Guide to the Renewed Market for Local Distribution Companies (LDCs)

April, 2025

Connecting Today.
Powering Tomorrow.

AN IESO MARKETPLACE TRAINING PUBLICATION

This training publication has been prepared by the IESO as a training aid for market participants. The content of this publication is presented for illustrative purposes and is not intended to represent actual market participant data or market outcomes. Users of this training publication are reminded that they remain responsible for complying with all of their obligations under the market rules and associated policies, standards and procedures relating to the subject matter of this training publication, even if such obligations are not specifically referred to herein. While every effort has been made to ensure that any extracts from the market rules or other documents in this training publication are accurate, users must be aware that the specific provisions of the market rules or particular document posted on the web site of Ontario's Independent Electricity System Operator shall govern.

Table of Contents

1. Introduction

Through its Market Renewal Program (MRP), the IESO is implementing a renewed electricity market to modernize Ontario's electricity markets, addressing existing inefficiencies, and enabling the IESO to realize significant operational improvements, reduce costs for market participants, and establish a robust market to integrate emerging and new technologies. The effects on Local Distribution Company (LDC) processes of these changes to the electricity market will largely be related to settlements.

This guide discusses the main features of the renewed market; provides information about the settlement price to be charged to LDCs for energy consumed from the IESO-controlled grid; explains how prices used in the calculation of prudential support obligations will be determined; and discusses settlement processes.

1.1 Learning Objectives

- Explain at a high level the primary elements of the renewed market
- Explain the components of the price which will be charged to non-dispatchable loads like LDCs
- Explain how prices used to calculate prudential support obligations will change
- Explain the effects of the renewed market on settlement

1.2 Related Knowledge

- Day-Ahead-Market Quick Take
- Guide to Prudentials at the IESO
- Guide to Prices in the Renewed Market

1.3 Related Resources

- Market Rules, Chapter 9: Settlements and Billing
- Market Rules, Chapter 9: Appendices – Settlements and Billing
- Market Manual 5.5: IESO-Administered Markets Settlement Amounts
- Market Manual 5.6: Non-Market Settlement Programs
- Market Manual 5.7: Settlement Process
- Market Manual 5.8: Settlement Invoicing
- Market Manual 5.10: Settlement Disagreements

2. The Renewed Market

The IESO-administered market (IAM) will be changing in several fundamental ways as a result of the implementation of the Market Renewal Program. These updates are needed to correct inefficient aspects of the current design and to prepare Ontario's electricity market to effectively accommodate new and emerging technologies.

The three primary design reforms are the Single Schedule Market (SSM), the Day-Ahead Market (DAM) and enhancements to the pre-dispatch scheduling and pricing processes. The chief impact of these for local distribution companies (LDCs) will be a change in the market price used for settlements.

2.1 Single Schedule Market (SSM)

The SSM is being implemented to correct several deficiencies of the current market. Under an SSM, both prices and schedules are determined by the same type of calculation. This calculation is referred to as "constrained" because it includes the effects of losses and system and resource limits in addition to the economics of offers and bids. Prices in a SSM are referred to as Locational Marginal Prices (LMPs) because they are derived for specific injection and withdrawal points on the grid.

Using the same type of calculation for both LMPs and schedules means there will be a close, apparent relationship between the two. These transparent price signals will enhance open competition, leading to more efficient outcomes. The introduction of a SSM will also establish the foundation for other important changes to the energy markets.

The current market, in contrast, has a two-schedule arrangement. In this system, dispatch schedules are determined using a constrained calculation, while prices are derived by an 'unconstrained' algorithm. As the name implies, the unconstrained algorithm largely ignores losses and physical limits. Because of this, there is a much greater chance that prices and dispatch will be misaligned under a two-schedule model than under an SSM. To counter some of the effects of this misalignment, payments in the form of congestion management settlement credits (CMSC) are required. These out-of-market payments account for the differences between what a dispatchable resource[1] paid (as a load) or was paid (as a supplier) through the market based on their actual constrained schedule, and what they should have paid or been paid based on their unconstrained schedule. These payments, however, are non-transparent, complex, and provide a possible gaming opportunity.

As non-dispatchable load (NDL) resources, LDCs won't be charged for their energy consumption using LMPs directly. They will continue to be charged a uniform price, but, as will be explained in Section 2.2, LMPs will underlie this price.

