Integration of Renewables into the Ontario Electricity System

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ABSTRACT

The Ontario electricity industry has a 'hybrid' structure: electricity is bought and sold in a competitive wholesale electricity market while supply mix planning and procurement are conducted through a government agency. Most generation is secured through long-term contracts. Aggressive renewable energy programs have led to rapidly growing renewable capacity, mainly wind generation. Coal-fired generation has been eliminated and electricity sales have dropped.

The competitive hourly market price has declined and there is a clear merit-order effect: an increase of wind generation from 500 MW to 1500 MW can be expected to decrease price by 7 CAD/MWh. However, the all-in price, which incorporates contractually guaranteed supply prices, has risen from about 60 to 100 CAD/MWh between 2009 and 2014. Operational and market integration of renewable resources has been achieved relatively smoothly. The procurement process is over-centralized: increased reliance on market discipline and greater separation between governmental policy makers and regulators would enhance both the efficacy and efficiency of decarbonization policies.

Keywords: renewable integration, wind generation, solar power, feed-in-tariffs, subsidiarity and separation

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1. INTRODUCTION[1]

The Ontario electricity industry has a 'hybrid' structure where energy is bought and sold in a competitive wholesale market while supply mix planning and procurement are conducted through a government agency. Most generation is secured through long-term contracts. Over the last decade, Ontario has embarked on an aggressive renewable energy program, mainly through feed-in-tariffs (FITs). Wind generation now approaches 10% of total capacity, coal-fired generation has been eliminated. Various conservation initiatives have also comprised an important part of the decarbonization portfolio. We focus on three aspects of renewable integration in Ontario: prices and the merit order effect, operational and market integration, and the procurement process.

The all-in price of energy consists of three components—the market price, known as the Hourly Ontario Electricity Price (HOEP); the 'global adjustment' (GA) which covers differences

1. Unless otherwise indicated, monetary values are in Canadian dollars (CAD), which earlier in the decade, were trading at close to par with the U.S. dollar. By early 2016, the exchange rate fell to \$1 CAD ≅ \$0.70 USD.

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between market and contract prices, and conservation program costs; and an uplift charge which among other things, recovers the costs of ancillary services and payments reflecting differences between constrained and unconstrained prices. As renewable capacity has increased, the market price component has declined and there is a clear merit-order effect: an increase in wind generation from 500 MW to 1500 MW can be expected to decrease market price by 7 CAD/MWh. On the other hand, the 'global adjustment' has increased dramatically so that the all-in energy price has risen from about 60 to 100 CAD/MWh since the introduction of FIT programs in 2009. Not surprisingly, electricity sales have declined.

Operational and market integration of renewable sources has been achieved relatively smoothly. In order to integrate wind generation, which can be unpredictable and volatile, the Independent Electricity System Operator (IESO) introduced centralized forecasting and five-minute dispatch. Market rules have evolved incrementally and an overseer constantly assesses the market to promote competitive bidding practices.

The procurement process is highly centralized and controlled by the government which uses 'ministerial directives' to effect supply mix. We argue that two important principles should inform the process by which the industry should evolve. The first is subsidiarity which states that in a hierarchy, decisions and actions should be taken at the lowest level at which they can be competently executed. In the present context it implies that a degree of decentralization of procurement would improve outcomes. The second is a clear separation between policymaking on the one hand, and regulation and implementation on the other. Convolution of these functions has led to decisions which at times have been driven by short term political considerations, rather than longer term economic and societal objectives.

While the current model for promoting and integrating renewables has been effective in increasing renewable supply, the costs have been excessively high, as underscored by the presence of excess generation, in particular baseload generation, and the frequency with which wind displaces other non-carbon supplies, such as hydraulic and nuclear generation.

The literature on integration of renewables is massive. To gain a foothold, we suggest the following papers and references therein: Haas et al. (2008), Schmalensee (2009), Barroso et al. (2010), Pollitt (2010), Alagappan et al. (2011) and Green and Yatchew (2012).

Numerous studies have also been conducted on merit order effects in various parts of the world, including Australia (Cutler et al., 2011), Denmark (Munksgaard and Morthorst, 2008; Jacobsen and Zvingilaite, 2010), Germany (Sensfuß et al., 2008; Ketterer, 2014; Paraschiv, et al., 2014), Italy (Cló et al., 2015) and Spain (Gelabert et al., 2011; Gil et al., 2012). U.S. studies have been conducted for California (Woo et al., 2014), PJM (Gil and Lin, 2013), the Pacific Northwest (Woo et al., 2013), and Texas (Woo et al., 2011; Zarnikau et al., 2014). See also Hirth (2005).

The structure of the paper is as follows. Section 2 provides background information on the industry, its evolution, its structure and supply mix. Section 3 begins with a model of the hourly price, estimation of merit order effects and a model of the determinants of negative prices. It continues with a discussion of operational integration and closes with an analysis of the procurement process. Section 4 concludes.

In summary, Ontario has successfully eliminated coal-fired generation and rapidly increased renewable capacity (mainly wind). However, the procurement system has been over-centralized and there is an excess supply of capacity, leading increasingly to lower (even negative) prices in the hourly market, at the same time that the total price of electricity, which also includes contractual obligations to generators has risen dramatically. The Province would benefit from decentralization and depoliticization of the decision-making and regulatory processes.

2. THE EVOLUTION AND STRUCTURE OF THE ONTARIO ELECTRICITY INDUSTRY

2.1 The Evolution of the Industry[2]

The Ontario electricity industry combines centralized planning and long-term contracting functions with a competitive electricity wholesale market. The Province officially deregulated its electricity sector in 1998 with the enactment of the *Electricity Act*; the wholesale market opened in May of 2002. It began as an "energy-only" market with the expectation that energy prices would drive investment. However, the market was dominated by a large government owned supplier, Ontario Power Generation (OPG), whose ability to exercise market power was palliated by a Market Power Mitigation Agreement with the government. The uncertainty surrounding OPG's incentives in the wholesale market and its intentions relating to the return to service of certain nuclear assets had a chilling effect on investment.

While the wholesale market initially opened with relatively low prices, within a few months prices doubled and remained at levels well above the regulated level of 4.3 cents/kWh that consumers had been charged prior to deregulation. This prompted the Government to announce in November 2002 that it would freeze prices at the previously regulated rates and retroactively rebate consumers for the difference. The price freeze, which was applied to low volume consumers and certain designated entities such as municipalities, universities, and hospitals, remained in effect until 2006. These developments impeded the evolution of a competitive retail market.

The price levels that ensued after opening of the wholesale market indicated that there was a shortage of generation capacity in the Province. However, given the cloud of uncertainty surrounding the future direction of the sector, private investment was not forthcoming. In 2004 the government enacted the *Electricity Restructuring Act* (ERA) which created a "hybrid market" structure which is more or less still present today. The "hybrid market" consists of a competitive wholesale electricity market supported by a central planning and procurement function. The competitive wholesale market is used to guide the short-term trade and dispatch of electricity and other ancillary service products. The central planning and procurement function secures longer term investment in generation and promotes and funds various conservation programs. At the time of enactment, the Independent Electricity System Operator (IESO) operated the competitive wholesale electricity market, while the newly created Ontario Power Authority (OPA) managed the central planning and procurement functions.[3]

The ERA also expanded the role of the government which had legislative authority to issue directives to the OPA, creating a mechanism through which it could directly intervene in the generation and transmission planning processes. Included in this power was the ability to set the supply mix and goals for conservation and renewable energy. Virtually no private investment occurred in the absence of a long-term contract with the OPA and eventually almost all operating generation assets in the Province were provided with an OPA contract, or in the case of OPG, regulated rates.

