Market Power Indices and Wholesale Price Elasticity of Electricity Demand

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Abstract: We investigate price responsiveness of wholesale electricity customers in the hourly Ontario wholesale electricity market. We use detailed generator and market level data to calculate market power measures such as the Lerner Index, Residual Supplier Index, and Pivotal Supplier Index which are combined with the competition model to structurally estimate price elasticity of demand in peak hours of summer and winter seasons. We find that the hourly price elasticities are small and change over the peak hours of seasons and years. For instance, in 2008 the elasticity estimates are in the interval of (0.019, 0.083). Comparing high demand winter hours to summer hours indicates that consumers' price responsiveness is lower in summer than in winter. We also employ these indices along with the estimated price elasticities to project the likely impacts of interconnection capacity expansions on market prices. Our calibrations show that even small amount of transmission investments (and hence trade activities) can result in substantial market price reductions.

Keywords: Price elasticity of demand; market power measures; electricity market;

JEL Codes: D22; D24; L13; L94; Q41

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1. Introduction

Measuring price responsiveness in electricity markets at the wholesale and retail levels has been an important focus of the recent literature. Especially in the era of restructuring wholesale electricity markets, it is imperative for market designers, system operators, power producers, and regulators to know how wholesale or retail customers would respond to market-based rates (e.g., wholesale market clearing prices) or regulated rates (e.g., time-of-use prices). In the case of low price responsiveness or near zero price elasticity of demand the market prices can theoretically increase up to the price cap, and practically this has been observed in many wholesale power markets around the world.[1] Evidently, some degree of price responsiveness is needed to foster welfare improving market outcomes, yet which pricing mechanisms lead to more efficient results in a given market has not been clearly addressed mainly due to the difficulty of allocating fixed costs of operations in the industry.

It is generally assumed that the price elasticity of demand (at both retail and wholesale levels) is small because most customers are not able to respond to changes in electricity prices in the short-run. This is because they are subject to some form of regulated tariffs. To create some price responsiveness especially in the retail sector, regulatory agencies have implemented several pricing methods such as time-of-use prices, multi-tier prices, and wholesale market clearing prices. For instance in the US, only one percent of households are subject to time-varying rates and one percent of this one percent are on dynamic pricing rates.[2] In Ontario, Canada time-of-use pricing was initially implemented in mid-2005 and gradually extended with smart meter installations.

Knowing aggregate market demand elasticity is equally important for all market participants including power producers, and customers such as exporters, importers, industries and businesses. The aggregate electricity demand elasticity indicates wholesale customers' ability to reduce their consumptions in the case of wholesale price increases. This wholesale price response will ultimately impact all types of customers (wholesale customers in the short-run, and retail customers in the long-run through regulatory rate changes) in the market. While low price

[1] Examples include California, Texas, and Ontario markets.
[2] See Faruqui et al. (2014). Charging wholesale prices to the retail customers is an example of dynamic pricing.

responsiveness in the aggregate demand can harm the consumers' welfare, high price responsiveness can limit market power of power producers and cause productive efficiency by making use of the low-cost production technologies.[3] Moreover, having known the elasticity estimates can help both power sellers and buyers to form and submit their offer and bid schedules optimally.

Price elasticity of electricity demand studies mainly focus on the price responsiveness of the residential (and small industrial and business) customers who are essentially subject to regulated rates. Research incorporating wholesale customers who are subject to real-time market prices is rare. The wholesale buyers (such as industrial customers, regional electricity distribution companies, exporters, dispatchable loads) are sensitive to the peak price conditions and the distribution of prices affected by the hourly (or a finer time scale) consumption behavior, and supply and weather conditions. A notable paper examining short-run price elasticity of demand for wholesale customers is Patrick and Wolak (1997) who study industrial customers' electricity demands and their price responsiveness in the day-ahead UK market using a nonlinear econometric model. In their model each industry minimizes its electricity consumption cost function. The solution of the cost minimization leads to each industry's demand function for electricity, which is then being estimated using the industry level data such as consumption levels and electricity prices. They find that price elasticities are small, specifically between 0 and -0.05 for four out of the five industrial sectors in the UK. They estimate relatively higher price elasticity (in absolute terms) of -0.27 in the water supply industry.[4] Our elasticity estimates are closer to their estimates although our modeling framework is different and based on a competition setting in which we focus on the aggregate wholesale customers' response to the real-time hourly Ontario wholesale electricity prices, called hourly Ontario energy prices (HOEP). Along with the competition model we utilize actual firm and market level data to estimate price elasticities during the peak months and peak load periods over the years. For

[3] For example, Borenstein and Bushnell (1999) find that demand inelasticity is an important determinant of market power exercise in the California electricity market.

[4] Lijesen (2007) estimates hourly price elasticity in the Dutch power market using a reduced form regression model and finds the price elasticity of -0.0014 in a linear specification and of -0.0043 in a log-linear specification.

example, we find that price elasticity is in the range of (-0.144, -0.013), depending on the time of year in 2007.

There is also a growing literature examining the impacts of several types of static and/or dynamic time-varying pricing methods applied to residential, and small commercial/industrial customers. In this literature, a number of studies have extended the work of Vickrey (1971) and Chao (1983) to incorporate the efficiency gain analysis and price responsiveness predictions for pilot projects run in certain cities/states/provinces.[5] Price elasticity estimates in this literature are highly variable depending on the rate structures and locations. In another study, Reiss and White (2005) develop and estimate a household electricity demand model for assessing the effects of rate structure change in California. They find that a small fraction of households respond to the price changes, and the price elasticities range from 0 to -2.[6]

The main contributions of our work are as follows. First, we measure the price elasticities of wholesale electricity demand based on a Cournot competition model. As a solution of the model we link the market power indices of Lerner Index (LI) and Residual Supply Index (RSI) through which we estimate the wholesale price elasticities. The main advantage of using these indices is that they are computable in hourly basis as we have marginal costs, productions, and capacities information available. Also we do not need to specify a functional form for the hourly electricity demand in the competition framework. Second, due to the endogeneity issue between the left and right hand side variables (the LI and RSI, respectively) observed in the equilibrium conditions, we introduce temperature, which varies independently of demand and supply conditions, as an instrument to robustly estimate the elasticities. As we show this instrument is a quite powerful predictor of the RSI. Third, instead of obtaining a single elasticity estimate in the entire sample, we subdivide time frames of the study period into the yearly sample, the peak seasons only sample, and the peak load periods in the peak months only sample. As price responses will differ across the time periods we will compare and discuss the implication of these variable elasticity estimates.

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[5] Examples include Borenstein (2005), Wolak (2011), and Faruqui et al. (2014), among others.

[6] Related to the price response of residential demand in San Diego-California, Bushnell and Mansur (2005) estimate the impact of lagged residential prices on the consumption and find elasticity of demand equal to -0.1.

Linked to our work the Residual Supply Index (RSI)[7] has been used as a market power measure in the electricity markets in the US and Europe, and examples include Sheffrin (2002), Bergman (2005), and Gianfreda and Grossi (2012). By definition a firm's RSI is calculated as the ratio of total market supply capacity (excluding this firm's production capacity) to the market demand quantity at a given time. Therefore, it measures pivotal status of the firm and determines whether this firm's production is needed to meet the market demand. As observed in the US and European electricity markets and theoretically re-derived in Newbery (2009), a firm's market power measured by the Lerner Index (LI) is inversely related to this firm's RSI: the lower the RSI the higher is the firm's market power. In the situations in which marginal cost information is not readily available, the RSI can be computed (as capacity and demand quantities are observable) to determine the level of market power held by the firm.

Our paper is different than the above mentioned RSI-based studies, but indicates some parallels to the work of London Economics (2007). Similar to the London Economics study we are able to compute both hourly LI and RSI, and estimate the relationship between them. Based on this relation we obtain hourly price elasticities of demand. However, our study differs from the London Economics study (which runs multiple regressions using European market data to test the relationship between these indices) in several ways: a) we argue that the London Economics regressions are inconsistent due to the endogeneity issue between LI and RSI. We propose to use temperature as an instrument, which is simple yet effective variable, to overcome this issue and obtain reliable coefficients for the regressions between these indices; b) as opposed to focusing on a few firms, we carefully compute the marginal costs of every generator in the system employing flexible marginal cost formulations; c) we also focus on the policy implications of our findings and project market prices using our elasticity predictions to be able to assess the likely impacts of some supply scenarios stemming from transmission capacity expansions.

Initially to assess the competitiveness of the Ontario wholesale electricity market we calculate market power measures; the pivotal supply index (PSI), the residual supply index (RSI), and the Lerner index (LI) using hourly generator and market level data. We then model the competition

[7] The RSI was first designed by the California Market Surveillance Committee. Sheffrin (2002) shows that there is a negative relationship between the RSI and LI in the California electricity market in summer 2000.

in the Ontario market as a capacity constrained Cournot model and solve it to derive the theoretical relationship between the RSI and LI. Using this relation and the computed hourly values of these indices we estimate the wholesale price elasticity of demand over several time intervals in 2007-2008. Finally, we illustrate how these indices and estimated elasticities could be used to project market prices in the case of change in supply conditions. Specifically, we project market prices under certain transmission capacity investments.

