Locational Pricing Study

The attached paper was presented to the Market Pricing Working Group, outlining the scope of the locational pricing study. It has been updated to include our findings in Appendix A.

The current LMP study will use historical shadow prices from the constrained algorithm to provide some insight into what locational prices might look like in Ontario. It is important to remember that the results will be limited in their value as the current shadow prices are not used for settlement in Ontario, and as such, have very little, if any impact on participant behaviour. We are confident that at least some participants would adjust their behaviour if exposed to these prices rather than an unconstrained Ontario price. The IESO will be providing a qualitative analysis of the impacts of participant behaviour adjustments.

The study will use data beginning in the summer of 2004 after the introduction of MIO to the constrained algorithm. The IESO will provide monthly average prices as well as on-peak and off-peak average prices for several different types of locational price models described below. The raw data for the study will also be available (off line via CD) to any participants who request it.

Locational Pricing – Possible Models

The study will examine several possible locational price schemes starting with the highest level of granularity, nodal pricing, and moving to less precise definitions of location, or zones. It is possible to split Ontario into larger or smaller zones. Typically zones are created based upon an electrical model of the province, focusing on the major electrical interfaces as the dividing points between zones. Ideally, all nodes within a zone will experience similar nodal prices.

Depending on the frequency of congestion on the major interfaces, it is also possible that multiple electrical zones may experience similar prices the majority of the time. If this is the case, these smaller zones could be combined into a larger zone. For the purposes of this study, the IESO will examine several zonal pricing models, including one zone, two zones, ten zones and some smaller number of zones based on the similarity of prices from the ten zone model.

It should be noted that it is possible to produce mixed locational prices; for example, the use of nodal prices for dispatchable participants, and zonal pricing for non-dispatchable participants. These decisions do not impact the parameters for the current study.

The following text describes some of the characteristics of different locational pricing methodologies and models in more detail.

Nodal Methodology

Nodal pricing can be considered the "truest" form of locational marginal pricing, where prices are calculated for each node – consumer withdrawal or generation injection point – on the power system. Each consumer pays the price at their node and each generator is paid the price at their node. This is the most efficient methodology possible as participants get the most accurate price signal for their location and there is no need for constraint payments[1] or uplift charge for line losses. In this case, dispatchable facilities are only dispatched when they are "in the money" i.e. the nodal price is above the offer price from generators or below the bid price for consumers. This methodology is however complex, especially for consumers who may only be infrequently interested in their nodal prices such as at times when they are evaluating their forward contracting options. For such participants, the simplification brought about by zonal prices or even trading reference bus pricing may be preferred. The nodal methodology also raises concerns about local market power during times of congestion, and about the liquidity of available trading opportunities at any particular nodal location.

Zonal Methodology

The region is divided into zones, usually based on electrical system characteristics such that there is little transmission congestion within a zone. The zone boundaries could also be determined by grouping nodes with similar prices, which should create the same result, as the nodal prices only materially vary when transmission congestion is present. Settlement prices are calculated[2] for each zone and all consumers within that zone pay that same price and all generators within that zone are paid that price. The use of zones may require some form of side payment for dispatchable facilities that are "constrained" such that they are dispatched when not "in the money" i.e. zonal price is below offer for generators or above bid for consumers. The quantity of side payments will depend on how close the zone price is to the nodal prices within it – better price convergence means smaller side payments – and this is determined by the level of congestion and to a lesser extent by the losses within the zone. However, because it is not possible to completely eliminate intra-zonal congestion – especially that caused by contingencies on the transmission system – there will likely be a need for some form of side payment scheme. This methodology could be much simpler to implement from an IT systems perspective when compared with the full nodal methodology although this would depend on the number of zones.

Combination of Zonal and Nodal Methodologies

It is possible to combine these two concepts in a locational pricing methodology and several other electricity markets currently do this. The most commonly used combination is to use nodal for generators and zonal for consumers. This allows the efficiency gains of the nodal

[1] There may still be occasions when ISO operators are required to dispatch facilities out of merit for reliability reasons and some form of compensation would likely be needed for this. This is handled via a production cost guarantee in several other jurisdictions.