2.2 The Day-Ahead Market

[1] Dispatchable resources are ones which enter offers or bids into the market indicating how much energy they wish to inject or withdraw, when they wish to do so, and the price they are willing to be paid or to pay for the energy. They then receive dispatch instructions from the IESO indicating what their injections or withdrawals should be. LDCs are non-dispatchable resources which consume energy as needed without the requirement to enter bids or follow IESO dispatch instructions.

Having an accurate day-ahead demand and supply picture in relation to actual real-time operations supports better price and operational signals to the market and reduces the number of control actions required from a system operator such as the IESO. These out-of-market actions, although required for reliability, can result in increased consumer costs.

The current Day-Ahead Commitment Process (DACP) is not a DAM. It is a reliability mechanism which commits eligible generators and imports to be available in real-time in exchange for an out-of-market guarantee payment. This guarantee means they won't receive total revenue less than that implied by their day-ahead offer price and their schedule. Other Ontario-based resources participating in the DACP do not have such a guarantee.[2]

This differs a great deal from a DAM, where day-ahead schedules are financially binding – that is, a resource is settled for their day-ahead schedule at their day-ahead LMPs. Deviations from their day-ahead schedule in real-time operations are settled at real-time LMPs. This provides all dispatchable, self-scheduling and intermittent participants, and price-responsive loads[3] with operational and/or financial certainty day-ahead. At the same time, it allows them flexibility to adjust their operations post-DAM, if so desired.

Day-ahead price certainty, coupled with LMPs, will incent dispatchable resources to submit day-ahead dispatch data that reflects their expected real-time availability as much as possible. Increased day-ahead participation is also expected from resources with little reason to participate today, such as exports. This will further improve the day-ahead outlook of supply and demand, increasing the accuracy of the day-ahead planning process, and reducing consumer costs.

2.3 Pre-Dispatch Process Enhancements

Pre-dispatch is currently used to help the market and market participants transition from day-ahead scheduling to real-time operations. For example, if required, pre-dispatch can commit additional supply from eligible Ontario generators. These resources receive a real-time generator cost guarantee which, similar to the DACP guarantee, ensures they recover certain cost if these are not covered by market revenues. For other resources, pre-dispatch provides a look at how they may be dispatched in future hours, allowing them an opportunity to prepare.

Pre-dispatch will continue to fulfill the same basic function in the renewed market, but it will be enhanced. The current pre-dispatch determines schedules for each hour in its look-ahead period in isolation. Because each hour is looked at on its own, pre-dispatch does not determine commitments and advisory schedules in a way that necessarily optimizes costs or operations across the day.

Pre-dispatch in the renewed market will be updated to evaluate costs across its look-ahead period and to model resource physical limitations that span multiple hours, increasing its accuracy and efficiency. This will reduce costs to consumers by increasing transparency and competition within the commitment process.

---

[2] Imports from other jurisdictions have access to the Day-Ahead Intertie Offer Guarantee.

[3] Price responsive loads (PRLs) are a new resource type. PRLs will bid in the day-ahead market, and, if scheduled, secure a day-ahead LMP for their expected real-time consumption. They will not be required to bid in pre-dispatch or real-time, nor will they receive IESO dispatch instructions. Instead, they can consume in real-time as desired, like a non-dispatchable load. PRLs will be settled for their day-ahead schedule using their day-ahead LMP. If their real-time consumption deviates from their day-ahead schedule, the difference will be settled at their real-time LMP.

3. Non-Dispatchable Load Prices

3.1 Introduction

LDCs are classed as NDLs. The overall goal of NDL energy market settlement is to collect monies in keeping with the costs incurred to serve its demand. As such, the price charged to NDLs needs to reflect as closely as possible the cost of supply. With the renewed market, this means the price has to include costs created across both the day-ahead and real-time markets.

3.2 Non-dispatchable Load Settlement Price

As discussed above, Ontario-based resources are settled for their real-time operations using an unconstrained energy price which is uniform across the province. Unconstrained prices largely ignore the effects of system and resource limits and losses. Dispatchable resources are settled for their real-time operations using a price calculated every five minutes. NDLs such as LDCs are settled using the Hourly Ontario Energy Price (HOEP), which is the average of the twelve, five-minute real-time prices during the hour.