The structural modeling framework that we apply is more appealing and easier to use than its competitors, which need to use more variables and data points to structurally specify demand and supply curves. This could be a daunting task in the electricity markets context as some firm-level data are private and hard to obtain. Contrary to the alternative approaches, we do not need to specify the functional forms of the demand and supply curves and the factors causing demand and/or supply shifts. For example, we need only assume that the market demand curve is downward sloping and differentiable.

In this study we find that there are a few players who are pivotal and exercise market power in the Ontario market. Using the largest firm's RSI and the various LI measures (based on different marginal cost approximations) we observe that hourly price elasticities are small, and change over the peak hours of seasons and years. Specifically, in 2007 the wholesale customers' price response is the lowest in summer Q3 (the highest demand quartile) with elasticity 0.013, which is smaller than the winter Q3 elasticity of 0.071.[8] The price responsiveness in all hours of 2007 is 0.144. The elasticity figures in Q3 are lower than the summer/winter Q2 (top 50 percent of the highest demand hours) elasticities. When we compare the elasticities over the peak seasons we find that consumer price responsiveness is lower in summer than in winter for all time intervals of Q2, Q3, and all hours in the year. This could be due to the lack of alternatives in summer time when the weather gets hot. In winter, however, when it is cold some of the consumers facing high electricity prices can switch to substitutes for electricity such as natural gas and fuel-oil for space heating. As for the regression results for 2007, we also validate the predicted negative relationship between the LI and RSI in all regressions run for the year 2008, where the elasticity estimates are in the interval of (0.019, 0.083) depending on the time periods examined.

[8] Although we find negative price elasticity of demand in all of our estimations, for the sake of expository brevity we report them in positive magnitudes.

Comparing high demand winter hours to summer hours indicates that consumers' price responsiveness is lower in summer than in winter. For all peak seasons and their peak periods (Q2 and Q3), and the overall hours in the year, elasticities were lower in 2008 than in 2007. This can be explained by the increased electricity consumption in each study period of 2008, while the market price levels on average were near each other in both years.

To check the robustness of these elasticity estimates, we will also directly use the fuel prices as a proxy for the marginal costs in computing the hourly LI. We find that the elasticity figures are similar both qualitatively and quantitatively regardless of employing actual fuel prices or actual dollar amounts spent for each fuel type in the LI calculations. For example, in 2008 the winter elasticities are in the range of (0.026, 0.049) when the average variable fuel prices are used, and between (0.025, 0.047) when the hourly fuel spot prices are directly used. The summer elasticity figures show some minor differences especially at the Q2 and Q3 periods, but throughout the summer they are of similar magnitude. Therefore, we conclude that our elasticity estimates are robust to a different measure of the LI obtained by the alternative marginal cost formulation.

As an application of the model, we also examine the impact of two counterfactual supply scenarios regarding expansions in interconnection capacity facilitating more trade activities. These scenarios are justifiable because transmission investments in Ontario and hence the volume of the trade between the neighboring jurisdictions have been increasing since the opening of the wholesale market. Specifically, we will project the market prices in case of increase in import quantities from the adjacent markets in the transmission network. In these supply scenarios we will assume actual import levels increased by 25% and 50%, respectively, during the highest demand hours of winter 2008. We find that wholesale market prices go down as a result of increased import activities. The average market prices during the peak hours are 82.2, 52.5, and 37.5 dollars per MWh in the actual market, and the markets with the increased imports, respectively. The market prices under the 50% increase in imports scenario are always less than the ones with a 25% increase. This is due to the fact that imports are part of market supply and increased supply reduces the residual demand of the Ontario Power Generation (OPG), the largest firm in the market.

The organization of the paper is as follows. Section 2 examines the Ontario market structure along with the specifics of the data sets. Section 3 defines the competition model employed in the paper. In Sections 4 and 5 we compute the market power indices to determine the competitiveness of the market and use these indices to estimate the hourly price elasticity of wholesale electricity demand in several periods of 2007 and 2008. Section 6 offers a robustness check of the estimated elasticities using the fuel spot prices directly. Section 7 proposes an application of the modeling framework to project likely impacts of certain supply scenarios. Finally, we conclude the paper in Section 8 with a short discussion of the key findings.

2. Data and the Market Structure

To measure wholesale buyers' price responsiveness in the hourly Ontario wholesale electricity market, we utilize detailed plant and market level data provided by the Independent Electricity System Operator (IESO) and the Statistics Canada. The data includes hourly export/import quantities, hourly production and available production capacity of each generator, hourly market clearing prices and demand quantities, technical features of generators (such as heat rates and emission rates) and fuel data (including fuel spot prices, actual money spent on each fuel type, and energy content of the fuel). In computing the market power indices we use all of the active generators out of 563 registered ones and apply the hourly data in 2007 and 2008 in the Ontario market. We map the generators to the owners of the firms and observe that there are a few dominant firms with many small fringe firms in the market. As examined in Aydemir and Genc (2014), who analyze the impact of electricity trade on equilibrium outcomes (such as welfare losses, emissions levels, and productions) using a portion of the above data, the dominant firms are Ontario Power Generation Inc (OPG), Bruce Nuclear Inc (Bruce), and Brookfield Renewable Energy Inc (Brookfield) in the study period.

OPG has over 60 generators in its hydroelectric, nuclear, coal, and natural gas fired plants. Using their production characteristics, available capacities and production costs we are able to construct marginal cost function of OPG for each hour. The total available capacity of OPG generators changes every hour (due to, e.g., generation outages/de-ratings, and regulatory/environmental restrictions); the minimum available total capacity is 12,900 MW, the maximum is 19900 MW, and the average is 16,917 MW per hour in year 2007. Its average hourly output is 11,966 MWh electricity, covering 64% of the total market demand which is on average 18,778 MWh in the year.[9] The bulk of its production comes from nuclear and hydropower stations with market shares 44.2% and 29.6%. In 2008, both average market demand quantity and OPG's average production has increased to 19,453 MWh and 12,201 MWh, respectively. However, its total share in meeting market demand is slightly reduced to 62.7%, but its share of production from nuclear and hydro units is increased to 45.1%, and 32.8%, respectively.

Bruce nuclear has six nuclear generators with identical heat rates. Total available production capacity from these six nuclear generators changes almost every hour, and in 2007 its average total capacity is 4,224 MW with average production 4094 MWh. In 2008 its average production slightly goes down to 4041 MWh out of 4231 MW average available production capacity.

Brookfield operates hydropower and wind facilities and a natural gas–fired generator. We assume that marginal cost of production for the wind and hydro generators is zero as their inputs are free.[10] Therefore, Brookfield has a two-step marginal cost function: zero marginal cost up to the total hydro and wind available capacities, and a positive marginal cost for the natural-gas unit. Its total available capacity for production changes every hour, and in year 2007 its average available capacity is 941MW and its average production is 247 MWh. In year 2008, its average output is increased to 317 MWh out of 916 MW average capacity.

The rest of the firms in the market run hydro, wind, biomass, and natural gas-fired production technologies. These firms are generally small in production capacity and hence they are assumed to be price taking fringe firms in Aydemir and Genc (2014). However, in the current setting of the paper we do not impose such behavioral restriction on the fringe firms: they could act as strategic or non-strategic. They operate many gas-fired generators with different heat and emission rates, and marginal costs, and their sizes are asymmetric: for a given hour available production capacity of a gas generator ranges from 0 to 580 MW. In 2007 these small firms on average has produced 1509 MWh (meeting 8% of average demand) out of 2921 MW average

[9] The maximum market demand levels are recorded 26,658 MWh and 27,477 MWh in 2007 and 2008, respectively; however the load factor - the ratio of average demand to peak demand- is 0.7 in each year. Utilities, generation firms and the system operators generally prefer higher load factors to lower ones in order to reduce generation costs and maintain system stability.

[10] However, in reality opportunity cost or shadow price of hydro, which is harder to compute due to the complications in dynamic optimization, could be positive for some operating hours, especially in peak periods.

available capacity. In 2008 their average production reduced to 1462 MWh (meeting only 7.5% of the average demand) out of the increased available capacity of 3974 MW. Most of their production comes from the high cost natural-gas fired generators. The combined output from hydro and wind comes second, and biomass-fired generation is the third in both years.

Using the firms' actual outputs one can measure the market concentration level via Herfindahl-Hirschman Index (HHI) which is equal to sum of the squared market shares of all firms.[11] As we have hourly production data for each firm and its generators, it is easy to compute the hourly HHI at the firm or generator level.[12] Nevertheless due to the firm's ownership and operational control over its generators it is more plausible to calculate the market share of each firm by aggregating outputs of all its generators.

If the three dominant firms (OPG, Bruce, Brookfield) with fringe market structure, where all fringe firms' output is aggregated, is assumed then the average hourly HHI in 2007 is 5131 with the standard deviation 294. The winter (Jan-Mar) and summer (June-Aug) HHI averages are 5265 and 5169, resp. Although the winter and summer HHI averages are close to the sample mean, the highest levels of HHI are still observed in peak winter and summer seasons. If we define the "high level" of HHI as a value above mean plus standard deviation, we find that for 1447 out of 8760 hours in the year, the HHI exceeds this high level in the range of [5425, 6180]. 662 hours of the winter and 350 hours of the summer, the HHI surpasses this high HHI level. That is, the high levels of HHI are observed 16.5% of time in all hours and 11.5% of the time it happens in the peak winter and summer seasons.