[2] There are different ways to calculate the zone prices. One would be to use an average of the nodal prices within the zone. Another method is to use an unconstrained model of the zone to calculate price as we currently do for the market clearing price in Ontario (a one-zone model).

methodology for generation, which are the only dispatchable facilities in most other jurisdictions. On the consumption and therefore non-dispatchable side, the simpler zonal methodology is used. The amount of efficiency loss caused by using zonal for non-dispatchable participants is dependent on the zone boundaries – a zonal methodology where there is very little price difference between the nodes within a zone is more efficient. In Ontario, the question of how to treat dispatchable load would have to be addressed in a zonal/nodal combination methodology – will they be charged the nodal price, paralleling the fact that generation is paid the nodal price, or would they be charged the zonal price, as would be all other consumers in the zone. Similarly, the treatment of non-dispatchable generation would also have to be addressed.

Discussion of Possible Models for Ontario

Several possible zonal models exist for Ontario, depending on the criteria used to determine the zone boundaries. As mentioned earlier, a ten-zone model of the province has existed for many years based on significant transmission interfaces. However, the historical nodal price data indicates that several of these zones have very similar average prices, which might suggest that a simpler model with fewer zones will do. Depending on how liberally one applies similar price criteria for zone definition, this could result in as few as two zones – one for the North or Northwest and another for the remainder of the province - or even one single zone for all of Ontario. These different zonal models could employ a true zonal methodology in which the zonal price applies to all market participants or could be combined with a nodal methodology such that all dispatchable facilities within a zone are settled based on their nodal prices and all non-dispatchable facilities are settled based on the zonal price. However, if a zonal methodology is applied to dispatchable facilities, then some type of constraint payment scheme will likely be required. This is especially true if the one-zone model is used, as one can expect constraint payment levels similar to that of our current uniform pricing model. The historical data analysis presented here does not provide estimates of the constraint payments that would be required if dispatchable facilities are settled based on zonal prices, but the need for such payments can be roughly estimated by examining the degree of variability of the nodal prices in the zone at any particular time.

Appendix A – Data Analysis and Initial Conclusions

Summary

Our data examination to date leaves us with the conclusion that this locational pricing study was a good starting point but significantly more work needs to be done for a complete analysis. Simply analyzing shadow prices does not present an adequate starting point from which to make locational pricing policy decisions. Our analysis identified that if locational pricing had existed in the past under exactly the same market circumstances, the nodal prices would be different from the historical shadow prices. Therefore using historical shadow prices as a basis for decision making would be short-sighted. But the analysis does provide useful information. For example, we do believe that the shadow prices do provide a directional signal for most locational prices and under any locational pricing model, energy prices for the majority of participants will likely be higher than the unconstrained Ontario price (HOEP). But there will be mitigating factors. Import/export behaviour will change significantly under any locational pricing model, reducing any expected change in price. Also, price differences between North-East and Southern Ontario will likely be smaller than suggested by historical shadow prices. If historical congestion on East-West tie continues, then there will be lower prices in Northwest Ontario, but this condition is very sensitive to other factors such as fuel prices, water conditions, and generator availability and as such may significantly impact just how much lower the prices will be compared with the rest of the Province in the future. Any locational pricing policy decisions will require a better understanding of all the locational price impacts. We believe that this can be achieved by further analyzing and modifying historical data or pursuing modelling capability to reflect expected behavioural and/or mechanical differences that we have exposed through this study.

Study Details

The study was completed by extracting and examining the historical 5-minutes prices for 118 nodes (shadow prices) from July 1 2004 through August 31 2006. Shadow prices are the marginal cost of energy at an injection or withdrawal point on the grid. The marginal cost is the cost to satisfy one additional increment of demand at a node over and above actual system-wide demand. This calculation has to respect the effects of transmission congestion and losses, and it does this by calculating the cost of energy assuming that all of the demand in the system was at a single point, (called the "reference node") and then works out shadow prices by adding the cost of losses and transmission congestion between each node and the reference node. The Richview bus is used as the reference node, and was chosen because it is close to the largest consumption point in the Province (Toronto). However, any node could be used as the reference node and the shadow prices would not change; only the loss and congestion factors would be different. The formula is described as follows:

Shadow Price	=	System Marginal Cost of Energy at Reference Node (Richview)	+	Marginal Cost of Losses Incurred for the Next MW at the Node Relative to the Reference Node	+	Marginal Cost of Transmission Congestion for the Next MW at the Node to the Reference Node

As a starting point for the study, we looked at the differences between the current settlement pricing methodology (unconstrained algorithm which calculates the Ontario price, HOEP) and the shadow pricing methodology (constrained algorithm). In order to compare and contrast, both algorithms were reviewed and the following was revealed:

- differences from the unconstrained algorithm were much more significant than simple accounting for losses and congestion, and
- direct comparison of constrained shadow prices to any future locational prices is problematic due to market factors.

