	$39.91	$31.75
NORTHWEST	$16.08	$35.07	$-14.85	$43.04	$49.89	$67.17	$87.58	$101.33	$109.33	$83.57	$64.35	$-12.98

Total Make Whole Payments (DAM and Real-Time), by week, Northeast and Northwest Zones

February and March P502X circuit outage periods highlighted in pink



6 CONCLUSION

The introduction of locational marginal pricing in Ontario's renewed markets is enhancing price transparency and providing greater visibility into the drivers of price divergence between zones. This initial assessment of real-time LMPs indicates that congestion in Ontario is highly localized, with locational marginal pricing revealing both recurring structural constraints (e.g., Northwest) and infrequent but high impact events (e.g., Ottawa). A more comprehensive statistical overview of these localized effects is presented in the Appendix to this report.

The observed real-time LMP patterns also provide valuable insights for central planning and procurement processes. For example, persistent price divergences and recurring congestion may signal the potential need for investment within specific zones. However, the MSP notes that price spreads represent only one of many inputs in the investment decision making process. While necessary, LMP spreads alone are not sufficient to justify new capital investments. The MSP recognizes that a comprehensive cost-benefit analysis is required to evaluate and compare potential investment options.

While most observed outcomes over the first year of the renewed markets align directionally with expectations, further analysis is warranted to better understand the underlying drivers of congestion across different zones.

As stated previously, the MSP will continue its analysis and routine monitoring of the locational marginal pricing design and, where warranted, report observations and make recommendations. Areas of monitoring for the MSP may include:

- The efficiency of locational price signals, internal congestion rents, and their implications for long-term transmission and generation investment
- Comparative outcomes between day-ahead and real-time markets, including the role of virtual trading
- Impact of non-locational marginal pricing incentives (i.e., IESO contracts and OPG regulation) on the hydroelectric production profile in northern Ontario

- Impact of variable generation forecast accuracy and unexpected deviations in output on zonal prices
- Drivers of real-time price volatility
- The role of hourly intertie scheduling in zonal price formation
- The impact of market power mitigation measures on market efficiency and price formation
- The appropriateness of constraint violation penalty curves used in the pricing algorithm
- A detailed review of congestion in the Northwest and Northeast zones to identify any underlying contributing factors

These areas of analysis may inform future MSP reports and contribute to a more comprehensive understanding of how locational pricing interacts with other market design elements to support both short-term efficiency and long-term investment signals in the IESO-administered markets.

7 APPENDIX

All data presented in this appendix spans the period from May 1, 2025 to April 30, 2026, and uses uncapped LMPs, congestion and loss values, unless otherwise indicated. The report uses the following definitions for the various metrics in this Appendix:

Congestion Frequency

Congestion frequency is the share of hours with non-zero congestion.

Congestion Frequency = (number of hours with congestion ≠ 0) / (total hours)

Congestion Episode Duration

A congestion episode is defined as a continuous stretch of hours during which congestion occurred. Consecutive hours of non-zero congestion are grouped into episodes. The duration of each episode is calculated as the total number of consecutive congested hours within that sequence. Durations are then grouped into bins to analyze the frequency distribution of congestion episode durations.

Episode Duration = number of consecutive hours with congestion ≠ 0

Typical Congestion Magnitude

The typical congestion magnitude is the median value of congestion within a zone during congestion hours. The median is used because congestion values are highly skewed with occasional extreme spikes. The median is robust to outliers and provides a more representative measure of the central tendency of congestion values.

Typical Magnitude = median (|congestion| | congestion ≠ 0)

Persistent Congestion

The Persistent Congestion Index (PCI) for each zone measures the extent to which congestion occurs in sustained, long-duration events. It identifies continuous runs of congestion lasting **6 hours** or more and calculates the share of time a zone spends in these prolonged congestion episodes. Formally, the PCI is defined as the ratio of total persistent congestion hours (i.e., hours within runs of at least 6 consecutive congested hours) to the total number of observed hours for that zone.

Persistence = (# of months with ≥6-hour congestion events) / total months

Standard Deviation

Standard deviation measures the average squared deviation of congestion values from their mean, providing a comprehensive indicator of overall variability. It captures both typical fluctuations and extreme deviations, making it sensitive to large congestion spikes.

