Influence of wind power on hourly electricity prices and GHG emissions: Evidence that congestion matters from Ontario zonal data

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Influence of wind power on hourly electricity prices and GHG emissions: Evidence that congestion matters from Ontario zonal data

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Abstract

With the growing share of wind production, understanding its impacts on electricity price and greenhouse gas (GHG) emissions becomes increasingly relevant, especially to design better wind-supporting policies. Internal grid congestion is usually not taken into account when assessing the price impact of fluctuating wind output. Using 2006-2011 hourly data from Ontario (Canada) , we establish that the impact of wind output, both on price level and marginal GHG emissions, greatly differs depending on the congestion level. Indeed, from a 3.3% price reduction when wind production doubles, the reduction jumps to 5.5% during uncongested hours, but is only 0.8% when congestion prevails. Similarly, avoided GHG emissions due to wind are estimated to 331.93 kilograms per megawatt-hour (kg/MWh) using all data, while for uncongested and congested hours, estimates are respectively 283.49 and 393.68 kg/MWh. These empirical estimates, being based on 2006-2011 Ontario data, cannot be generalized to other contexts. The main contribution of this paper is to underscore the importance of congestion in assessing the price and GHG impacts of wind. We also contribute by developing an approach to create clusters of data according to the congestion status and location. Finally, we compare different approaches to estimate avoided GHG emissions.

Keywords

Wind energy; Electricity prices; Congestion; marginal GHG emissions

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1. Introduction

1.1. Literatures review

There is a growing literature on the impacts of wind generation upon the reliability and operation of power grids ([1]-see reference's footnote 1). Environmental concerns have also stimulated interest in wind generation as an environmentally-friendly alternative energy source [2, 3]. Despite these interests, far too little attention has been paid to the "price effects" of this intermittent resource in a competitive electricity market and to the avoided emissions resulting from wind generation. By "price effects", we refer to the price drop per megawatt hour (MWh) of generated wind power. By "avoided emissions", we refer to the emission increase that would have prevailed, given the current generation mix, if wind power had not been injected to the grid.

A paper by Sensfuss et al [4] where the effect of renewable energy (RE) generation on German electricity spot prices in 2006 were measured, shows that there is no impact of RE production on electricity spot prices during the low-load period, while it reaches up to 36 €/MWh in hours of peak demand. The final results show a reduction in the average market price of 7.83 €/MWh in 2006 due to renewable energy production. Jónsson et al [5] reach similar results in studying how the spot prices in West Denmark are affected by wind power forecasts. However, the study points out that the extent of this impact is difficult assess. Using an example, the authors explain that when the forecast wind penetration is below 4% of total output, there is little or no effect on spot prices, but with a forecasted wind generation of 11% or more of the total, the spot prices gradually decrease. Munksgaard et al [6] also analyse the impact of wind on the spot hourly market price with and without the wind power capacity included in the power system. Results show that in a "no wind" situation (under 500 MW), prices can increase by up to 600 DKK/MWh (80 €/MWh) and in an "extreme wind situation", when wind power penetration exceed 1,500 MW, spot prices on hourly basis are reduced to a range of approximately 250 DKK /MWh (34 €/MWh). These figures reflect price extremes which are very unlikely; nevertheless, the paper concludes that the extreme scenarios would lead to a decreased spot price of 12-14% in West Denmark and 2-5% in East Denmark. Similar conclusions are reached for other countries in Weigt [7], Woo et al [8, 9], and Culter et al [10], where eventual cost saving resulting from wind energy are estimated in the German, the North American (i.e. ERCOT) and the Australian market respectively.

As we can see, the reviewed papers cover a wide range of figures for the price effects of wind power generation. Price heavily depend on certain key characteristics such as the wind penetration level, the power generation mix (grid mix), and the cost of the marginal technology displaced by wind. Nevertheless, despite the fact that each paper covers a specific set of characteristics, they essentially draw similar conclusions: *increased wind power penetration and production places a downward pressure on spot prices*.

Wind power does contribute to a reduction in energy prices, but interconnector capacities can play a very significant role in bringing the price to zero at times. Bach [11] claims that Swedish congestion policy is the reason for unstable prices in East Denmark. Sweden tries indeed to maintain uniform prices over all the country, which means that local variations in demand are not mitigated by price changes (or weakly so), but have to be matched by variations in supply. If local generation is not able to match these changes, power has to be conveyed to the zone, meaning that the grid is easily congested. Eventually, internal bottlenecks are transferred into reduced trading capacity with (East) Denmark, which is left on its own to cope with the variations in wind generation. A similar effect is also identified in a study by Li et al. [12], in an agent-based model. The authors evidence that, during peak hours, a relatively lower price is observed within isolated submarkets endowed with exceeding generation capacity. This comes as a consequence of the congestion following insufficient transmission capacities that prevent power to be transferred to the areas where it is most needed. Clearly, accounting for congestion is essential when assessing the price drop per megawatt hour (MWh) of wind power, as the additional wind power is dispatched over a smaller or a larger area. Surprisingly, this fact is ignored in the studies mentioned in the literature review. Moreover, these studies only assess the price effect of wind production and ignore the impact of wind power on GHG emissions. Some studies on the impact of wind generation on GHG emissions can be found in the literature. A 2013 paper by Kaffine et al [13] looks at avoided emissions in Texas related to wind generation. They cover 25,000 hours between 2007 and 2009 and build a model to estimate the impact of hourly wind generation on hourly emissions data, independently obtained from different sources. Their approach ignores congestion issues and requires the availability of hourly emissions data – which is problematic in many cases.

To the best of the author's knowledge, this study is the first attempt towards quantifying the impacts of large-scale wind power in reducing electricity prices and GHG emissions from the power system, while taking into consideration internal congestion effects. The Ontario deregulated electricity market is the selected case study to reach the paper's objective.

1.1. The Ontario real time electricity market

Ontario is the most wind powered province in Canada with slightly more than 2,000 MW of installed wind generation capacity in 2013 [14]. This position is expected to remain unchanged, as there is a 2018 target of 10,700 MW of renewable energy generation capacity. This excludes hydropower, and is expected to be met thanks to a 7,500 MW wind generation capacity, as stated in the Ontario Government's Long Term Energy Plan (LTEP) [15]. Moreover, the Ontario Government released the results of the Feed-in-Tariff review and made a commitment to meet the 2018 wind generation capacity target by signing required contracts by 2015 [16].

The Ontario's Feed-in-Tariff program offers 11.5 cents/kWh to wind producers [17]. This appears to be very generous when compared to the average Hourly Ontario Electricity Price (HOEP) [1], which ranged between 3.1 and 4.8 cents/kWh from 2006 to 2011, see Table 1.

[1] The HOEP is a wholesale spot price fluctuating according to bids and demand levels. One can learn more about how it is determined by going to the IESO web page https://www.ieso.ca/imoweb/siteShared/wholesale_price.asp

Moreover, the increased wind penetration comes in a context of increased relative share of nuclear generation, significant decrease of coal generation (see Table 2), and reduced demand after 2008, as a result of economic recession. Thus, wind power is added to an electricity system which tends to be, at least currently, in over-capacity, and for which associated GHG emissions are decreasing. In such context, concerns regarding the relevance of wind power have risen in recent years. Engineers in particular have expressed their worries about negative prices (Table 1), see for instance the Ontario Society of Professionnal Engineers's (OSPE) recent report [18]. The Ontario independent electricity system operator (IESO) indeed started in 2010 a stakeholder consultation on renewable integration, leading to new dispatch rules for variable generation (i.e. wind and solar), among other changes (see [19]). These changes are however considered relatively minor by some commentators (see [20]) and will not eliminate the price impact of growing wind outputs.

Table 1. Negative Electricity Price Periods in the Ontario Wholesale Market [18]

Annual Period Sept 15 to Sept 14	Hours with Negative prices	Days with negative prices	Lowest HOEP* $/MWh	Average HOEP* $/MWh	Wind penetration (%)**	Total demand (TWh)
2006/07	3	2	-1.66	44.89	0.5	151
2007/08	32	11	-14.59	48.68	0.8	143
2008/09	319	62	-52.08	38.35	1.5	135
2009/10	58	31	-128.15	33.56	1.8	137
2010/11	138	56	-138.79	31.58	2.4	138
Totals	550	162	--	39.48	1.3	786

*HOEP is the Hourly Ontario Electricity Price (Wholesale price).