In June of 2006, the government issued a directive which included targets to increase the amount of renewables by 2,700 MW by 2010. The plan was to undergo a prudence review by the

2. This section borrows from Rivard and Yatchew (2015).

3. On January 1, 2015, the OPA merged with the IESO to create a new organization that combined their respective mandates. The merged entity retained the IESO name.

provincial regulator, the Ontario Energy Board (OEB). In September 2008, a new directive was issued to the OPA requiring it to revisit the plan to increase the amount and diversity of renewables, to increase the amount of distributed generation, to explore the conversion of coal to biomass generation, and to accelerate conservation initiatives. This set the stage for the introduction of the *Green Energy, Green Economy Act* of 2009 (GEA) which ultimately led to further expansion of renewables through the use of feed-in-tariffs. The GEA reaffirmed and strengthened the government's authority to issue directives.[4,5]

The evolution from an "energy-only" market to a "hybrid market" has had some successes but it has also had costs. On the positive side, the policies to eliminate coal, encourage conservation and rapidly expand the deployment of renewables has helped to significantly reduce GHG emissions from the electricity sector; these have declined from 35 mega-tonnes in 2005 to less than 7 mega-tonnes in 2014 (http://www.ontarioenergyreport.ca/pdfs/OntarioEnergyReportQ12015_Electricity_EN_Supply.pdf at p. 9). However, the electricity sector contributes a small fraction of GHG emissions in Ontario which are estimated to be in excess of 160 mega-tonnes annually, the major contributors being transportation and industrial sectors.[6]

On the negative side, there is a growing dissatisfaction with the high cost of electricity. Figure 1 shows the trend in the monthly average all-in energy price which includes the average Hourly Ontario Energy Price (HOEP), the Global Adjustment (GA) and the 'uplift'. In theory, the HOEP is driven primarily by the marginal fuel cost for producing electricity, and is dependent on prevailing supply and demand conditions. The GA covers all the remaining fixed generation costs that are not recovered through the market, but are committed through contracts or regulation. The GA also includes the costs of delivering the Province's conservation programs. The 'uplift' includes congestion management charges, and operating reserve costs. Since 2005, there has been a steady decline in the average monthly HOEP. This is largely due to the decline in demand (both in terms of total energy and peak demands), increase in supply and the decline in natural gas prices. On the other hand, the GA has steadily increased over this period as more of the committed fixed generation costs need to be recovered outside the market. The net effect is that the average monthly all-in energy prices have increased.

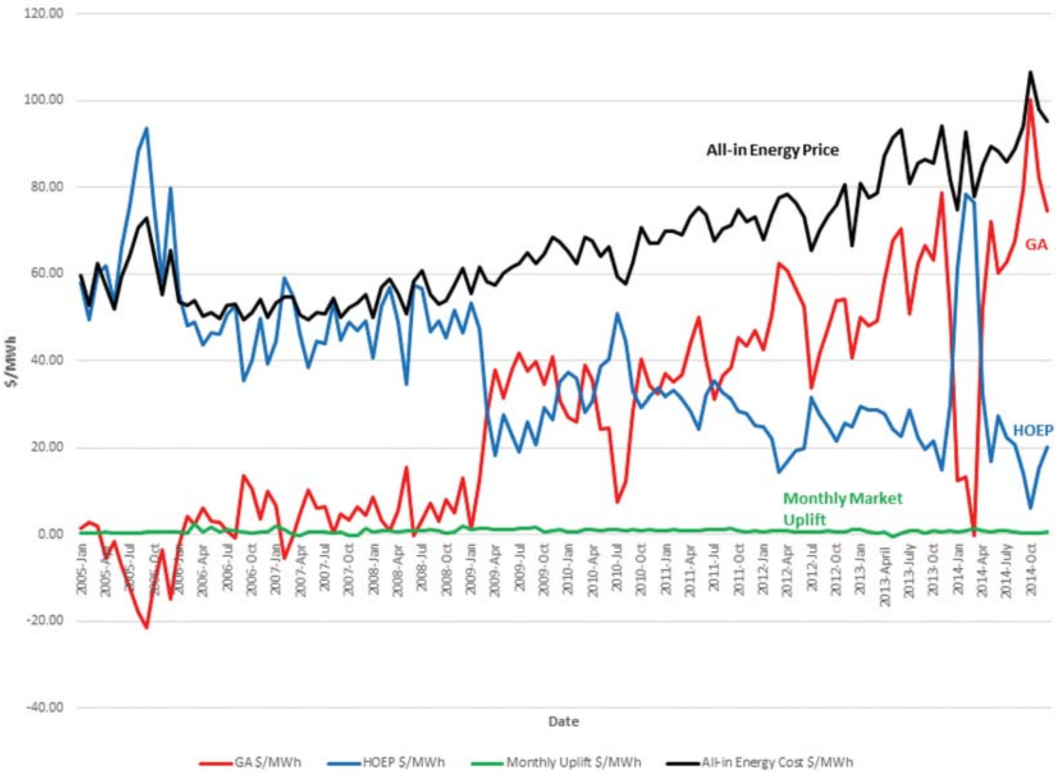
Ontario has been in a state of oversupply for the last several years both in terms of installed capacity to meet peak demand, and in terms of baseload supply during low demand periods. From 2005 to 2013, peak hourly energy demand declined by roughly 4% and annual energy demand declined by nearly 11%. Over the same period, Ontario replaced its coal generation facilities with refurbished nuclear generation assets, natural gas generation and new renewable energy generation such as wind, solar, hydro and biomass. As a result of the addition of significant baseload and renewable sources the IESO has had to manage numerous periods of "surplus baseload generation" (i.e., when electricity production from baseload facilities, if not managed, would otherwise exceed demand). Ontario has become a net exporter of electricity, particularly during periods of surplus when it sells "clean" electricity to its neighbours, typically at a price that is substantially below the price paid by Ontario consumers.

4. Over the last decade, numerous directives have been issued, many of them related to renewable energy and conservation programs. See http://www.ieso.ca/Pages/Ontario's-Power-System/Ministerial-Directives/default.aspx and http://powerauthority.on.ca/about-us/directives-opa-minister-energy-and-infrastructure.

5. Bill 135, Energy Statute Amendment Act, 2015, currently under consideration, would transfer the responsibility for development of the Long Term Energy Plan from the IESO to the Ontario Ministry of Energy, further centralizing these processes within the Ministry.

6. Ontario Ministry of the Environment and Climate Change (2015).

Figure 1: Monthly Average Price Trends in Ontario (2005 to 2014)



2.2 Competitive Wholesale Energy Markets

Market participants in the wholesale energy markets can be classified as dispatchable or non-dispatchable. The dispatchable participants submit bids to buy electricity or offers to sell electricity to the system operator, the IESO. Based on these offers and bids, they receive dispatch instructions. Dispatchable participants are typically generators connected to the bulk transmission system, large industrial consumers and energy traders (for example, those that import and export electricity).

Non-dispatchable participants do not provide bids or offers; nor do they receive dispatch instructions. Instead, they are paid or charged the market clearing price based on their metered quantities. Examples of non-dispatchable participants include local distribution companies and generators that are eligible to self-schedule their production.

The markets are jointly optimized for energy and three classes of operating reserve, a day-ahead and a real-time energy commitment process, and a recently added capacity based demand response market. Dispatchable participants submit hourly bids to buy or sell electricity to the IESO, as well as offers to sell three classes of operating reserve, namely 10 minute synchronized reserve, 10 minute non-synchronized reserve, and 30 minute non-synchronized reserve. At the same time, the IESO forecasts the amount of non-dispatchable demand and establishes the amount of reserve required for each of the three classes of reserve.

The offers and bids, along with the IESO forecast of non-dispatchable demand are processed through the Dispatch Scheduling and Optimization (DSO) algorithm to solve for the market clearing schedules and prices. The objective of the DSO is to maximize the market's "economic gains from trade" which, at least conceptually, is intended to approximate total economic surplus.

The DSO operates in two-time frames—pre-dispatch and real-time dispatch. The former provides participants with advance projections of the schedules and prices on an advisory basis. The first pre-dispatch for a given dispatch day runs at 11am the day prior and provides schedules and prices for each of the 24 hours of the dispatch day. The pre-dispatch continues to run, producing schedules and prices for each hour in the dispatch day until one hour prior to the actual dispatch hour. At that point, the DSO is run every five minutes to produce prices, schedules and dispatch instructions.