Our analysis found that the two algorithms (unconstrained and constrained) differ in their handling of primary demand, ramp rates of dispatchable facilities, and generator characteristics which at times can collectively explain a significant portion of the pricing differences in the algorithms. In terms of primary demand, the unconstrained algorithm is run at the end of the interval and uses actual primary demand. In contrast the constrained algorithm runs before the interval to determine the unit dispatch and therefore must use forecast demand. The unconstrained algorithm optimizes over one interval assuming a 12 times ramp rate (myopic optimization). Conversely the constrained algorithm's optimization includes several intervals over the next hour and uses a 1 times ramp rate (multi-interval optimization). Generators loading points are handled differently in the two algorithms. The unconstrained algorithm ignores the minimum loading points while the constrained algorithm respects minimum loading points. Each of these calculation differences impacts the resulting prices in the respective algorithm (HOEP versus shadow price).

When attempting to use the constrained algorithm shadow prices as a basis for estimating any future pricing, we found that it was not a simple exercise to due several factors. First, the current treatment of losses is too simplistic for locational pricing, and often yields inappropriate shadow prices. The impact on Northeast shadow prices from the use of static loss factors is of specific concern as static loss factors make these prices appear too low during off-peak periods when the predominant flow on the transmission system connecting the Northeast to the South reverses from that of on-peak periods.

Furthermore, we expect participants to react differently with settlement based nodal prices. Specifically we expect there to be bidding behaviour changes. We believe that if offer prices were likely to define payments, there would be changes in bidding – mostly likely resulting in a higher or lower nodal price for some nodes than what is currently reflected in historical shadow prices. Changes in import/export behaviours and local market power changes would also alter the nodal prices. Finally sensitivity to external factors such as fuel prices, water conditions and generator availability would be reflected in nodal prices which currently are not reflected in the historical shadow prices.

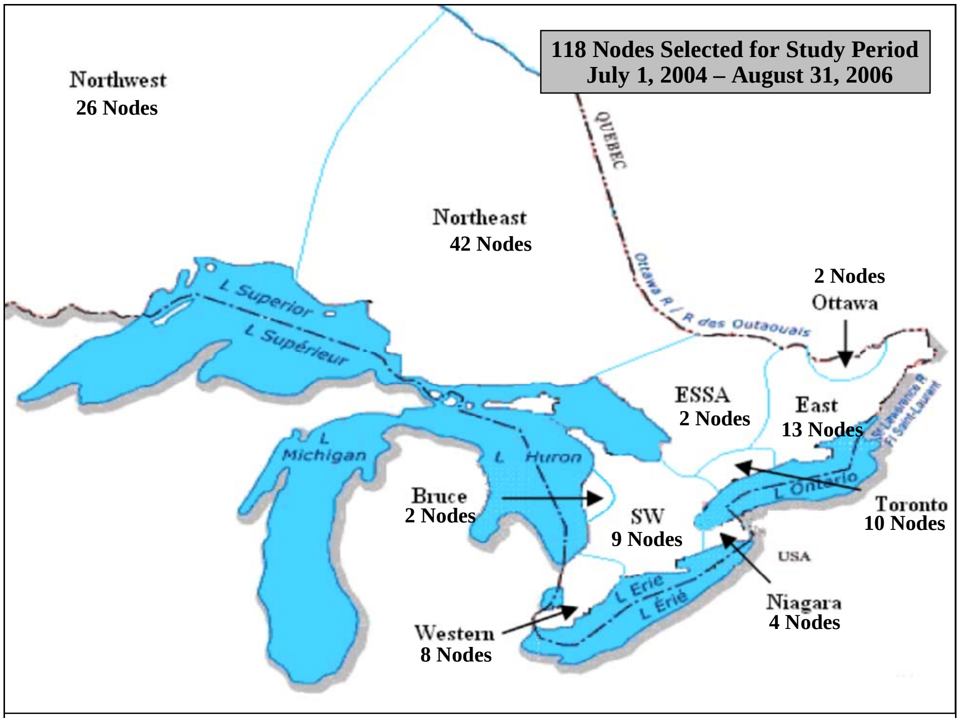
Our analysis of the two algorithms leads us to believe that while regional nodal price differences will exist, they would not be nearly as dramatic as suggested by simply comparing historical shadow prices to the historical HOEP. More importantly, average historical shadow prices in no way reflect either future pricing or pricing that would have existed if prices were based on nodal prices.