** Average wind penetration as a percentage of the total yearly output (MWh).

Given the above, knowing the extent to which wind power reduces electricity prices and GHG emissions of the Ontario power system appears extremely relevant, while providing useful insights for other markets. Section 2 presents the proposed methodology to tackle these issues.

Table 2. Electricity generation by fuel type and percentages (as a function of the total output (MWh)) [21]*

Annual Period Sept 15 to Sept 14	Coal (%)	Hydro (%)	Gas (%)***	Biomass (%)	Nuclear (%)	Wind (%)
2006/07**	17.9	22.0	6.7	0.7	52.2	0.6
2007/08	16.2	23.9	6.3	0.6	52.2	0.8
2008/09	8.8	25.2	6.3	0.7	57.5	1.4
2009/10	9.8	22.3	7.7	0.8	57.6	1.8
2010/11	3.3	24.1	8.1	0.9	61.2	2.4

* Hourly energy output and capability of each generating facility are provided by IESO upon request

**since March 2006.

***The Lennox generating station can operate using either gas or oil. All its output has been included in the gas-fired category.

2. Methodology

2.1. Data collection

Detailed data obtained for this study come from the IESO. These data include variables such as the hourly wind electricity production from each operational wind farm. Table 3 summarises the data used and their sources. These data are grouped on a zonal basis, as the province of Ontario is divided into ten interconnected zones. For every zone, a dataset is compiled on an hourly basis (i.e. 51,140 hours) and include the amount of produced electricity per fuel type, the zonal demand and the zonal price. The Ontario zone diagram, shown in Figure 1, identifies the ten zones and the generation technologies available in each zone.

Table 3. Datasets sources for the period between March 2006-December 2011

Data name	Description and comments	Resolution	Source
Wind Output	Hourly energy output of each Wind farm (MWh)	Site specific	[22]
Electricity Zonal Price*	Hourly Nodal Prices for the 10 Zones ($/MWh)	Zonal	[22]
Hourly Ontario Electricity Price (HOEP)	Wholesale market price ($/MWh)	Provincial	[22]
Electricity Demand	Hourly Demand for the 10 Zones (MWh)	Zonal	[22]
Generator Output	Hourly energy output and capability of each generating facility (MWh)	Site specific	[21]**

*For all zones, zonal prices correspond to nodal prices. Exception resides for the northeast and the northwest zones, as for each zone, three nodal prices are available. For the sake of simplicity, the nodal price within which the wind farm is located is selected.
**Hourly energy output and capability of each generating facility were provided by the IESO.

As illustrated in Figure 1, transmission lines link together Ontario zones. Congestion caused by limited transmission capacity happens. If the transmission capacity of a branch is limited during high wind generation, the magnitude of price changes is likely to be higher. Congestion leads to the emergence of distinct pricing areas. Therefore wind generation has a different impact on prices and on power production by other sources, whether there is congestion or not. The additional wind power is indeed dispatched over a smaller or a larger area. Surprisingly, as mentioned earlier in the literatures review, congestion issues are ignored in the studies assessing the effect of wind production.

Fig 1. Ontario with zones superimposed including available power plants by fuel types [23, 24]

We define uncongested hours as those for which the price in different zones are within a $5/MWh range. While being arbitrary to some extent, there is no “typical” price spread due to congestion, according to the IESO.[2] This $5 threshold allows the identification of large price

[2]IESO customer relations personnel communication

differentials due to congestion rather than other technical network or dispatch constraints (e.g. transmission losses).

If the price difference between adjacent zones exceed 5$/MWh, for a given hour, clustering techniques are applied to isolate subgroups of adjacent zones having a price difference below 5$/MWh. To do so, we assessed for every hour (for a total of 51,144 hours), where the price difference between adjacent zones exceeded the 5$/MWh threshold. The MATLAB/Simulinks software was used for that purpose. In addition to this, a frequency analysis is applied to isolate the most frequent price difference locations (i.e., frequent congestion locations). Figure 2 presents the obtained 12 clusters. The analysis proceeds in five steps or “levels”. Level 0 is the complete data set. From this set, we extracted the 19,458 hours where all the 10 zonal prices are within a $5 price range (Cluster 1). We interpret this price convergence between all zones as a sign of absence of network congestion. The remaining 31,682 hours (All\Cluster 1) were further divided in four groups, out of which two clusters could be identified (Clusters 2.1 and 2.2), based on geographic and price proximity. The two remaining data groups were further divided into smaller clusters, as illustrated in Figure 2. The 10 obtained clusters are described in Table S1 (see supporting information).

Fig 2. Profile of the spatio-temporal clusters

2.2. Price statistical analysis

Articles reviewed in section 1.1 quantified the impacts of large-scale wind power in reducing electricity prices using several methods. These methods can be classified as either “accounting” methods [8, 9, 25], or “modeling” ones [3, 12]. Accounting methods use historical generation data. The primary advantage of such approach is the fact that it relies upon data collected from the actual grid and upon measures attached to real grid operations. Datasets used in this approach include various historical plant-level datasets, such as the ones presented in Table 3. The most significant limitation of accounting methods is the inability to redispatch the system if some changes are introduced, and this is where simulation models (i.e. “modeling” methods) are useful. The later allow for system redispatch, investigation of possible power exchanges between regions, and more generally, the exploration of scenarios that differ markedly from the actual situation.

Redispatching the power system as a consequence of wind power penetration is very unlikely in the short run and anyway not within the scope of this study. Moreover, we aim at measuring the actual impact of wind generation upon the (historical) hourly price and GHG emissions within each of the IESO zonal markets. We thus naturally adopt the “accounting” approach and perform a regression analysis to measure the impact of wind generation. This analysis was performed with the SPSS statistical software for Windows, version 19.0. We are aware that, due to the complexity of electricity price dynamics, regressions are unable to fully explain the price behavior or produce accurate forecasts. However, these regressions are sufficient to test the main claim of this work that is the very fact that wind production has an impact on both electricity spot prices and GHG emissions, and that this impact depends on congestion.

The regression model is presented in equation (1) and results are presented in section 3.2. A panel regression model is used, where all metric variables are expressed in the log form.

$$log\ Y_t = \alpha + \sum_r (\beta_r\ log\ x_{rt}) + \sum_i (\gamma_i\ M_{it}) + \sum_j (\delta_j\ D_{jt}) + \sum_k (\lambda_k\ H_{kt}) + \gamma\ T_t + \varepsilon_t \quad (1)$$

Y_t denote the zonal price in a particular cluster at time t (i.e. hour, t=1,…, 51,144). When multiple zones are in a cluster, we use the average of the different zonal prices. When all zones are used, we use the HOEP. The price Y_t, which is the dependent variable in a linear regression model with partial adjustment, is driven by two sets of variables. First, numeric metric variables, denoted x_{rt} (r=1,…, 7) provide information on hourly demand and production. These variables are defined below in more details. Second, a set of three time-dependent binary indicators account for the month of the year (M_{it}), the day of the week (D_{jt}), and the hour of the day (H_{kt}), with i=1,…, 11 (Januray to November); j=1,…, 6 (Monday to Saturday); k=1,…, 23, (hours of the day) respectively. A trend variable (T_t) also captures the long-term trend across the six years covered by the data set. Twelve sets of coefficients are estimated, one for each of the 12 clusters, the whole data set and a subset of the data (all congested hours). These results are used to explore the impact of changes in wind generation the price level.

The seven metric variables x_{rt} are defined as follows:

- x_{1t} is the hourly wind generation within the IESO system (in MWh), which is largely at the mercy of random wind conditions. We hypothesize that rising wind generation reduces price, which translates into the hypothesis: $\beta_1<0$.

- x_{2t}, x_{3t} is the hourly MWh nuclear and hydropower generation in the IESO system. Nuclear generation is baseload. Reducing nuclear output due to maintenance, repair or refuel is expected to be associated to a raise of the price. The same reaction is expected with a decrease of hydropower generation. This translates into the hypothesis: $\beta_{2,3}<0$.