The DSO operates in two modes, the constrained and unconstrained modes. The constrained mode optimizes the gains from trade considering all physical limitations of the system. It produces the actual dispatch instructions (i.e., constrained schedules) and "informational" shadow prices. The unconstrained mode optimizes the gains from trade but ignores some of the physical limitations of the system, particularly transmission limits and transmission losses; it produces uniform Ontario prices and "market schedules." In a sense, the unconstrained mode assumes that all Ontario consumption and generation are located at a single point in the Province. Constrained prices vary by location; a particularly important reference is the 'Richview' price. Correlation between unconstrained (HOEP) and constrained (Richview) prices was 0.65 over the period 2009–2014.

The Market Clearing Price (MCP) is calculated every five minutes in the real-time unconstrained mode. Thus, there are twelve MCPs computed for energy and the three classes of operating reserve in each dispatch hour. The Hourly Ontario Energy Price (HOEP) is calculated as the arithmetic average of the five minute MCPs. For settlement purposes, the MCP applies to dispatchable participants and the HOEP applies to non-dispatchable participants. There are price floors and price ceilings: prices cannot exceed the Maximum Market Clearing Price (MMCP) which is set at $2000/MWh and cannot be lower than the Minimum Market Clearing Price (negative MMCP) of −$2000/MWh. The MCPs have rarely reached these limits.

Dispatchable participants are also eligible for Congestion Management Settlement Credits (CMSC) whenever their dispatch schedule is different from their market schedule. There is a presumption in the Ontario market design that the dispatchable participants' offers and bids represent their marginal cost or benefit and that these participants should be made whole to the "operating profit" that they would have earned had there been no physical limitations on the grid, as is assumed in the unconstrained mode. The operating profit for dispatchable suppliers, such as a generator or an importer, is the difference between the revenue received for the energy sold and their marginal cost of supplying the energy. The operating profit for dispatchable consumers such as a dispatchable load or an exporter is the difference between what they are willing to pay and what they have to pay.

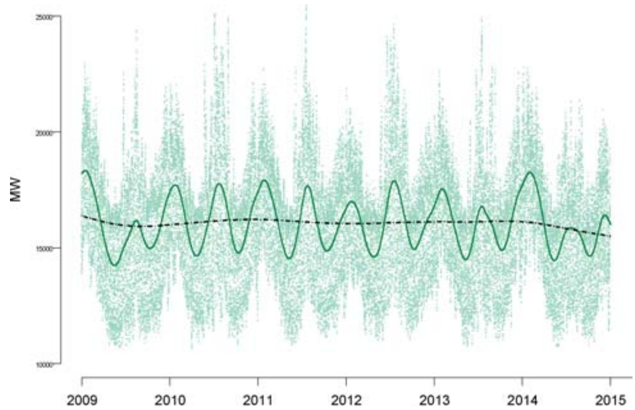
2.3 Supply and Demand

2.3.1 Generation Supply Mix

There are currently 35,221 megawatts (MW) of installed generation connected to Ontario's bulk transmission system. This consists of 12,978 MW of nuclear generation, 9,942 MW of natural gas, 8,432 MW of hydroelectric, 3,234 of wind generation, 495 MW of biofuel and 140 MW of solar. There is also an estimated 2,500 MW of embedded generation, largely wind and solar, installed within Ontario's distribution systems.[7] The Ontario supply mix has changed significantly in the last

7. IESO (2015), page 9.

Figure 2A: Hourly Ontario Demand (MW)



decade, driven by the government's decision to phase out all coal fired generation and to replace it with natural gas, renewables and certain refurbished nuclear facilities. The installed capacity and output of renewables, primarily wind but also hydro and solar, have grown steadily.[8] Nuclear currently represents roughly 60% of the total electricity produced. The second largest share is hydroelectric at 24%, followed by natural gas at 10%, wind at 4%, biofuel at 0.3% and solar at 0.1%.

2.3.2 Electricity Demand

In 2014, total Ontario electricity demand was 139.8 TWh with a peak hourly demand of 22,774 MW. Electricity demand has trended downward since the market opened in 2002, but particularly since the recession in 2008 (Figure 2A). The decline is a result of several factors including the impacts of government conservation and demand management programs, large increases in the price of electricity and increased investment in distributed generation.[9] The all-time hourly peak demand of 27,005 occurred in the summer of 2006. Since 2008, there has not been an hourly system peak demand that has exceeded 25,300 MW. The percentage of demand by consumer class is as follows: commercial 40%, residential 34%, industrial 25% and agriculture 1%, (electric vehicles consume a tiny share of 0.02%).

There are characteristic summer and winter peaks. The amplitude has varied somewhat (Figure 2A). Spectral analysis of hourly demands, unsurprisingly indicates dominant 24 and 12 hour cycles (see Appendix). Distinct spikes are also observable at other harmonics.

Since the installation of smart meters, which was completed over the period 2007–2010, there has been a small decline in peak vs off-peak consumption, falling from about 43% in 2009 to 42% in 2014 (Figure 2B). Peak hours are defined as 7AM to 7PM on weekdays. The load duration curves have shifted down substantially in recent years though the shape has not changed significantly. (Figure 2C.)

8. For purposes of comparison, in 2003, there were 30,481 MW of installed generation capacity including: 10,836 MW of nuclear, 7,669 MW hydroelectric, 7,546 MW of coal generation, 4,634 of natural gas and oil. There was also a small amount of wood waste generation.

9. The IESO reports electricity demand that is metered at the transmission level. This includes the net demand (actual electricity use less electricity generated within the distribution system) metered for each of the distribution companies, but excludes embedded generation.

Figure 2B: Per Cent of Total Energy Consumption on Peak

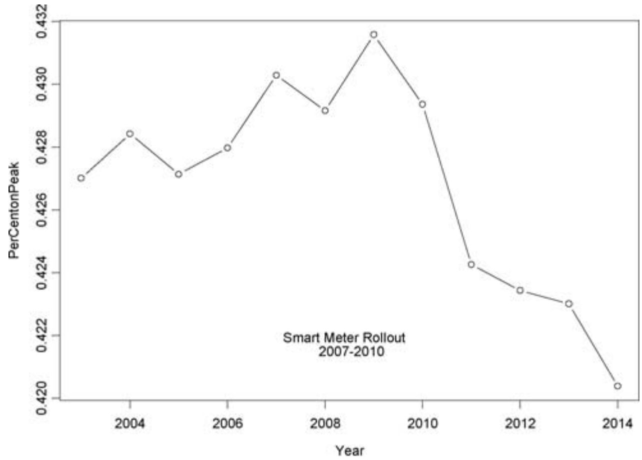
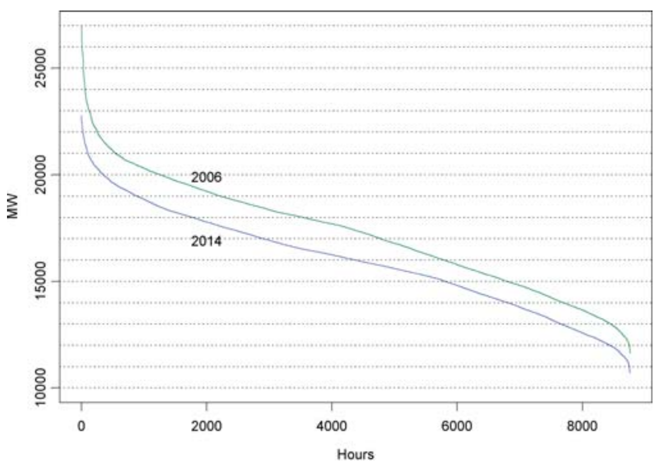


Figure 2C: Load Duration Curves—2006 v. 2014

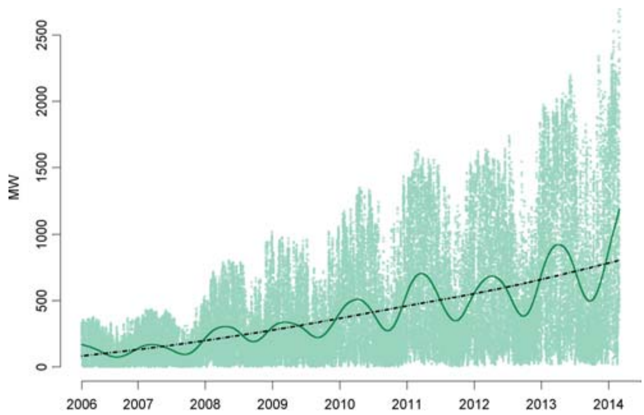


2.3.3 Ontario Transmission and Interconnections

The Ontario transmission system is comprised of a 500 kV transmission network, a 230 kV transmission network, and several 115 kV transmission networks, spanning 30,000 km and owned by Hydro One, a descendant of Ontario Hydro. Until recently this entity was a wholly owned agency of the government. In November 2015, the government began selling shares in the company to the public. Hydro One is the largest transmitter, owning roughly 97% of the Ontario transmission system. It is regulated by the Ontario Energy Board.