Data Analysis

The IESO publishes shadow prices for approximately 250 nodes, or electrical locations throughout Ontario. For study purposes, this number was reduced to 118, removing duplication that results from large facilities that have multiple nodes. Shadow prices exceeding $2000 were set to $2000 to simulate the maximum market clearing price allowed by the Market Rules.

Nodal Methodology

As discussed, nodal pricing can be considered the "truest" form of locational marginal pricing. In a nodal pricing model, each generation injection or consumer withdrawal point has a unique price calculated. These nodal prices represent the marginal cost of energy at a reference location, as well as the cost of losses and congestion at that node. The constrained algorithm produces nodal shadow prices every 5 minutes as part of the Dispatch Scheduling Optimization. Analysis of shadow prices was performed using hourly averages of these 5-minute prices. Due to the volume of data, this information was made available via CD to Market Pricing Working Group members who requested it.



Zonal Methodology

Historically, Ontario has been divided into 10 electrical zones, defined by electrical characteristics and major transmission interfaces. In markets employing zonal pricing, zones are generally defined by grouping nodes that are subject to similar congestion. Analysis of Ontario's historical shadow prices (see the table below) shows that prices are fairly consistent within and between the 8 southern zones. Shadow prices in the 2 northern zones show the most variability. The similarity of the prices in the 8 southern zones suggests that the number of zones could potentially be reduced.

Variability of Prices within Zones ($/MWh)

Zone	Average St. Dev
Bruce	0.30
Niagara	0.83
Toronto	1.07
South-West	2.09
Ottawa	2.17
West	3.32
Essa	3.65
East	4.25
North-East	11.20
North-West	15.48
8 South zones combined	3.97
All 118 nodes	20.68

As discussed earlier, the variation in nodal prices within a zone results in part due to differences in congestion and losses. Further examination of the data shows that much of the variation within the southern zones is due to losses, rather than congestion. To quantify the relative effects of each, shadow prices were adjusted using historical static loss factors. The table below represents the variability of prices within zones due to congestion only.

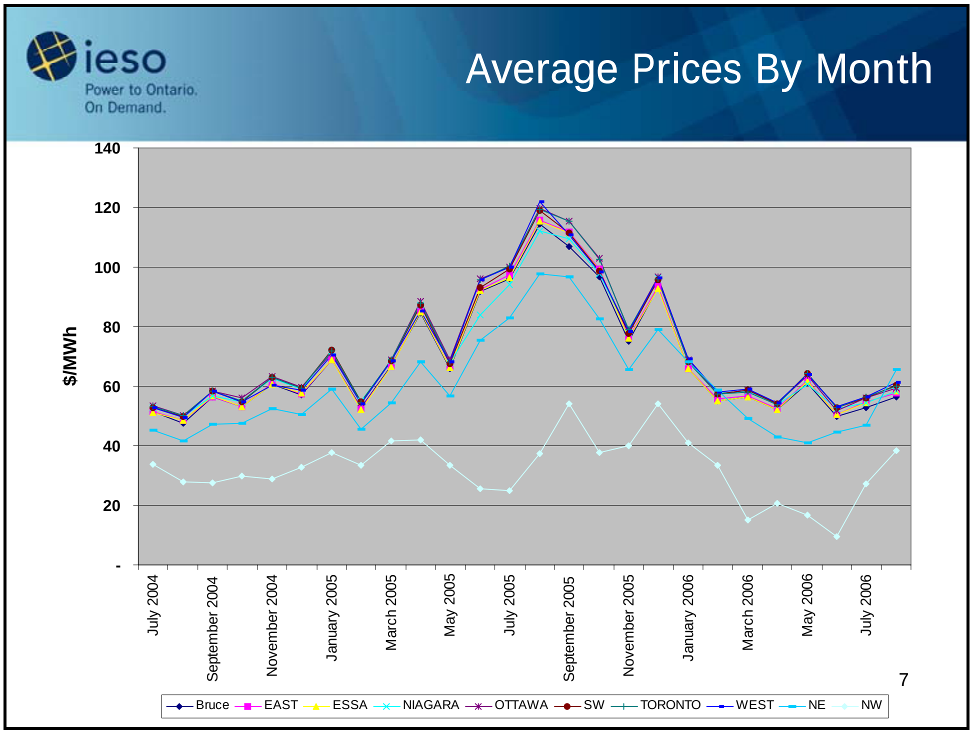
Variability of Prices within Zones due to congestion ($/MWh – Losses removed)