- x_{4t}, x_{5t}, and x_{6t} are the hourly MWh coal, natural gas[3], and biomass generation in the IESO system. They are likely to be the marginal technologies. We thus hypothesize that rising generation will be associated to a raise of the electricity price, which translates into the hypothesis: $\beta_{4,5,6}>0$.

- x_{7t} is the hourly MWh demand in IESO's zones for a given cluster. Higher loads will be associated to a raise of the prices; hence, β_7 is hypothesized to be positive.

2.3. GHG emissions reductions

Wind generation is a technology with low variable, operating and maintenance costs. When wind plants are integrated in power systems and generate electricity, if they are used, technologies with higher marginal costs, such as coal, gas and oil-fired plants, are displaced in the merit order (supply curve) [26]. To estimate the GHG emissions reductions, price bids from

[3] The Lennox generating station can operate using either gas or oil. All its output has been included in the gas-fired category.

generators, defining the supply curve, would be ideal for the analysis. However, price bids are not publicly available in Ontario. In the absence of such data, the identification of technologies operating at the margin is not straightforward. A variety of methods to estimate "avoided emissions" can be used, based on a) average emissions or b) marginal emissions, or c) a combination, our "hybrid approach". A harmonization of these methods is still missing [27]. In the absence of a clearly dominant method, we used four different ones to estimate the avoided emissions resulting from the Ontario wind energy deployment over the March 2006 - December 2011 period. The selected methods, based on the use of our hourly electricity generation dataset per fuel type, are described in the following subsections. Once again, hourly energy output and capability data of each generating facility were provided by the IESO.

A-Average approach

A common way of modeling electricity supply considers the regional grid mix, such as the Ontario average mix. This approach, which significantly simplifies the complexity of the grid, is still commonly used to estimate the avoided emissions from electricity production [28]. Environment Canada has estimated the average GHG intensity of electricity generation in Ontario to be 170 Kg CO_2eq/MWh [29] (see Table 4). By using this GHG intensity, we consider that for every MWh from wind, 170 kg CO_2eq are avoided. This GHG intensity, which is based on reported facility data from Environment Canada's GHG emissions reporting program, considers only operations of power plants (fuel combustion) and does not account for the full life cycle GHG emissions associated with electricity generation. Emissions associated to the construction and decommissioning of facilities or those related to mining, refining and transportation of fuels are indeed ignored. Mallia et al. have recently estimated that the average life cycle GHG intensity of electricity generation in Ontario is 201 kg CO_2eq/MWh [30]. Table 4 contains GHG intensities for electricity generation in 2008 for the Ontario region. In this paper, when using the average approach, we assume no change in these figures from 2006 to 2011.

Table 4. GHG emission rates in the Ontario Province (kg CO_2eq/MWh) [29, 30]

	Operation emissions only	All life cycle emissions
Average	170.0	201.0
Nuclear	0.2	4.8
Hydropower	0.0	22.0
Coal	1,006.0	1,069.0
Natural gas	435.0	497.0
Wind	0.0	10.7

B-Marginal approach

Methods based on average emission rates are criticized for failing to identify and account for the displaced generation units. Indeed, hourly variations are lost when using annual average figures. The difference in annual and shorter time periods may be highly relevant, in particular when there is significant variation in electricity production mix between peak and base load [30]. Therefore, the marginal approach is considered superior to the average approach, even if marginal data related to electricity supply are often considered too complex to be modeled accurately [28]. Such complexity explains why studies often assume only one specific marginal technology, even in contexts where several technologies are at the margin at different times of the day.

To isolate the marginal technology at different times, we used the hourly output by technology provided by IESO. We use two different marginal approaches. The first one consists in computing, on an hourly basis, the relative change in the use of each technology, to identify which technology is the most responsive. For each type of technology, the difference in output between a given hour (t) and the preceding one (t−1) is divided by the latter output (t−1) [4]. The technology showing the highest absolute value (of percentage change) is defined as the marginal one. Therefore, the marginal technology is identified as a responsive technology adjusting its electricity production more than other technologies. As an example, coal power plants can be marginal units if their use can quickly change according to fluctuating zonal price. In the second marginal approach, we repeat the computation without dividing by the output at (t−1). The technology showing the highest output change (in MWh) is defined as the marginal one. The first marginal approach tends to identify technologies contributing relatively less to the total production, but that are more able to quickly increase their production (for instance natural gas or coal). The second marginal approach, by not normalizing, tends to identify the technology the more able to adjust its production quickly, regardless of its initial level of use (for instance, hydropower). Once marginal units are identified on an hourly basis, the specific GHG emission rates (Table 4) are used to quantify the avoided emissions as a consequence of wind generation.

C-Hybrid approach

As a combination of the marginal and the average approach, this method is based upon the fact that more than one technology sees its production level changing as a consequence of wind generation. Indeed, from the observed hourly power outputs of the Ontario system, almost all power plants change their production on an hourly basis (even low cost technologies such as nuclear, hydro or coal). Therefore, this approach suggests that changes as a consequence of wind production have an impact on possibly all power plants. For this approach, we estimate the individual contribution of each generation type to the variation of the total hourly electricity production between an hour (t) and the preceding one (t−1). This is then used as the basis to estimate a weighted GHG emission impact of wind.

[4] We applied this procedure before clustering to avoid loss of information related to the output of the preceding hour.

3. Results

3.1. Descriptive statistics: correlation

Table 5 (A and B) shows that the correlations between zonal prices and both total production and total demand (loads) are much higher than the correlation between wind output and prices. Correlations found are almost always highly statistically significant. This observed higher correlation confirms findings of previous studies that were not considering congestion effects [8, 31]. Also, there is no clear evidence of the influence of wind generation on the spot price. While Table 5-A hints at a usually negative effect of an increase in wind generation on the spot price (-0.19 with all data, without clustering), it does not paint a clear picture of what the real effect may be. Indeed, many other variables can simultaneously have an impact on price; mostly demand levels, making the marginal impact of wind hardly observable with correlation data. Furthermore, depending upon the considered cluster, the correlation between wind generation and prices indeed ranges between -0.13 (cluster 4.5) and 0.07 (cluster 2.1).

Table 5-A. Summary statistics for the sample period of March 2006-December 2011. "*" and "**" denote significance at the level α=5% and α=1% respectively.

	Variable	N	Min	Mean	Max	Standard deviation	Correlation with			
							Price	Total Production	Total Demand	Wind Output
All w/o Clustering	HOEP	51,144	-138	39	1,891	26	1.00	0.56**	0.58**	-0.19**
	Total Production	51,144	10,879	16,822	39,108	2,358		1	0.90**	-0.13**
	Total Demand	51,144	10,493	16,496	26,768	2,564			1	-0.11**
	Wind Output	51,144	0	231	1,610	250				1
Cluster 1 All zones	Zonal Price	19,458	-36	22	1,846	18	1.00	0.30**	0.34**	-0.03**
	Total Production	19,458	10,342	15,510	33,324	1,799		1.00	0.88**	0.11**
	Total Demand	19,458	10,097	14,639	22,760	2,137			1.00	0.10**
	Wind Output	19,458	0	330	1,610	299				1.00
Cluster 2.1 NW-ESSA	Zonal Price	5,983	-50	37	193	12	1.00	0.39**	0.47**	0.07**
	Total Production	5,983	331	2,149	3,931	722		1.00	0.64**	0.10**
	Total Demand	5,983	1,366	2,276	3,187	333			1.00	0.03*
	Wind Output	5,983	0	48	257	50				1.00
Cluster 2.2 OTTAWA-W	Zonal Price	25,129	-650	44	1,265	19	1.00	0.34**	0.40**	-0.09**
	Total Production	25,129	12	15,123	35,351	1,794		1.00	0.80**	-0.05**
	Total Demand	25,129	8,880	14,077	22,169	1,995			1.00	0.01*
	Wind Output	25,129	0	134	1,347	176				1.00
Cluster 3.1 TORONTO-W	Zonal Price	4,079	-149	88	1,923	49	1.00	0.18**	0.23**	-0.09**
	Total Production	4,079	7,434	15,020	19,227	1,634		1.00	0.79**	-0.16**
	Total Demand	4,079	7,651	13,184	18,982	1,739			1.00	-0.13**
	Wind Output	4,079	0	91	962	108				1.00
Cluster 3.2 OTT-East	Zonal Price	1,980	-480	75	1,925	82	1.00	0.18**	0.29**	-0.02**
	Total Production	1,980	367	1,480	3,418	493		1.00	0.66**	-0.09**
	Total Demand	1,980	1,344	2,452	3,523	467			1.00	-0.22**
	Wind Output	1,980	0	15	191	35				1.00

Table 5-A (Continued). Summary statistics for the sample period of March 2006-December 2011. “*” and “**” denote significance at the level α=5% and α=1% respectively.