Interquartile Range

The interquartile range represents the difference between the 75th and 25th percentiles of congestion values, capturing the spread of the middle 50% of observations. It provides a robust measure of typical variability that is not influenced by extreme outliers.

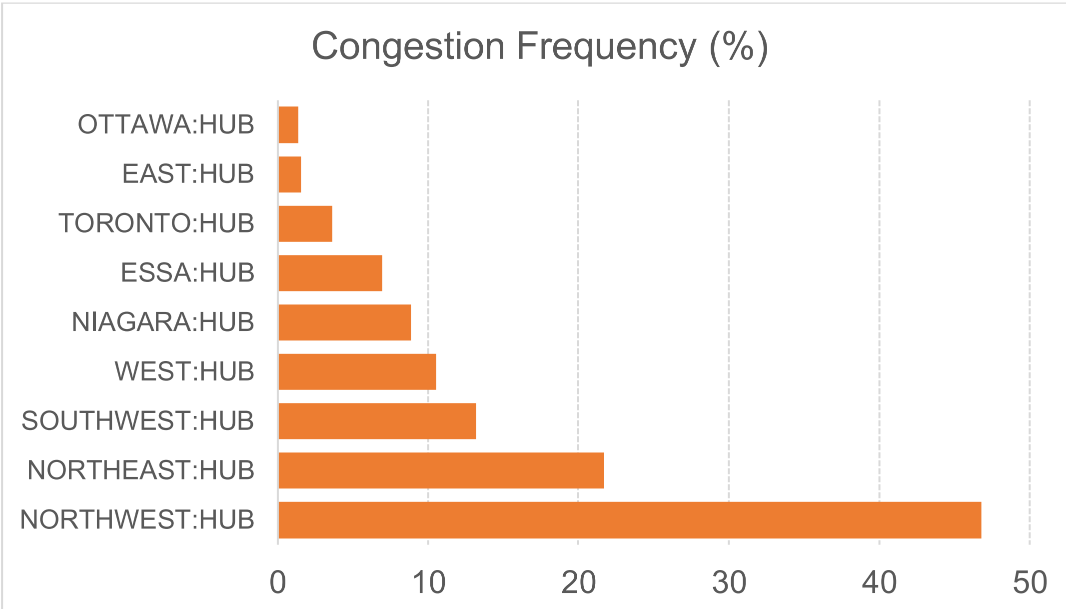
Mean Absolute Deviation

Mean absolute deviation measures the average absolute deviation of congestion values from their mean. It provides an intuitive measure of variability by quantifying how far values typically deviate from the central tendency, with less sensitivity to extreme values than standard deviation.

95th percentile of absolute congestion

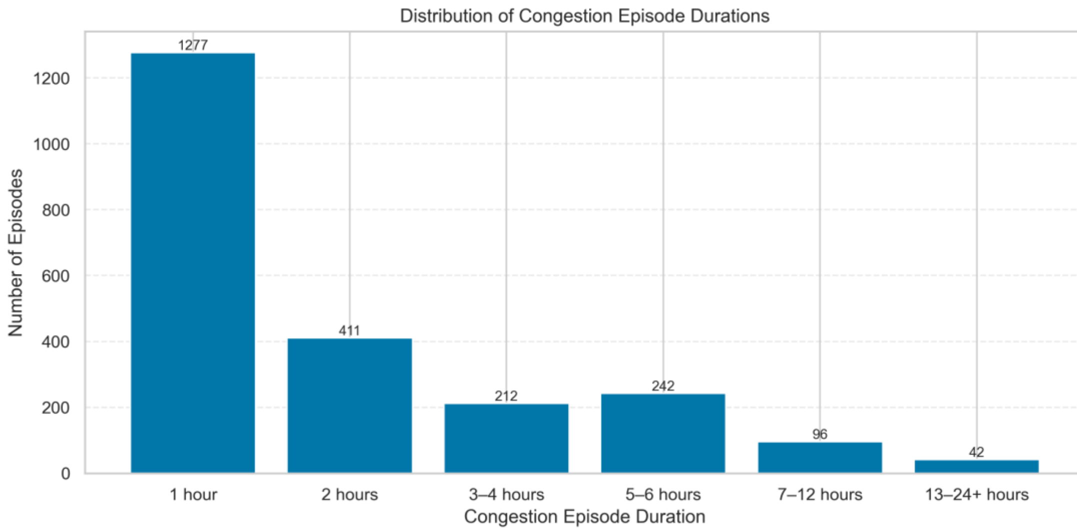
The 95th percentile of absolute congestion represents the level below which 95% of congestion magnitudes fall. It captures high-impact congestion events while excluding the most extreme observations, providing a stable measure of congested system conditions.

