Electricity Trade Patterns in a Network: Evidence from the Ontario Market

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Abstract: We investigate whether trade has any effect on the price formation process in a specific electricity market, and identify interconnected markets that have higher impacts on prices in that market. In particular, we study Ontario wholesale electricity market and its trade with 12 interconnected markets including New York, Michigan, and Minnesota markets. We find that imports are unambiguously related to prices, while exports are not. Furthermore, imports have a *positive* and significant relationship with prices. We argue that the results are associated with auction design, production constraints, and technological differences. Out of the 12 studied interties, only three have a significant impact on price, two of which are the largest ones.

Keywords: electricity trade; simultaneous trade; transmission network; electricity prices; non-linear Granger causality; Ontario, New York, Michigan, Manitoba, Quebec wholesale electricity markets.

JEL codes: C5, F14, L94, Q4

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1. Introduction

Evolution of electricity markets since the restructuring process throughout the world has produced fruitful results especially in the production and transmission sides of the industry. Competitive market designs along with applicable market rules, efficient auction institutions, and welfare improving transactions have radically changed the wholesale electricity markets. Moreover, open access in transmission has entailed more flow of electricity across interconnected jurisdictions.

One of the aims of the deregulation of electricity markets is to increase welfare, notably by reducing significant price differentials between states/provinces. To facilitate this, electricity is traded among neighbouring jurisdictions through networks. Exports and imports, in theory, should minimize price differentials in the presence of no network externalities and no transmission capacity constraints. However, these constraints always exist in electricity networks. Accordingly, we investigate whether trade has any effect on the price formation process in an electricity market, and then we examine which interconnected markets may have more influence in the price formation of that specific market. In particular, we study Ontario wholesale electricity market and its trade with twelve interconnected markets and submarkets within the network.

Many studies have analyzed restructured electricity markets; however, interregional trades in interconnected electricity markets and their effects on market prices have been ignored. This is an important issue, because it can have significant impact on market prices, and therefore on generation and transmission investments not only within a jurisdiction but also outside. Furthermore, as electricity market integration between jurisdictions progresses, more trade is expected. Trade effects should be well understood not only for the political economy of the sector but also to foresee the evolution of investment in production and transmission capacities.

Electricity has been auctioned in wholesale electricity markets in many parts of the world. In the electricity auctions (uniform-price or discriminatory) the last accepted energy offer sets the market price (which is paid to all suppliers in the uniform-price auction, and only paid to the market clearing supplier in the discriminatory auction). As this last accepted energy offer can come from a local generator or from a wholesaler importing electricity, the market price can be set from outside the home market. For example, in the New York electricity market (NYISO) and the Midwest electricity market (MISO) exporters and importers can set the market clearing price in the day-ahead market. The Ontario market (IESO) allows exports and imports to set the pre-dispatch price one hour before the delivery during the pre-dispatch sequence, and these export and import quantities can be scheduled in the real-time. In many commodities markets, imports tend to reduce the product price at home market. A similar argument is claimed for electricity markets, that is, the presence of imports may lower the market price by making more energy available at a given time, avoiding the need to accept higher energy offers from the home market. Similarly, exports (energy bids from out-of-state players) may increase the market price, as expensive energy offers have to be accepted to meet demand faced by the local market. We will test this claim in this paper, and find that this claim may not hold true in general.

We in particular examine the role of trades (exports and imports) in the wholesale electricity market price formation process in Ontario, the largest province of Canada in terms of population and economy. The Ontario market has peculiar features; connecting regulated markets to deregulated markets via transmission grid and having the most volatile market in its transmission network. Ontario has two main physical markets: the real-time energy market and the real-time operating market. Contrary to the US electricity markets, it does not have a day-ahead market: market prices are settled every 5 minutes in real-time, not one day in advance. Its market price volatility is higher than the ones in neighbouring jurisdictions such as New England (NE), New York (NY) and Pennsylvania-New Jersey-Maryland Interconnection (PJM). These markets have the two-settlement markets (day-ahead and real-time markets) in which most of the real-time demand is cleared in the day-ahead market (for instance, on average 97% for the NE market, 90% for the NY market in 2004, according to Zareipour et al., 2007). The high volatility in Ontario market is argued to be correlated with the single-settlement nature of the market that is the real-time balancing market.

In the best of our knowledge this is the first paper analyzing the effects of trade on electricity market price formation process. This research has implications on integration of electricity markets, and possible investments in transmission and production capacity, also gives guidance on determining trading zones which are more important than the others in the network.

There are several papers in the literature that examined the Ontario wholesale electricity market. These papers studied production capacity investments (Genc and Sen, 2008), identification of variables explaining peak price (Rueda and Marathe, 2005), measuring price volatility (Zareipour et al., 2007), and the effects of power outages on prices (Melino and Peerbocus, 2008) in the Ontario market. These studies, among others, have not considered the likely effects of trade on market prices. An exception is Serletis and Dormaar (2007) who examine whether exports and imports cause changes in Alberta market prices. We, however, take advantage of an extensive data set and use recently developed non-linear causality tests, in addition to linear ones, to determine trade effects on Ontario prices. With high frequency export and import data, we also pinpoint the neighbouring jurisdictions that significantly affect the Ontario prices through energy trading in the transmission network.

To our knowledge there is no an established trade theory for electricity. This may stem from peculiarities associated with electricity. Electricity demand should be continuously met to avoid power cuts (e.g., brownouts and blackouts), which harm the economy. Unlike other goods, electricity can be instantly transmitted from an injection point (or a production location) to an end-user. Hence, it is not subject to any delay in transportation process (electrons move at the speed of light). Other goods can be stored at least for some time. However, electricity is either very expensive to store or impossible to store even at a modest scale. If it is generated and transmission lines do not have enough capacity to carry a certain MWh power, it should be dumped to the earth near its generation location. Thus, sometimes prices for this surplus production are negative. If this excess amount of electricity is not withdrawn from the grid, it may cause network system-wide collapse, leading to blackouts.

Virtually all trade theories (Ricardian, Heckscher-Ohlin, etc.) explain price differentials among autarky markets and trade effects on income distribution and welfare, and predict that goods will flow from low price markets to high price markets. However, these theories may fall short in explaining dynamics of trade in electricity markets due to the peculiarities of electricity and the constantly changing supply and demand conditions at every moment in time. Moreover, trading electricity between jurisdictions is limited by transmission line capacity and is subject to interventions by system operators. It can even happen that, due to hedging purpose and market rule differences between jurisdictions, exports and imports of electricity could occur simultaneously within a given trading period. In the Ontario market, this type of simultaneous trade (import of energy into Ontario and export of energy from Ontario) is called a wheeling-through transaction.

Our Ontario study uses hourly data from 2002 to 2009, in a context where imports and exports are made with five different jurisdictions (New York, Michigan, Minnesota, Manitoba and Quebec), interconnected through 12 trading zones.