In the renewed market, resources scheduled to meet demand will be settled using LMPs through a two-settlement system. Here, LMPs determined by the day-ahead market will be used to settle a resource's day-ahead schedule. Real-time LMPs will be used to settle deviations between the resource's day-ahead schedule and their real-time actual operations.[4]

In the renewed market, as now, NDLs such as LDCs won't submit bids. Instead, the IESO will forecast their expected real-time demand for use in day-ahead, pre-dispatch and real-time processes. As such, NDLs won't directly participate in the two-settlement system. Instead, NDLs will continue to be settled for their real-time consumption using a uniform price. However, costs associated with serving their demand will be generated across both the day-ahead and real-time markets. To account for this, the price charged to NDLs will have two components: The Day-Ahead Ontario Zonal Price (DA-OZP) and the Load Forecast Deviation Adjustment (LFDA).

Day-Ahead Ontario Zonal Price (DA-OZP)

The DA-OZP will be the hourly, load-weighted average of the day-ahead LMPs calculated for each NDL[5]. Since LMPs reflect the cost of delivering energy to a specific location on the grid, this allows the total day-ahead cost of serving NDLs to be spread across all NDL market participants.

Since NDLs will be charged based on their real-time consumption, why are day-ahead prices used instead of real-time ones? It's because under a two-settlement system, most energy supply will be scheduled in the DAM. This means that the largest proportion of NDL costs to the market will be accumulated there.

[4] For more information on LMPs, please see the "Guide to Market Prices in the Renewed Market" available on the Marketplace Training pages of the IESO website.

[5] LMPs will be calculated for NDLs but will not be charged directly to each individual market participant.

Load Forecast Deviation Adjustment (LFDA)

NDL real-time consumption is forecast by the IESO for use in the DAM. Since most demand is NDL, this forecast is an essential input used by the DAM to decide how much supply to secure for the next day. Resources scheduled day-ahead are given financially binding schedules. If actual NDL real-time consumption is different than what was forecast, the market will have secured too little, or too much, supply day-ahead for which it will pay day-ahead prices. These real-time deviations from DAM schedules will be settled at real-time prices. As such, simply applying a day-ahead price to real-time consumption won't accurately reflect NDL costs to the market. Instead, the financial impact of forecast deviations must be accounted for. This will be done through calculating and adding the LFDA to the DA-OZP before applying the result to NDL real-time consumption.

The LFDA will be the hourly sum of two components (positive or negative), allocated across all NDLs; the:

- DAM Volume Factor Cost/Benefit, and the
- Real-Time Purchase Cost/Benefit.

The DAM Volume Factor Cost/Benefit represents the total hourly cost or benefit to all NDLs arising from DAM load forecast deviations as assessed in the DAM. It's calculated on an hourly basis as follows:

DAM-OZP x (DAM forecasted load – RT energy withdrawn + RT energy injected)

This determines the charge/credit at the day-ahead price for the difference between the energy consumption forecast day-ahead and what was actually withdrawn in real-time.

The Real-Time Purchase Cost/Benefit represents the total hourly cost or benefit to all NDLs resulting from DAM load forecast deviations as assessed in the real-time market. It's calculated for each five-minute interval of an hour for each NDL settlement point and then summed for the hour as follows:

Sum of [RT-LMP x (RT energy withdrawn – RT energy injected – DAM forecasted load)/12]

This determines the charge/credit at the real-time price for the difference between the energy actually withdrawn and the amount forecast day-ahead (for more information, see Appendix: NDL Settlement Price Calculation Example).

3.3 Energy Settlement Price If DAM Fails

The DAM is designed to operate every day of the year. There is a small possibility, however, that issues may arise that preclude DAM completion. If this occurs, NDLs including LDCs will be settled using the real-time Ontario Zonal Price. This will be calculated as the average of NDL real-time energy LMPs.

3.4 Public Price Reports

Several public price reports[6] will be available, including:

[6] Please see the Technical Reference Materials page of the IESO website for more information.