Figure 8 — Congestion Frequency



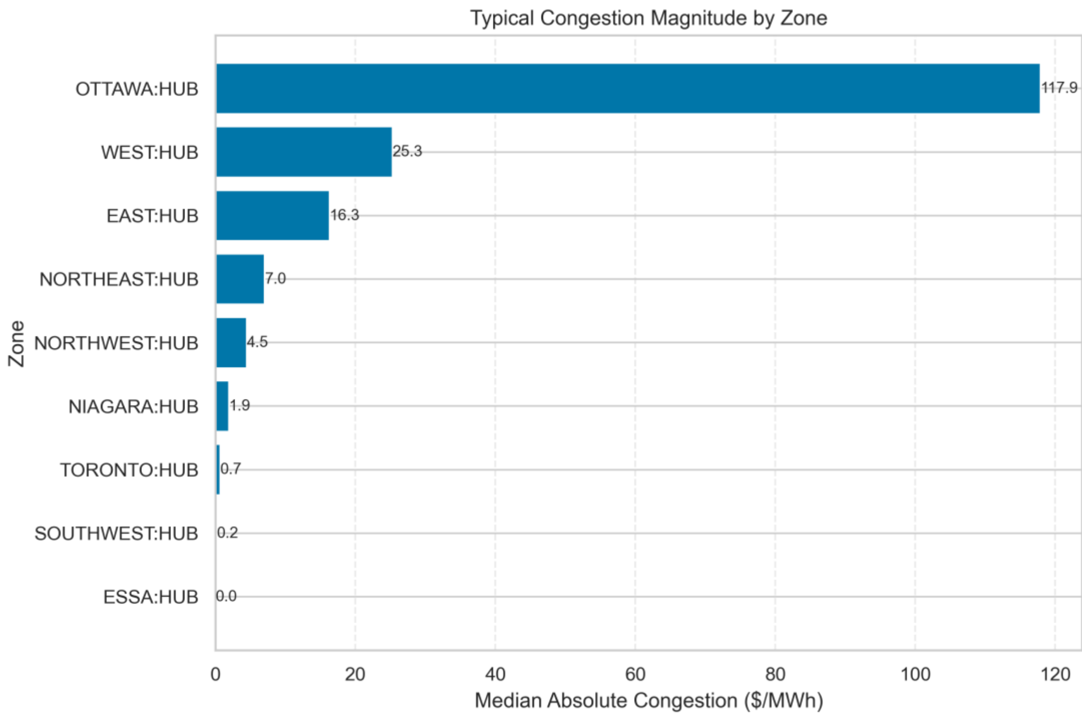
The Northwest zone exhibits significantly higher congestion frequency than all other regions, with congestion occurring in approximately 45% of hours. The Northeast follows at around 22%, indicating a moderate but materially lower level of congestion relative to the Northwest. Most other zones, including Southwest, West, Niagara, and ESSA, experience congestion less frequently, generally in the range of 5% to 15% of hours. In contrast, Toronto, East, and Ottawa show very low congestion frequency, with congestion occurring only in a small fraction of hours. These results highlight a clear regional disparity, with congestion concentrated in a few zones while remaining relatively limited in others.