Zone	Average St. Dev
Essa	0.16
Bruce	0.28
Toronto	0.56
Niagara	0.58
Ottawa	1.17
South-West	1.24
East	1.37
West	1.48
North-East	8.73
North-West	14.37
8 South zones combined	2.28
All 118 nodes	15.2

Variability in Northern zones suggests intra-zonal congestion. Further analysis required.

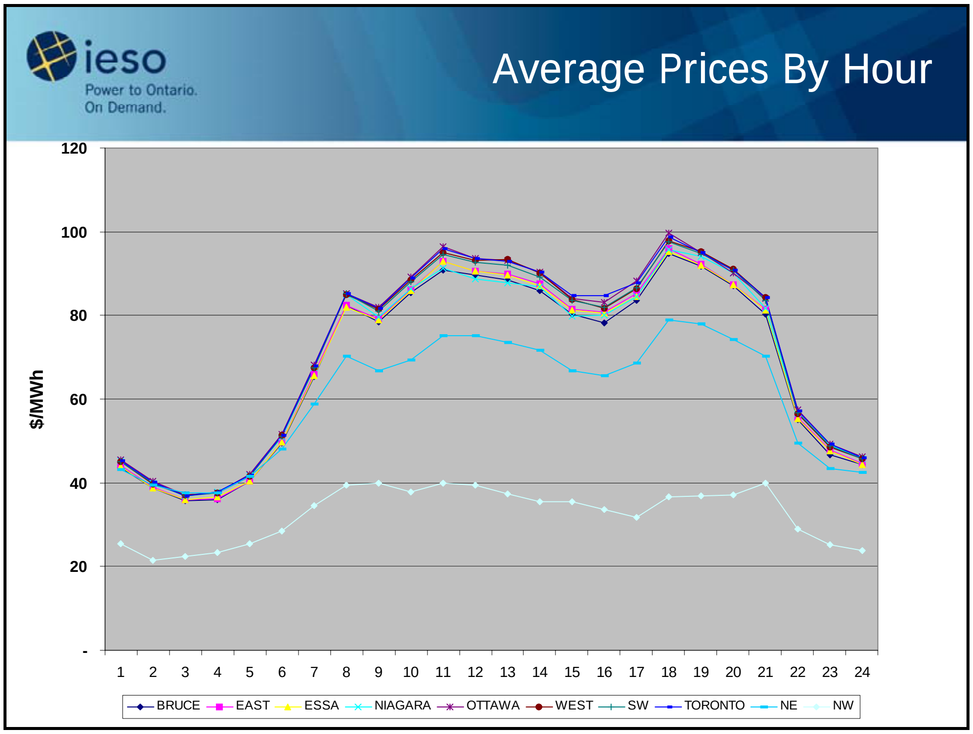
Average monthly zonal prices:

By grouping shadow prices into the existing 10 electrical zones, price differences become more readily apparent. The graph below represents the arithmetic average of the shadow prices within the 10 zones. The shadow prices are relatively uniform for the 8 southern zones, with the North-East and North-West zones showing consistently lower prices.