We make several contributions in this paper. This is the first paper examining a transmission network to analyze trade effects. Moreover, we use an extensive data set applying recently developed non-linear causality tests to determine whether exports and/or imports cause price formation process in a local market. In addition, we determine the main trading zones/markets that have more influence on prices than others in that local market. Our main findings are the following. First, we find that while Ontario imports can be unambiguously tied to the hourly Ontario energy price, exports cannot. We find Granger causality for all lags in the case of imports by utilizing linear and non-linear tests. Second, in the aggregate data we observe positive relationship between imports and prices. In the disaggregated data, by making use of an extensive database, we obtain a unique evidence that imports have an influence on prices in hourly basis, even if only a limited number of intertie have a significant impact. Third, we observe low capacity utilization rates and significant trade activities during trading periods.

The structure of the paper is as follows. The following section describes the structure of the Ontario market and the interconnecting markets. The third section explains the data set, the methodology, and some results. The fourth section quantifies the relationship between imports and prices. Fifth, using disaggregated data of imports neighbouring jurisdictions affecting the Ontario prices are analyzed. Finally, conclusions are presented.

2. The Ontario Electricity Market and its Interconnections

In this section we describe the advancement of the reform process in the Ontario electricity industry, the structure of the wholesale electricity market and the intertie zones in which Ontario trades electricity.

The Ontario wholesale electricity market has many interesting features. It has a diversified generation portfolio, with all types of production technologies (fossil-fuelled, nuclear, hydropower and some other renewable technologies). It is also the most volatile market in the region (as established by Zareipour et al., 2007). Along with the Alberta market, Ontario market is the only market having a one settlement market which is the real-time spot market in North America. Indeed, neighbouring jurisdictions to Ontario and other deregulated US electricity markets have both a day-ahead market and a real-time balancing market.

The reform framework of the Ontario electricity industry was largely established in the 1996 "Macdonald Report" (Macdonald et al., 1996).[1] Following recommendations made in this report, an Independent Electricity Market Operator (IEMO) was created in 1998. The IEMO became in charge of system operations and of the wholesale market. In 1999, as the result of the 1998 Energy Competition Act, the regulated monopoly Ontario Hydro was split into a large generation company (Ontario Power Generation, OPG), and a transmission company (Hydro One) with a significant distribution business. Both companies remained governmentally owned. The Ontario spot market started its operations in May 2002, with hourly energy offers received from all generators. However, the generation market is still dominated by OPG, which produced 66% of the 158 TWh generated in 2007 in Ontario (Statistics Canada, 2009 and OPG, 2007).

Soon after the start of the spot market, due to significant price increases, a retail price cap was established in November 2002 (Electricity Pricing, Conservation and Supply Act). Although the wholesale spot market continued its operation as initially planned, the retail consumers have seen their electricity price re-regulated further in 2003 (Ontario Energy Board Amendment Act - Electricity Pricing). This regulation guaranteed a fixed price for some end-users (e.g., small businesses and residential customers). In 2005, this approach became the "Regulated Price Plan" that most retail consumers still subscribe to (alternatively, small consumers can opt for a retail contract, freely negotiated with an electricity retailer).

As concerns over electricity prices and adequacy of investment grew, the 2004 Electricity Restructuring Act re-introduced long-term planning with a new institution, the Ontario Power Authority (OPA). The IEMO also changed its name to Independent Electricity System Operator (IESO). Under this act, OPG is mandated to sell some of its hydro production and all of its nuclear production (from designated "Prescribed Generation Assets") at a regulated price. In 2007, 62.3 TWh from OPG (almost 60% of its production) was sold at a regulated price to some end-user consumers (OPG, 2007). However, the wholesale market continues to operate on freely set energy offers (even for the OPG prescribed generation assets), with the IESO selecting the cheapest energy offers to meet demand. An Hourly Ontario Energy Price

[1] More details about the history and the current market structure of the Ontario electricity market can be found in EDA (2007), which is the main reference for this section.

(HOEP) is set through a uniform price auction. This HOEP is actually the average value of the twelve 5-minutes market clearing prices of a specific hour.

Price regulation for retail consumers and for OPG comes as a retroactive accounting adjustment. This dual system preserves an operating spot market with some price stability for retail consumers, but creates some additional administrative and accounting procedures to monitor and adjust prices on a regular basis (so that market and regulated prices balance with actual payments made by consumers).

Along with the main regulator (the Ontario Energy Board (OEB)), the Ontario market has the following registered market players (OEB, 2008): electricity generators, electricity distributors, electricity transmitters, electricity wholesalers, and electricity retailers.

The Ontario wholesale electricity market consists of energy market, operating reserves and financial transmission rights market. The IESO issues dispatch instructions to loads and generators, and runs the uniform price auction for each five minute interval of every day. The spot market price is set by simply ranking all received energy offers (from generators and wholesalers/importers) in increasing price order, until the forecasted demand is satisfied. The last accepted energy offer sets the market price, which is paid to all suppliers (IESO, 2009d).

The IESO governs the wholesale market, ensures the reliability of the integrated power system, and forecasts supply requirements and demand (total Ontario market demand is equal to domestic demand plus export demand). Suppliers submit energy offer (quantity-price pairs) to sell electricity and wholesale buyers submit energy bids to buy electricity. The IESO runs a uniform price auction to balance total market supply and demand and establish the Hourly Ontario Energy Price (HOEP), which is the price paid to generators that supply power. Indeed, the market clearing price (MCP) is calculated every five minutes a day and the average of these MCP prices results in the HOEP, which is also known as spot price. Although the price elasticity of total demand is low, some large wholesale customers are able to respond to changes in prices by either shifting some of their demand to off-peak periods or participating in the market and bidding how much electricity they plan to consume at what price.[2]

[2] According to IESO 2010 market's program (www.ieso.ca), there are 13 facilities operating as "dispatchable load" in the market, offering 700 MW of potential demand response.

The IESO does not have a day-ahead market due to regulatory reasons. Generation dispatch and market clearing prices are set in the real-time energy market. However, for reliability purpose, the IESO has a Day-Ahead Commitment Process (DACP), created in 2006, to manage day-ahead available energy units and determine approximate import transactions.[3] On the other hand, neighbouring jurisdictions have two-settlement markets, namely day-ahead and real-time energy markets. Day-ahead market has the dominant share of transactions in the neighbouring US markets. The two-settlement market structure enables that most of the market demand is cleared a day before market opens and generators have enough time to adjust their operations for the instances of unpredictable events in real-time.

Table 1 presents the available generation capacity within Ontario in 2009. This capacity has grown at an average rate of 2% during the period 2002-2009 (Statistics Canada, 2009), while the total energy made available (generation plus imports, minus exports) has stayed at the same level from 2002 to 2009, at about 155 TWh per year.

Table 1. Ontario Generation Capacity by Fuel Type, MW, 2009 (IESO, 2009a)

Fuel Type	Total Capacity (MW)	Share
Nuclear	11,426	32.2%
Hydroelectric	7,911	22.3%
Coal	6,434	18.1%
Oil / Gas	8,535	24.1%
Wind	1,084	3.1%
Biomass / Landfill Gas	75	0.2%
Total	**35,465**	

As noted by Zareipoura et al. (2007), coal-fired generators are the most-frequent market price setters in Ontario, while gas-fired generators are the price setters only during extreme demand hours in a day.