Figure 9 — Congestion Episode Duration



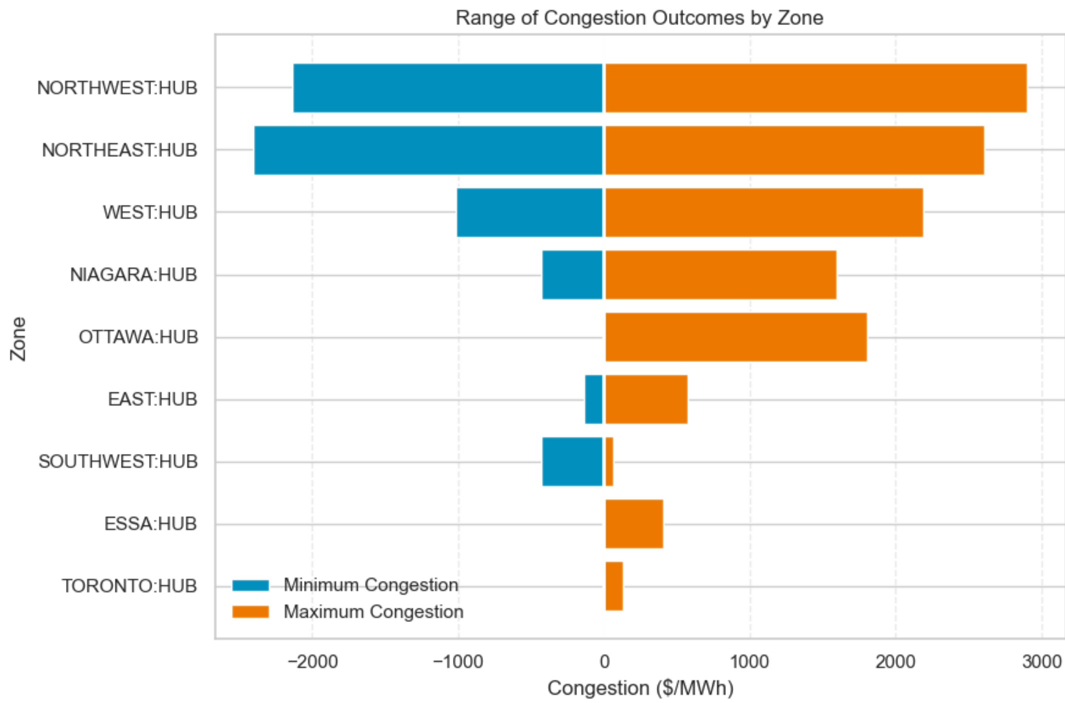
Most congestion episodes are short in duration, with one-hour events occurring far more frequently than all other categories. The number of episodes declines sharply as duration increases, indicating that congestion is typically resolved within a relatively short time frame. However, there remains a meaningful number of longer-duration events, particularly those lasting 5 hours or more, suggesting that sustained congestion does occur under certain system conditions. While these extended episodes are less common, they are operationally significant, as they may reflect persistent transmission constraints or system stress. Overall, the results indicate that congestion in the system is generally short-lived, but with occasional periods of prolonged disruption.

Figure 10 — Typical Congestion Magnitude



Ottawa stands out as a clear outlier, with substantially higher median absolute congestion (approximately $120/MWh) than all other zones. This indicates significantly larger typical deviations in congestion when it occurs, reflecting the presence of high-impact constraint conditions. Other zones exhibit relatively modest congestion magnitudes, with median values generally remaining below $30/MWh. This suggests that, outside of Ottawa, congestion effects are typically limited in scale and less severe under normal operating conditions. Overall, the results highlight a pronounced disparity in congestion intensity, with Ottawa experiencing fundamentally different conditions compared to the rest of the system.