	Variable	N	Min	Mean	Max	Standard deviation	Correlation with			
							Price	Total Production	Total Demand	Wind Output
Cluster 3.3 NE-ESSA	Zonal Price	22,090	-650	51	1,916	33	1.00	0.28**	0.39**	0.02**
	Total Production	22,090	0	1,517	3,047	601		1.00	0.54**	0.12**
	Total Demand	22,090	1,347	2,352	3,344	311			1.00	0.01
	Wind Output	22,090	0	40	185	49				1.00
Cluster 3.4 NW	Zonal Price	25,703	-2,000	-12	1,866	287	1.00	0.03**	0.02**	-0.02**
	Total Production	25,703	0	706	1,538	169		1.00	0.51**	-0.14**
	Total Demand	25,703	0	13	690	81			1.00	-0.10**
	Wind Output	25,703	0	1	94	6				1.00
Cluster 4.1 NE	Zonal Price	3,613	-975	94	1,786	142	1.00	0.16**	0.34**	-0.06**
	Total Production	3,613	314	1,873	3,075	629		1.00	0.35**	0.18**
	Total Demand	3,613	782	1,290	1,874	178			1.00	-0.13**
	Wind Output	3,613	0	42	185	52				1.00
Cluster 4.2 ESSA	Zonal Price	3,613	-461	106	1,920	158	1.00	0.14**	0.37**	--
	Total Production	3,613	0	310	422	120		1.00	0.23**	--
	Total Demand	3,613	539	1,030	1,609	201			1.00	--
	Wind Output	--	--	--	--	--				--
Cluster 4.3. OTTA	Zonal Price	4,577	-660	139	2,000	151	1.00	0.02	0.16**	--
	Total Production	4,577		59	74	19		1.00	0.16**	--
	Total Demand	4,577	419	1,444	2,205	228			1.00	--
	Wind Output	--	--	--	--	--				--
Cluster 4.4 East	Zonal Price	4,577	-979	116	1,933	142	1.00	0.17**	0.22**	-0.04*
	Total Production	4,577	359	1,529	3,625	521		1.00	0.65**	-0.02
	Total Demand	4,577	361	1,195	1,759	179			1.00	-0.13**
	Wind Output	4,577	0	4	191	21				1.00
Cluster 4.5 RESIDUEL TORONTO-W	Zonal Price	2,478	-459	139	1786	180	1.00	0.26**	0.34**	-0.13**
	Total Production	2,478	7,917	14,497	19,406	2,142		1.00	0.84	-0.24**
	Total Demand	2,478	7,085	12,901	19,424	2,418			1.00	-0.28**
	Wind Output	2,478	0	123	1,060	152				1.00

That correlations between wind generation and prices appear limited is not surprising given that wind generation remain anyway relatively small when compared to loads variations. This makes of more remarkable the results of the correlation decomposition that we perform (explained below), which evidence that accounting for congestion is indeed important when measuring the impact of wind generation.

Given a data set, it is always possible to write the correlation between two variables as a combination of (1) the correlation measured on a subset of data, (2) the correlation measured on the complementary subset and (3) the “inter-sets correlation” *i.e.* the product of the difference in the average values over the two subsets, for the two variables of interest (see the formula in supporting information).

We look at the statistical distribution of the variable of interest over non-congested hours (Cluster 1) and congested hours (All\Cluster 1). This gives rise to Table 5-B. We compute in turn the decomposition of the correlations attached to this dataset partition, which gives rise to table 5-C. This provides interesting hints to the understanding of the following correlation table, as computed for the complete dataset.

Table 5-B makes it clear that accounting for congestion is essential when looking at electricity market. The statistical distribution of variables is completely different during congested hours and non-congested hours. In particular, the average price (HOEP) during congested hours is about twice its value during non-congested hours (48.52$/MWh as compared to 24.79$/MWh). This remarkable gap is observed despite the fact that our definition of congestion is not very restrictive, so that a number of hours that are considered as "congested" actually display a very low level of congestion. In fact, more 60% of the hours are classified as "congested" and the average load during "congested" hours is only at 76% of the maximum load observed with no-congestion. It is also worth noticing that wind generation during uncongested hours is on average twice the average generation then during congested hours (respectively 330 and 170 MW). This makes clear, if needed, that it is not wind generation that causes congestion. In fact, even at its maximum (1,610 MW), wind generation remains smaller than one tenth of the average load (16,496 MW). By contrast, the average load is higher by almost 3,000 MW during congested hours, as compared to uncongested ones.

Table 5-B Statistical distribution over non-congested hours (Cluster 1) and congested hours (All\Cluster 1). "*" and "**" denote significance at the level α=5% and α=1% respectively.

	Variable	N	Min	Mean	Max	Standard deviation	Correlation with			
							Price	Total Production	Total Demand	Wind Output
Cluster 1	HOEP	19,458	-128.4	24.79	299.54	13.53	1	0.43**	0.51**	-0.03**
	Total Production	19,458	10342	15510	33324	1799		1	0.88**	0.11**
	Total Demand	19,458	10097	14639	22760	2137			1	0.10**
	Wind Output	19,458	0	330	1610	299				1
Cluster All\Cluster 1	HOEP	31,686	-138.79	48.52	1891.14	28.60	1	0.48**	0.50**	-0.11**
	Total Production	31,686	12	17629	39108	2299		1	0.88**	-0.08**
	Total Demand	31,686	10531	17347	26768	2424			1	-0.05**
	Wind Output	31,686	0	172	1464	193				1

We can go further in the analysis of correlation. As a careful reader may have noticed, the correlation between wind generation and price as measured on each set of data separately (ρ=-0.03 and ρ=-0.11) is smaller in absolute value than the correlation measured on the whole set of data (ρ=-0.19-see Table 5-A). As illustrated in Figure 3, this is not a typo or an error in the computation but a consequence of the differences in the average values over the two sets. We actually compute that more than 67% of the correlation as computed over the overall set is actually explained by these differences. This makes plain the importance of performing a disaggregated analysis.

Fig 3. Aggregate and within clusters effects.

That 67% of the correlation between wind generation and price can be seen as an artefact of the measure (that follows from not distinguishing uncongested and congested hours) may have been considered by some as an extreme case, only exhibited to support our approach. It is not, not only from a theoretical standpoint, but also from an empirical one. In fact our data reveal that, during uncongested hours, wind generation and load are weakly positively correlated (small positive correlation). By contrast, during congested hours, there is on average slightly less wind generation when the demand is higher (small negative correlation). It follows that the figure obtained by looking at whole dataset is entirely explained by the difference in average values over the two subsets. We obtain that inter-cluster differences explain 112% of the correlation, meaning that the number obtained is larger and with the opposite sign of the (weighted) average correlation, as calculated over each data cluster.

Table 5-C Decomposition of the correlations

	Variable	Contribution to the correlation				Contribution in the variance-covariance matrix			
		Price	Total Prod.	Total Demand	Wind Output	Price	Total Prod.	Total Demand	Wind Output
Cluster 1	HOEP	0.098	0.063	0.082	-0.008	9.83%	11.26%	13.23%	3.86%
	Total Production		0.221	0.213	0.037		22.13%	22.60%	-27.22%
	Total Demand			0.264	0.039			24.44%	-28.09%
	Wind Output				0.539				53.94%
All\Cluster 1	HOEP	0.715	0.311	0.316	-0.056	71.46%	55.21%	50.96%	28.64%
	Total Production		0.588	0.504	-0.038		58.84%	53.62%	28.13%
	Total Demand			0.554	-0.023			51.23%	16.51%
	Wind Output				0.367				36.74%

Beside the methodological point that accounting for congestion is essential in performing a sound numerical analysis, the above is also an additional illustration that correlation is a very crude instrument. Further analysis is needed to characterize wind generation's price effects, to control for the many other variables influencing the hourly price. The price regressions presented below provide a first step in this direction, where in fact the initial correlation observations are interchanged between uncongested and congested hours: wind generation lowers electricity price much more during uncongested hours than during congested one.