[3] In 2008 the IESO Board approved the implementation of an Enhanced Day-Ahead Commitment Process (EDAC) to deliver some minor changes to the existing Day-Ahead Commitment Process.

2.1. Export and Import Structure in the Ontario Market

Ontario power network has interconnections with two Canadian regulated markets (Manitoba and Quebec) and three deregulated US markets (Minnesota, Michigan and New York) as shown in Figure 1. The capacity of each interconnection is presented in Table 2, although the total actual export/import capacity is not the arithmetic sum of individual capacities. Due to some network constraints, the cumulative export/import capacity is actually closer to 4,000 MW (IESO, 2009c). In Table 2, exports (imports) column represents the maximum exports (imports) quantities from (to) Ontario to (from) the interconnection. For instance, on a given hour, Ontario can sell to NY up to 1,925 MWh, or can import at most 1,680 MWh of energy from NY.

Figure 1. Ontario's Main Power Plants and Transmission Lines (OMEI, 2009)

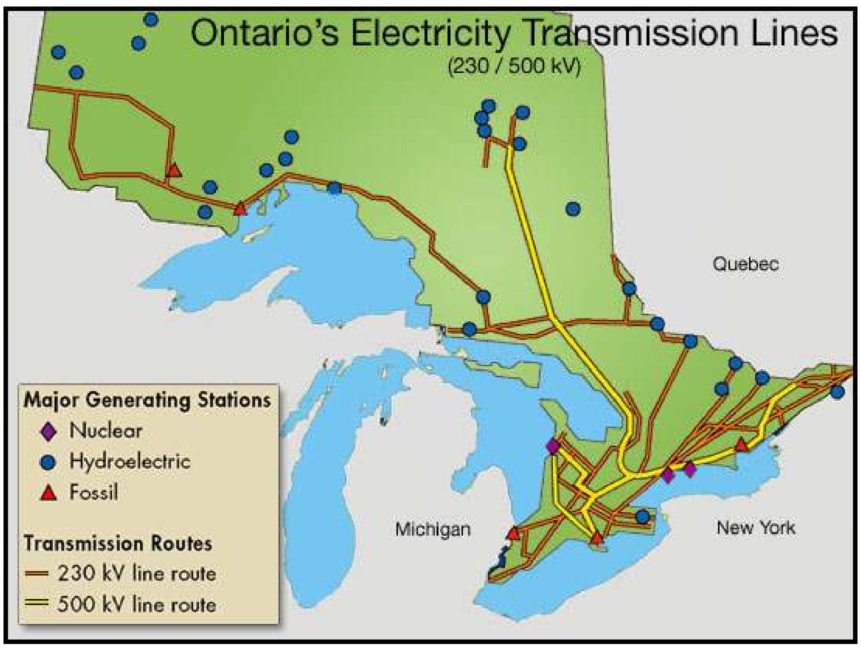

Table 2. Ontario Interconnection Capacity for Exports and Imports, in MW, 2009 (IESO, 2009b)

	Exports	Imports
Manitoba	268	336
Minnesota	140	90
Michigan	2,275	1,675
New York	1,925	1,680
Quebec	1,329	2,210
Total	**5,937**	**5,991**

Except for a 625 MW addition to the Quebec interconnection in July 2009, interconnection capacities remain very stable from 2002 to 2009. Detailed individual transmission line information is published many times a year by the IESO (see IESO, 2009b). In Table 2 the export and imports capacities are about 6,000 MWh which is very significant because it may cover almost one third of the average load in Ontario. However, these transactions are subject to transmission and network constraints and availability of generation units.

Producers can sell at the real-time spot market price (known as Hourly Ontario Energy Price, HOEP) or can sell their production to other external markets. A home generator can export directly to other markets without participating in the home market. That is, it can submit energy offers in other markets, before offering its energy to the Ontario market. Therefore, an Ontario generator can export while having no sales in Ontario. However, even though the exports are already scheduled, the system operator may recall or curtail some export transactions for system adequacy or reliability reasons. Importers of electric power are given price guarantee for the energy they bring into the market. If the spot price is lower than the pre-dispatch accepted price of the importer, the difference is paid by the operator to the importer. To signal market conditions, the IESO releases pre-dispatch schedules with forecasted demand and supply requirements (e.g., generation availability, imports and exports) along with price signals (e.g., projected HOEP for the day, intertie offer guarantee estimate). Importers use these market signals before placing their bids. Due to unexpected outages, even if there is available capacity in Ontario, the home market price may increase which may create a trade opportunity for importers. This could, for instance, be explained by high ramping rates of power plants and/or low spinning reserve capacity. Depending on the price differential between the home market and interconnected markets, and on the transmission constraints, importers may benefit from arbitrage opportunities.

Currently, IESO employs "Dispatch Scheduling and Optimization Algorithm" to determine pre-dispatch sequence of prices and load for the future periods. These are predicted prices for the forecasted demand. The algorithm is run every hour, and the pre-dispatch prices and quantities calculated for each hour for the future 12-36 hours are published at the IESO web site[4]. Specifically, market participants use the pre-dispatch data to reform their operations planning and participation in the (real-time) market. For example, when the 3-hour ahead pre-dispatch price is above $120, if the market participants reduce their demand in real-time then the IESO compensates them to increase price responsiveness.

Imports and exports are scheduled one-hour before the delivery hour given that they have submitted their bids in the pre-dispatch scheduling, and imports have offered below the hour-ahead pre-dispatch price, and exports have bid above the hour-ahead pre-dispatch price. Imports and exports are settled in the real time at the sum of the real-time market clearing price and the congestion price determined during the hour-ahead pre-dispatch sequence. Importers are given a price guarantee so that if the real-time market price is lower than their bid price in the hour-ahead pre-dispatch they will be paid at least the average price of their bids. Therefore, pre-dispatch prices are crucial for payments to importers. Pre-dispatch prices also help form finalizing future import offers.

From the operations in the hour-ahead dispatch planning and the market clearing in the real-time market, it is clear that imports and exports can potentially affect the real-time prices. Imports offered below the hour-ahead pre-dispatch price and exports bid above the hour-ahead pre-dispatch price are all scheduled in real-time dispatch with sure probability. Therefore, exports and imports will play an important role in determination of real-time market prices. Nevertheless, they do not set the market clearing price in real time as they cannot be dispatched in every five minutes. In Ontario, imports and exports can set the pre-dispatch price in the hour-ahead market. However, intertie transactions (exports and imports) in the neighbouring jurisdictions such as MISO (Midwest ISO) and NYISO that have day-ahead markets can set the market prices ahead of the day.