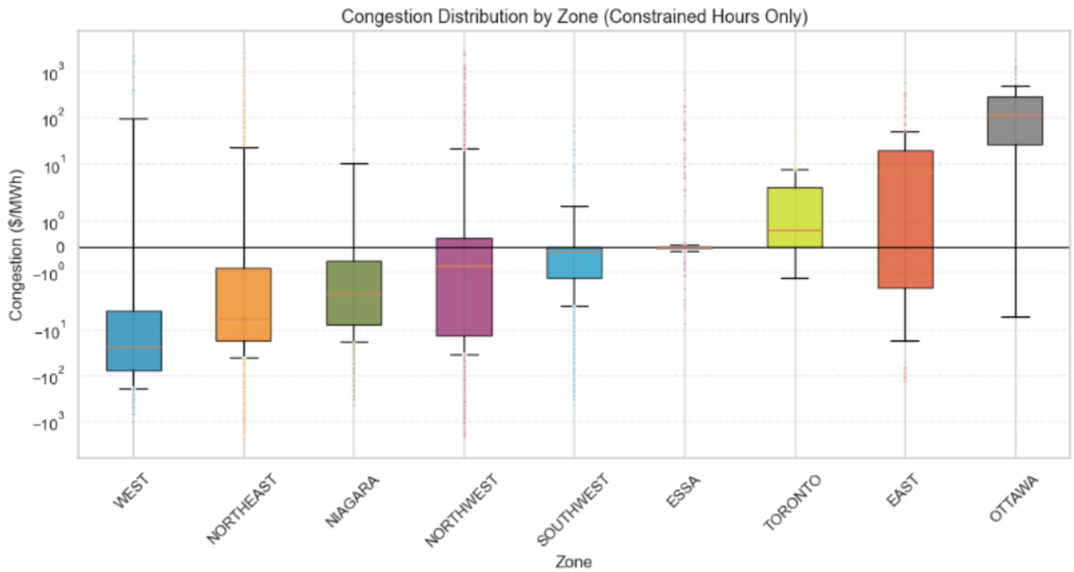
Figure 11 — Minimum and Maximum Congestion by Zone



The range of congestion outcomes across zones highlights significant variability in both the direction and magnitude of network constraints under the locational marginal pricing design. While median congestion values capture typical conditions, the minimum and maximum congestion levels reveal the full extent of price divergence that can occur during periods of system stress. In several zones, particularly those with export constraints such as West and Niagara, large negative congestion values indicate periods in which excess local supply cannot be fully transmitted out of the region.

Conversely, zones such as Northwest, Northeast, and Ottawa exhibit extremely high positive congestion spikes, reflecting tight import constraints and limited local generation. This wide dispersion between minimum and maximum congestion underscores the highly locational nature of system constraints and reinforces the importance of locational marginal pricing in exposing both routine and extreme transmission limitations that would have been less visible under the previous market design.

Figure 12 — Volatility of Congestion Values



Volatility in this chart is interpreted as the spread and extremity of congestion values during constrained hours. The box plots, presented on a logarithmic scale, reveal substantial differences in congestion volatility across zones. Ottawa exhibits high volatility driven by infrequent but high-impact congestion events, while Northwest shows the broadest dispersion, reflecting both frequent and extreme congestion outcomes. These observed patterns are consistent with, and reinforced by, the dispersion metrics presented in Table 4 — *Dispersion Metrics Across Zones*

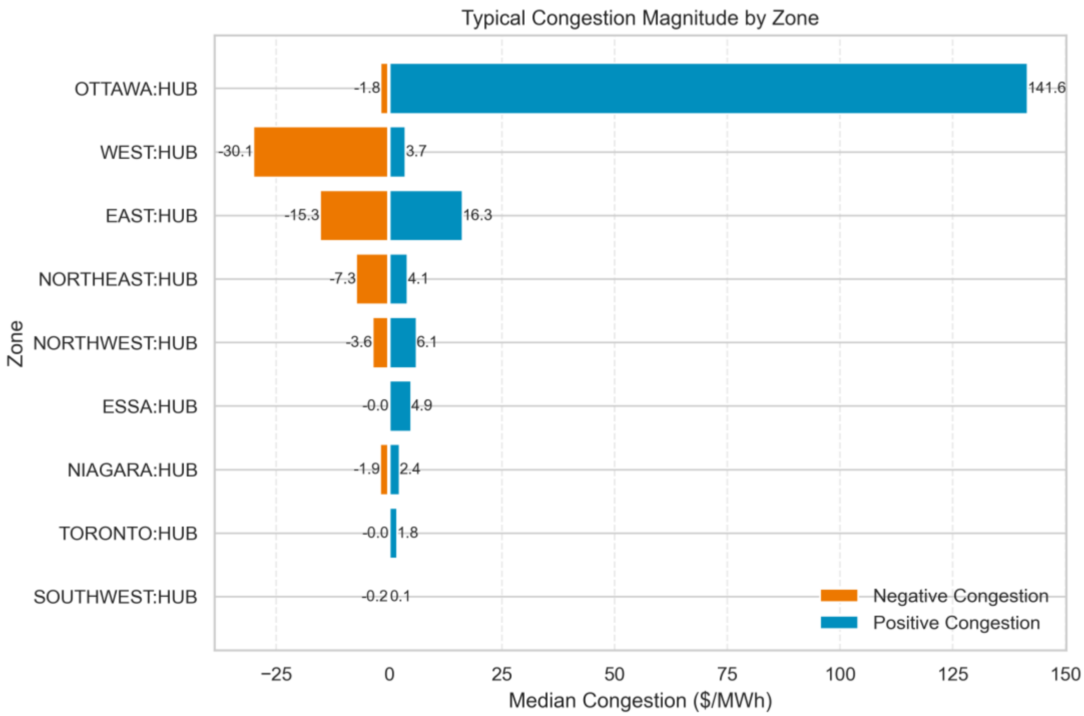
Table 4 — Dispersion Metrics Across Zones