Report	Description
Day-Ahead Hourly Ontario Zonal Energy Price Report	This public report will show the day-ahead market Ontario Zonal Energy Price, as well as the applicable Energy Loss Price and Energy Congestion Price components. It will usually be published at 13:15 EPT following completion of the DAM but may be published as late as 15:15EPT if the DAM is delayed.
Pre-dispatch Hourly Ontario Zonal Energy Price Report	This public report will show pre-dispatch market Ontario Zonal Energy Price, as well as the applicable Energy Loss Price and Energy Congestion Price components. It will be published hourly after completion of the pre-dispatch run. Two reports will be issued for pre-dispatch runs with outlook horizons longer than 24 hours – one for each day.
Real-time 5-min Ontario Zonal Energy Price Report	This public report will show the real-time market Ontario Zonal Energy Price, as well as the applicable Energy Loss Price and Energy Congestion Price components. It will be published every 5-minutes
Customer Energy Summary Report	This report is provided to support a better understanding of a consumer's electricity use and to simplify the settlements process. This report provides a synopsis of relevant market data in an easy-to-use format.

4. Prudential Support Obligation Calculation Changes

The prudential support process is used in the current market to reduce the risk of default by net debtors. A net debtor is a market participant, such as an LDC, whose energy withdrawals result in a market cost which exceeds the value of their injections. Under the prudential support process, net debtors are required to provide and maintain sufficient financial surety to cover an expected potential debt amount. This surety is referred to as a prudential support obligation (PSO). A PSO is a calculated amount of money provided by a market participant that the IESO holds and can call upon if the market participant fails to pay their invoice within the allowable time.

With the renewed market, the purpose and process for establishing and maintaining a PSO will remain largely the same with one main difference: The price basis for determining the PSO will change since HOEP is being replaced by the DA-OZP plus the LFDA.

4.1 PSO Calculations Overview

PSOs for LDCs are determined considering the following[7]:

- Maximum net exposure (MNE) – This is the IESO's estimate of the net amount a market participant could owe to the market. MNE is the sum of the default protection amount and the greater of the IESO-determined minimum trading limit or the self-assessed trading limit provided by the market participant. A trading limit is the maximum amount of market debt that a market participant can incur. A trading limit protects the market participant from potential market over-exposure.
- Default protection amount – This is the IESO's estimate of the additional debt a market participant could accumulate from the time they defaulted on a payment to the time they could be removed from the market.
- Self-assessed trading limit – A market participant's estimate of what their trading limit should be. This involves determining the expected cost of their likely purchases from the market.
- Minimum trading limit – An IESO-determined trading limit which assumes a minimum of market activity.
- Credit information – The IESO may reduce a prudential support obligation based on a market participant's credit rating from a bond rating agency which is on the IESO-approved list.
- Payment history – A reduction to the PSO is allowed if the market participant has demonstrated a good payment history within the IESO-administered markets.

---

[7] For more information about prudential calculations and processes, please see Market Manual 5.4: Prudential Support and Market Rules, Chapter 2: Participation, section 5 – Prudential Requirements and Appendix 2.3. For information about current prudential calculations, please see marketplace training guide Guide to Prudentials at the IESO.

.

- Reductions due to the provision of prudential support by an LDC's customers – LDCs who have selected the margin call option[8], or who qualify as a small distributor[9], and have supplied an affidavit and proof regarding prudential collections from their customers, can have their MNE reduced by 60% of the qualifying prudential support that the LDC has collected. This reduction is applied before other PSO deductions are factored in.

Calculation of a PSO for a market participant that selected the margin call option involves a few steps. The IESO:

- Assesses a minimum trading limit and default protection amount;
- Reviews this minimum trading limit against the self-assessed trading limit submitted by the market participant and selects the greater of the two;
- Establishes the market participant's maximum net exposure as the sum of the selected trading limit and the default protection amount;
- Applies reductions to the MNE as appropriate; and
- Calculates the market participant's PSO as being equal to their maximum net exposure, as reduced if applicable.

4.2 Regulated Price Plan Class

Currently, the IESO assumes that an LDC is either a Class A or Class B participant for its entire load when assessing the Global Adjustment charge to be factored into the MNE calculation. In the renewed market, an LDC will be able to submit their Class A/Class B split, which will inform the GA estimate.