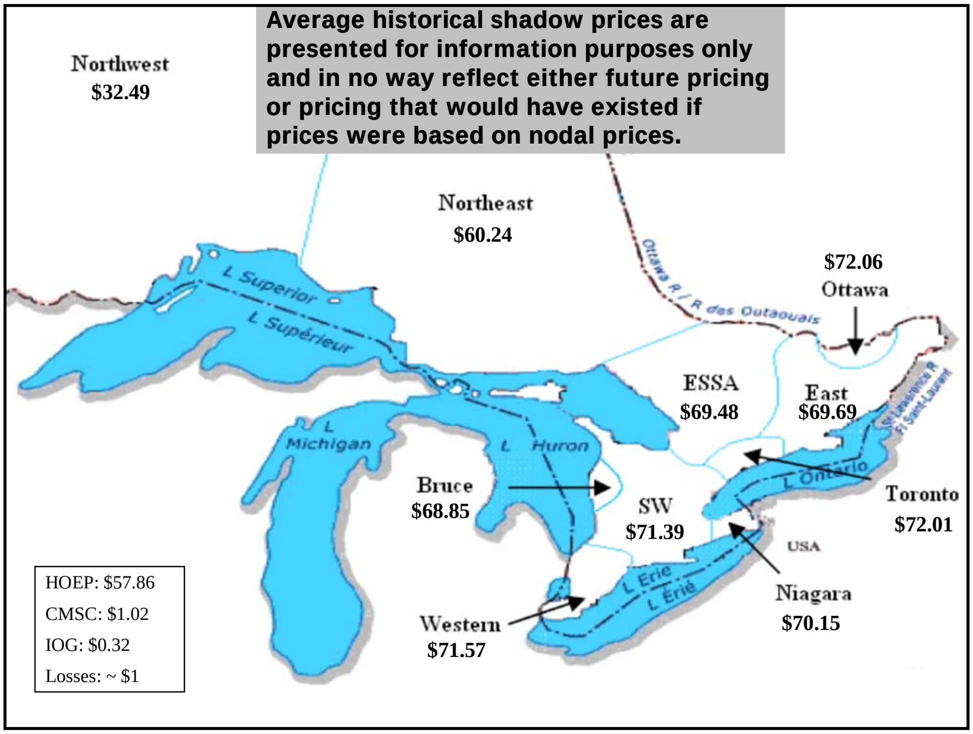


Average hourly zonal prices:

Examination of hourly data shows that prices for the southern zones are fairly consistent throughout the day. North-Western zonal prices are consistently lower. North-Eastern prices follow a similar pattern to southern prices, but diverge during on-peak hours.



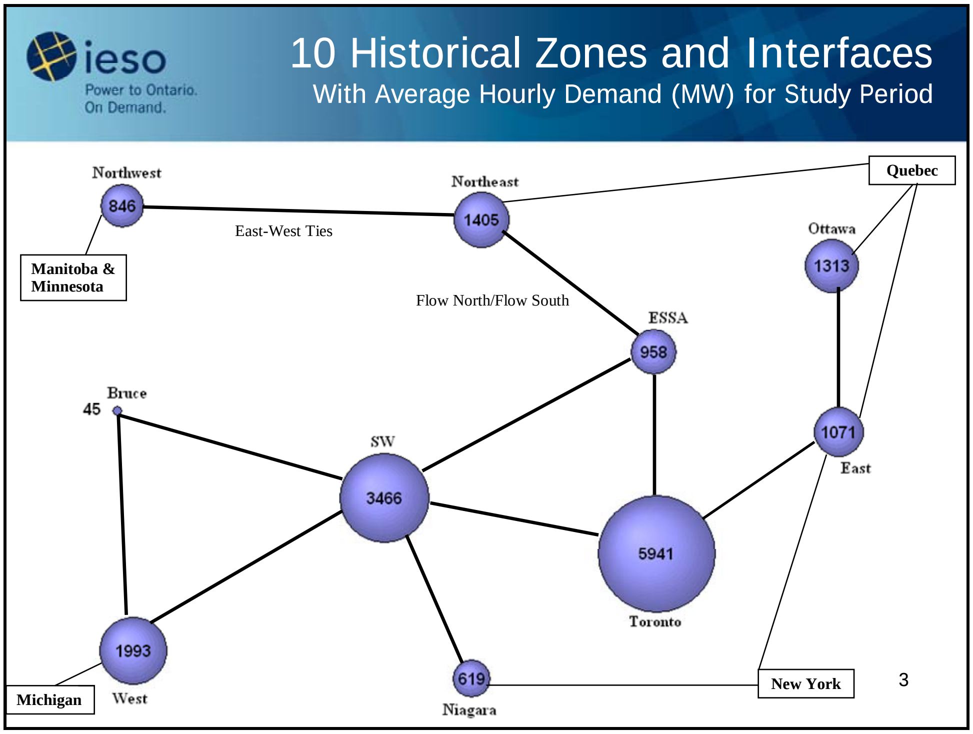
On occasion, the Market Surveillance Panel (MSP) has published zonal prices to illustrate some of the inefficiencies inherent in the HOEP uniform pricing model. This data supports the findings of the MSP, with historical shadow prices lower in the Northern zones.