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[4] The pre-dispatch prices and quantities are posted at www.theimo.com/imoweb/marketdata/marketToday.asp

It is argued by the "market pricing working group" in the IESO that pre-dispatch prices would approach to the real-time prices if the pre-dispatch prices would be determined 5-minute ahead of the real-time auction instead of the hour-ahead operations.[5] The IESO is about to design a day-ahead market which will aim to set electricity prices on an hourly basis one-day ahead of the real-time.[6] In the planned day-ahead market design imports and exports will be able to set the day-ahead market prices. The real-time market, however, will remain effective and run the auction in five-minute basis to clear the unmet demand.

3. Data, Methodology and Some Results

Below we explain the data set and the econometric approach we use to assess the relationship between trade and market prices. In particular, we investigate causality between trade and market prices in this section. We employ linear and recently developed non-linear Granger causality tests from export and import volumes to electricity prices during on-peak, off-peak and all times periods. We will provide our causality results in this section. Further results on the effects of trading activities on market prices will follow in the next sections.

3.1 Data

Our data set include electricity prices, export and import volumes and total market demand. They span the time period of May 1, 2002 – June 9, 2009 on hourly basis, including all week and weekend days (62,328 data points for each variable).

We also analyze this data set in subcategories as peak and off-peak hours. Peak time data are defined as the hours between 08:00 and 22:00 (including 8.00 and 22:00) during week days and excluding whole weekends (27,825 data points for each variable). Off-peak time data includes week day's hours between 23:00 -07:00 and whole weekends (34,503 data points for each variable). See the Appendix for summary descriptive statistics on hourly imports (M), exports (X), total quantity demanded (Q) and price (P).

3.2 Testing Granger Causality and Some Results

[5] See http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG_2004Aug20_ISS01_PreDispPrice.pdf and the Issue 30 on forecast of real-time price.

[6] See http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060303-Issue7-Imports-Exports-Setting-Price.pdf. The day-head market has not been implemented by IESO yet.

In this section, we test the Granger-causality from export and import volumes to electricity prices. The conventional approach of testing Granger-causality is to assume a parametric, linear time series model for the conditional mean and test whether the lags of one variable enter into the equation for another variable. However, as we explain in Section 3.3, the linear test statistics may not be sufficient to detect nonlinear effects on the conditional distribution. As a first step we perform conventional linear Granger-causality tests, and then we extend our analysis in the following section by running recently developed nonlinear tests.

In the linear framework, it is a common practice to test the Granger-causality within a Vector Autoregressive (VAR) model using Wald (or F) criteria that are considered to be asymptotically chi-squared, as indeed they are in stationary or trend stationary systems. However, as now well understood (see Toda and Phillips, 1993, among others) the asymptotic theory of Wald tests is typically much more complex in systems that involve variables with stochastic trends. The first issue is that whether there are common stochastic trends among the variables in the VAR. Therefore, one has to test for cointegration first, if there is no evidence on cointegration a VAR on first differenced series would be appropriate and, given the fact that all series are integrated with order 1, I(1), Wald test is asymptotically chi-squared distributed. Should there be evidence on cointegration, one may use either the procedure in Toda and Phillips (1993) or Augmented Wald (A-Wald) test proposed by Toda and Yamamoto (1995) and Dolado and Luktepohl (1996)[7]. Both Toda and Yamamoto and Dolado and Luktepohl proved that in integrated and cointegrated systems the Wald test for linear restrictions on the parameters of a VAR(p) has an asymptotic chi-squared distribution when a VAR($p+d_{max}$) is estimated, where p is the true lag order of the VAR and d_{max} is the maximum order of integration in the system.

Since the Augmented Wald test is indifferent whether the series in VAR are cointegrated or not, or whether they are I(0) or I(1), or mixed, to avoid pre-testing biases (either in unit root or cointegration tests) one can directly use this procedure without embarking on problematic unit root or cointegration tests. Hence, we use this approach to test the presence of (linear) Granger-causality from export and import volumes to electricity prices. In short, this testing procedure simply involves augmenting the underlying VAR in levels by extra lags that equal to d_{max} and performing the usual Wald test for the non-causality restrictions in the non augmented VAR.

[7] We recommend Luktepohl (2006, section 7.6.3) for a textbook treatment of this test.

Serletis and Dormaar (2007) assume four-variable VARs for Alberta market. Rueda and Marathe (2005) use support-vector-machine-based learning algorithm for sensitivity analysis to find the main determinants of real-time Ontario average peak price. They find that the main explanatory variables of the peak prices are lagged average peak price, the actual import peak volume, the peak Ontario market load, and net available supply after accounting for load (excess supply) for the data studied in the period May 2002- May 2003. Due to these reasons we estimate four-variable VARs for the Ontario market. The variables included in VARs consist of electricity prices, export and import volumes and total demand (load). We tested the null hypothesis of Granger non-causality by restricting the relevant coefficients to zero in the following equation of the VAR(p+d_{max}) model.

$$(1) \qquad P_t = \alpha + \beta t + \sum_{i=1}^{p+d_{\max}} \phi_{i-1} P_{t-i} + \sum_{i=1}^{p+d_{\max}} \varphi_{i-1} X_{t-i} + \sum_{i=1}^{p+d_{\max}} \psi_{i-1} M_{t-i} + \sum_{i=1}^{p+d_{\max}} \gamma_{i-1} Q_{t-i} + u_t^p$$

where P_t, X_t, M_t, Q_t stand, respectively, for price, export, import and total demand at hour *t*, and u_t^p represent the usual error term of the price equation of VAR. In this equation, the null of "export does not granger cause to power prices" and the null of "import does not granger cause to power prices" are tested by using following restrictions: $H_0 : \varphi_1 = \varphi_2 .... = \varphi_p = 0$ and $H_0 : \psi_1 = \psi_2 .... = \psi_p = 0$, respectively.

To determine d_{max} in our four-variable system, we use standard ADF tests that have the null hypothesis of non-stationary. Table 3 displays the results of ADF tests in which the underlying lag length of the test is selected by Akaike Information Criteria (AIC)[8] over the maximum of 360 lags[9].

Table 3. Unit Root Tests

	M	**X**	**Q**	**P**
ADF	-5.45393**	-5.02739**	-5.70100**	-6.49798**

Note: The table shows test statistics for the unit-root hypothesis of ADF(*p*) where *p* is the number of lags determined by Akaike Information Criteria. The tests in levels include an intercept and trend term. (*), and (**) rejection of the null hypothesis at 10 and 5 percent significance levels.

[8] The usage of other criteria such as SBC and HQC yield the similar results.
[9] We only use the all-hours data for unit root testing for which 360 lags correspond to a period of 15 days.

A consequence of results shown in of Table 3 is that all variables are stationary, hence we identify $d_{max} = 0$, according to ADF tests. Nevertheless, since low-power of these tests is well known, we proceed by reporting both classic and Augmented Wald tests as a robustness check. In Augmented tests we assume d_{max} is equal to 1 to take into account at least one possible unit root in the system, which cannot be detected by ADF tests.