The system is interconnected with two Canadian provinces, Manitoba and Quebec, and three US states New York, Michigan and Minnesota. There are 26 interties grouped into 12 intertie zones which allow for the import and export of more than 6,400 MW of electricity. Their overall exchange capability varies depending on internal constraints in the Ontario and neighbouring transmission systems, as well as on the season. These interties permit trade of electricity with markets in eastern North America.

Figure 3A: Hourly Wind Output (MW)



Ontario has transitioned from being a net importer of electricity in 2002 to a net exporter of electricity today. This trend has been driven by the relative decline in electricity demand in Ontario but also the changing supply mix which has seen an increase in the quantity of relatively low marginal cost resources such as wind and solar.

2.4 Characteristics of Renewable Supply in Ontario

Wind capacity and output has been growing steadily since 2006. Trend growth is depicted using a dashed blue line in Figure 3A. There is a strong cyclical pattern with substantially higher output in the winter, depicted using the solid green line. The aquamarine points are the actual hourly output levels which display high volatility and a clear seasonal cycle. Diurnal cycles are evident in the spectral density (see Appendix) with spikes that are visible at 24, 12, 8 and 6 hour frequencies.

For the period Mar 2006–Aug 2013, wind output was negatively correlated with Ontario Demand and with Total Market Demand, which includes exports. Both correlations were approximately -0.1. For the period September 2013 to mid-August 2015, the correlation between wind output and Ontario Demand was 0.12 and with Total Market Demand it was 0.23. This change was presumably due to the introduction of wind dispatch in September 2013.

Hydraulic output also exhibits considerable variance, along with seasonal cycles of varying amplitude (Figure 3B). The spectrum displays daily cycles driven by controlled supply of hydraulic energy to optimize price benefits in the market (Appendix). For the period 2009–2014 the hourly correlation between Ontario demand and hydraulic output is about 0.57. Storage is largely an intra-day phenomenon. Correlation between daily Ontario demand and daily hydraulic output is about 0.07.

Wind and hydraulic outputs exhibit seasonal cycles. Both sources tend to produce less output in summer months, a time of high demand, thus increasing the need for backup natural gas generation capacity. (Ontario is a summer peaking jurisdiction, with all 20 of the recent system peaks occurring during summer months http://www.ieso.ca/Pages/Power-Data/Demand.aspx.)

Nuclear output has been trending upwards with some evidence of cyclicality. Hourly correlation with Ontario demand is about 0.23. Daily correlation is about 0.31. During this period, coal is steadily being phased out, with the last day of production occurring on April 8 2014.

Figure 3B: Hourly Hydro Output (MW)

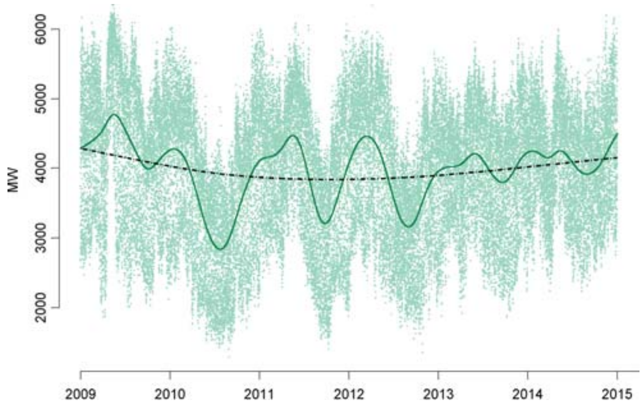
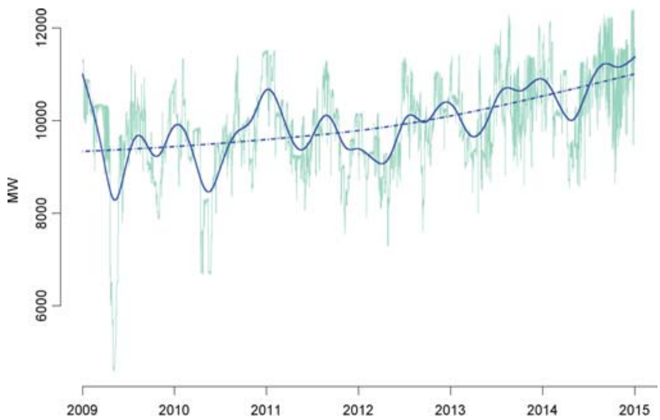


Figure 3C: Hourly Nuclear Output (MW)



3. INTEGRATION OF RENEWABLES

3.1 Price Impacts

Our reference model for the market price HOEP ('Price') is additively separable in functions of explanatory variables:

$$\text{Price} = f_1(\text{Demand}) + f_2(\text{NatGasPr}) + f_3(\text{Nuclear}) + f_4(\text{Hydro}) + f_5(\text{Wind}) + \varepsilon. \qquad (1)$$

'Demand' is hourly Ontario electricity demand (in MW) which we treat as exogenous. We do not include export sales as they are price sensitive in real time. 'NatGasPr' is the daily Henry Hub price per thousand cubic feet (Mcf). 'Nuclear' is the level of generation from nuclear units in MW. 'Hydro' is the level of hydraulic generation also in MW; because of the potential for storage, this variable is treated as endogenous. 'Wind' is the level of wind generation in MW. Additional components, for example categorical variables such as seasonal dummies, can be readily included in the model. We use hourly data for the period 2009–2014.

The f_k functions can be individually specified to be parametric or nonparametric. If both types appear in the model, then we have a semiparametric specification. We have not allowed for

Figure 4A: Effect of Ontario Demand on Electricity Price

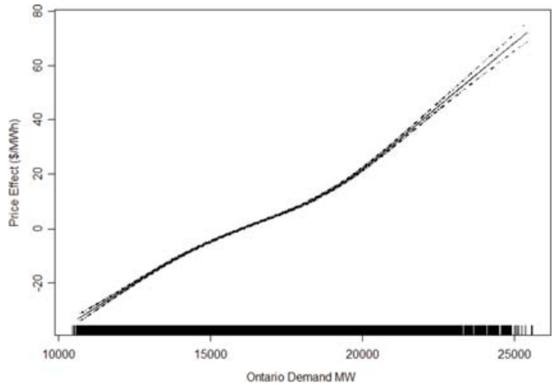
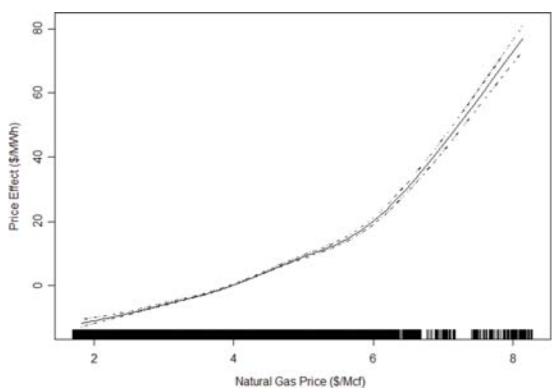


Figure 4B: Effect of Natural Gas Price on Electricity Price



interaction effects, but could readily do so. The advantage of allowing these functions to be non-parametric is that it permits one to identify nonlinearities in the effects of explanatory variables on the price of electricity. Estimates were obtained using the 'gam' function (for generalized additive model) available in R or S-Plus.