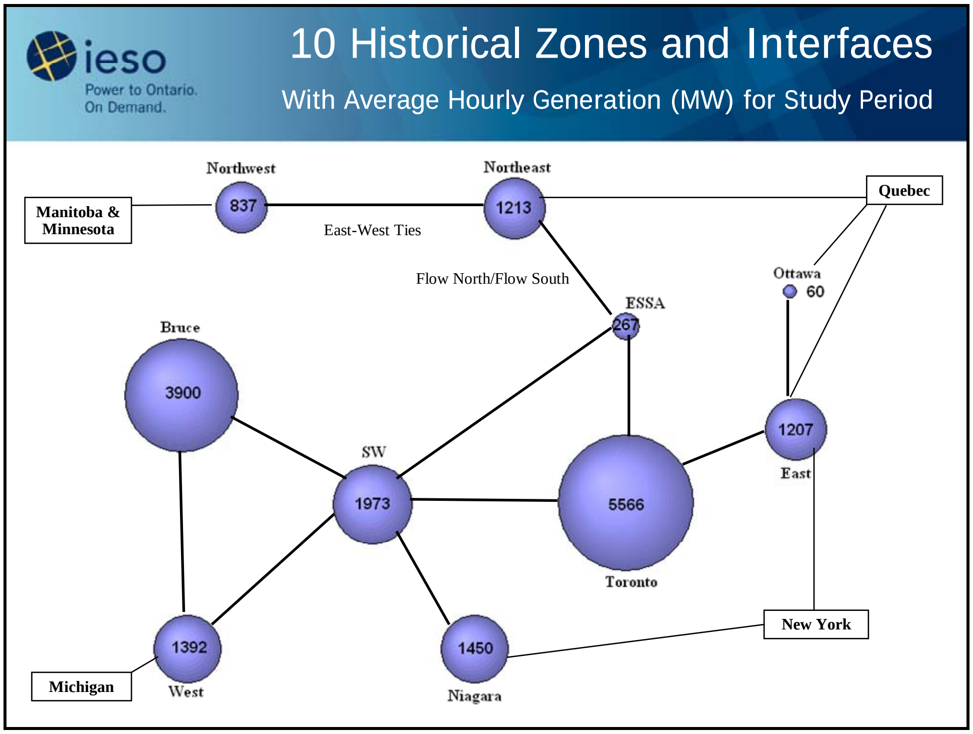


Calculating a Uniform Price using Nodal Values:

It is possible to calculate a uniform Ontario price by weighting the zonal prices shown above. For the study period, these generator-weighted averages, produce an Ontario price of $67.54 ($84.79 on peak, $53.05 off-peak).

Ontario Supply/Demand at a glance:





More work needs to be done - Questions that we are left with:

1. We expect that participant's will alter bid/offer strategies due to this change. How much impact will this have on the final price outcomes?

2. Other participant actions – e.g. reduce generator output to avoid frequent dispatch instructions when near a system limit – How much does this affect shadow prices and how might it be addressed if locational prices are implemented?

3. The use of loss factors that are static and have not been adjusted since market opening causes anomalies in the shadow prices. How would this be addressed?

4. The DSO uses penalty functions when necessary to overcome system limitations such as global OR or energy shortage and transmission limit violations. Are these functions appropriately priced? Does it matter if we have $2,000/MWh MMCP?

5. We have capped all shadow prices at MMCP and –MMCP, assuming that our current price cap would not change. Other jurisdictions use bid/offer caps and no price cap. Which method is appropriate for a locational pricing scheme in Ontario?

6. Manual actions of ISO operators – manual dispatches will still be required for reliability in some situations and these may affect locational prices.

7. Locational pricing will result in higher generation concentrations in some areas. How is local market power addressed?

8. What zonal construct is appropriate, if zones are to be implemented? Should NW and NE zones be further divided? Should southern zones be combined?