Table 4 displays the results of the linear Granger-causality tests. Panel I of Table 4 illustrates the test statistics obtained by using the data resulted from all hours. Panel II and III do the same for off-peak and peak hours. Since the result of the Granger-causality tests can critically depend on the choice of lag length underlying VAR, we estimate all VARs up to a maximum number of lags. For each case, the maximum lag length p in Equation (1) is determined by the number of hours corresponding to one month. Hence, p is determined as 720, 405 and 315 for all, off-peak and peak hours respectively. We computed all the test statistics up to maximum lag length p. Table 4 summarizes the results for some chosen lags[10].

Table 4 Linear Granger Causality Tests

I. All Hours

	X does not Granger cause P				**M does not Granger cause P**			
Lag *p*	**Wald**	**p-value**	**A-Wald**	**p-value**	**Wald**	**p-value**	**A-Wald**	**p-value**
50	85.850	0.001	85.203	0.001	296.030	0.000	289.916	0.000
100	114.434	0.153	114.335	0.155	346.297	0.000	344.192	0.000
150	168.389	0.145	168.715	0.141	382.181	0.000	383.977	0.000
170*	184.848	0.206	185.145	0.202	392.781	0.000	394.007	0.000
200	218.239	0.179	217.888	0.183	426.224	0.000	426.303	0.000
300	304.801	0.412	303.758	0.429	542.195	0.000	542.657	0.000
400	393.182	0.587	393.180	0.573	622.389	0.000	622.242	0.000
500	501.528	0.472	501.990	0.467	752.187	0.000	751.440	0.000
600	611.195	0.378	608.415	0.397	861.877	0.000	862.672	0.000
700	735.909	0.168	731.817	0.196	982.413	0.000	980.930	0.000
720 (Max)	753.840	0.185	750.852	0.199	1000.807	0.000	996.368	0.000

[10] The complete results, code and data are available upon request. To compute the tests statistics we run Matlab codes using Matlab 7.9 64-bit version in an Intel(R) Xeon(R) CPU X5570 @ 2.93GHz and 3.14 GHz, 16 GB of RAM machine. Given the huge matrix operations, due to the highly large data set used, involving in the calculations the codes would not be able to be run in a less qualified machine unless a smaller data set used.

II. Off-Peak Hours

	X does not Granger cause P				M does not Granger cause P			
Lag *p*	**Wald**	**p-value**	**A-Wald**	**p-value**	**Wald**	**p-value**	**A-Wald**	**p-value**
50	103.756	0.000	102.070	0.000	209.313	0.000	203.454	0.000
100	169.801	0.000	167.956	0.000	202.933	0.000	202.534	0.000
150	221.778	0.000	221.110	0.000	261.835	0.000	260.328	0.000
196*	274.980	0.0001	274.991	0.0001	324.487	0.000	324.957	0.000
200	278.317	0.000	281.056	0.000	329.892	0.000	328.321	0.000
300	387.510	0.000	387.984	0.000	400.714	0.000	400.760	0.000
400	483.049	0.003	478.064	0.004	506.838	0.000	505.927	0.000
405 (Max)	491.277	0.002	483.075	0.004	509.622	0.000	507.398	0.000

III. Peak Hours

	X does not Granger cause P				M does not Granger cause P			
Lag *p*	**Wald**	**p-value**	**A-Wald**	**p-value**	**Wald**	**p-value**	**A-Wald**	**p-value**
50	74.445	0.014	74.024	0.015	157.235	0.000	153.056	0.000
65*	89.895	0.022	90.766	0.019	202.484	0.000	205.293	0.000
100	126.754	0.037	126.952	0.036	235.249	0.000	234.927	0.000
150	179.211	0.052	178.936	0.054	287.205	0.000	286.939	0.000
200	229.403	0.075	230.011	0.072	325.765	0.000	325.794	0.000
300	342.559	0.046	339.820	0.056	498.463	0.000	496.974	0.000
315 (Max)	363.475	0.031	361.951	0.032	514.898	0.000	514.736	0.000

Note: Wald tests are calculated as their likelihood ratio (LR) equivalents by using $2(\ln L^{*} - \ln L)$, where L^{*} and L represent the unconstrained and the constrained maximum log likelihood respectively. These test statistics are asymptotically distributed as $\chi(g)$ under the null hypotheses, where n is the number of restrictions. The lag length chosen by Akaike Information Criteria (AIC) is indicated by *.

In all-hours data, the null hypothesis of Granger-non causality, while it can be rejected for relatively small lags, cannot be rejected for most of the lags. After p = 71 and p=94 (not reported in the table) all tests indicate non rejection at 1 and 5 percent significance levels. On the other hand the usage of AIC, for which p is chosen as being equal to 170, indicates that export prices do not granger cause to power prices. Similarly, for peak hours at 5 percent significance level most of the tests statistics points out granger non-causality as well as the statistics selected by AIC. However, for off-peak hours all tests reject the non-causality. Note also that both Wald and A-Wald tests conclude in the same direction.

Contrary to the export case, Granger-causality tests unambiguously reject the null hypothesis of no causality from imports to power prices for all cases and all tests. Hence, we obtain conclusive evidence on causality running from imports to power prices but not for the causality from exports to power prices.

3.3 Robustness using Nonparametric Model

We extend our analysis by running recently developed nonlinear tests. While the parametric approach we employed in Section 3.2 is appealing due to its simplicity, the tests statistics are only sensitive to causality in conditional mean and may not be sufficient to detect nonlinear effects on the conditional distribution. Baek and Brock (1992) explain that parametric linear causality tests have low estimation power against certain nonlinear alternatives. For testing causality, nonlinear nonparametric techniques seem to be attractive since they focus on prediction without imposing a certain functional form. Various nonparametric tests have been proposed in the literature. Perhaps, the most influential one is developed by Hiemstra and Jones (1994) (HJ, henceforth). HJ test is a modified version of Baek and Brock (1992) test. Dijks and Panchenko (2005, 2006), DP hereafter, show that the relationship tested by HJ test is not generally compatible with Granger causality, leading to the possibility of spurious rejections of the null hypothesis. As an alternative, DP developed a new test statistic that overcomes these limitations.

To test the nonlinear causality between P_t and X_t, and P_t and M_t, we use both HJ and DP's tests. These tests are applied to the estimated residual series from the VAR model, u_t^p , u_t^x, u_t^m, where the last two terms refer to the residuals estimated from the export and import equations of the VAR model, similar to the price equation depicted above. By removing linear predictive power, if any, with a linear VAR model, any remaining predictive power of residual series can be considered nonlinear predictive power.