3.2. Price statistical analysis

Before estimating model (1), we conducted on the entire data set a series of standard tests to ensure our results would not be coming out of spurious regressions due to the presence of a unit root. The Augmented Dicky-Fuller, Phillips Perron, KPSS and DF-GLS tests unanimously reject the presence of a unit-root in the time series in levels (HOEP) and logs (log HOEP)[5]. In

[5] More details on the result of these tests are available on request.

addition, standard errors estimated with the Newey-West automatic lag selection yielded quasi-identical results to the one obtained without this procedure. For the sake of simplicity, we used the ordinary least square (OLS) to obtain all our estimates, for the different clusters.

Table 6 presents the analysis results from equation (1) for each of the twelve clusters, plus the two other sets of data (all data and data for all congested hours). Estimates of coefficients lead to the following four observations:

1. Impact of wind generation. The statistically significant estimates for β_1 in the whole data set, for uncongested hours (Cluster 1) and for congested hours (All\Cluster 1) indicate that a 100% increase in wind generation is associated to a decrease in price of respectively 3.3%, 5.5% and 0.8%. This corroborates the price effects already founded by previous studies [8, 32], and supports our first hypothesis. However, the more important observation to make is the higher impact of wind during uncongested hours than during congested hours. The further breakdown of congested hours in smaller clusters even shows that the impact becomes non-significant, except in one cluster (2.2). There is strong intuition behind this finding: in Ontario, uncongested hours (which are of course base load hours) are mostly supplied by nuclear power plants. As they can hardly be adjusted to let the wind output be used instead of theirs, the electricity price has to decrease by a larger amount. This induces a higher demand, absorbing the increased wind production. During peak hours (congested ones), there are more power plants online, and therefore more possibilities to reduce output to let the wind output be a substitute to other technologies, instead of stimulating electricity demand by lowering prices.

Another explanation for the lower impact of wind during congested hours than during uncongested hours, which can be surprising given the correlations presented in Table 5, lies in the correlation between demand and wind output. As shown in Table 5-B, demand is positively correlated to wind output during uncongested hours (0.10) while it is negatively correlated during congested hours (-0.05). Both correlations are small but significant. This helps explaining why the price-wind correlation is lower during uncongested hours (-0.03) than congested hours (-0.11): higher demand during windy hours lead to higher prices (due to the higher demand), despite the influence of wind. Conversely, during congested hours, lower demand during wind hours decreases the price… which “inflates” the observed higher negative correlation between price and wind. The econometric analysis made here corrects the erroneous conclusions one could make by simply using the correlation results.

2. Impact of nuclear and hydro generation. Estimates for β_2 indicate that a 10% drop in nuclear generation (MWh) is associated to a price increase of 6.6% when all data are used, but of 10.53% during uncongested hours (Cluster 1). The impact is much lower when there is some congestion: only a 3.59% increase. This comes in support of our second hypothesis. The second hypothesis is also supported when we refer to the β_3 estimate (hydro generation) for the whole data set: a 10% drop in hydro generation would increase the price by 1.09%. However, this finding does not hold when we look into uncongested and congested clusters: hydro generation actually follows price, as the positive (and significant) estimates for β_3 show in most clusters.

This corresponds better to the intuitive idea that flexible hydro generation is used when demand requires it (and is use to a lower extent when demand declines).

3. Impact of thermal generation. The statistically significant, and positive, estimates for β_4 (coal) and β_5 (natural gas) come in support to our third hypothesis. However, β_6 (biomass) is negative, and may indicate that biomass power plants operate more like base load plants than marginal ones. Some exceptions are also noticed for β_5 (natural gas): during uncongested hours (cluster 1) and in some specific congested clusters (2.1, 3.3, 3.4, 4.1), natural gas generation lowers the price. This could simply be explained by an energy overflow, moving the supply curve to the left, and consequently decrease the price in these clusters [11]. As a matter of fact, when we refer to Table 2, one can notice that electricity generation from natural gas increased between 2006 and 2011 (from 6.7% or 10.12 TWh to 8.1% or 11.12 TWh). This happened while the Ontario demand decreased from 151 to 138 TWh. Consequently, high supply frequency can increase in such market conditions, especially under some tight grid conditions. In these three clusters, indeed, loads are much greater than local supply, meaning that natural gas comes as a relief to supply from other Ontario zones.

4. Impact of load. The statistically significant estimates for β_7 support our fourth hypothesis that an increase in electricity demand is systematically associated to an increase of the price.

Finally, we can mention that there is a slightly positive (significant) trend throughout the data set: when accounting for all other variables, the hourly prices tend to grow from 2006 to 2011. However, the decrease in loads during the same period explains why average yearly prices are decreasing (see Table 1).

3.3. GHG emissions reductions from Ontario wind production

GHG emissions reductions should also be considered as part of a comprehensive analysis on the impacts of wind generation, which is usually presented as a substitute to "dirty" generation and sometimes as a source of carbon "credits"[6]. In fact, when wind plants are integrated in power systems, the system supply curve is altered in a way that more thermal generation such as coal, gas and oil-fired plants may be displaced.

Table 7 summarizes our estimates of the decrease in GHG emissions associated with increased wind. As a result of the four estimation approaches we use, without clustering, GHG emissions reduction amounts to an average of 170 kg of CO2-eq./MWh (with average approach), 615 (first marginal approach), 290 (second marginal approach) and 331 (hybrid approach). These results suggest the modest efficiency of wind production in reducing GHG emissions: less than emissions from a natural gas power plant in most cases. In the first marginal approach, the high value is mostly the result of the bias this approach has to identify coal as a marginal unit, as discussed in section 2.3. Table S2 (in the supporting information) documents the decrease in

[6] See for instance the Alberta (Canada) "Quantification Protocol For Wind-Powered Electricity Generation", where wind can be used as offsets in the carbon market.[33] Alberta Environment. Offset Protocol Development Guidance. Edmonton: Alberta Environment; 2011. p. 92.

GHG emissions as a consequence to wind penetration using a life cycle methodology. It is found that, extending the boundaries by including GHG emissions from all life cycle stages (resource extraction to end-of-life) increases the net result of avoided GHG emissions by a maximum of 31%, over the 2006–2011 period. This percentage of increased GHG emissions is representative of the electricity sector when we take into account all the life cycle stages [34].

As we did for the price impact (Table 6), we compare the avoided GHG emission differences when congestion issues are taken into account and when they are not (Tables 7 and 8). As mentioned above, there may be congestion in power transmission during period with wind power generation. Thus if the transmission capacity cannot cope with the required power export, the supply area is separated from the rest of power market and constitutes its own pricing area. With an excess supply of power in this area, conventional powers have to reduce their production, since it is generally not possible to limit the power production of Wind [35]. Hence, the final estimates of avoided GHG emissions should be sensitive to transmission capacity and its state.

In table 7, we observe that the GHG impact of wind greatly varies between clusters. As intuitively expected given the greater reliance on nuclear and hydro power during low demand/uncongested hours, our estimates show that more GHG is avoided during congested hours (All\Cluster 1) compared to uncongested ones (Cluster 1 All zones). The second marginal approach shows that indeed 364 versus 233 kg/MWh are avoided during congested hours, while the hybrid approach results in a 393 versus 283 kg/MWh comparison. Obviously, the average approach cannot account for these differences, while the first marginal approach, because of its bias towards identifying coal as a marginal technology, and although less during high load/congested hours, leads to opposite figures.

Table 6. Regression results obtained by OLS. For brevity, this table does not report the coefficient estimates for the intercept and binary indicators (hour of the day, day and month) that indicate statistically significant time-dependence of the hourly prices. Values in ( ) are standard errors of the coefficient estimates, ''*'' and ''**'' denote significance at level α=1% and 5% respectively.