The additive separability, combined with nonparametric structure of the model permits us to analyse the effects of various variables on the hourly market price. The effects are depicted in the figures below. Dashed lines depict approximate 95% pointwise confidence intervals. The horizontal axes also contain rug-plots which are indicative of the density of data on the explanatory variable. The R-squared value for the model estimated using equation (1) is approximately 29%.

Figure 4A illustrates the estimated impact of Ontario demand on price. It is monotone increasing with an increased slope as demand exceeds 20,000 MW. An increase in demand from 15,000 MW to 20,000 MW increases expected price by about $15/MWh; an increase from 20,000 to 25,000 MW increases expected price by about $40/MWh.

The effect of natural gas prices is also nonlinear (Figure 4B). As the reference Henry Hub price increases from $2 USD/Mcf to $4 USD/Mcf, the expected electricity price increases by about $11/MWh. An increase from $4 to $6 USD /Mcf results in an expected increase in electricity price of $20/MWh. A further increase from $6 to $8 increases expected electricity price by an additional $50/MWh.

Figure 4C: Effect of Nuclear Capacity on Electricity Price

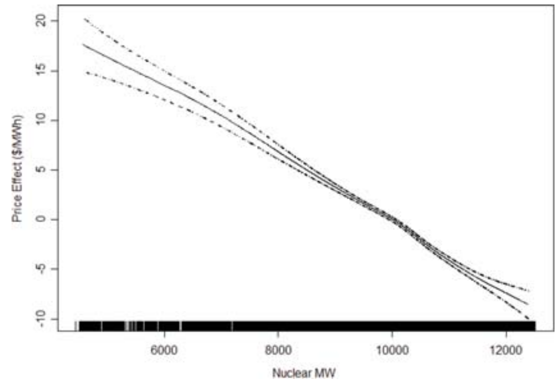
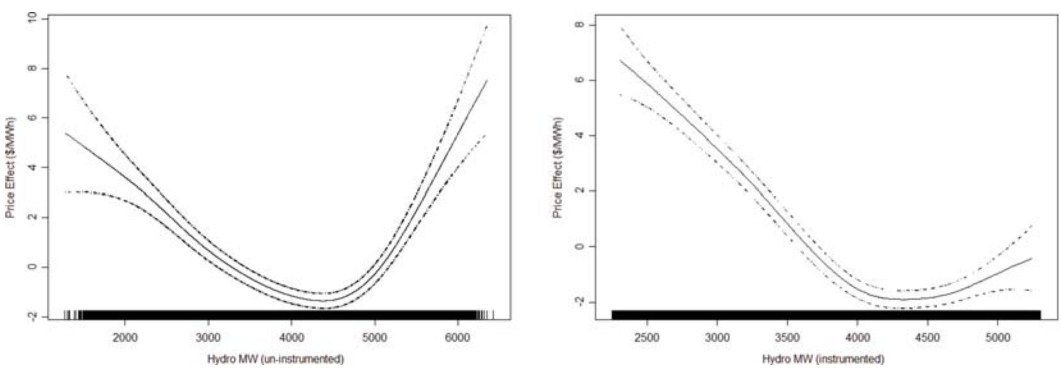


Figure 4D: Effect of Hydroelectric Supply on Electricity Price—Un-instrumented and Instrumented



During the data period, nuclear generation was typically between 7,000 MW and 12,000 MW. Each additional 1000 MW of nuclear supply reduces price by $3 to $4/MWh.

The effect of hydraulic generation is somewhat more complicated because of the potential for endogeneity. The first panel in Figure 4D illustrates the estimated effect of hydro under the assumption that the level of hydraulic generation is exogenous. Below approximately 4500 MW of hydraulic supply, there is a modest downward effect on price: for example, increasing supply from 2500 MW to 3500 MW reduces expected price by about $2/MWh. Beyond 4500 MW, there appears to be a pronounced positive association between additional hydraulic supply and price. When corrected for endogeneity, the downward pressure on price below 4500 MW becomes substantially stronger: increasing supply from 2500 MW to 3500 MW now reduces expected price by about $6/MWh. Beyond 4500 MW, there is a modest upward estimated effect.

Finally we turn to the effect of wind generation, which comprises a relatively small portion of total generation. As output increases from 500 MW to 1,500 MW, the expected price of electricity declines by about $7 / MWh. From 1500 to 1700 MW the effect attenuates, but then appears to become stronger beyond 2000 MW. It should be noted, however, because of the sparseness of data at high levels of wind output, the effect is estimated quite imprecisely.

During the period 2009–2014, negative market prices occurred about 3.9% of the time, but these have increased substantially, particularly since 2013 (Figure 5). We estimate a simple

Figure 4E: Effect of Wind Generation on Electricity Price

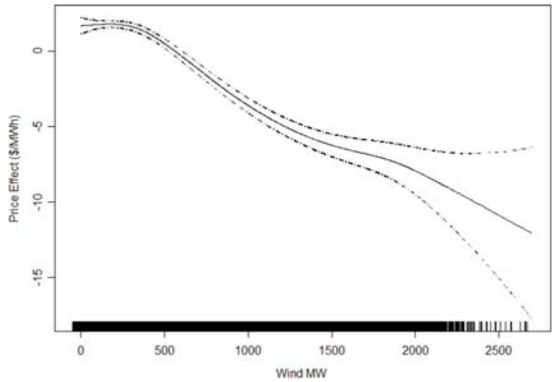


Figure 5: Negative Electricity Prices

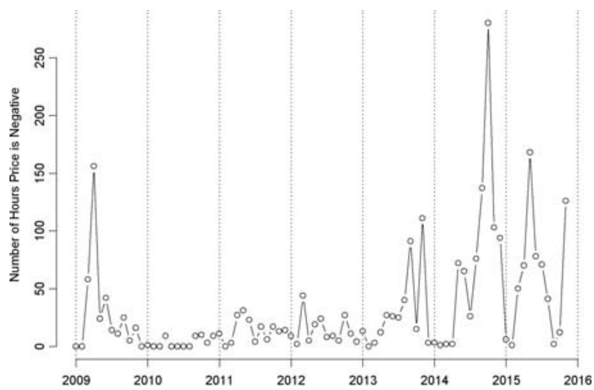


Table 1: Probit Model of Negative Electricity Prices

Variable	Coefficient	Standard Error	Asymptotic t-Stat
(Intercept)	−6.711	0.2398	−27.989
NucShr	8.039	0.3148	25.535
WndShr	12.03	0.4889	24.608
GasShr	−4.786	0.5386	−8.886
CoalShr	−29.623	2.1298	−13.909

probit model, where the dependent variable is 1 if the price is negative. (A logit specification yields very similar results.) Explanatory variables in the model are the respective shares of nuclear, wind, natural gas and coal. (Hydraulic production has been omitted to avoid multicollinearity.) Increased availability of wind, nuclear and hydraulic capacity increases the likelihood of negative prices. All terms are strongly statistically significant.

3.2 Operational Integration and Market Modifications

Shortly after the passage of the Green Energy Act of 2009, and in anticipation of a large increase in renewable generation entering the system, the IESO began an extensive consultation entitled “The Renewable Integration Initiative” http://www.ieso.ca/imoweb/consult/consult_se91.asp. Its purpose was to determine how the IESO would adapt grid operations and the IESO-administered markets to accommodate increases in renewable generation. The process would address forecasting methodologies, information requirements, bidding and dispatch procedures. From the outset, the IESO stressed the importance of transparency. In the result, vast quantities of price and output data, are publicly available on its website http://www.ieso.ca/Pages/Power-Data/Data-Directory.aspx. Also included are detailed real time meteorological data and forecasts.