When we keep the dominant firms intact but disaggregate the fringe firms into nine firms[13] according to their generator ownership, we obtain a 12-firm market structure. We then compute hourly HHI and find that the average hourly HHI in 2007 is 5108 with the summer average of 5160 and winter average of 5237. Similar to the 4-firm structure, the higher HHI levels are

[11] Formally, $HHI = \sum_i s_i^2$, where $s_i = 100 * q_i/Q$, q_i is the output of firm i, Q is the total market output at a given time (hour).

[12] Most of the North American wholesale electricity markets do not release the hourly generator-level actual production data. Ontario market is an exception and quantifying the concentration index is a worthwhile exercise to get a sense of the extent of the market's competitiveness.

[13] These firms are Trans Alta, Brighton Beach, Northland Power, Trans Canada, Cardinal, Abitibi, GTAA, Tractable Canada, and the rest of the generators are aggregated to form the ninth company.

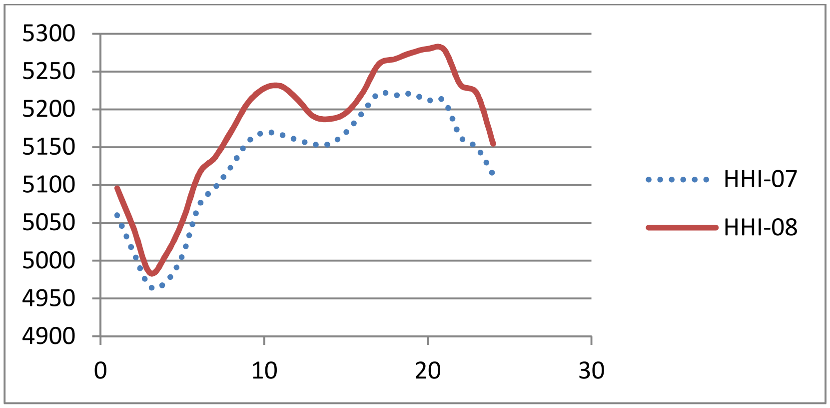
mostly observed in the peak winter and summer seasons in the 12-firm structure: the high levels of HHI occur 16% of the time, and its share in the summer and winter seasons is 11% in the whole sample.

Clearly the 4-firm and 12-firm structures lead to the similar HHI properties as the small firms' production shares are small. The high HHI values may suggest the existence of market power in the Ontario market. However, this index does not tell which firm holds how much market power or whether firms actually impact the market prices. Hence, studying other market power measures becomes indispensible to draw conclusions about the magnitude of market power.

We also compute the HHI for all hours in 2008 with the 4-firm market structure. The average HHI is 5177 with standard deviation 348. The number of high levels of HHI (i.e., the HHI values above mean plus standard deviation) is 1413. That is, 16% of time HHI was higher than the benchmark. The winter and summer average HHI values are 5504 and 5296, resp. Similar to the year 2007 findings, the high levels of HHI are observed in winter and summer months with 9% and 5% of the time, resp. That is, 14% of time high levels of HHI is observed in the peak seasons of 2008. Comparing 2007 HHI values to 2008 ones indicates that the market has become more concentrated and the share of high levels of HHI in the peak seasons has gone up over the years. When the 12-firm structure is assumed, the average HHI in 2008 becomes 5122 with standard deviation 366. The summer and winter average HHI values are 5263 and 5348. Similar to the 4-firm structure the high HHI vales are observed 16% times in the year. The distribution of high HHI levels over the seasons is 8% and 5% for the winter and summer, resp.

In Figure 1 we plot 4-firm structure HHI by the hour of the day in years 2007 and 2008: for all hours the Ontario market is more concentrated in 2008 than in 2007. Evidently the highest HHI gap appears in the peak hours, although the average HHI values over the 24-hours are only slightly different: they are 5131 and 5177 for the years 2007 and 2008, resp.

Figure 1: HHI in 4-firm structure over the years of 2007-2008 by the hour of the day: x-axis hours; y-axis average HHI.



3. Modeling Competition

Our modeling framework assumes a Cournot competition in the Ontario wholesale power market where the dominant firms are OPG, Bruce, and Brookfield.[14] There are also some small firms who could behave as strategic firms or price-taking competitive fringe. All firms strive to maximize their profits while meeting the total market demand which is represented by $Q_h = Q_h(p)$ is continuous, differentiable, and downward sloping function of the wholesale price p.[15]

Each strategic firm i maximizes its profit function for each hour h

(1) $\pi_{i,h} = p_h(Q_h)q_{ih} - c_{ih}(q_{ih})$.

If the fringe firms are price takers then the residual demand for firm i as a function of market price p is $[Q_h(p) - S_h(p) - I_h - q_{-i,h}]$, and $S_h(p)$, I_h are the fringe firms' aggregate supply and total imports, respectively. $q_{-i,h}$ is the quantity produced at price p by other dominant firms (-i), and $c_{it}(q_{ih})$ is the total production cost function for firm i at time h.[16]

[14] Cournot models are commonly used in market power studies in the electricity markets (e.g., Borenstein and Bushnell (1999), Puller (2007)), not only because they are tractable and implementable, but also some Cournot assumptions are justifiable in electricity context.

[15] Different than Aydemir and Genc (2014), we do not constrain the behavior of the small firms, and also let the demand function be as general as possible. They restrict the small firms to act as price takers and assume an affine demand curve.

[16] There is no forward market nor are forward sales in Ontario due to the market design. All power exchanges are carried out in the pool type real-time market. If there would be forward sales then firm i's profit function would be $\pi_i = p(q_i - x_i) + fx_i - c_i(q_i)$, where x denotes forward quantity sold at forward price f.

If fringe firms are strategic then each strategic firm j, including the dominant firms, maximizes its profit function for each hour as in expression (1), but the residual demand faced by firm j will be equal to $[Q_h(p) - I_h - q_{-j,h}]$, where $q_{-i,h}$ is the total quantity supplied at price p by the rivals of firm j.

For each firm production from each of its generators is bounded by the hourly available production capacity K_{igh} for firm i from a generator g at time h.

In constructing a firm's marginal production cost function we take into account of aggregate fuel costs, generator characteristics such as heat and emissions rates, and available production capacities of each generator owned by this firm. As an alternative approach we will also use the fuel spot prices directly as an approximation to the marginal production costs in checking robustness of the model outcomes in Section 6. For each generator we compute the marginal cost of production as:

(2) Marginal Production Cost = *Marginal Fuel Cost+ Marginal SO2 emission cost+ Marginal NOx emission cost,* where

Marginal Fuel Cost = Heat rate of generator (in kj/kwh)* Dollar spent on fuel($)/[Total fuel consumption (in ton)*Energy content (in kj/kg)] * a conversion factor = $/MWh.

The emissions costs are,

Marginal SO2 emission cost = Heat rate of generator (kj/kwh) * SO2 rate of generator (g/MJ) *Price of SO2 emission permit ($/lb) * a conversion factor = $/MWh

Marginal NOx emission cost = Heat rate of generator* NOx rate of generator*Price of NOx emission permit * a conversion factor = $/MWh

The marginal emission cost for a generator will include SO2 and NOx emissions rates (g/MJ) and permit prices, as firms pay for emission certificates of NOx and SO2 gasses.[17] In Ontario diesel, refinery gas, wood and wood waste, landfill gas, coal (lignite, bituminous, sub-bituminous), natural gas, and oil-fueled production technologies release NOx emissions. Among

[17] The cost of CO2 emissions is not part of the marginal cost formulation as it is not traded in the Ontario market.

these technologies, only coal (lignite, bituminous, sub-bituminous) plants generate $SO2$ emissions. Wind, hydropower and nuclear generators are emissions free. Once the total marginal costs for each generator are calculated, for a given cost level we add the available production capacities of generators, which change hourly, to obtain the marginal cost curve for a firm. We find a different marginal cost curve for each firm for each hour.

4. Market Power Indices

To examine market power and estimate the price elasticity of aggregate demand in the Ontario market first we need to compute the market power indices which will be directly implied by the quantity choice profit maximization problem. In the electricity markets there are several commonly used market power indices which are the Pivotal Supplier Index (PSI), the Residual Supply Index (RSI), and the Lerner Index (LI). The first two indices include quantity information such as market demand quantity and firms' production capacities. The latter one is a function of prices; mainly market prices and marginal costs. The PSI is a weaker form of the RSI which is interlinked with the LI through a Cournot firm's first order necessary conditions as we explain in Section 5.

4.1 Pivotal Supplier Index (PSI)

The PSI measures market power based on a generator's pivotal status (see Borenstein et al., 1999). If the production capacity of one firm/generator is greater or equal to the total available capacities of all firms/generators minus the total market demand (in equilibrium market demand equals market supply which is a summation of total generation plus imports) that must be served, then this generator is considered to be a pivotal supplier, which can exercise market power and increase market price up to the price cap[18]. Alternatively, if a firm faces a positive residual demand (market demand minus the total available capacity of rival firms) then this firm is called pivotal. For a given period of time, the PSI is a binary variable for a firm such that, if the residual demand is greater than 0 then the PSI equals 1 and the firm is assumed to be pivotal, otherwise it becomes 0 and the firm is non-pivotal. Accordingly, the PSI for a firm/generator is obtained by averaging PSI's over time at which it is pivotal. In essence the PSI measures the frequency of monopoly power held by a firm.