4.3 PSO Calculations Price Basis

Currently, the IESO uses the Ontario Energy Board's electricity price forecasts as the basis for the energy prices used to calculate the minimum trading limit and default protection amount. After implementation of the renewed market:

- The higher of the DAM and the average real-time OZPs for each hour over the last three years will be stacked from lowest to highest;
- The price corresponding to a set percentile rank within the stack will then be used.

For the interim period before three years of LMPs are available, a mix of HOEP and OZP prices will be used.

---

[8] Market participants can select a 'margin call' or 'no margin call' option. The margin call option results in the requirement to post a lower PSO since the IESO will notify a market participant if their actual exposure (i.e., the amount determined to be owed currently to the market) reaches or exceeds their trading limit requiring them to post additional support. Market participant's registering for the no-margin call option are instead required to post substantially higher PSO amounts up front. For example, they are not eligible for PSO reductions and 70 days of market activity are currently used to calculate their MNE.

[9] A 'small distributor' is a distributor with a projected annual energy consumption that is not more than 0.25% of the projected total system energy.

5. Settlement

5.1 IESO Settlement Processes

Much of the existing settlement process will remain the same after implementation of the renewed market.

The renewed market won't introduce any change to metering requirements or the metering registry information currently established as part of the process for registering a meter. Measurement quantities specific to a resource and its associated delivery point will continue to be received by the IESO's Meter Data Management System (MDMS) and processed as per current practices, including validation, estimation, editing and totalization.

Similar to the current practice, every delivery point within Ontario will be associated with a single, authorized metered market participant (MMP). Any physical transaction settlement amounts associated with such delivery points will be allocated to the registered metered market participant (RMP).

The overall structure and timing of the settlement statement and invoicing processes will remain the same. However, the contents of settlement statements will change to accommodate the new market:

- Preliminary settlement statements using settlement-ready meter data will continue to be available 10 business days after each trade date. For any one trade date, preliminary settlement statements will contain both the first and second settlement – that is, settlement of both the day-ahead and real-time markets.
- Final settlement statements will continue to be issued ten business days after the preliminary settlement statement to which they relate. They will similarly reflect both day-ahead and real-time settlement.
- Recalculated settlement statements (RCSS) will continue to be produced if needed as per current timelines.
- Notices of disagreement (NODs) will continue to be a method for MMPs to submit concerns they may have with aspects of settlement statements.[10] The period for NOD submission will remain 6 business days after issuance of the physical market settlement statement which is the subject of the NOD.
- Invoices will continue to be issued ten business days after the last trade day of the month to which they relate. Load MMPs will continue to have two business days to pay their invoice.

5.2 Charge Types

Charge types are used to identify charges and payments on settlement statements. A number of existing charge types will be fully retired; e.g., congestion management settlement credit and Day-Ahead Commitment Process-related charge types. A large number will be the same, some will be entirely new, while a smaller number will be replaced with new charge types.

---

[10] Other than new items or adjustments contained on a final recalculated settlement statement. For more information, please see Market Manual 5.10: Settlements Disagreements, section 2.1.

The IESO has created a transitional informational spreadsheet on settlement charges for LDCs. This explains what the charge type relates to (commodity charge, Wholesale Market Services Charge, Wholesale Transmission Charges, etc.), the current charge type number and name, the related OEB Retail Variance Settlement Account, the impact of MRP on the charge type, as well as the replacement charge type number and name, where appropriate. The 'MRP Mapping Summary of Charge Types and Variances for LDC's' is available upon request by emailing market.renewal@ieso.ca. Please also see the Charge Types and Equations document.

5.3 Settlement of IESO Contracted Generation

Local Distribution Companies (LDCs) have a role in the settlement of generators contracted with the IESO under several programs, including:

- Feed-In Tariff (FIT);
- Hydroelectric Contract Initiative (HCI);
- Hydroelectric Standard Offer Program (HESOP);
- Large Renewable Procurement (LRP); and
- Renewable Energy Standard Offer Program (RESOP).

These contracts contain references to the Hourly Ontario Electricity Price (HOEP), which will no longer be available upon implementation of the renewed market. The definition of HOEP under these contracts provides for replacement pricing. The IESO plans to align the HOEP replacement price under these contracts with the replacement price for HOEP identified by the Ontario Energy Board's (OEB's) Retail Settlement Code (RSC).