Variable coefficient	All w/o Clustering (1)	Dependent variable: Market price (i.e. Average zonal prices)												
		Cluster 1 All zones	All\ Cluster1	Cluster 2.1 NW-ESSA	Cluster 2.2 OTT-W	Cluster 3.1 TOR-W	Cluster 3.2 OTT-EAST	Cluster 3.3 NE-ESSA	Cluster 3.4 NW	Cluster 4.1 NE	Cluster 4.2 ESSA	Cluster 4.3 OTTAWA	Cluster 4.4 EAST	Cluster 4.5 RESIDUAL
Total R^2	0.49	0.37	0.46	0.47	0.27	0.39	0.48	0.33	0.62	0.41	0.42	0.15	0.42	0.45
Root mean squared error (RMSE)	0.04	0.07	0.02	0.01	0.02	0.02	0.09	0.03	0.03	0.12	0.11	0.06	0.12	0.09
Trend	0** (0)	0** (0)	0** (0)	0** (0)	0** (0)	0** (0)	0** (0)	0** (0)	-0.016** (0.003)	0 (0)	0 (0)	0** (0)	0 (0)	0** (0)
β_1:Hourly wind generation (MWh)	**-0.033** (0.002)**	**-0.055** (0.005)**	**-0.008** (0.002)**	0.006 (0.003)	**-0.013** (0.002)**	-0.002 (0.004)	0.04 (0.025)	-0.004 (0.002)	0.09 (0.048)	-0.008 (0.012)	--	--	-0.01 (0.037)	0.011 (0.012)
β_2:Hourly nuclear generation (MWh):	-0.66** (0.026)	-1.053** (0.06)	-0.359** (0.023)	--	-0.247** (0.025)	-0.015 (0.063)	--	--	--	--	--	--	--	-0.02 (0.179)
β_3:Hourly hydro-power gen (MWh)	-0.109** (0.014)	0.071* (0.03)	0.158** (0.014)	0.058** (0.015)	0.148** (0.018)	0.974** (0.055)	-0.18 (0.113)	0.012* (0.006)	1.372* (0.576)	-1.695** (0.283)	-0.038 (0.023)	--	0.051 (0.228)	2.3** (0.132)
β_4:Hourly coal generation (MWh)	0.074** (0.002)	0.138** (0.004)	0.046** (0.002)	0.048** (0.005)	0.033** (0.003)	0.118** (0.008)		-0.029** (0.01)	0.202* (0.082)	--	--	--	--	0.035* (0.014)
β_5:Hourly natural gas gen (MWh)	0.075** (0.01)	-0.101** (0.023)	0.183** (0.009)	-0.153** (0.022)	0.02** (0.008)	0.019 (0.014)	-0.044 (0.1)	-0.103** (0.007)	-1.189** (0.353)	-0.193** (0.058)	--	0.011 (0.039)	-0.149 (0.165)	-0.045 (0.04)
β_6:Hourly biomass generation (MWh)	-0.048** (0.005)	0.029* (0.012)	-0.075** (0.004)	-0.081** (0.011)	--	--	--	--	-0.489 (0.291)	-0.02 (0.036)	--	--	--	--
β_7:Hourly zone load (MWh)	3.267** (0.043)	2.826** (0.1)	2.177** (0.04)	1.519** (0.077)	1.705** (0.043)	1.333** (0.098)	2.756** (0.378)	2.455** (0.043)	-0.817 (1.52)	5.579** (0.205)	5.067** (0.163)	2.314** (0.124)	3.767** (0.671)	2.494** (0.252)

Number of hours	51,144	19,458	31,686	5,983	25,129	4,079	1,980	22,090	25,703	3,613	3,613	4,577	4,577	2,478
Average zonal price (1) ($/MWh)	39.49	21.91	48.52	37.21	43.56	87.61	74.68	51.37	-11.55	82.31	106.43	138.56	115.79	139.49
Average production (MWh)	16,822	15,510	17,629	2,149	15,123	15,020	1,480	1,517	706	1,873	310	59	1,529	14,497
Average demand (MWh)	16,496	14,639	17347	2,276	14,077	13,184	2,452	2,352	13	1,290	1,030	1,444	1,195	12,901
Average Wind production (MWh)	231.98	329.77	172	47.87	134	91.39	15.13	40.31	0.66	41.83	--	--	4.29	122.82

(1) The HOEP is used for the Ontario w/o Clustering regression.

Table 7. GHG emissions reductions from Ontario wind energy resources (million tonnes of CO2eq, totals for 2006–2011, unless otherwise specified)

Approach	All w/o Clustering	Cluster												
		1 All zones	All\ Cluster1	2.1 NW-ESSA	2.2 OTT-W	3.1 TOR-W	3.2 OTT-EAST	3.3 NE-ESSA	3.4 NW	4.1 NE	4.2 ESSA	4.3 OTTAWA	4.4 EAST	4.5 RESIDUAL
Average	2.02	1.09	0.93	0.05	0.57	0.06	5.09E-03	1.51E-01	2.89E-03	2.57E-02	--	--	3.34E-03	5.17E-02
Marginal (1)	7.32	4.05	3.28	0.11	2.19	0.16	4.26E-03	6.76E-02	3.41E-03	1.69E-02	--	--	2.09E-03	1.51E-01
Marginal (2)	3.46	1.50	1.98	0.02	1.75	0.19	2.76E-03	2.29E-02	1.36E-03	4.36E-03	--	--	1.19E-03	1.24E-01
Hybrid	3.95	1.82	2.14	0.04	1.62	0.17	3.32E-03	4.62E-02	1.97E-03	8.90E-03	--	--	1.49E-03	1.22E-01
Total wind production (TWh)	11.9	6.42	5.45	0.286	3.38	0.373	0.03	0.89	0.017	0.151	--	--	0.0196	0.304
Average approach (1) (kgCO2eq/MWh)	170	170	170	170	170	170	170	170	170	170	--	--	170	170
Marginal approach(2) (kgCO2eq/MWh)	615.13	630.84	600.61	384.62	647.93*	428.95	142.00	75.96*	200.59	111.92	--	--	106.63	496.71
Marginal approach(3) (kgCO2eq/MWh)	290.76	233.64	364.15	69.93	517.75*	509.38	92.00	25.73*	80.00	28.87	--	--	60.71	407.89
Hybrid approach (4) (kgCO2eq/MWh)	331.93	283.49	393.68	139.86	479.29*	455.76	110.67	51.91*	115.88	58.94	--	--	76.02	401.32

(1) A common way of modeling electricity supply considers the regional grid mix, in this case the Ontario average mix.

(2) The first marginal approach consists in computing the relative change (%) in the use of each technology (output (t)-output (t-1))/ output (t-1)

(3) The second marginal approach consists in computing the total change (MWh) in the use of each technology (output (t)-output (t-1))

(4) All power plants change their production on an hourly basis, therefore, the hybrid approach suggest that changes as a consequence of wind production has an impact on all power plants.

* These values represent the highest and the lowest value within each approach.

Table 8 compare aggregated estimates with and without clustering. The difference does not exceed 8%[7]. These results show that from a combined perspective, taking congestion into account does not radically change the estimates of avoided emissions – even if these avoided emissions greatly depend on the marginal technology used at the time of wind production (as shown in the cluster values presented in Table 7).

Table 8. Avoided GHG emissions estimates and approaches comparison (million tonnes of CO2eq, totals for 2006–2011).

Approach	System boundary					
	Operation emissions only			All life cycle emissions		
	Without Clustering	With Clustering	**Difference***	Without Clustering	With Clustering	**Difference**
Average (1)	2.02	2.02	**0%**	2.38	2.38	**0%**
Marginal (2)	7.32	6.76	**8%**	7.80	7.22	**7%**
Marginal (3)	3.46	3.61	**-5%**	3.75	3.92	**-5%**
Hybrid (4)	3.95	3.84	**3%**	4.27	4.16	**3%**

*(Without Clusturing – With Clusturing) /Without Clusturing

(1) A common way of modeling electricity supply considers the regional grid mix, in this case the Ontario average mix.