[18] The price cap is set to \$2,000/MWh in the Ontario market.

Related to the supplier's pivotal status the Supply Margin Assessment (SMA) was designed by the FERC as a form of market power measure. It is a type of PSI applied to annual peak condition: during the peak hours, if a supplier is pivotal, then this supplier fails the SMA screen test. The FERC assumes 20% threshold rule for the PSI; if the firm's average PSI is above 0.2 during the peak hours then this firm is assumed to have a market power.

In Table 1, we report the average hourly PSI for each firm, and the results of SMA test in 2007 and 2008. In the SMA test peak hours are defined as the top quartile of the highest demand hours in summer and winter. In a given year, the PSI values are always higher in peak hours than all hours, and all firms but Brookfield fail the SMA test. From year 2007 to 2008, all firms gain more market power as their PSI values rise. It is clear that OPG is pivotal in all hours, and Bruce is pivotal 66% of peak time in 2007 and 74% of peak time in 2008. According to the FERC criteria, the only firm that passes the market power test is Brookfield, although it has some market power less than 1% of time. If fringe firms would act in concert and behave strategically, then they would be able to affect the market outcomes significantly; they are pivotal 21% and 40% of the high demand times in 2007 and 2008, resp.

Table 1: Average hourly PSI and SMA test results in years 2007 and 2008.

	2007	**2007peak**	**SMA-07**	**2008**	**2008peak**	**SMA-08**
OPG	1	1	Fail	1	1	Fail
Bruce	0.22	0.66	Fail	0.21	0.74	Fail
Brookfield	0.002	0.005	Pass	0.004	0.009	Pass
Fringe	0.06	0.21	Fail	0.11	0.4	Fail

4.2 Residual Supply Index (RSI)

Another practical and commonly used market power index in electricity markets is the Residual Supply Index (RSI), originally developed by the California Market Surveillance Committee (see Sheffrin (2002)), and now being used in other power markets in the world. The RSI is considered to be more generalized form of PSI and is originally calculated as the ratio of residual supply (total supply minus largest seller's supply) to the total demand quantity, where the total supply is the summation of total in-state supply capacity and total net imports, and the demand quantity is the sum of metered load and purchased ancillary service, and the largest seller's supply refers to the difference between its capacity and contract obligation to load. The RSI calculations are important as we will show in Section 5 that the RSI becomes a significant predictor of price-cost markups.

Similar to the PSI, the RSI can also be calculated for any firm and the RSI of the firm indicates its pivotal status which determines whether this firm faces any positive residual demand (market demand minus the rival firms' total production capacity or output). The firm that is facing a positive residual demand is able to unilaterally raise the market price above its marginal cost.

We define firm i's RSI at hour h as,

$RSI_i(h) =$ [Total available market production capacity(h) plus imports(h) minus firm i's production capacity(h)] divided by total market demand(h) = $[K(h) + I(h) - k_i(h)]/D(h)$.

In the definition of RSI in Sheffrin (2002) and Newbery (2009) it seems that they use the installed capacities of generators. We argue that the relevant capacity measure is not the installed capacity but the available production capacity in a given hour, (which significantly varies over trading hours because of generation outages/deratings, regulatory/environmental restrictions, wind forecast, and the IESO's manual actions, e.g., to constrain a generator to a fixed production level) because some portion of the installed capacity is never used or may not be available for production either due to the production specific reasons mentioned above or the transmission constraints which restricts the production. Moreover, the installed capacities of the power firms are a static indicator and are time invariant. Therefore, in calculating total production capacity in any hour we will only consider the available production capacities of all generators/firms. The available capacity for a generator at each hour indicates the maximum possible production quantity. The treatment of the intermittent technologies such as wind and solar power generators in the RSI calculations is that we discard their production capacities as in reality the production constraints only bind for a few hours in a year in the Ontario market, and therefore we assume that their actual production quantities are equal to their available capacities in each time period in the RSI formulation.

If $0 < RSI_i(h) < 1$, then firm i's production is needed to meet the market demand, and hence it is pivotal and has an absolute market power. Otherwise, the rivals of firm i are able to meet the demand.

Due to the reasons mentioned in Section 2, we will focus on 4-firm structure in the Ontario wholesale electricity market where there are OPG, Bruce, Brookfield, and the fringe firms whose outputs are aggregated in the RSI computations. In Table 2, we present the average RSI values of all firms in all hours and peak seasons (winter and summer) of 2007-08.

Table 2: Average hourly Residual Supply Index (RSI) for all firms in 2007 and 2008 winter, summer, and all hours in the years.

2007	**RSI-OPG**	**RSI-Bruce**	**RSI-Brook**	**RSI-Fringe**
Winter	0.431	1.121	1.278	1.178
Summer	0.461	1.165	1.357	1.271
All hours	0.463	1.147	1.325	1.229
2008				
Winter	0.437	1.138	1.296	1.204
Summer	0.528	1.237	1.426	1.268
All hours	0.516	1.199	1.380	1.232

Table 2 indicates that the lower the RSI the higher is the firm's market power. In 2007 the average hourly RSI for OPG is 0.463 with the winter RSI of 0.431 and summer RSI of 0.461 implying that the largest firm OPG has a market power and can impact market prices, and it has more market power in winter than in summer. Bruce Nuclear is another dominant firm whose average RSI is 1.147, and its winter and summer RSI are 1.121 and 1.165, resp. The highest RSI values in the market are observed only for Brookfield whose average RSI is 1.325, and it is 1.277 in the winter and is 1.357 in the summer. It is clear that for both Bruce and Brookfield the RSI values are higher in high demand-high price summer season than the overall year RSI. This implies that they have a lower market power in summer as opposed to what is expected in the summer season. One explanation for this result is that they have higher available production capacities in summer and hence produce more to benefit from high prices. This behavior is also observed from fringe firms but not from OPG in the summer. The RSI values for fringe firms are 1.229 for all hours, 1.271 in the summer and 1.178 in the winter. All firms have higher market power in winter than in summer. A reason for this finding is that during winter time there is less water available for hydro production.

The RSI values for all firms but OPG are above 1 implying that they have a limited market power. According to the RSI benchmark of 1.2, which has been applied in the California market (see Sheffrin 2002), a power firm with RSI higher than 1.2 is considered to be competitive. Based on this threshold level all dominant firms have a market power, including Brookfield whose RSI is below 1.2 for 21% of time (1825 out of 8760 hours in 2007), even though its average RSI is about 1.325. This implies that each dominant firm has a market power at least 20% of time.[19]

Compared to year 2007, the average hourly RSI values for all firms have increased in 2008. This implies that firms had less market power in 2008. This result also holds for all dominant firms across the winter and summer hours.

Finally, it is worthwhile to note that the RSI determines whether a firm has a market power or not based on the quantity information such as market demand quantities, imports/exports, and available production capacities. The existence of market power alone does not say how much a firm can influence the market prices. Therefore, below we will link the existence of market power (RSI) to the market power exercise (e.g., price-cost markup measure) and examine implications of RSI on the price-cost markups.

4.3 Lerner Index (LI)

A simple market power index that indicates a relative difference between the actual market price and marginal cost price is the Lerner Index (LI). If the LI is defined for a market (in which marginal cost of the last dispatched generator determines the system/market marginal cost), then it measures the overall market power in the industry. If it is defined for a firm (in which the firm's marginal cost of the most expensive dispatched generator determines the firm's cost), then it measures the firm's ability to raise the market price above and beyond its marginal cost.

Formally, $LI_k = (p - mc_k)/p$, $k = i \text{ or } m,$ where i represents firm i and m denotes market. If k refers to firm then the LI gives firm i's ability to raise the market price to p given that its marginal cost of production at the supplied output is mc_i, which can be non-constant and vary with the production level over time. If k refers to market then the LI leads to a measure of market

[19] OPG is pivotal at all times and its RSI is always less than 1 for all hours.

performance and determine how competitive the market is. In this case, one needs to figure out the marginal cost of the marginal generator/firm, which will be the highest marginal cost in the system and hence it is called the system marginal cost (SMC). In a given hour the marginal output can come from any firm (with any size) whose output is needed to equilibrate market demand to market supply.

The SMC in any hour is determined as follows. First we compute the marginal production cost of every generator based on the formula (incorporating fuel and permit prices, and heat and emission rates) defined in expression (2). Then we choose the maximum of marginal costs of all active generators in the system producing positive output, which will be denoted by mc_m, in a given hour. This SMC will probably change every hour as the marginal production technology can change from hour to hour depending on supply and demand conditions. Similarly, to calculate firm i's (highest) marginal cost in any hour, we take the maximum of marginal costs of all generators owned by this firm producing positive outputs. Firm i's marginal cost will be denoted mc_i. We exclude back-up generators providing spinning reserve capacity in the system from firm i's production portfolio in calculating its marginal cost mc_i, as the back-up power is priced differently than the wholesale power, possibly higher than the market price depending on the scarcity conditions. When we calculate the system market power LI_m (or the relative markup over the system marginal cost) we observe that a fringe firm with a natural gas plant, which has been called upon for production, has the highest marginal cost in the market for all hours of 2007-08.