Once MRP has been implemented, LDCs will need to implement the replacement price to account for HOEP being eliminated. The replacement price for HOEP will not affect the contract price.

On March 27, 2025 the OEB issued a final Notice of Amendments to the RSC. This indicated that upon the effective date of the renewed market, the code will be updated to replace the HOEP with the sum of the DA-OZP and the LFDA (described earlier in Section 3: Non-Dispatchable Load (NDL) Prices). It was indicated in the notice that this will be called the Ontario Electricity Market Price. If the IESO declares a failure or suspension of the Day-Ahead Market, the hourly price to be used for the applicable settlement hours will be the Real-Time Market Ontario Zonal Price.

No amendments to the LDC-settled contracts will be required. The IESO notified affected generators on April 2, 2025 regarding the replacement of the HOEP.

If you have any question, please contact mr.contractmanagement@ieso.ca.

5.4 Global Adjustment Settlement

The Global Adjustment (GA) is a charge applied to all Ontario electricity consumers which is intended to cover the costs of:

- Maintaining/refurbishing existing generation resources,
- Delivering conservation programs,
- Building new electricity infrastructure, and
- The difference between market revenues and contracted/regulated generation rates.

Implementation of the renewed market will not affect the process for LDC GA settlement. The IESO will continue to publish all of the current information on the current timelines to support LDC settlements.

For more information, please see the Global Adjustment (GA) (ieso.ca) page on the IESO website and the Guide to Settlement Claims and Data Submissions via Online IESO.

5.5 Regulated Price Plan (RPP) Variance Settlement

The basic process for Regulated Price Plan (RPP) customer settlement will be unaffected by MRP implementation. Within 4 business days after the end of a month, each LDC will need to submit their preliminary Regulated Price Plan claims to the IESO via the portal. These will indicate the difference between the amount charged by the LDC to their Regulated Price Plan customers for energy versus the cost paid by the LDC to the IESO for that energy.

To create this entry, LDCs will need to know market prices. As discussed above, market prices for non-dispatchable loads such as LDCs include both the Day-Ahead Ontario Zonal Price (DA-OZP) and the Load Forecast Deviation Adjustment (LFDA).[11] The DA-OZP is published each day for the next day and is normally final. The LFDA, however, may be adjusted subsequent to its initial posting because, for example, as a load-weighted average cost it is affected by non-dispatchable load meter readings which can take time to finalize.

To help LDCs determine their claim submissions for the previous month, a new report called the 'Monthly Load Forecast Deviation Adjustment Report' will be provided. This report will show estimated LFDA values for all hours where a Preliminary Settlement Statement has not yet been issued. These can then be applied to published DA-OZP prices and the sum used to value the energy purchased from the IESO-administered markets by LDCs to serve their RPP customers. Since the LFDA's in this report will be an estimate, there may be differences between the values shown and the actual LFDAs. LDCs will be able to true-up the difference between the estimated and final LFDA values as part of later month's submissions.

6. Additional Resources

Additional resources to be found on the Settlement Reference Materials (ieso.ca) webpage include:

- MRP Mapping Summary of Charge Types and Variance Accounts for LDCs, and
- Sample Settlement Statements and Data Files.

[11] See section 2.2 above.

APPENDIX: NDL Settlement Price Calculation Examples

The following are simplified examples of DA-OZP and LFDA calculations.

a) **Day-Ahead Ontario Zonal Price**

As stated above, the DA-OZP will be the load-weighted average of all DAM LMPs calculated for NDLs in Ontario. For example, assume there are only three NDLs across the province with the following DAM forecasted consumption:

NDL A = 5,000 MW

NDL B = 2,000 MW

NDL C = 3,000 MW

So, the total forecast is 10,000 MW.

Assume the following DAM LMP's for each NDL:

NDL A = $40/MWh

NDL B = $50/MWh

NDL C = $30/MWh

As mentioned earlier, although LMPs are calculated for NDLs, they are not directly applied for settlement. Instead, they will be used to arrive at an average price which will serve as the basis of NDL settlement.

In this example, the DA-OZP would be:

DA-OZP = ((5,000/10,000) x 40) +((2,000/10,000) x 50) +((3,000/10,000) x 30))

= 20 + 10 + 9

= $39.00/MWh

b) **Load Forecast Deviation Adjustment (LFDA)**

As stated above, the LFDA is a price adjustment applied to the DA-OZP to reflect the two-settlement nature of the renewed market. Let's look at an example.