Zone	SD	IQR	MAD	P95	Volatility
OTTAWA	291.29	268.20	191.08	671.30	1
NORTHWEST	195.59	14.04	69.74	252.70	2
WEST	146.12	74.42	67.09	242.01	3
NORTHEAST	175.10	16.27	55.75	190.86	4
EAST	93.76	21.02	49.11	167.16	5
NIAGARA	74.41	7.34	25.59	103.24	6
SOUTHWEST	33.58	1.21	14.07	51.39	7
TORONTO	9.04	3.01	2.88	7.10	8
ESSA	22.28	0.06	5.07	2.06	9

Table 4 provides a structured comparison of congestion behaviour across zones by capturing both typical variabilities, through the Interquartile Range (IQR) and Mean Absolute Deviation (MAD), and extreme variability, measured by the 95th percentile (P95) and standard deviation (SD). This approach enables a clear distinction between zones characterized by sustained variability and those driven by occasional but high-impact congestion events. Volatility rankings are determined by ordering zones primarily based on P95, which captures high-impact stress conditions, and secondarily on standard deviation, which reflects overall dispersion. This approach ensures that both extreme outcomes and general variability are incorporated into the final ranking.

Consistent with the box plots presented Figure 12, Table 4 shows that Ottawa and Northwest rank highest in terms of volatility, although driven by different dynamics—Ottawa by infrequent but severe congestion spikes, and Northwest by a broad and persistent range of congestion outcomes. In contrast, Toronto and ESSA lie at the lower end of the volatility spectrum, exhibiting tightly clustered congestion values and limited absolute variability.

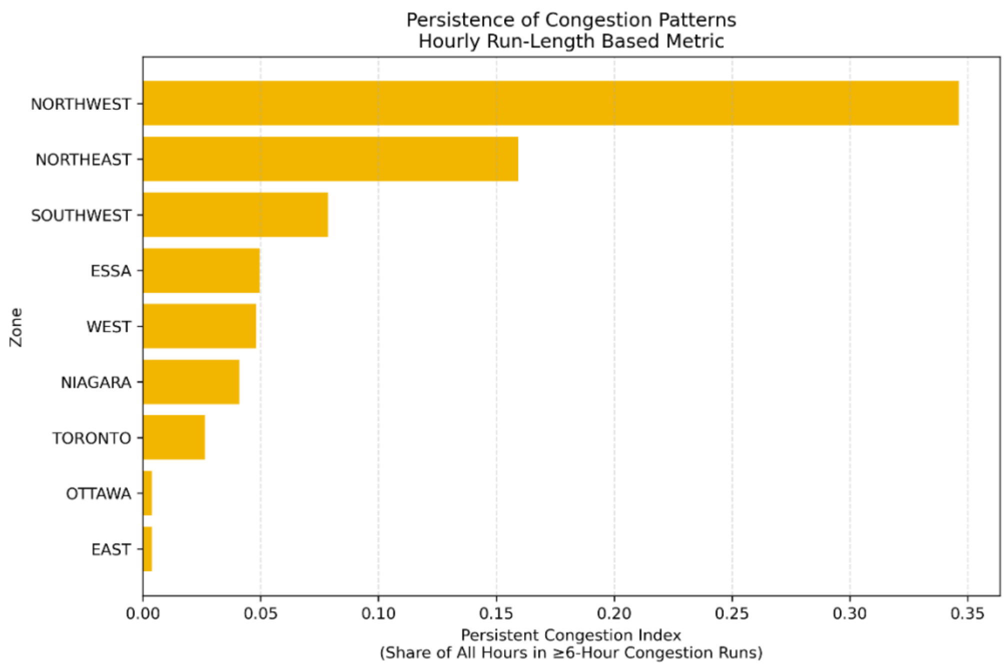
Figure 13 — Typical Congestion Magnitude by Sign of Congestion