The market power indices RSI and LI are interconnected through the profit maximization problem. The LI includes price information and is usually burdensome to calculate as the marginal cost data needs to be derived for all generators using their technical characteristics and fuel prices. The RSI incorporates quantity information such as demand quantity and available production capacities of all active generators. Both the RSI and LI are dynamic indices and change over time (e.g., hourly) as demand, available production capacity, price, and marginal costs vary. In the next section we will derive the structural interplay between the LI and RSI, compute their hourly values and run series of regressions to quantity the linear inverse relationship between them.

5. Estimating Price Elasticity of Wholesale Demand

Using the RSI and LI values we will estimate price elasticity of wholesale electricity demand in various time periods. Similar to Newbery (2009), firm *i* maximizes its profit function

$\pi_{i,h}(q) = p_h(Q_h)q_{ih} - c_{ih}(q)$, where Q_h is the total demand quantity met by the firms' productions plus imports in hour h. Here we need not to specify the functional form of the inverse demand $p_h(Q_h)$ but only assume that it is downward sloping and differentiable. Market demand function is $Q_h(p)$ and the quantity demanded at market price p is $Q_h = Q_h(p)$. The production cost function $c_{ih}(q)$ is convex and differentiable.

The optimum output for an interior solution satisfies

$$\frac{\partial \pi_{i,h}}{\partial q_{ih}} = 0 = p_h - c'_{ih} + q_{ih}\,\partial p_h/\partial Q_h.$$

$$p_h - c'_{ih} = -q_{ih}\frac{p_h}{p_h}\frac{Q_h}{Q_h}\partial p_h/\partial Q_h = q_{ih}\frac{p_h}{Q_h}\frac{1}{\varepsilon_h} = (Q_h - k_{-ih})\frac{p_h}{Q_h}\frac{1}{\varepsilon_h} = \left(1 - \frac{k_{-ih}}{Q_h}\right)\frac{p_h}{\varepsilon_h} = (1 - r_{ih})\frac{p_h}{\varepsilon_h}.$$

The second equality comes from the definition of price elasticity $\varepsilon_h = -(p_h/Q_h)\,\partial Q_h/\partial p_h$. The last equality is due to the definition of RSI for firm *i*: $r_{ih} = k_{-ih}/Q_h(p_h)$, where –*i* is referring to all firms other than firm *i* and k_{-ih} is the total available capacity of firm *i*'s rivals. Then we obtain

$$(3) \qquad LI_{i,h} \equiv \frac{p_h - c'_{ih}}{p_h} = \frac{1 - r_{ih}}{\varepsilon_h}.$$

Note that due to the definition of RSI the expression (3) holds in equilibrium such that all firms but firm *i* are at their available production capacities. Also observe that (3) can technically be calculated for all firms; however as the production data shows the largest firm OPG who meets about 60% of the market demand is the only firm whose production constraints never bind. Therefore, it is plausible to assume that firm *i* is referring to OPG in the expression (3).[20] If firm *i* is pivotal so that r_{ih} is less than 1, then firm *i* can profitably increase the market price above the

[20] In calculating OPG's market power index $LI_{OPG,h}$ we first compute marginal costs of all generators owned by OPG. Then based on the real time OPG hourly production we pinpoint the most expensive OPG generator, which gives $c'_{OPG,h}$. For a given hour we use the spot market price and the marginal cost of the most expensive OPG generator to calculate the hourly $LI_{OPG,h}$. We find that the type and the name of the generator becoming the most expensive are highly variable from hour to hour and they are either gas-fired or coal-fired generators which are located in different regions.

marginal production cost of its most expensive dispatched generator. Indeed, as explained in section 4.2 and also exhibited in Table 2 that OPG is the only firm whose RSI is always less than one.

As it is clear from the above analysis that we need not to model demand function explicitly to measure the price response of the aggregate demand. The competition model directly obtains the price elasticities as a solution of the equilibrium outcome. Wholesale customers are comprised of all customers who are subject to the hourly changing electricity prices called hourly Ontario energy prices (HOEP), p_h. These customers include large industrial customers, regional electricity distribution companies, and others (such as exporters and dispatchable loads) who are subject to the market clearing prices HOEP.

In (3) the LI is linearly decreasing in RSI. For any hour we can rewrite firm i's LI as

$$(4) \quad LI_{i,h} \equiv \frac{p_h - c'_{ih}}{p_h} + \frac{smc_h - smc_h}{p_h} = \frac{p_h - smc_h}{p_h} + \frac{smc_h - c'_{ih}}{p_h},$$

where smc_h denotes the system marginal cost which is equal to the marginal cost of the marginal generator clearing the market. By definition, the system market power index can be measured by the system (or market) LI, which equals $LI_{smc,h} = (p_h - smc_h)/p_h$ at hour h. From the expression (4) $LI_{i,h} > LI_{smc,h}$ if $smc_h > c'_{ih}$, and $LI_{i,h} = LI_{smc,h}$ if $smc_h = c'_{ih}$.[21] That is, a firm's LI is always higher than the system LI unless this firm is the marginal producer.

Using the definition of $LI_{smc,h}$ we rewrite the relationship between $LI_{i,h}$ and $LI_{smc,h}$ as

$$\frac{1 - r_{ih}}{\varepsilon_h} = LI_{i,h} = LI_{smc,h} + \frac{smc_h - c'_{ih}}{p_h}.$$

The first equality is due to the profit maximization problem and the second one stems from the definitions of $LI_{i,h}$ and $LI_{smc,h}$. We then rearrange the terms to obtain

$$(5) \quad L_{smc,h} = \frac{1}{\varepsilon_h} - \frac{smc_h - c'_{ih}}{p_h} - \frac{r_{ih}}{\varepsilon_h}$$

[21] Note that by definition $smc_h \geq c'_{ih}$.

which indicates the theoretical relationship between the system market power index and firm i's residual supply index. Using the data on $L_{smc,h}$ and r_{ih} we will run the regression

(6) $LI_{smc,h} = \alpha + \beta r_{ih} + e_h$,

where the error term e_h is assumed to be independently and identically distributed. From (5) $0 < \alpha \leq \beta$ always holds as long as firm i is not the marginal firm, otherwise $smc = c_i'$ and hence $\alpha = \beta$.

When OLS regression is run for (6) the regression coefficients will be inconsistent due to the endogeneity issue. [22] The right hand side variable r_{ih} is a function of demand quantity which is a function of price, so is the Lerner index $LI_{smc,h}$. To overcome this endogeneity problem we will employ 2SLS estimation procedure as follows.

In the first stage we will regress r_{ih} on hourly temperature[23], which is independent of market price and quantity, and is one of the key determinants of demand. Then the estimated RSI will be

(7) $\hat{r}_{ih} = \hat{a}_1 + \hat{b}_1 Temp_h$,

which will be accordingly used in the 2SLS:

(8) $LI_{smc,h} = \alpha + \beta \hat{r}_{ih} + e_h$.

In Table 4 we run the regression in (8) with OPG for various time intervals of 2007. We separate the peak summer and winter seasons from all hours of 2007. These are the seasons associated with high demands, high productions, high temperatures (low in winter) and high prices in the year as clearly observed in Table 3.

< Insert Table 3>

We also subdivide these seasons into the second and third quartiles of high demand hours. That is, we will examine the LI and RSI during 50% of the highest demand hours (2[nd] quartile=Q2)

[22] London Economics (2008) has run regression (6) with OLS assumption.
[23] We use dew point temperature in centigrade degree obtained from the Environment Canada which gives rise to more accurate temperature level than the air temperature as it takes into account of humidity. We apply the city of Toronto temperature as a representative temperature in Ontario province, as the largest population in Ontario (that is where the demand is) dwells in Toronto, and temperature wise it represents an average temperature in Ontario.

and the top 25% of the highest demand hours (3rd quartile=Q3). These seasonal subcategories define the peak hours of each peak season, where peak hours defined as the "highest demand periods". In the literature peak hours are usually corresponding to certain hours of each day (e.g., 8am-5pm in weekdays). However this approach has shortcomings as it ignores the seasonal demand conditions and their extreme values, which will be taken into account in our choice of highest demand hours in Q2 and Q3. Also, for example, the price responsiveness or consumption behavior during 8am-5pm interval of spring will be probably different than the one in summer 8am-5pm periods.

In the regression of (8) we also test whether the parameters α and β are statistically different. Theoretically we expect them to be different as it is clear from the expression (5). Therefore, our null hypothesis and the alternative will be

(9) $H_0: \alpha = \beta$ and $H_1: \alpha \neq \beta$.

< Insert Table 4>

In Table 4 we present the 2SLS regression results in 2007 using the OPG's RSI and system LI. The results in Table 4 demonstrate that the coefficients of all variables are highly significant and all regressions are significant with large F statistics and zero p-value. It is clear that the (dew point) temperature ("Temp" in the table) is an appropriate explanatory variable in estimating the RSI. The 2SLS coefficients $\hat{\alpha}$ and $\hat{\beta}$ in expression (8) are all significant mostly with p<0.01. Moreover, the sign of coefficient $\hat{\beta}$ is always negative for all time intervals, confirming the theoretical prediction in (5) and implying that as the RSI increases (that is firm's market power reduces) the price-cost markup goes down (that is market becomes more competitive). Therefore, we can conclude that the RSI is a useful measure of market power and can be used to explain the variation in the system LI.