By definition, u_t^x (or u_t^m) strictly Granger causes of u_t^p if past and current values of u_t^x contain additional information on future values of u_t^x that is not contained in the past and current u_t^p values alone. More formally, let $\mathbf{u}_t^x = \left(u_t^x, \ldots, u_{t-l_x-1}^x\right)$ and $\mathbf{u}_t^p = \left(u_t^p, \ldots, u_{t-l_p-1}^p\right)$, $\left(l_x, l_p \geq 1\right)$ denote the information sets consisting past observations of u_t^x and u_t^p up and including time *t*. Let "□ " denote equivalence in distribution. Then u_t^x does not Granger cause of u_t^p if

(2) $$H_0: \quad u_{t+1}^{p} \mid \left(\mathbf{u}_t^{x}, \mathbf{u}_t^{p}\right) \sim u_{t+1}^{p} \mid \mathbf{u}_t^{p}$$

This is a more general setup for testing Granger non-causality than the above linear case since it does not involve assumptions on the data generation process and the test of noncausility simply consists of comparing one-step-ahead conditional distribution of u_t^p with and without past and current observed values of u_t^x.

The HJ and DP's T_n tests applied to residuals of the linear VARs chosen by AIC as indicated in Table 3 above. The null hypothesis of conditional independence is tested using lags of the VAR residuals[11] in conditioning set, which is set to 8 as the maximum.

As in the linear case, the evidence on causality from import volumes to power prices is highly conclusive. Results are presented in Table 5. The null of (nonlinear) non causality from import to prices are unambiguously rejected by all tests for all, peak, and off-peak hours data. However, similar to linear case, the evidence on causality from export volumes to power prices differ across the data considered in the analysis. Non causality from export to prices is unambiguously accepted by all tests in peak hours. However, for all and off-peak hours the results are mixed and vary between HJ and DP's test as well as between different lags used in the analysis. Therefore, overall, we obtain similar results with linear tests that the noncausality from exports to prices can only be accepted for peak and, to some degree, for all hours but not for off-peak hours.

Table 5. Nonlinear Causality Test

I. All Hours

	X does not Granger cause to P				**M does not Granger cause to P**			
l_x=l_y	**HJ**	**p-value**	**DP**	**p-value**	**HJ**	**p-value**	**DP**	**p-value**
1	0.100	0.460	-0.001	0.500	82.936	0.000	10.892	0.000
2	0.597	0.275	0.089	0.465	91.415	0.000	12.136	0.000
3	2.597	0.005	0.389	0.349	90.025	0.000	11.892	0.000
4	0.069	0.473	0.066	0.474	78.165	0.000	10.252	0.000
5	3.399	0.000	0.528	0.299	68.841	0.000	9.011	0.000
6	6.176	0.000	0.876	0.190	57.618	0.000	7.499	0.000
7	5.858	0.000	0.797	0.213	51.098	0.000	6.635	0.000
8	13.355	0.000	1.753	0.040	48.809	0.000	6.269	0.000

[11] The C code has been provided by Diks and Panchenko.

II. Off-Peak Hours

	X does not granger to P				M does not granger to P			
l_x=l_y	HJ	p-value	DP	p-value	HJ	p-value	DP	p-value
1	3.574	0.000	0.477	0.000	9.799	0.000	9.584	0.000
2	3.731	0.000	0.665	0.000	10.201	0.000	10.005	0.000
3	2.967	0.002	0.939	0.002	8.562	0.000	8.348	0.000
4	1.237	0.108	0.214	0.112	6.306	0.000	6.117	0.000
5	0.271	0.393	0.252	0.400	4.249	0.000	4.089	0.000
6	-0.288	0.613	-0.308	0.621	3.099	0.001	2.972	0.001
7	0.047	0.481	0.020	0.492	3.117	0.001	2.984	0.001
8	0.821	0.206	0.776	0.219	3.320	0.000	3.137	0.001

III. Peak Hours

	X does not granger to P				M does not granger to P			
l_x=l_y	HJ	p-value	DP	p-value	HJ	p-value	DP	p-value
1	-0.966	0.833	-1.002	0.842	6.206	0.000	6.112	0.000
2	-1.899	0.971	-1.949	0.974	6.766	0.000	6.729	0.000
3	-1.621	0.947	-1.650	0.951	7.077	0.000	7.022	0.000
4	-1.147	0.874	-1.167	0.878	7.281	0.000	7.210	0.000
5	-0.310	0.622	-0.293	0.615	7.841	0.000	7.750	0.000
6	-0.594	0.724	-0.617	0.732	7.919	0.000	7.759	0.000
7	-0.905	0.817	-0.946	0.828	6.919	0.000	6.705	0.000
8	-0.959	0.831	-1.003	0.842	5.862	0.000	5.658	0.000

Note: T ratios for HJ and DP tests for the bandwidth value of 1.5, the value used by Hiemstra and Jones (1994). l_x,l_y refer to the lags of the variables in the conditioning set.

Consequently, the results of granger causality tests (both linear and nonlinear) indicate that while there is ample evidence for the hypothesis of import having a causal (linear and nonlinear) impact on prices, the evidence for exports is ambiguous and depend on the hours of the day. For off peak hours there seems to be an effect exerted on prices from exports. While, when the demand is high in peak hours exports cannot be able to affect prices, this effect can enable to manifest itself when the demand is low in off peak hours. The result can be easily seen as ambiguous when these two data sets join together in all hours.

We next explain why exports may not cause prices in general. In Ontario exports are scheduled one hour before the dispatch, and performed in the expectation that the market supply is enough to cover local demand. Given that the home market supply security is attained, and the neighbouring jurisdiction price is above the local production cost and the home market prices, export transactions are carried out. In this case, clearly we do not expect exports to affect home market prices. On the other hand, the IESO can intervene into export schedules when the home supply conditions are tight or when some home generators fail to deliver the scheduled power. Should this case occur, exports are cancelled to increase local market supply. Hence, the supply increase may burst the possible price spikes. These opposing effects, on average, can balance each other and cause no direct effect on prices. Indeed, this becomes clear in the test statistics.

In contrast, imports influence prices due to several reasons. First, it is clear that the last accepted bid clearing hour-ahead pre-dispatch scheduling can come from a local generator or a generator from other market via imports. Therefore, the pre-dispatch prices and scheduled imports in the hour-ahead planning can affect the market clearing prices in the real-time uniform-price auction. Second, imports are additional sources of supply, hence can increase supply schedule. Therefore, we expect causality from imports to prices and empirical evidence obtained above is in line with this expectation.

4. The Relationship between Imports and Prices

In the above analysis we concluded that there is a causal relationship between prices and imports but not so for exports to a large extend. In this section we quantify this relationship. To do so, we estimate the long-run solution of Equation (1), which can be interpreted as the Ontario supply curve, when exports are excluded from the relation.

(3) $P_t = \alpha' + \beta' t + \psi' M_t + \gamma' Q_t + u_t^p$, where

$$\alpha' = \frac{\alpha}{1-\sum_{i=1}^{p}\phi_{i-1}},\ \beta' = \frac{\beta}{1-\sum_{i=1}^{p}\phi_{i-1}},\ \psi' = \frac{\sum_{i=1}^{p}\psi_{i-1}}{1-\sum_{i=1}^{p}\phi_{i-1}},\ \gamma' = \frac{\sum_{i=1}^{p}\gamma_{i-1}}{1-\sum_{i=1}^{p}\phi_{i-1}}$$, in which the parameters are

stated as in equation (1). The coefficient estimates of Equation 3 are given in Table 6 below.