Given the variability and distributed nature of wind generation, the IESO established a centralized forecasting procedure which would be produced at high resolution (real-time forecasts would be at five minute intervals). Accurate forecasts were not only necessary from a system operation point of view, but also to ensure proper payments to wind generators: those that were ‘dispatched down’ would, by virtue of their FIT contracts (which require the system operator to purchase all output), would need to be compensated for output that would have been produced in the absence of a system constraint. The costs of centralized forecasting were folded into general IESO costs.

All wind based generators were required to provide both static plant information (such as the physical coordinates and elevation, proximity to nearest meteorological recording facility, the power curve) and dynamic real-time telemetry data (such as wind speed, power output and availability information).

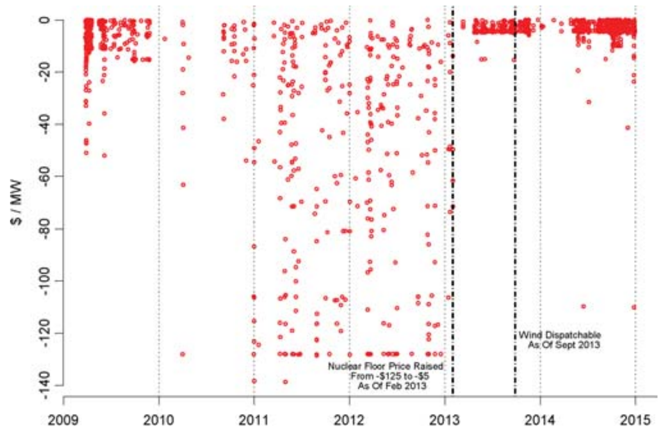
To support reliable and economic supply, using the real-time forecasting process, the IESO moved to five minute dispatch of all variable resources. The objective was to achieve reliable dispatch at least cost (“security constrained economic dispatch”) which incorporated ramping considerations and specific circumstances of surplus baseload generators.

Wind generators were required to operate within a compliance dead-band when meteorological conditions allowed. These dead-bands are similar to those for dispatchable generators, in particular, for facilities exceeding 30 MW, the dead-band range is +/− 15 MW or +/− 2% of facility’s dispatch, whichever is larger. (The vast majority of wind generation in Ontario is produced at facilities exceeding 30 MW.)

Variable generators were granted the opportunity to collect congestion management payments in circumstances where they needed to reduce output as a result of dispatch instructions.

There was considerable concern about the possibility of excess baseload generation, particularly as the share of wind and other renewables increased. One of the objectives of the market integration process was to determine appropriate price floors for negative bids. At the time the consultation commenced, the minimum market clearing price was −$2000 CAD. During 2011 and 2012 the frequency of observed negative prices increased substantially. Although prior to 2011, prices below −$40/MWh were rare, they began occurring increasingly often (Figure 6) as certain generation resources that wanted to run for operational or economic reasons began to lower their offer prices to avoid having their output ‘dispatched down’. The consultations led to the creation of offer floor prices for certain generation types. In February 2013, a floor price of −$5 / MWh was imposed on the manoeuvrable portions of nuclear generation. In September of 2013, price floors were imposed on wind and solar generation. A floor price of −$10 / MWh was imposed on wind and solar output for up to 90% of the registered capability of the resource, with a price floor of −$15 / MWh for the remaining 10% of the registered capability. In the fall of 2015, the IESO held a consultation to review the price floor amounts for wind and solar. The review led to adjustments: the floor price for wind output for up to 90% of registered capability and the entire registered capability for solar generation was increased to −$3/MWh, while the floor price for the remaining 10% of a wind generator’s registered capability remained at −$15/MWh.

Figure 6: Negative Electricity Prices



3.3 Procurement Process—Subsidiarity and Separation

To situate our discussion of the procurement process within a broader conceptual framework, we begin with two ideas: subsidiarity and separation. Subsidiarity proposes that decisions be made, and tasks be carried out at the lowest level in a hierarchy at which they can be competently decided and executed.[10] A second and related idea, that of a clear definition and separation of responsibilities as between regulatory agencies and political entities, is also helpful.

One of the implications of subsidiarity is that governments should undertake responsibilities only if individuals, groups of individuals or organizations (such as firms) cannot fulfill them adequately on their own. The principle generally favours decentralization. It can improve efficiency and accountability. It is helpful in illuminating lines between private and public spheres, it provides a rationale for markets (as opposed to central planning), it is helpful in establishing regulatory boundaries, and it is useful for allocating responsibilities across local, provincial and federal governments.

In government and in governance, the idea of separation is of profound importance. Amongst its purposes is to lessen the potential for conflicts of interest, and enhance independence and transparency of decision making.

These ideas have specific implications in discussing electricity industry procurement processes. In broadest terms one can ask to what degree should the market be relied upon to promote and implement decarbonization. Feed-in-tariffs typically require the government or a governmental agency to select technologies, and to target specific quantities and prices. (This has been the case in Ontario where FITs involved specification of prices to be paid to particular renewable technologies. See, e.g., Yatchew and Baziliauskas 2011.) The subsidiarity principle would suggest that a decentralized approach, such as a carbon tax or cap-and-trade, would be more efficient as it would devolve technology choice to firms and individuals. Even renewable portfolio standards offer greater latitude for choice by electricity providers.

A second application of the subsidiarity idea relates to the roles of different levels of government in arriving at decisions. For example, how much input should local governments have into siting decisions? In Ontario, following the GEA of 2009, the provincial government proceeded

10. For a brief outline of the subsidiarity principle in energy contexts, see Yatchew (2014).

with siting approvals for wind generation, evidently without sufficient consultation with local governments. This led to significant push-back. Subsidiarity suggests that an alternative process, with greater involvement of local communities, would have resulted in a less tendentious process and a more favourable outcome. The subsequent Premier promised that communities would be consulted if facilities were to be built nearby (a weaker version of subsidiarity).

The idea of separation is also relevant in analysing the procurement and approval process. It underscores the desirability of having the government set policies and objectives, and having the regulator implement them. In short, this idea favours an arms-length relationship between the government and the regulator.[11] Such separation reduces the risk of politicization of policy implementation and provides the government with political cover if unpopular regulatory decisions are seen by the electorate to be impartial and objective.

In the face of aging facilities, retirement of coal-fired generation and the need for peaking plants, Ontario put forth a plan to develop gas fired generators at various locations around the Province. However, shortly before a provincial election, and after considerable pressure from certain affected communities, the Government decided to cancel two plants which were to be located near Toronto. This reversal would cost Ontario ratepayers hundreds of millions of dollars. In the aftermath, the Premier indicated that political staff would no longer have the authority to alter commercial transactions (a weaker form of separation).

In its most recent report, the Auditor General of Ontario identified a number of problematic issues with the electricity procurement process of Ontario. These included overpayment for wind and solar energy within the FIT program, costly cancellation by the Government of natural gas plants, an ineffectual electricity system planning process, excessive use of Ministerial directives rather than reliance on regulatory oversight by the OEB, and excessive costs of carbon reduction, among others.[12]

Why is it that governments are often attracted to managing electricity industries at a granular level rather than taking a more arms-length approach? Why is it that a more decentralized approach is often eschewed? In Ontario there are a number of reasons.

First, there is the historical context. From the beginning of the 20th century, when hydroelectric generation was first being developed at Niagara Falls, electricity was in the public sector. Electrification was seen as a critical public policy objective that would spur economic development, and its implementation was achieved by public sector corporations, most importantly, Ontario Hydro as well as numerous municipal electric utilities.

Second, there was and continues to be a public perception that the government has the power to control outcomes in the electricity sector, and therefore it is the recipient of blame when prices rise or supply is insufficient or unreliable. Ontario's brief flirtation with an energy only market in 2002 provides a particularly salient example. The rise in prices following market opening led to political risks that the government of the day was not prepared to bear, and the centralized procurement approach was eventually restored.