The slope term $\hat{\beta}$ in Table 4 is in the range of [-71.6, -6.9]: the lowest is observed in the top quartile of summer demand hours and the highest is observed in all hours of 2007. The economic implication of this outcome is that the inverse of this slope gives rise to the price elasticity of demand estimation as indicated in equations (5) and (6). Therefore, wholesale customers' price response is the lowest in summer Q3 (top quartile) with elasticity 0.013, which is smaller than the winter Q3 elasticity of 0.071. The price responsiveness in all hours of 2007 is 0.144. As expected, the summer or winter Q2 elasticity figures are higher than the ones in Q3 hours. These elasticity estimations are also reported in Table 7, where we see a clear trend between the peak seasons. When we compare the elasticities over the peak seasons we find that the consumer price responsiveness is lower in summer than in winter for all time intervals covering all hours, Q2, and Q3. In winter when the weather is cold some of the consumers (like dispatchable loads) facing high electricity prices can switch to the substitutes of electricity such as natural gas and/or fuel-oil for heating.

Note that in Table 4 (or Table 7) we observe how elasticities change over time. The literature (e.g., see Borenstein and Bushnell, 1999, and Aydemir and Genc, 2014, and the references therein) in general fixes the elasticity number by either using a constant elasticity demand function or assuming a fixed elasticity for other type demand functions. However, our findings suggest that elasticity is not constant and shows great variance over the periods/seasons and hence it is more appropriate to apply variable elasticities (even over the peak hours of different seasons) in the economic models involving simulations and/or calibrations.

Also note that theoretically we expect the intercept term α to be smaller than the (absolute value of) slope term β in equation (5), and our regression in (8) confirms this fact in Table 4. Indeed we do the hypothesis testing in (9) and find that the magnitudes of these terms are statistically different than each other.

Our findings confirm that in predicting the relationship between the market power index (i.e., LI) and a firm's residual supply index, we should use the larger firm's RSI. This outcome is sensible because the bigger firm is more representative of the market (as in this case OPG is with 60% market share) and hence associated with the market power in the industry.

In the production data we observe that one of the fringe firms is always the marginal producer for all hours of 2007 to equilibrate demand to supply. That is, system marginal cost is coincided with a fringe firm's marginal cost of production for all hours. In particular this marginal producer is running its natural-gas fired generators with positive outputs for all hours in the year. This confirms why we have to use the equation (5) instead of (3) in examining the interplay between LI and RSI.

Next we quantify the interplay between these indices using the 2SLS regression in (8) with the hourly 2008 data. Similar to the regression results in 2007, in all regressions reported in Table 5 the coefficients are highly significant (except the regression encompassing all hours of 2008) and the intercept terms are always less than the slopes (in absolute value). We also validate the theoretical negative relation between them in all regressions: the coefficients of the estimated RSI are always negative.

< Insert Table 5>

The RSI coefficients in Table 5 are in between (-52, -12) implying that the elasticity estimates are in the interval of (0.019, 0.083), which are also reported in Table 7. Comparing high demand winter to summer hours in 2008 indicates that wholesale consumers' price response is lower in summer than in winter. An exception arises in the Q3 hours: the price elasticity in summer is 0.083, and it is 0.049 in winter. One explanation for this finding is associated with the fact that in summer Q3 the wholesale prices HOEP were higher (42% higher) than the ones in winter Q3 even though the demand quantities in both periods were almost identical, as it can clearly be seen from Table 3. Compared to the year before summer Q3 prices, the 2008 prices are also well above their counterparts. Also different than the year 2007 elasticity estimates, for all peak seasons and their peak periods, and the overall hours in the year elasticities are lower in 2008 than in 2007 (exception is the summer Q3, as explained above). This can be explained by using the definition of elasticity: the consumption quantities are higher in each study period of 2008 but the market price levels are on average near each other in both years (except the summer Q3).

In general we find very low price responsiveness during these high demand periods. The small elasticity figures stem from the low number of wholesale customers who are subject to the HOEP. These customers are mainly industrial customers, exporters and dispatchable loads.[24] In this case a natural question arises: why do these wholesale customers barely respond to high

[24] A dispatchable load receives instructions from the system operator regarding how much to reduce its consumption in the case of market price exceeding certain levels. One clear benefit of being the dispatchable load is that it can participate in the operating reserve market and receive stand-by payments.

See the role of dispatchable loads in the Ontario market at
http://www.ieso.ca/imoweb/marketsAndPrograms/disp_loads.asp

prices? The reasons we can think of are the following: *a*) there are large fixes costs of industrial operations associated with turning on/off the machines, hence while they are running it may become infeasible to cease the production as a response to high prices; *b*) the large industrial firms' labor force is generally on shift basis, and in the real time workers cannot be shifted to another time slot while they are working; *c*) production process is continuous and harder to shift to other hours due to the commitments in the output deliveries; *d*) exporters have commitments to deliver a predetermined amount of power (as exports scheduled two hours before wholesale market clears in Ontario) to the neighboring jurisdictions, and their commitments prevent them to effectively respond to the high prices; *e*) weather conditions may hinder dispatchable loads to reduce their consumptions due to, for instance, a lack of alternative energy resources. However, adjustments in the operational and managerial decisions such as timings of productions and logistics, planning of labor shift schedules and employee vacation entitlements, and substitution over the production technologies can be done for longer time horizons such as weeks, months, or years. Due to these flexibilities in the long run, higher price responsiveness is expected in the seasonal or year around elasticities.

6. Robustness Check: Using Henry Hub Natural Gas Prices

Thus far we have employed the marginal cost formulation in expression (2) to compute the marginal costs of all generators in the system and hence obtained the hourly LI values. Indeed these marginal costs are representing the average variable costs of production because we use the financial data on the total amount of money spent for each fuel type; therefore we intrinsically assumed that the average variable cost equals the marginal cost. In this section we will relax this assumption and directly use fuel prices as a proxy to the marginal costs. Because the marginal production technology is the natural-gas fired generator(s) for all hours of years 2007-2008, we can use the Henry Hub natural gas spot prices as an approximation for the system marginal cost of production. [25] The Henry Hub prices are reference prices and the major firms with the natural gas fired generators in the North America are concerned with or subject to these prices. In Canada there are two natural gas markets which are Intra-Alberta and Dawn Hub. However, only Henry Hub and Dawn Hub prices are relevant for the Ontario power producers. The Dawn Hub

[25] Also, during the high demand periods Q2 and Q3 the correlation coefficient between the market demand quantities and the natural-gas fired generators' outputs are positive and near 50%.

is located in Ontario and the smallest of all as it is a secondary market. However, large volume natural gas buyers such as OPG are subject to the Henry Hub prices which are always less than the Dawn Hub prices. Historically, the Intra-Alberta prices are the lowest but Alberta's natural gas is mainly sold to the US markets. When analyzing the Henry Hub prices we find that the correlation coefficient between daily Henry Hub natural gas prices and Ontario wholesale electricity prices are 0.15 and 0.09 in the years 2007-8, resp. Also, the OLS regressions between daily power prices and natural gas prices are statistically significant.

Once we collect the daily Henry Hub spot prices, we convert them into the hourly prices by assuming that the daily price is uniform across hours of the day. Originally natural gas prices are in \$/MMBtu, and using the marginal generators' heat rates and a conversion rate (from GJ to MMBtu) we transform the natural gas prices into \$/MWh to make it the same unit with electricity. Using these hourly prices we calculate the system LI and run the 2SLS regression from the system LI to the OPG's RSI in 2007 and 2008 during which natural gas prices were higher than the previous and subsequent years.

< Insert Table 6>

In Table 6, we report the results of 2SLS regressions in 2007-2008 using the Henry Hub natural gas spot prices. Since the outcomes of the first stage regression in (7) (they are the same as the ones in Tables 4 and 5) will hold irrelevant of which cost formulation we use to compute the LI, we only report the final outcomes of regression (8) in Table 6. The corresponding elasticity estimates are reported in Table 7, where we observe that the elasticity figures are similar in nature whether we use Henry Hub prices or actual dollar amounts spent for fuel in the LI calculations. Comparing the 2007 elasticity estimates (columns 1 and 3) in Table 7 over the various time intervals demonstrates that the elasticity estimators in the summer, summer Q2, and summer Q3 are all significant at 1% level and are near each other. The winter values show small discrepancies in magnitude, however at the highest demand levels of winter (i.e., Q3) the elasticities are almost identical. Comparison of the 2008 elasticity estimates (columns 2 and 4) displays the similar features and characteristics. For example, the winter elasticities are in the range of (0.026, 0.049) when the average variable fuel prices are used (the second column in Table 7), and it is in between (0.025, 0.047) when the Henry Hub prices are directly used (the last column in Table 7). The summer elasticity figures present some minor differences especially at the Q2 and Q3 periods, but throughout the all summer hours they are about the same magnitude. Therefore, we conclude that our elasticity estimates in Tables 4 and 5 are robust to the choice of marginal cost formulation and one can simply use the natural gas spot prices directly in computing the LI, if the natural gas generators are the marginal technologies at all times, as is the case in the Ontario market. This, on the other hand, confirms that our marginal cost formulation in (2) would be very useful in case the marginal production technologies alter over the hours and their fuel prices are not readily available.