Table 6. Impact of Imports on Price

Variables	All	Peak	Off-Peak
Constant	-54.684 (0.000)	-57.062 (0.000)	-23.112 (0.000)
Trend	-0.0007 (0.037)	-0.0002 (0.047)	-0.0001 (0.007)
M	0.009 (0.000)	0.011 (0.000)	0.007 (0.000)
Q	0.005 (0.000)	0.006 (0.000)	0.004 (0.000)

Note: The p-values, derived from the standard errors computed by delta method, are given below in the parentheses. The lag length, p, in the underlying Equation (1) is chosen by AIC. The results from the lag length selected by SBC or HQC are qualitatively the same.

In all these equations imports affect prices positively with significant coefficients. For all hours, one percent increase in imports leads to 0.009 percent increase in prices, in the long-term when all the other variables stay constant. Similarly, this long-run effect of imports on prices is estimated at 0.011 and 0.007 for peak and off-peak data, respectively. Note also that these magnitudes are larger than the corresponding estimates of equilibrium quantity demanded coefficient indicating that, the largest percentage impact on equilibrium prices results from imports rather than the equilibrium quantity demanded or exports in our estimates.

We cannot directly observe the reasons behind the positive effect of imports on prices due to the complexity of the electricity flow in the network and data limitations. For instance, it may happen that simultaneously Ontario is exporting to and importing from New York. This simultaneous import and export by a market participant is called "a wheeling through transaction" in which the market participant (e.g., generation owner) moves energy through the Ontario grid and into another jurisdiction.[12] This type of transaction is mainly done for hedging purpose to minimize the market price risk exposure. However, we provide several plausible reasons for the positive relationship between imports and prices. When the system is in stress, that is either supply conditions are tight (e.g. due to unscheduled outages) or demand increases suddenly and unexpectedly (e.g. due to the temperature increase), and/or when the power producers exercise market power and withhold capacities from production (indeed, as we explain in the following section, capacity utilization rates are low during trade

[12] See the economic dispatch of linked wheel transaction at www.ieso.com/imoweb/consult/consult_se45.asp

activities), price increases in the auction until the unmet demand is served by high-priced offers. These increasing prices in the auction signal that in the upcoming auctions (for the following hours) the prices will rise unless the supply and/or demand conditions turn to normal. Alternatively, the auctioneer/system operator could announce that supply is in shortage and imports must be scheduled and they would be given price guarantees, as it happens in Ontario. These extra offers can come from imports or expensive spinning reserves. Prices can increase, even though imports are coming, because these imports may not be sufficient to render excess supply or restore the imbalance in supply and demand differential. Therefore, a positive relationship between imports and market prices can be observed.

In the following section we examine the main trading partners of Ontario and their impact on the Ontario prices.

5. Trade Patterns between Ontario and Neighbouring Jurisdictions

To determine the effect of imports from neighbouring markets on Ontario prices we use disaggregated data of imports. The disaggregated imports are only available for a limited period of time in our data set, which consists of imports from 12 neighbouring markets, for the period between May 1, 2002 and December 09, 2003[13].These regions are Manitoba (MB), Michigan (MI), Minnesota (MN), New York (NY), and eight trading zones in Quebec (which are called PQBE, PQDA, PQDZ, PQHA, PQHZ, PQPC, PQQC, PQXY).

Table 7 provides some descriptive statistics on the 12 interties that Ontario has with its neighbours. It can be seen that on average Ontario trades a lot with Michigan and New York, mostly importing from them. Although there are a lot of connections with Quebec (the 8 interties starting with "PQ"), relatively little trade takes place. Only one intertie, PQBE, through which Ontario exports to Quebec on average more than 300 MW during its export hours, and imports more than 338 MW during its import hours. The intertie PQPC is also a source of imports for Ontario, with an average of 170 MW coming every hour from Quebec. All other interties with Quebec are relatively less important.

[13] We still have 14,112 observations in total (about 20 months).

Table 7. Descriptive statistics of Ontario intertie, May 1, 2002 to Dec. 9, 2003

		MB	MI	MN	NY	PQBE	PQDA
Average Hourly Trade (MWh)	*Export*	56.2	315.6	50.1	483.3	302.5	71.0
	Import	-172.3	-521.9	-59.6	-499.4	-338.4	-70.7
Number of Hours of ...	*Export*	1,289	3,047	3,296	6,570	1,766	4,031
	Import	12,796	10,988	10,197	7,535	2,042	4,363
Maximum Value (MWh)	*Export*	237	1,366	152	1,700	432	98
	Import	-296	-1,441	-98	-1,992	-851	-194

		PQDZ	PQHA	PQHZ	PQPC	PQQC	PQXY
Average Hourly Trade (MWh)	*Export*	1.0		32.4	1.7	60.6	
	Import	-32.6	-85.1	-7.6	-170.0	-26.2	-27.7
Number of Hours of ...	*Export*	2	-	11,023	13	7,882	-
	Import	575	147	2,504	1,233	11	966
Maximum Value (MWh)	*Export*	1	-	98	5	123	-
	Import	-74	-104	-46	-315	-48	-58

We re-estimate equation (3) by using disaggregated import data, for all, peak and off-peak hours and summarize the results in Table 8 below.

Table 8. Impact of Imports on Price, by Intertie

Variables	*All*	*Peak*	*Off-Peak*
Constant	-77.424 (0.000)	-115.557 (0.000)	-52.410 (0.000)
Trend	-0.00009 (0.834)	0.001 (0.465)	-0.0003 (0.565)
Q	0.006 (0.000)	0.007 (0.000)	0.005 (0.000)
Manitoba	0.025 (0.307)	0.063 (0.098)	0.014 (0.419)
Michigan	0.013 (0.008)	0.008 (0.301)	0.015 (0.000)
Minnesota	0.020 (0.725)	0.052 (0.489)	0.013 (0.753)
New York	0.032 (0.000)	0.031 (0.000)	0.029 (0.000)
PQBE	-0.025 (0.290)	0.002 (0.932)	-0.031 (0.102)
PQDA	-0.047 (0.387)	-0.030 (0.617)	-0.024 (0.641)

Variables	*All*	*Peak*	*Off-Peak*
PQDZ	0.152 (0.646)	-0.095 (0.789)	0.233 (0.420)
PQHA	0.403 (0.387)	0.357 (0.147)	0.241 (0.139)
PQHZ	-1.214 (0.026)	-1.539 (0.027)	-0.238 (0.544)
PQPC	0.083 (0.189)	0.038 (0.550)	0.026 (0.690)
PQQC	3.676 (0.305)	-	-0.088 (0.949)
PQXY	-0.376 (0.172)	-0.287 (0.394)	-0.224 (0.369)

Note: The p-values, derived from the standard errors computed by delta method, are given below in the parentheses. The lag length, p, in the underlying Equation (1) is chosen by AIC.