(2) The first marginal approach consists in computing the relative change (%) in the use of each technology (output (t)-output (t-1))/ output (t-1)

(3) The second marginal approach consists in computing the total change (MWh) in the use of each technology (output (t)-output (t-1))

(4) All power plants change their production on an hourly basis, therefore, the hybrid approach suggest that changes as a consequence of wind production has an impact on all power plants.

[7] Observations remain the same when we compare the avoided emissions results of (cluster 1 + All\cluster 1) and All Without Clustering, no matter the applied approach (see Table 7).

Conclusion and Outlook

This paper explores wind power integration issues by assessing, for the province of Ontario (Canada), the impacts of hourly regional wind generation on prices and GHG emissions, over 6 years of market operations (2006-2011). The main contribution of this research paper is to account for internal grid congestion in the analysis. Ontario's wind energy penetration reached a level of 2.4% and is expected to increase despite the limited interconnection between the zones within the province. As such, it represents an interesting example of low and constrained wind penetration in a wholesale electricity market. Our findings suggest that while electricity demand continues to have the greatest influence on prices, wind output is associated to a decrease of the electricity price. The impact of wind during congested and uncongested hours is found to be very different, both in terms of price and avoided GHG emissions. During uncongested hours, the impact of a 100% increase in wind production reduces the price by 5.5%, while during congested hours the price decreases by only 0.8%. When not discriminating between the two, one would conclude in a 3.3% price decrease. With respect to GHG emissions, we find that avoided GHG emissions per MWh of wind increase by about 50% (more than 100 kg CO_2eq/MWh) during congested hours compared to uncongested ones, in two of our estimation approaches.

Beyond illustrating the importance of congestion, and providing estimates of its impacts in a specific context, our contribution is to propose a methodological approach to create clusters and to estimate avoided GHG emissions, by using four different approaches to identify the marginal technology. While wind penetration grows in electricity systems, these contributions are important to fully understand the impacts of wind outputs on electricity prices and grid-related emissions. Without such understanding, incorrect economic incentives could be given to wind producers (e.g. in the amount of carbon credits their production is entitled to) and unforeseen price levels could lead to problematic dispatch outcomes and payments.

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Appendices

Table A.1. Clusters description

	No Cluster	Cluster											
	Ontario w/o Clustering	1 All zones	2.1 NW-ESSA	2.2 OTT-W	3.1 TOR-W	3.2 OTT-EAST	3.3 NE-ESSA	3.4 NW	4.1 NE	4.2 ESSA	4.3 OTTAWA	4.4 EAST	4.5 RESIDUAL
Included zones	All (10) zones	All (10) zones	NW-NE-Essa	Ottawa-E-Toronto-Niagara-SW-Bruce-W	Toronto-Niagara-SW-Bruce-W	Ottawa-E	NE-Essa	NW	NE	ESSA	OTTAWA	EAST	Toronto-Niagara-SW-Bruce-W
Number of hours	51,144	19,458	5,983	25,129	4,079	1,980	22,090	25,703	3,613	3,613	4,577	4,577	2,478

Table A.2. GHG emissions reductions from Ontario wind energy resources using life cycle methodology (million tonnes of CO2eq, totals for 2006–2011).
Avoided GHG emission excludes life cycle GHG emission from wind power of 10.7 KgCO2eq/MWh

Approach	Ontario w/o Clustering	Cluster											
		1 All zones	2.1 NW-ESSA	2.2 OTT-W	3.1 TOR-W	3.2 OTT-EAST	3.3 NE-ESSA	3.4 NW	4.1 NE	4.2 ESSA	4.3 OTTAWA	4.4 EAST	4.5 RESIDUAL
Average	2.38	1.29	0.06	0.68	0.07	6.02E-03	1.79E-01	3.42E-03	3.04E-02	--	--	3.95E-03	6.12E-02
Marginal (1)	7.80	4.30	0.12	2.34	0.18	4.98E-03	8.39E-02	3.79E-03	2.01E-02	--	--	2.51E-03	1.63E-01
Marginal (2)	3.75	1.64	0.03	1.87	0.20	3.34E-03	3.51E-02	1.62E-03	6.47E-03	--	--	1.52E-03	1.33E-01
Hybrid	4.27	1.98	0.05	1.73	0.18	3.95E-03	6.05E-02	2.28E-03	1.14E-02	--	--	1.85E-03	1.31E-01
Total wind production (TWh)	**11.9**	**6.42**	**0.286**	**3.38**	**0.373**	**0.03**	**0.89**	**0.017**	**0.151**	**--**	**--**	**0.0196**	**0.304**
Average approach (1) (KgCO2eq/MWh)	201	201	201	201	201	201	201	201	201	--	--	201	201
Marginal approach(2) (KgCO2eq/MWh)	655.46	669.78	419.58	692.31*	482.57	166.00	94.27*	222.94	133.11	--	--	128.06	536.18
Marginal approach(3) (KgCO2eq/MWh)	315.13	255.45	104.90	553.25*	536.19	111.33	39.44*	95.29	42.85	--	--	77.55	437.50
Hybrid approach (4) (KgCO2eq/MWh)	358.82	308.41	174.83	511.83*	482.57	131.67	67.98*	134.12	75.50	--	--	94.39	430.92

(1) A common way of modeling electricity supply considers the regional grid mix, in this case the Ontario average mix.
(2) The first marginal approach consists in computing the relative change (%) in the use of each technology (output (t)-output (t-1))/ output (t-1)
(3) The second marginal approach consists in computing the total change (MWh) in the use of each technology (output (t)-output (t-1))
(4) All power plants change their production on an hourly basis, therefore, the hybrid approach suggest that changes as a consequence of wind production has an impact on all power plants.
* These values represent the highest and the lowest value within each approach.

A.3. Correlation Decomposition:

Let *I* be a set of data and consider any decomposition into two disjoint sets *J* and *K.* (*I = JUK* and $J \cap K = \varnothing$).

The correlation of the two variables *p* and *w* over the set *I* which writes by definition:

$$\rho_I^{p,w} = \frac{\sum_{t \in I} \left(p_t - \overline{p_I}\right)\left(w_t - \overline{w_I}\right)}{\sqrt{\sum_{t \in I} \left(p_t - \overline{p_I}\right)^2 \sum_{t \in I} \left(w_t - \overline{w_I}\right)^2}} = \frac{\operatorname{cov}_I\left(p, w\right)}{\sqrt{\operatorname{var}_I(p)\operatorname{var}_I(w)}},$$

where $\overline{p_I}$ and $\overline{w_I}$ stand for the average values of p and w over *I* respectively and var_I and cov_I stand for the variance and the covariance of their arguments, as computed over the set *I.*

The above formula can be rewritten as:

$$\rho_I^{p,w} = \frac{\left(\overline{p_J} - \overline{p_K}\right)\left(\overline{w_J} - \overline{w_K}\right) + \left(1 + \frac{\|J\|}{\|K\|}\right)\operatorname{cov}_J\left(p, w\right) + \left(1 + \frac{\|K\|}{\|J\|}\right)\operatorname{cov}_K\left(p, w\right)}{\sqrt{\left(\overline{p_J} - \overline{p_K}\right)^2 + \left(1 + \frac{\|J\|}{\|K\|}\right)\operatorname{var}_J(p) + \left(1 + \frac{\|K\|}{\|J\|}\right)\operatorname{var}_K(p)}\sqrt{\left(\overline{w_J} - \overline{w_K}\right)^2 + \left(1 + \frac{\|J\|}{\|K\|}\right)\operatorname{var}_J(w) + \left(1 + \frac{\|K\|}{\|J\|}\right)\operatorname{var}_K(w)}}.$$

This allows decomposing the correlation between the variables *p* and *w* over the set *I* as deriving from the correlation within each subset but also from the differences across sets.