< Insert Table 7>

7. An Application: Using the RSI and LI to Project Market Prices

Hitherto we have examined how to employ the market power measures to estimate market price responsiveness of the wholesale customers. In this section we will show that these indices can be used as a quick and useful tool for projecting market prices in the case of changing market supply conditions. As an example, we will examine the impact of two counterfactual supply scenarios regarding expansions in the interconnection capacity facilitating more trade activities between the adjacent power markets.[26] These scenarios are defensible because in Ontario transmission investments and hence the volume of trade have been expanding since the opening of the wholesale market[27]. Specifically, we will project market prices in the case of increase in the import quantities coming from the neighboring jurisdictions (which are New York, Michigan, Minnesota, Manitoba, and Quebec markets). In these supply scenarios we will consider actual import levels increased by 25% and 50%, respectively, during the highest demand hours of winter 2008.[28]

In the first set of predictions we use the expression in (5) along with the coefficients estimated in the Table 5 to calculate the price projections for the top 24 hours of the highest winter demand hours. Specifically, we use the following formula derived from the expression in (8):

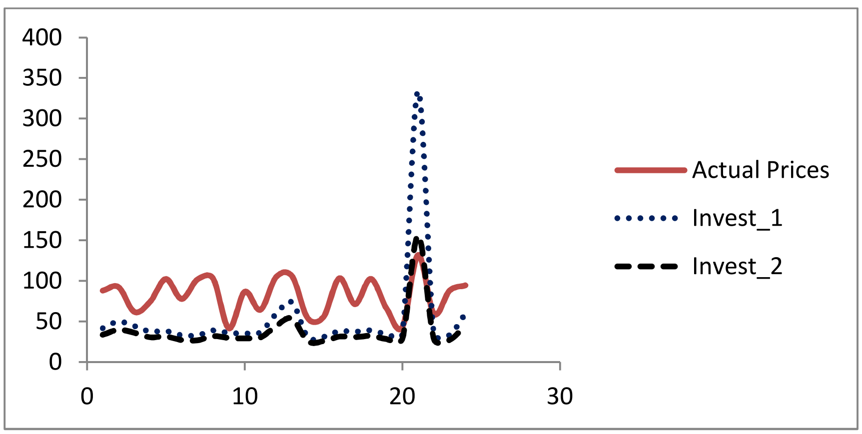
$$(10) \qquad \hat{p}_h = \frac{smc_h}{1-(\alpha_1+\beta_1 r_{opg,h})} \;, \qquad h = 1,2,\dots,24$$

[26] See Gilbert et al. (2002) for market power mitigation through interconnection capacity investments.
[27] See Aydemir and Genc (2014) for the trade volumes between Ontario and its neighboring markets.
[28] The average import quantity is 2,263 MWh which corresponds to 8.8% of the average demand quantity during the top 24 hours of the highest winter demand periods.

where smc_h is the system marginal cost calculated based on the formula in (2), and $\alpha_1 = 8.174$, $\beta_1 = -20.52$ from the Table 5. For the scenario of 25% imports increase the OPG's RSI will be calculated for each hour h as $r_{opg,h} = K_h + 1.25\, I_h - k_{opg,h}$ where K_h is the total available capacity in the system and $k_{opg,h}$ is the OPG's total available capacity, and I_h is the total actual imports at hour h. For the scenario of 50% imports increase all of the above variables and coefficients will remain intact but $r_{opg,h} = K_h + 1.5\, I_h - k_{opg,h}$.

We present the price projections under both scenarios along with the actual market prices in Figure 2, where dotted line (Invest_1) presents the projected prices when transmission investment leads to 25% increase in imports and dashed line (Invest_2) displays the market price predictions when imports are increased by 50% from their current levels during the top 24 hours of the highest demand periods in winter 2008.[29]

Figure 2: Actual and projected market prices in the highest peak hours of winter 2008. X-axis hours; Y-axis wholesale prices in $/MWh.



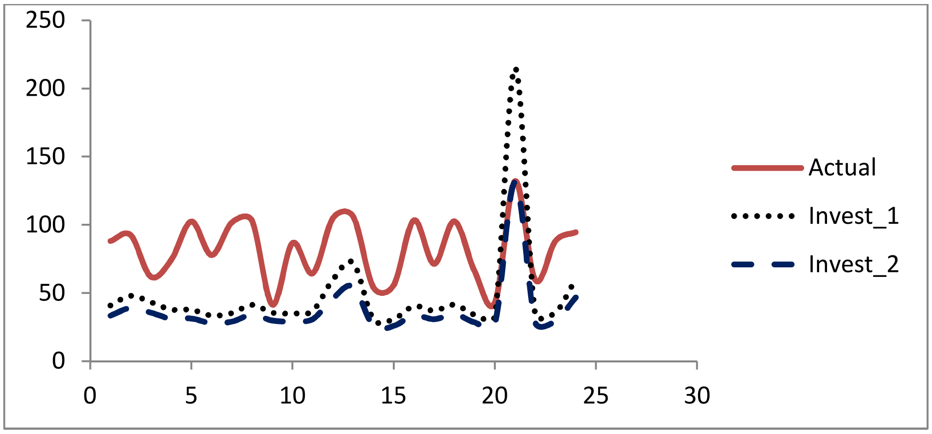
The Figure 2 shows that the wholesale market prices go down as a result of increased import activities stemming from the transmission capacity expansions. The average market prices during these peak hours are 82.2, 52.5, and 37.5 dollars per MWh for the actual market, and the markets with the increased imports, resp. The market prices with 50% imports increase are always less than the ones with 25% imports increase. This is due to the fact that imports are part of market

[29] When we closely examine the imports activities in the hourly data set of 2007-8 we observe that during the high demand periods both local production and imports increase to able to meet the demand. Hence examining the outcomes of increased imports on the market prices is interesting and a valid exercise.

supply and increased supply reduces the residual demand for OPG. Hence its market power reduces as its RSI rises in import quantities. The predicted market prices under these imports scenarios are less than the actual market prices except in hour 21, where we see a steep peak. The hour 21 is an extreme period, corresponding to a peak hour of February 11th, 2008, at which the market supply is tight and there are some peculiarities: i) the import quantity in this hour is 1302 MWh, which is almost half of the average import levels in the previous 20 hours and the subsequent three hours and is always less than the import quantities in any other hours; ii) the available market production capacity in this hour is also low and is equal to 26,694 MW which is less than the available capacities in the remaining hours; iii) the average demand in other hours is near the demand quantity in hour 21: that is, demand is as strong as the previous highest demand levels; iv) OPG's available production capacity in this hour is 19,194 MW which is higher than its average capacity of 19,031 MW in the remaining hours. Consequently, these tight supply conditions give the dominant firm an opportunity to increase the market price well above the system marginal cost. Indeed the actual market price jumps (about 86%) to \$103.2 from the previous hour price of \$55.6. However, our model predicts even higher price spike in this hour, mainly due to a very low price elasticity of demand estimate and the factors specified in i) - iv). This price spike in the figure indicates that even a small amount of increase in imports (from 25% to 50% change amounts to about additional 565 MWh import boost) can cause a substantial (about 100%) market price decrease.

In Figure 2 we have drawn the price projections based on the marginal cost formulation in (2). Next as a robustness check we employ the spot fuel prices directly to compute the expression (10). Since the marginal technology is the natural-gas plant during the simulation periods we use the Henry Hub prices along with the corresponding coefficients $\alpha_1 = 8.1852,\ \beta_1 = -21.0866$ demonstrated in Table 6. We plot the projected market prices under both supply scenarios in Figure 3.

Figure 3: Actual and projected prices in the highest peak hours of winter 2008 using the Henry Hub prices. X-axis hours; Y-axis wholesale prices in \$/MWh.



The Figure 3 once more confirms that imports would help reduce the market prices substantially: the average actual market price is \$82.2 per MWh, and the average prices under the import scenarios will diminish to 47.8 and 37.2 dollars per MWh corresponding to 25% and 50% import increases, resp. Clearly, these projections are near the ones observed in Figure 2. Again, the market prices with 50% import increase are always less than the ones with 25% import increase. Here we still observe a price spike in hour 21 due to the reasons mentioned above. However, in that hour the market price with 50% import increase scenario is slightly lower than the actual market price. Therefore, all the market price projections under this scenario lead to lower market prices than the actual ones for all hours, and the average price reduction is substantial (about 55 per cent). Overall we observe a similar pricing behavior when the simulation results in Figures 2 and 3 are compared, which validates the predictive power of the market power indices along with the estimated price elasticities regardless of the marginal cost formulations.