Note that, since there is no import from PQQC in peak hours it is omitted from the corresponding regression. There are not many differences between the above equations and those obtained with aggregated import data in terms of the estimates of the coefficient of total demand variable (Q). In all equations the coefficient is highly significant and remains within the same magnitudes as those of aggregated data. On the other hand, not all the imports seem to exert significant effects on prices. For instance, in all data estimation, while the imports from Michigan, New York, PQHZ markets have significant effects on prices, those of others do not appear to be significant. For off peak data, we have only Michigan and New York[14], whereas for the peak data, we have Manitoba (at 10 percent level), New York and PQHZ as being significant. Notice also that the effect of PQHZ on prices is negative, while the others and aggregate imports are affecting prices positively. This negatively signed effect has also higher impact on prices as its magnitude indicates.

As we explain in Section 4, positive impacts of imports on prices can stem from tight demand and/or supply conditions during which the auctioneer announces high prices to meet the demand. Increase in imports does not translate to increase in supply curve but into quantity supplied stemming from increase in imports as market prices rise. On the other hand, imports affecting prices negatively can also happen due to the technological differences. In some periods, instead of using scheduled high cost generators it can be cheaper to import from regions in which they generate power using their low cost base-load generators. In this case, imports can lower the market prices. This happens usually when there is excess supply, and/or when demand is low (or when there is excess capacity in the market).

We have obtained hourly capacity utilization (the ratio of total output to total available capacity) data for coal, hydro, nuclear, wind and other (fossil-fuel-fired) production technologies in the Ontario market for the years 2006-2008 in total of 132360 observations. The average hourly capacity utilizations for the years 2006, 2007, and 2008 are 56%, 59.2%, and 53.5%, respectively. The highest capacity utilization occurs in the months of January, February and March with the rates 63%, 64%, and 59% in year 2006; with 61%, 67% and 65% in year 2007; and with 60%, 60%, and 61% in year 2008, respectively. The lowest utilization varies over years. In most of the hours capacity utilization by nuclear producers, which provide the base-load, are close to hundred percent. The second largest capacity utilization comes from hydro producers and the third largest utilization is due to the coal-fired

[14] PQBE, a trading zone in Quebec, is just missing to be significant at 10 percent with a p-value being equal to 0.102.

generators. The lowest capacity utilization comes from wind turbines in which the variation of production is rather seasonal. Although capacity utilization rates are low, that is to say production capacity constraints are almost never binding; imports are scheduled from other jurisdictions into Ontario. For example, the maximum import quantity from New York is 1992 MWh, and it is 1441 MWh from Michigan, as Table 7 indicates.[15] On the other hand, the maximum export quantity is 1700 MWh to New York. The export quantity is part of the total demand (Ontario demand plus exports), and the capacity utilization numbers presented above already take into account of exports. Then, an interesting question arises: why import quantities are high given the low capacity utilization rates. As we find positive relationship between imports and market prices, low capacity utilization rates may confirm that trade activities could be used to exercise market power. A policy recommendation of this finding is that the system operators and/or regulators should scrutinize the trade transactions to check whether local generators are withholding power from production during import or export times.

6. Conclusions

As electricity markets reform and open access transmission interconnects increasingly large territories, it becomes more and more important to understand how imports and exports influence local market prices. Due to the characteristics of electricity markets (such as non-storability, continuous match of demand and supply, transmission network constraints, and constantly changing demand and supply conditions), it is a challenging task to develop a general international or interregional electricity trade theory. It can happen that electricity is exported from a high price market to a low price market; for instance, during an off-peak time New York exporters may sell electricity to a low price Quebec market. This benefits both jurisdictions because New York exporters can recover their marginal production costs and Quebec importers avoid using power units with high start-up costs or simply save hydro resources for higher priced time periods. Also, in electricity markets simultaneous exports and imports, called wheeling through transactions, are possible. That is, even though prices are different in both markets a market participant can export electricity to another market and import into the home market at the same time. These factors complicate modelling trade

[15] These maximum imports quantities are a bit different than the import capacities reported in Table 2, as they represent the capacities only in year 2009.

behaviour among electricity markets/jurisdictions and estimating trade effects on market prices.

We employ an econometric approach to analyze the trade activities between Ontario and its neighbouring jurisdictions in the network, and find that while Ontario exports cannot be unambiguously tied to the hourly Ontario energy prices, imports can. We have shown Granger causality for all lags in the case of imports, with linear and non-linear tests.

Our intertie analysis shows that imports from two lines have a significant impact on prices, while other lines have little or no impact. These two lines (interties with Michigan and New York) are the busiest in terms of trade, so this result in not surprising. This paper, by making use of an extensive database, provides unique evidence that imports have an influence on price on a hourly basis, even if only a limited number of intertie have a significant impact. In the aggregate data we observe positive relationship between imports and prices. When we disaggregate imports and account for the role of each market on Ontario prices we observe mixed results. The imports from Michigan and New York increase the Ontario prices most of the time during trading periods. However, interties in Quebec may help reduce Ontario prices. Production technology differences could explain the sign of relationship between prices and imports. Quebec has low-cost hydro facilities that accounts for 97% installed production capacity which may substitute Ontario’s high-cost fossil fuel fired generators through imports. On the other hand, the price setting major power generators in New York and Michigan markets are mainly fossil fuel fired which can increase Ontario prices when the demand is high in the Ontario market.

To fully grasp the network interactions and trade impacts on market price, more investigation is still required. Using additional empirical data sources (such as local loads, network constraints data, and possibly other explanatory variables, such as temperature), as well as firm-level data, could be helpful to provide an analysis for further insights. A trade analysis incorporating such data is a future research direction one may consider. However, some of the data required, especially firm level data, is confidential and unavailable to public in many jurisdictions.

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APPENDIX: Summary Statistics

Statistic	Import (M) *MWh*	Export (X) *MWh*	Demand (Q) *MWh*	Price (P) *$*
All Hours (62,328 observations)				
Mean	1,027.302	1,288.290	17,311.412	51.359
Median	1,008.00	1,216.000	17,448.000	43.360
Standard Deviation	609.782	864.660	2,628.485	33.907
Skewness	0.668	0.855	0.107	7.217
Kurtosis	0.759	1.193	-0.331	209.425
Peak Hours: 8:00 to 22:59 (27,825 observations)				
Mean	1,097.326	1,153.252	19,268.489	65.101
Median	1,044.000	996.000	19,069.000	58.210
Standard Deviation	680.443	914.886	1,869.812	39.509
Skewness	0.690	1.180	0.257	8.818
Kurtosis	0.532	1.716	1.744	238.984
Off-Peak Hours: 23:00 to 7:59 (34,503 observations)				
Mean	970.831	1,397.191	15,733.125	40.277
Median	985.000	1,376.000	15,603.000	36.220
Standard Deviation	539.610	805.614	2,020.234	23.301
Skewness	0.441	0.635	0.342	2.776
Kurtosis	0.283	1.031	-0.192	21.907