Appendix B

Possible Hedging Mechanisms:

Under a uniform pricing scheme, market participants are not directly exposed to the pricing risks associated with transmission congestion. Congestion costs are passed on to consumers through an uplift charge that cannot be hedged. A transition to a location-based pricing scheme can result in congestion risk for Participants, as the cost of congestion is included in the locational price. This creates a need for some kind of hedging mechanism to manage this risk. Markets that have implemented locational pricing have addressed this need through Financial Transmission Rights (FTR's). Similar to the IESO's intertie Financial Transmission Rights, internal FTR's allow Participants to hedge the risks associated with internal transmission congestion.

In markets using location-based pricing, the cost of congestion is represented by the difference in price between nodes or zones. The cost of congestion is not directly charged to any participant, but is reflected when the market operator pays producers less than it charges consumers. This results in a surplus, referred to as congestion rent. Holders of transmission rights are entitled to a share of this congestion rent.

In designing a system of financial transmission rights, some fundamental questions have to be addressed. The type of FTR's available, the method of allocation, and revenue adequacy are all important considerations.

Types of FTR

A financial transmission right is directional in nature. FTR's are defined by a source (point of injection), a sink (point of withdrawal), and a MW quantity. There are two types of FTR commonly used in markets employing location-based pricing: obligation rights and option rights. An obligation right entitles its holder to receive a share of congestion rents when congestion is positive, but also imposes an obligation to pay congestion costs when congestion is negative. An option right entitles its holder to receive positive congestion revenues, but carries no obligation to pay negative congestion revenues. Within the IESO-administered markets, option rights are available to manage price risks associated with intertie trading.

Method of Allocation

There are two basic approaches to the allocation of FTR's: direct allocation, and allocation through an auction. Direct allocation has been used in other jurisdictions to grant rights to Load-Serving Entities (LSE's) with pre-existing transmission arrangements. In a variation of this approach, some markets grant Auction Revenue Rights (ARR's), which entitle holders to a share of revenues from the FTR auction.

FTR's can also be allocated through a competitive bidding process. FTR auctions are conducted as a single locational clearing price auction, where Participants can bid for FTR's between any two locations (nodes or zones). This approach is used in the IESO-administered TR market for intertie zones. Revenues raised in IESO TR auctions are used to help fund payments to Transmission Rights holders.

Revenue Adequacy

A fundamental requirement of any FTR market is that it must be self-funding. To ensure that sufficient revenues are raised, ISO's require that all FTR's pass a "simultaneous feasibility test." The implied flow associated with awarded FTR's must be physically feasible, with FTR limits approximating transmission system limits for the time period covered by the FTR. As long as the capability of the transmission system does not change, the physically feasible solution should ensure that enough congestion rent is collected to honour the FTR's. To further reduce the risk of a funding shortfall, a combination of long-term and short-term FTR's are generally awarded. Long term rights are awarded based on the expected minimum capabilities of the transmission system for the time covered by FTR. This leaves some capacity available for short term FTR's, which can be assessed and awarded closer to the dispatch day. Despite efforts to ensure revenue adequacy, situations may arise that result in shortfalls. Transmission outages, changes in generator availability, and unexpected loop flows can result in system limits that differ from the assumptions underlying the FTR's. Administrative procedures are required to address these situations. Generally, ISO's set aside surplus funds to cover any potential shortfalls. If surplus funds are insufficient to cover shortfalls, FTR's can either be paid out fully, with costs passed on to participants through an uplift, or paid partially on a pro rata basis.

Transitional Measures

Any transition to a location-based pricing model will result in Market Participants being exposed to congestion–related price risks for the first time. To mitigate the potential impacts, and allow Participants to become familiar with a new market structure, transitional measures may be appropriate. It may be necessary to "grandfather" rights to certain participants through direct allocation of transmission rights or auction revenue rights. Other markets have experimented with grandfathered rights for LSE's. Such an arrangement could be phased out over a period of time, as affected participants gain knowledge of the market. The Ontario market, without LSE's, would need to discuss how such grandfathered rights should be allocated.

Other Features

The rules governing transmission rights can be tailored to fit the locational pricing model chosen. For the most part, other jurisdictions allow point to point FTR's within LMP markets. If a zonal pricing model was implemented, zone to zone FTR's would be appropriate. Markets that use a different pricing regime for producers and consumers (i.e. nodal/zonal) have experimented with zone to zone FTR's that can be "unbundled" into point to point components. This approach ensures consistency and contributes to liquidity in the TR market.

For an overview of the IESO's existing Transmission Rights Market:
http://www.ieso.ca/imoweb/marketplaceTraining/TransmissionIntro.asp