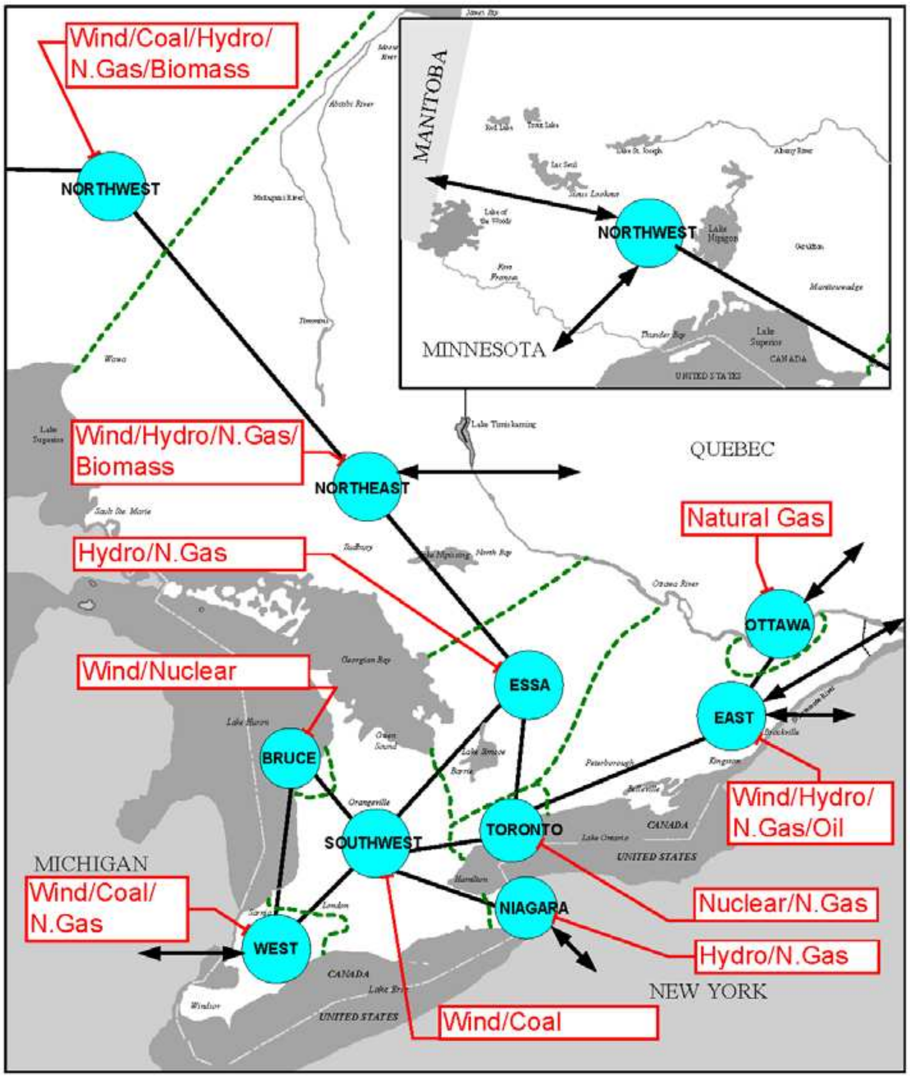

Fig 1. Ontario with zones superimposed including available power plants by fuel types [23, 24]

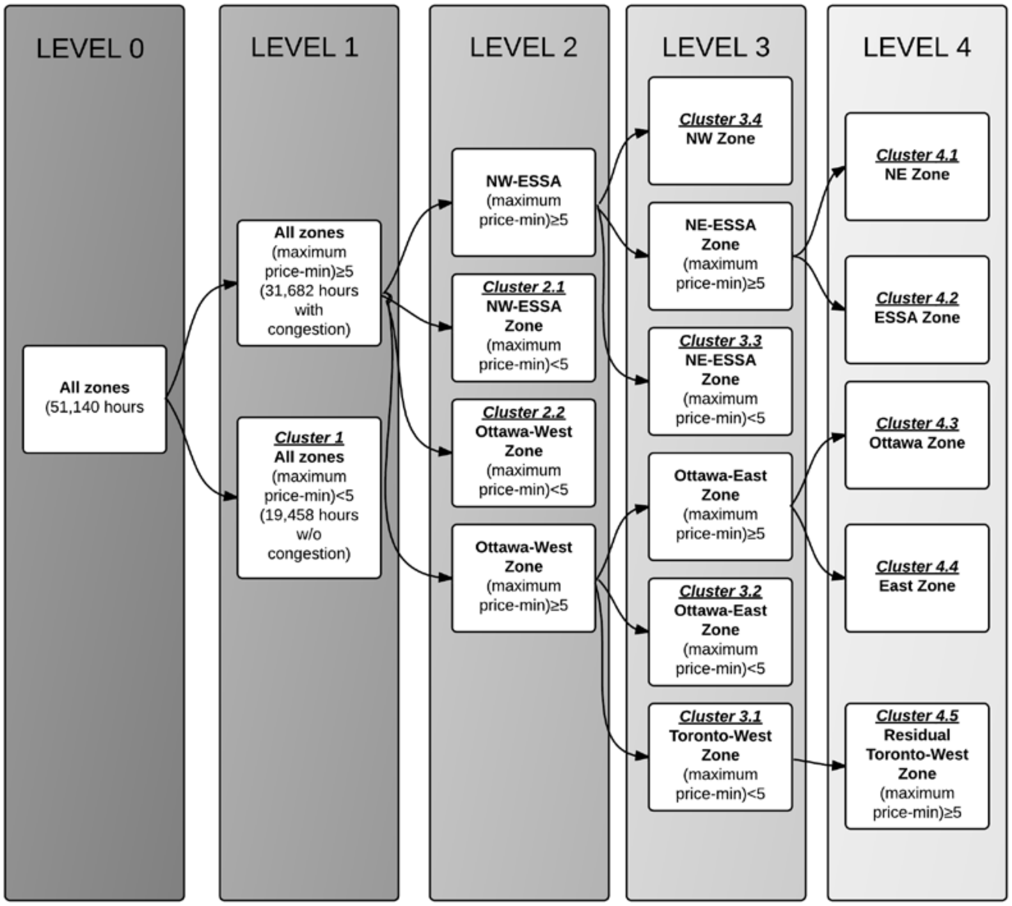

Fig 1. Profile of the spatio-temporal clusters

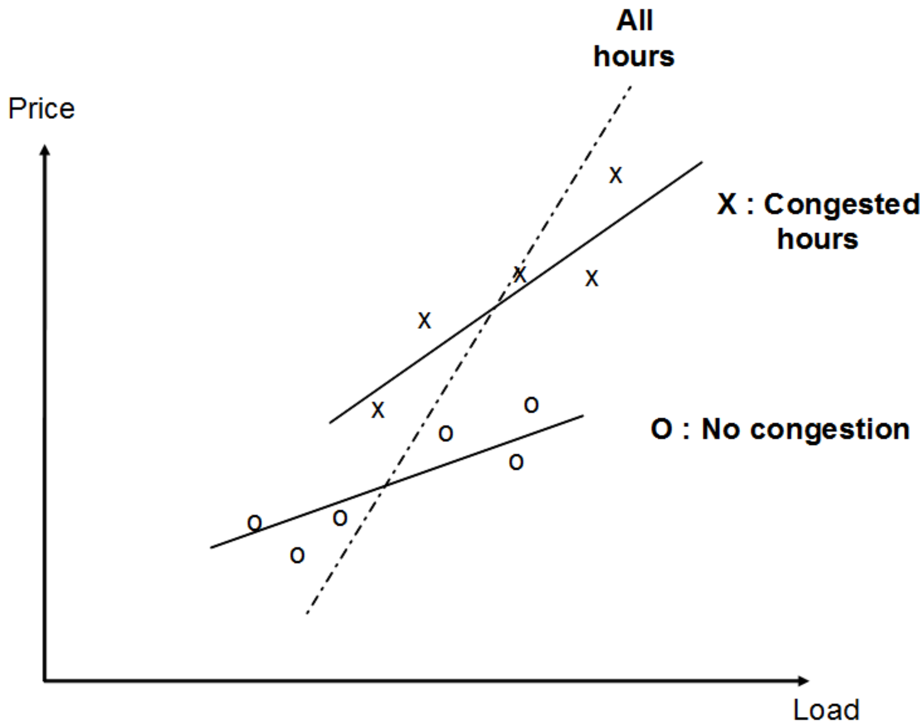

Fig 3. Aggregate and within clusters effects.