Continuing from above, the DAM-OZP was $39/MWh. Let's assume:

- The real-time LMPs for the three resources were $30, $55 and $31 in all intervals, and
- None of the resources injected energy in real-time (so the term RT energy injected = 0).

NDL	DAM- OZP ($/MWh)	RT-LMP ($/MWh)	DAM Forecast (MW)	Actual Consumption (MW)	Real-Time Purchase Cost/Benefit	DAM Volume Factor Cost/Benefit
NDL 1	$39	$30	5,000	4,750	-$7,500	$9,750
NDL 2	$39	$55	2,000	2,100	$5,500	-$3,900
NDL 3	$39	$31	3,000	3,225	$6,975	-$8,775
TOTAL			**10,000**	**10,075**	**$4,975**	**-$2,925**

For NDL 1:

- The Real-Time Purchase Cost/Benefit is

Sum of [RT-LMP x (RT energy withdrawn – RT energy injected – DAM forecasted load)/12]

= Sum of [$30 x (4,750 – 5,000)/12]

= Sum of [$30 x (-250) /12]

= -$625 x 12 (since the LMP was the same for each interval, and there are 12 intervals in the hour)

= -$7,500

- The DAM Volume Factor Cost/Benefit is

DAM-OZP x (DAM forecasted load – RT energy withdrawn + RT energy injected)

= $39 x (5,000 – 4,750)

= $39 x 250

= $9,750

If we do the same calculations for the other two NDLs, the total Real-Time Purchase Cost/Benefit is $4,975, the total DAM Volume Factor Cost/Benefit is -$2,925, and the total real-time demand was 10,075 MW. So, in this example,

LFDA = (Real-Time Purchase Cost/Benefit + DAM Volume Factor Cost/Benefit) / RT energy withdrawn

= ($4,975 + (- $2,925)) / 10,075

= $0.20/MWh

With this LFDA, the total price used to settle NDLs in this hour will be:

DAM-OZP + LFDA = $39/MWh + $0.20/MWh = $39.20/MWh

Charging this rate for real-time consumption ensures that NDLs are settled appropriately for their market costs. To illustrate that, let’s look at the above example in a different way:

- Forecast demand for NDL 1 was 5,000 MW. With a DA-OZP of $39, that would result in a total charge of $195,000. However, NDL 1’s real-time consumption was actually 250 MW less than that. In keeping with a two-settlement system, the difference is accounted for at the real-time price. With a $30 real-time LMP, this results in a charge reduction of 250 MW x $30, or $7,500.

- NDL 2's real-time consumption was higher than forecast by 100 MW. At a real-time LMP of $55, an additional $5,500 (i.e., 100 MW x $55) is required over and above what would have been collected based on the DA-OZP and the day-ahead forecasted quantity.
- Lastly, NDL 3's real-time consumption was 225 MW higher than forecast, and its LMP was $31. This results in a needed adjustment of 225 MW x $31, or $6,975.

NDL	DAM DA-OZP	DAM Forecast (MW)	DAM Cost	Actual Consumption (MW)	Difference DAM to RT (MW)	Real-Time LMP	Market Revenue Required Change
NDL 1	$39	5,000	$195,000	4,750	-250	$32	-$7,500
NDL 2	$39	2,000	$78,000	2,100	100	$55	$5,500
NDL 3	$39	3,000	$117,000	3,225	225	$31	$6,975
TOTAL		10,000	$390,000	10,075			$4,975

So overall, the total revenue required to cover these NDLs costs to the market is $394,975 (i.e., the DAM Cost of $390,000 plus the Market Revenue Required Change of $4,975). If the IESO settled the NDLs at the DA-OZP of $39 for their real-time consumption of 10,075 MW, they would only be charged $392,925. The DA-OZP has to be adjusted to ensure the correct market charges. Given real-time consumption, the required price is $394,975 / 10,075 MW = $39.20/MWh. Since the DA-OZP was $39.00, this makes the LFDA, as in the earlier calculations, 0.20.

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

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

ieso.ca

@IESO_Tweets
linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.