Positive congestion dominates in Ottawa by a substantial margin, indicating that congestion in this zone is primarily driven by import constraints and limited local supply, resulting in consistently high positive price components. In contrast, most other zones exhibit a more balanced mix of positive and negative congestion values, reflecting varying system conditions across locations. Notably, zones such as West and East display larger negative congestion values, suggesting the presence of export constraints where excess local supply cannot be fully transmitted out of the region. This divergence in congestion direction highlights the structural differences in how transmission constraints affect each zone. Overall, the results illustrate a clear split between zones dominated by import-driven price pressures and those influenced more by export limitations.

Persistent congestion (6 or more consecutive hours) patterns are primarily concentrated in the Northwest and Northeast zones, where congestion episodes frequently extend over longer durations. All other zones exhibit relatively limited long-duration congestion, indicating that congestion in these areas is generally short-lived. A positive relationship between congestion frequency and persistence is evident, as illustrated in Figure 14 with Northwest, Northeast, and Southwest ranking relatively high across both dimensions.

Figure 14 — Persistence of Congestion Patterns



However, notable differences emerge across zones. For example, although the West experiences more frequent congestion than ESSA (see Figure 8), congestion events in ESSA tend to persist for longer consecutive periods. This suggests that while congestion in the West is more common, it is typically resolved more quickly, whereas ESSA experiences fewer but more sustained congestion episodes.

Ottawa presents a notable contrast across congestion metrics. While the zone exhibits one of the lowest levels of congestion persistence and frequency (see Figure 8 for frequency), it ranks among the highest in congestion magnitude (see Figure 10 for magnitude). This indicates that congestion in Ottawa tends to occur in relatively isolated episodes rather than extended runs. As a result, Ottawa's congestion profile is best characterized by low persistence but high impact, demonstrating that congestion severity and congestion duration do not necessarily move together.

Overall, these results highlight that congestion patterns differ not only in how often they occur, but also in how long they persist, reflecting underlying differences in transmission bottlenecks and system dynamics across zones.

Table 5 — Comparison of Penalty Prices in Pricing and Scheduling Algorithms[33]

Constraint	Scheduling Pass	Pricing Pass
Minimum/Maximum daily energy limit	$100,000/MW	$100,000/MW
Transmission Limit	$60,000/MW	Violation>2%: $8,000/MW Violation<=2%: $2300/MW
Import/Export Scheduling Limit	$40,000/MW	$6,000/MW
Downstream Over/Under Generation	$37,000/MW	N/A
Net Intertie Scheduling Limit	$35,000/MW	$500/MW
Under and Over Generation	Under-Generation: $30,000/MWh Over-Generation: -$30,000/MWh	Under-Generation: $4,000/MWh Over-Generation: -$3,000/MWh
Operating Reserve	Total Reserve: $6,000/MW 10-Minute Total: $10,000/MW 10-Minute Spinning: $12,000/MW	Total Reserve: $250/MW-$/350MW 10-Minute Total: $700/MW-$900/MW 10-Minute Spinning: $1300/MW-$1,500/MW
Area Operating Reserve Requirement	Max. Requirement: $60,000/MW Min. Requirement: $4,000/MW	Max. Requirement: $8,000/MW Min. Requirement: $350/MW

[33] Market Manual 4: Market Operations. Part 4.3: Operation of the Real-Time Market, Issue 4, December 2025.