Third, a truly decentralized approach, with private companies bearing a high share of risk, requires that the government provide a clear and credible signal that markets will be relied upon far into the future, particularly as electricity assets are long-lived and investments need to be recovered over many years. Following the events in 2002, it became clear that private investment was likely to occur only if secured by long term contracts. Integration of renewables on a large

11. It has long been understood that the independence of the regulator of the money supply, i.e., the central bank, is in the public interest.

12. Auditor General of Ontario 2015.

scale created additional uncertainty for conventional electricity generators, further creating the desire for long-term arrangements.

Fourth, the initial objective of the GEA 2009 was to ramp up renewable supply rapidly. FITs, notwithstanding the costs associated with them, already had an established record of achieving this objective in other jurisdictions.[13] In order to be able to demonstrate success within the election cycle, the government relied on more interventionist approaches, which would presumably lead to more predictable and timely results. Ministerial directives were seen as a useful tool in this process. A more decentralized approach, such as a carbon tax or cap-and-trade was likely seen as less feasible from a political perspective.[14] In short, the economically preferable (decentralized) approaches were not seen as optimal from a political economy standpoint.

The results of the centralized and Ministerially managed approach to procurement taken in Ontario has resulted in rapid escalation of renewable capacity at the expense of escalating electricity prices, excess supply and suboptimal system planning.

3.4 Evaluation of Ontario's Renewable Electricity Program

The evaluation of decarbonization programs involves a range of criteria (see, e.g., Green and Yatchew 2012). Most important of these are efficacy, efficiency and sustainability. We provide a provisional and summary evaluation of Ontario electricity sector renewables policies within this framework.

Ontario policies, which rely heavily on feed-in-tariffs, have produced a rapid increase in renewables generation capacity. In 2009, when the FIT program was implemented, grid connected wind capacity was approximately 500 MW. By 2015 it had reached 3000 MW with additional wind (and solar) capacity embedded within distributor boundaries.

The efficacy of the FIT-based decarbonization program in reducing carbon output, however, is not quite as obvious. Although coal-fired generation has been eliminated, the majority (about 62%) of wind generation occurs at off-peak hours when it is often competing against other nuclear and hydraulic supply. As a result, one form or another of carbon-free generation may be ramped down, or "constrained off".[15] In these circumstances, wind may not be replacing gas fired generation, the remaining carbon-based source of electricity in Ontario's bulk electricity system. Though, in some instances, exported electricity may be replacing carbon based generation in other jurisdictions.

There are various types of efficiency that need to be considered. *Static efficiency* is usually seen as a short term concept referring to the capacity of an industry structure to promote efficient use of existing resources. This is largely within the purview of the IESO which operates the wholesale electricity market and governs the dispatch of resources. At its simplest level, one wants least cost production of electricity at every point in time given existing resources, as well as incentives to ensure that inefficient bidding does not occur.[16] Since the opening of the market the IESO has made numerous revisions to the Market Rules to promote efficient behaviour, including the introduction of wind and solar dispatch as part of the Renewable Integration Initiative.

13. Leading examples included Denmark, Spain and Germany where the share of renewables grew rapidly following the introduction of FITs, though electricity rates also increased quickly over the same period.

14. Ontario became a partner in the Western Climate Initiative in 2008 but chose not to participate in the first phase of cap-and-trade implementation in 2012. Current plans are to begin implementation in 2017.

15. In 2014 there were 588 reductions in nuclear output due to surplus baseload generation, totalling 1.2 TWh of energy, or about 1% of total nuclear supply. http://www.ieso.ca/Pages/Power-Data/2014-Electricity-Production-Consumption-and-Price-Data.aspx

16. The Market Surveillance Panel is charged with monitoring and reporting on anti-competitive behaviour.

Dynamic efficiency refers to the ability of an approach to promote efficient evolution of the industry with respect to structure, fuel mix, investment, technological choice and most importantly innovation. We suggest that the current arrangements, whereby the government is a primary decision maker with respect to technological choices made within the industry, hampers dynamic efficiency. These decisions are better devolved to firms and to the marketplace. If, conceptually, one seeks to minimize costs of production subject to a carbon constraint, an administrative process, such as a FIT program, is unlikely to achieve this objective.

The costs to ratepayers and taxpayers have been significant and the approach has been administratively complex. Administrative costs include not only those borne by regulatory agencies, but also compliance costs that are borne by companies and ultimately consumers. For example, carbon taxes are simple to implement while cap-and-trade schemes are more complex to administer; feed-in-tariffs also involve substantial administrative costs as they require governmental agencies to assess appropriate target levels and to determine tariffs that are sufficient to induce investments, keeping in mind that technological change is having a continuous impact on these costs. According to the Auditor General (2015) a comparable reduction of carbon output could have been achieved at substantially lower costs; she estimates that the cost of reducing carbon emissions using wind and solar generation has been approximately $257 per tonne (Auditor General of Ontario 2015, p. 228).

Closely related to these notions is the idea of *intra-sectoral abatement efficiency* which refers to the ability of a scheme to promote the equalization of abatement costs within the electricity sector. An industry model which focusses on acquisition of renewables, instead of directly targeting reduction of carbon output, is not likely to spontaneously yield outcomes which minimize carbon abatement costs. The objective should be to ensure that reductions of carbon production within the electricity sector are achieved at lowest cost.

More generally, *inter-sectoral abatement efficiency* refers to the capacity of policies to promote equalization of marginal abatement costs across energy sectors, so that overall provincial abatement costs are as low as possible. This too has not been an objective of electricity industry policies in Ontario over the period under study.

Electricity prices in Ontario have increased dramatically since the inception of FIT programs. Such issues have been the focus of elections and have resulted in a degree of opposition to policies that have been implemented. Rising electricity prices have been resisted by consumer groups. They have also had an adverse impact on the competitiveness of Ontario manufacturers. (The recent decline in the value of the Canadian dollar, as a result of the dramatic drop in world oil prices has, to a degree, improved manufacturing export opportunities.) On the other hand, increasing global momentum for dealing with climate change suggests that even expensive decarbonization programs may be politically sustainable.

Price pressures are likely to continue into the future given the need for nuclear refurbishment, aging wires infrastructure, expanding renewable capacity, and the costs of existing contractual obligations. However, as noted earlier, the historical context in Ontario, with public ownership of the electricity system and a centralized approach, has been generally compatible with promotion of renewables through FITs and an extensive role for government.

4. CONCLUSIONS

The Ontario experience offers several lessons. First, extensive government involvement and intervention in the market can significantly chill private investment. This was evident in Ontario from the outset when the market was launched in 2002, given the uncertainty surrounding the role of the dominant generator OPG and the sudden price freeze in November 2002. These interventions also created a sense among investors that the government was not committed to market principles or prepared to accept market outcomes.

Second, government intervention can be self-perpetuating in that ad hoc government actions often beget the need for further government intervention. Once the Ontario government acted to address the political uproar surrounding increasing prices, and realized that needed private investment was not immediately forthcoming, it had to act swiftly. It is important to avoid implementing policies in the electricity sector that appear ad hoc and focused on narrow short-term political pressures—such policies create considerable uncertainty for the investor community. Instead, policies should clearly state the long-term objectives and be implemented as transparently as possible.

Third, reliance on a single government agency to back generation investment through long-term contracts can seriously undermine a competitive marketplace in which private investors would bear substantial portions of risk. Such an approach is less likely to lead to efficient outcomes. The existence of a single government buyer for even a targeted portion of generation (say just for renewables) can distort the market more generally and undermine investment incentives for other types of generation. The single government buyer can also become a convenient instrument of the government for carrying out ad hoc polices, which has been the case in Ontario. The government issued 93 directives to the OPA over the course of 10 years, a number of which had more to do with broader economic policy goals or local area job retention, than sound electricity industry planning.

Fourth, investment decisions in Ontario have been shaped to a large degree by a series of shifting policy objectives, and not by competitive market forces or traditional utility planning. Reducing GHG emissions is a critical objective. But one should be wary of abandoning the use of market discipline in its pursuit of these goals.