8. Conclusions

In this paper we structurally develop a tractable and useful approach to estimate price elasticity of demand using a high frequency data in a wholesale electricity market. The model uses a Cournot competition framework to model the behavior of wholesale electricity producers then applies an econometric approach to identify the relationship between the market power measures of Lerner Index and Residual Supply Index to estimate price elasticity of wholesale demand. This approach is appealing and easier than its counterparts, which need to use more variables and data points to structurally specify demand and supply curves, which could be a daunting task in electricity markets context. For instance, as opposed to these alternative approaches, we do not need to specify the functional forms of demand and supply curves. They usually assume linear curves, which could be viewed as restrictive. In our approach demand curve is rather general with regular features of differentiable and downward sloping. Also there is no need to specify the market supply curve as we assume a Cournot behavior for the power producers, which is more reasonable than a fully competitive structure due to the existence of market power in the wholesale power markets.

We study the Ontario wholesale electricity market as we have a detailed firm and market level data. First we apply widely used market power indices to show that firms operating in Ontario do have a market power, which constitutes a justification for our modeling approach along with the fact that power producers decide how much electricity to produce. Second we test the inverse relationship between the LI and RSI, confirmed by the theory, using the generators' production characteristics, costs, outputs, and capacities along with the Ontario market data such as wholesale prices and demand. We use a robust econometric approach and find that this negative relationship is empirically supported for all data sets. Third we interpret the inverse of coefficient of the estimated RSI as the price elasticity of demand and demonstrate how elasticities vary over time and even across the peak times and seasons. Even though there is some variation over the periods, our hourly wholesale elasticity estimates are small, and for example, it is in the interval of (0.013, 0.144) in year 2007. Fourth we illustrate how these market power measures could be used for policy purposes: to determine firms with potential market powers and project market prices with respect to changing supply conditions. Although we have examined supply changes with respect to imports increases made possible by the interconnection investments, it is easy to extend the number of supply scenarios to examine their likely impacts on the market outcomes. To name a few, these supply scenarios could include outages in generation sites, power delivery failures in transmission system, or change in the number of firms due to entries or exits, or capacity investments in the power plants. Market analysis covering these supply scenarios could be a future research direction.

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Table 3: Summary statistics of average prices, quantities, trade and temperature data in peak and all hours of 2007 and 2008. TCap refers to the total available production capacity in which we use actual wind production as available capacity. Price is reflecting the hourly Ontario energy price (HOEP). Price= $/MWh; Temp= Celsius; TCap= MW; Demand, Production, Imp, Exp = MWh.

	Price	Temp	TCap	Demand	Production	Imp	Exp
2007							
all hours	47.8	4.2	24,669	18,778	17,819	822	1,403
winter	52.6	-7.1	25,329	19,820	18,980	703	1,307
winterQ2	64.8	-9.6	25,967	21,650	20,714	780	1,319
winterQ3	74.3	-11.5	26,366	22,678	21,662	851	1,448
summer	47.3	14.7	25,806	19,161	18,286	713	1,504
summerQ2	64.6	16.2	26,349	21,516	20,411	909	1,351
summerQ3	77.3	17.4	26,684	22,816	21,480	1,137	1,251
2008							
all hours	48.8	4.6	25,955	19,453	18,022	1,288	2,527
winter	49.7	-5.7	25,987	20,570	19,152	1,303	2,473
winterQ2	61.9	-6.3	26,306	22,406	20,732	1,585	2,635
winterQ3	66.6	-8.1	26,808	23,382	21,614	1,720	2,901
summer	53.5	15.9	27,421	20,143	18,540	1,448	2,951
summerQ2	77.0	16.6	27,649	22,584	20,673	1,779	3,238
summerQ3	94.7	17.8	27,704	23,865	21,580	2,164	3,520

Table 4: 2SLS regression results for the relationship between LI and RSI in 2007. *i*=OPG. We estimate expressions (7) in the first and second columns, and (8) in the third and fourth columns, using 2007 hourly data. n is the number of observations. Q3 corresponds to the highest demand hours (top 25%). Q2 represents the second quartile of the high demand hours.

	Model ($LI_{smc} \sim RSI_i$)				
1st Stage:	A1	Temp	2nd Stage: A2	$\widehat{RSI}_{opg}$	n
OPG all hours	0.46***	0.0012***	2.262**	-6.922***	8760
	(0.0007)	(0.0001)	(1.23)	(2.66)	
OPG_winter	0.45***	0.003***	5.177***	-13.273***	2160
	(0.0013)	(0.0001)	(0.34)	(0.79)	
OPG_winterQ2	0.42***	0.0019***	4.408***	-11.438***	1080
	(0.0015)	(0.0001)	(0.39)	(0.97)	
OPG_winterQ3	0.41***	0.0019***	5.412***	-14.018***	540
	(0.0023)	(0.0002)	(0.46)	(1.20)	
OPG_summer	0.5***	-0.0029***	13.862***	-32.216***	2208
	(0.0041)	(0.0003)	(1.37)	(2.96)	
OPG_summerQ2	0.44***	-0.0008***	9.59***	-22.628***	1104
	(0.0034)	(0.0002)	(1.56)	(3.70)	
OPG_summerQ3	0.42***	-0.0003	29.35***	-71.596***	552
	(0.0045)	(0.0003)	(5.07)	(12.4)	

Notes: Standard errors are in parentheses. Significance levels are ***p<0.01; ** p<0.05; *p<0.1.

Table 5: 2SLS regression results for the relationship between LI and RSI in 2008. *i*=OPG. We regress Lerner Index on the Residual Supply Index using OPG's RSI and the system market power index LI_{smc}.

	Model ($LI_{smc} \sim RSI_i$)				
	1st Stage: B1	Temp	2nd Stage: B2	$\widehat{RSI}_{opg}$	n
OPG all hours	0.50***	0.0025***	6.318	-16.509	8784
	(0.0009)	(0.0001)	(9.86)	(19.1)	
OPG_winter	0.449***	0.002***	15.916***	-38.733***	2184
	(0.0011)	(0.0001)	(2.83)	(6.47)	
OPG_winterQ2	0.424***	0.0009***	8.269***	-20.834***	1092
	(0.0013)	(0.0001)	(1.10)	(2.64)	
OPG_winterQ3	0.422***	0.0008***	8.174***	-20.520***	546
	(0.002)	(0.0002)	(1.75)	(4.22)	
OPG_summer	0.597***	-0.0043***	25.23**	-51.525**	2208
	(0.0066)	(0.0004)	(13.49)	(25.52)	
OPG_summerQ2	0.53***	-0.0028***	10.065***	-21.229***	1104
	(0.0048)	(0.0003)	(0.63)	(1.31)	
OPG_summerQ3	0.539***	-0.0037***	5.754***	-12.059***	552
	(0.008)	(0.0004)	(0.6)	(1.26)	

Notes: Standard errors are in parentheses. Significance levels are ***p<0.01; ** p<0.05; *p<0.1.

Table 6: 2SLS regression results of the relation between LI and RSI in 2007 and 2008 using Henry Hub hourly natural gas prices. *i*=OPG. Regressing Lerner Index on Residual Supply Index: Using OPG's RSI and system market power index LI_{smc}, which is generated by using the hourly Henry Hub natural gas spot prices.

	Model ($LI_{smc} \sim RSI_i$)			
	2007		2008	
	2nd Stage: A1	$\widehat{RSI}_{opg}$	2nd Stage: A2	$\widehat{RSI}_{opg}$
OPG all hours	-0.671	-1.1107	12.0476	-29.5269
	(1.32)	(2.84)	(15.19)	(29.43)
OPG_winter	3.3124***	-9.4325***	16.0966***	-40.0014***
	(0.33)	(0.76)	(3.37)	(7.7)
OPG_winterQ2	2.1443***	-6.3656***	8.5744***	-22.2331***
	(0.48)	(1.2)	(1.19)	(2.86)
OPG_winterQ3	4.6860***	-12.7393***	8.1852***	-21.0866***
	(0.57)	(1.48)	(1.89)	(4.56)
OPG_summer	17.8028***	-41.1259***	40.1184**	-82.4065**
	(1.52)	(3.30)	(19.12)	(36.19)
OPG_summerQ2	19.1404***	-46.0719***	16.1672***	-35.2048***
	(2.11)	(5.0)	(1.14)	(2.37)
OPG_summerQ3	42.2129***	-103.1626***	10.7226***	-23.8184***
	(5.81)	(14.21)	(1.11)	(2.35)

Notes: Standard errors are in parentheses. Significance levels are ***p<0.01; ** p<0.05; *p<0.1. 1st stage coefficients are the same as the ones in the previous Tables 4 and 5.

Table 7: Price Elasticity of demand estimates in 2007 and 2008 using system marginal costs calculated based on formula in (2), and Henry Hub (HH) fuel prices.

	$\mathbf{e_{smc}}$		$\mathbf{e_{HH}}$	
	2007	2008	2007	2008
All hours	0.144***	0.061	0.900	0.034
winter	0.075***	0.026***	0.106***	0.025***
winterQ2	0.087***	0.048***	0.157***	0.045***
winterQ3	0.071***	0.049***	0.078***	0.047***
summer	0.031***	0.019**	0.024***	0.012**
summerQ2	0.044***	0.047***	0.022***	0.028***
summerQ3	0.013***	0.083***	0.010***	0.042***

Note: Significance levels are ***p<0.01; ** p<0.05; *p<0.1.