Recently, the Premier of Ontario announced that the Province would be instituting cap-and-trade. Consistent with the principle of subsidiarity, it decentralizes decision making to a degree. Properly implemented, it can improve efficiencies by creating direct incentives for equalization of marginal carbon abatement costs, which are calibrated by the market place, rather than by government agencies. It should reduce the need for excessive government intervention.

Distributed generation will impose a new source of discipline on the electricity industry, particularly if solar costs continue their decline. In this connection, there is the potential for stranding of utility assets (both generation and wires), or at least reducing their value.

In the interest of reducing short-term political pressures, and promoting optimal long term decisions, consistent with the principle of separation the government would be well advised to institutionalize an arms-length relationship with the regulator. Increased reliance on market discipline and greater separation between governmental policy makers and regulators would likely enhance both the efficacy and efficiency of policy implementation.

Finally, the present paper provides a case study of the Ontario electricity market. A comparative inter-jurisdictional analysis of the effects of alternative approaches to decarbonization, the associated procurement practices (e.g., market based vs. government directed), the impacts on rates, and differences in implementation and integration, would be valuable in informing policy decision makers.

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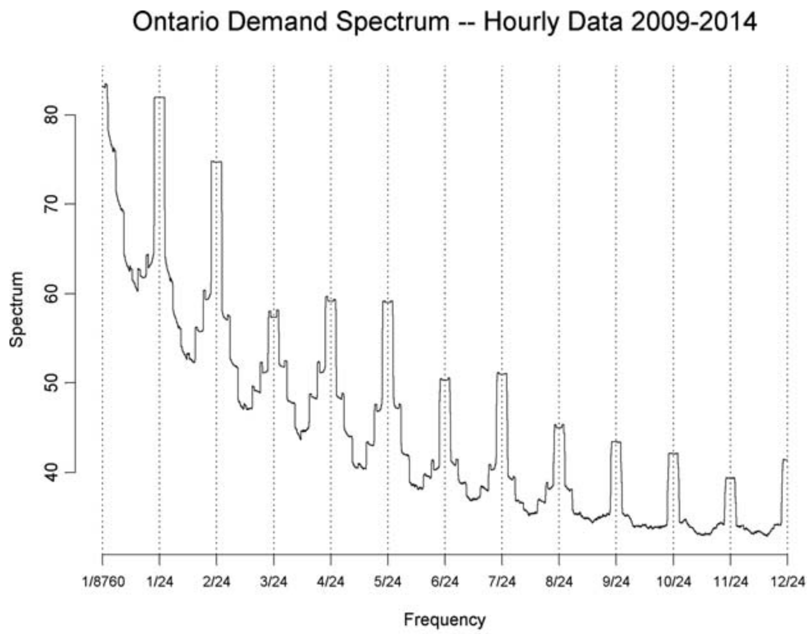
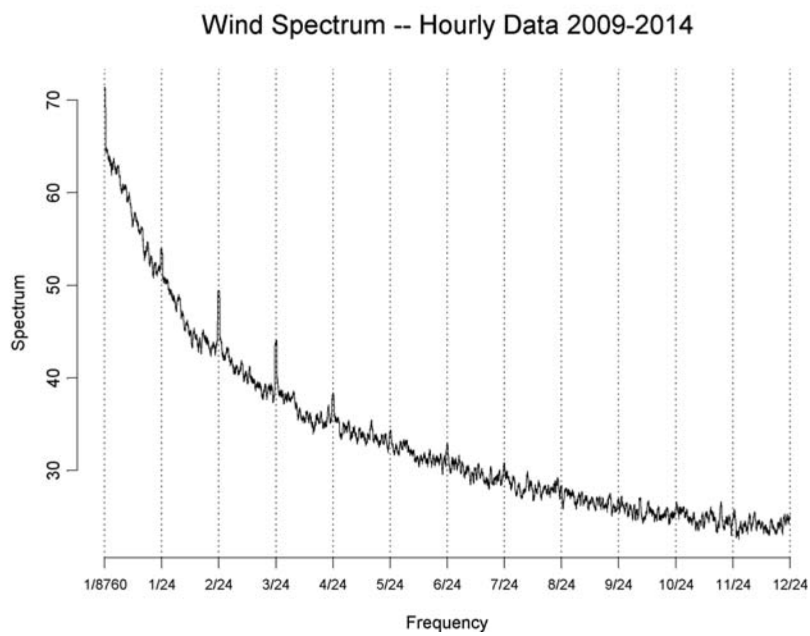
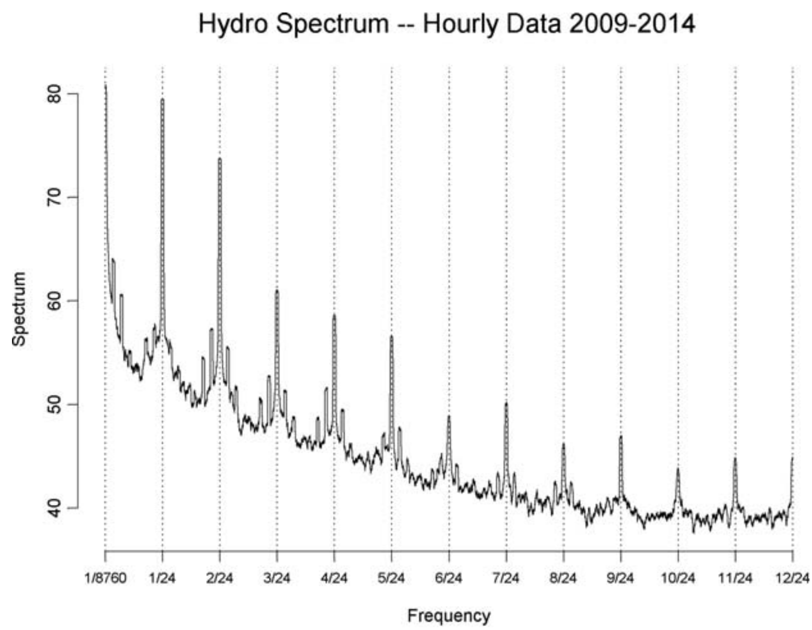
APPENDIX A—SPECTRAL ANALYSIS OF SERIES






Hydro Spectrum -- Hourly Data 2009-2014
Spectrum
40
50
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80
1/8760
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4/24
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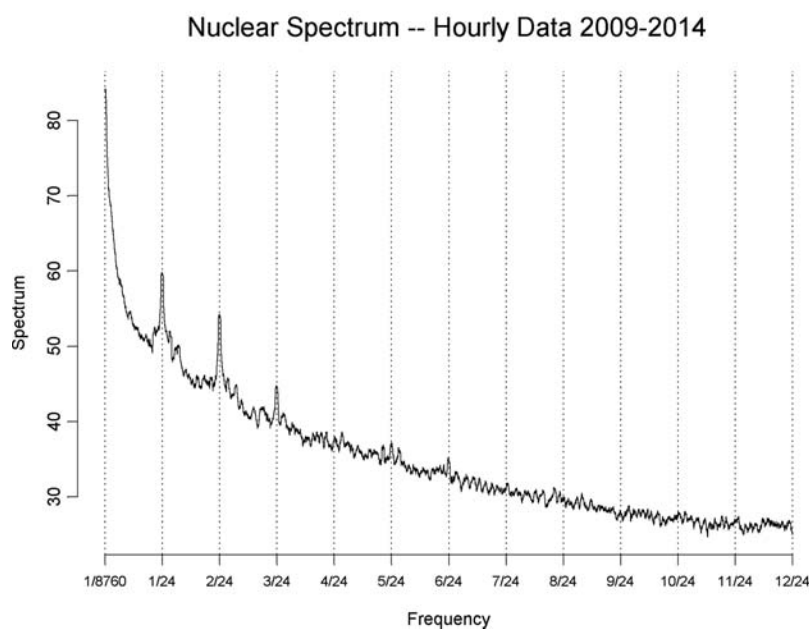
11/24
12/24
Frequency


Nuclear Spectrum -- Hourly Data 2009-2014
Spectrum
30
40
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80
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1/24
2/24
3/24
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6/24
7/24
8/24
9/24
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12/24
Frequency