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Electricity market price volatility: The case of Ontario

Hamidreza Zareipour[a,*], Kankar Bhattacharya[b], Claudio A. Cañizares[b]

[a]Department of Electrical and Computer Engineering, University of Calgary, 2500 University Drive NW, Calgary, Alberta, Canada T2N 1N4
[b]Power and Energy Systems Group, Department of Electrical and Computer Engineering, University of Waterloo, 200 University Avenue West Waterloo, Ontario, Canada N2L 3G1

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Abstract

Price volatility analysis has been reported in the literature for most competitive electricity markets around the world. However, no studies have been published yet that quantify price volatility in the Ontario electricity market, which is the focus of the present paper. In this paper, a comparative volatility analysis is conducted for the Ontario market and its neighboring electricity markets. Volatility indices are developed based on historical volatility and price velocity concepts, previously applied to other electricity market prices, and employed in the present work. The analysis is carried out in two scenarios: in the first scenario, the volatility indices are determined for the entire price time series. In the second scenario, the price time series are broken up into 24 time series for each of the 24 h and volatility indices are calculated for each specific hour separately. The volatility indices are also applied to the locational marginal prices of several pricing points in the New England, New York, and PJM electricity markets. The outcomes reveal that price volatility is significantly higher in Ontario than the three studied neighboring electricity markets. Furthermore, comparison of the results of this study with similar findings previously published for 15 other electricity markets demonstrates that the Ontario electricity market is one of the most volatile electricity markets world-wide. This high volatility is argued to be associated with the fact that Ontario is a single-settlement, real-time market.

Keywords: Ontario electricity market; Price volatility analysis; Volatility comparison

1. Introduction

The Ontario wholesale electricity market was launched on May 1, 2002, and consists of a physical market for energy and operating reserves and a financial transmission rights market (Zareipour et al., 2005). The Ontario power network is connected to the New York and Midwest electricity markets directly, and to the New England and PJM markets indirectly. It is also connected to the regulated utilities in Quebec and Manitoba, both having significant energy transactions with other utilities in the United States. On the other hand, Ontario is a single-settlement real-time market, which is not the case for the other four adjacent North American markets. In view of this, the operation of the Ontario electricity market can significantly impact the North American North-East and Mid-West power interconnections, and hence, its price behavior and the associated volatility calls for close examination.

Volatility refers to the unpredictable fluctuations of a process observed over time in everyday life. In economics and finance, volatility is basically a criterion to study the risks associated with holding assets when there is an uncertainty associated with the future value of the assets. Volatility analysis, volatility modeling, and volatility forecasting have various applications such as risk management and option valuation in financial markets (Jorion, 2001; Andersen et al., 2005). In competitive electricity markets, prices are not regulated any longer, being determined by market operators for each specific interval of the day (e.g. every 5 min), while taking into account various economic and operational factors (Bhattacharya et al., 2001). Furthermore, in such markets, the supply and

*Corresponding author. Tel.: +1 403 210 9516; fax: +1 403 282 6855.
E-mail address: h.zareipour@ucalgary.ca (H. Zareipour).
URLs: http://www.enel.ucalgary.ca/ (H. Zareipour),
http://www.power.uwaterloo.ca/ (K. Bhattacharya, C.A. Cañizares).

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demand sides have several options for managing their energy trades. For example, the supply-side has the option of selling electricity through spot markets, forward markets, or physical bilateral contracts. The demand-side also may choose to supply its energy needs using a combination of on-site generation facilities and electricity from the markets. Given the uncertainty associated with the electricity market prices, and such a wide variety of options, the applications of volatility analysis to competitive electricity markets are undoubtedly useful for market participants (Shahidehpour et al., 2002).

Historical volatility studies of electricity market prices can be found in the technical literature for various markets. In Alvarado and Rajaraman (2000), the periodic part of the price variations for an unknown market is separated out using a frequency-domain method, and volatility of the remaining part is analyzed. A value at risk methodology is used in Dahlgren et al. (2001) to study volatility of the Californian market prices. In Benini et al. (2002), volatility of the prices in the Spanish, Californian, UK, and PJM electricity markets is analyzed, concluding that the Spanish and PJM market prices were the least and most volatile, respectively. Volatility analyses for 14 electricity markets worldwide are reported in Li and Flynn (2004), with widely varying price volatility behaviors being observed across different markets. A multivariate GARCH model is employed in Worthington et al. (2005) to study the inter-relationship among prices and price volatilities in the five Australian electricity markets. Volatility features of the Nordic day-ahead electricity market are studied in Simonsen (2005) for a 12-year period up until the year 2004, reporting a high level of price volatility compared to other financial markets. To the best of the author's knowledge, no studies have been reported in the literature that quantifies price volatility in the Ontario electricity market.

More than 4000 MW of high voltage transmission lines interconnects Ontario with its neighboring markets, enabling the supply and demand sides within the region to rationally participate in the interconnected markets. Analyzing and comparing historical price behavior across the Ontario and its neighboring markets, along with a forecast of future price fluctuations, provides the markets participants in the region with price signals which can be incorporated into their inter-jurisdiction energy trade planning. Furthermore, these market participants may consider price volatility signals in their short-term, mid-term, and long-term investment plans in order to minimize the potential financial risks to which they might be exposed. Additionally, quantifying and comparing historical price volatilities across the neighboring electricity markets could help market authorities in making appropriate amendments and advancements to market regulations and the associated grid. No studies which compare price volatility across the electricity markets in north-eastern America have been reported in the literature.

Motivated by the aforementioned discussions, this paper presents a comprehensive price volatility analysis for the Ontario and its neighboring electricity markets. Volatility indices are developed here based on historical volatility (Jorion, 2001; Christoffersen, 2003; Andersen et al., 2005) and price velocity (Li and Flynn, 2004) concepts, which have been previously applied to other electricity market prices (Alvarado and Rajaraman, 2000; Benini et al., 2002; Li and Flynn, 2004; Simonsen, 2005). Intra-day, trans-day, and trans-week price fluctuations form the basis for the analyses. The volatility measures are also applied to the historical locational marginal price (LMP) data of various pricing points from the New England, New York, and PJM electricity markets for comparison purposes. It should be pointed out that the goal of this paper is not to introduce new volatility measures, but to use available volatility measures and compare price volatilities in Ontario's electricity market with respect to other electricity markets.

The rest of this paper is organized as follows: the volatility measures employed in this work are described in Section 2. In Sections 3 and 4, the presented measures are applied to the Ontario market prices and to three neighboring market prices, respectively, and the numerical results is analyzed. A more detailed and comparative analysis of price volatility for Ontario and New England markets is presented in Section 5, discussing the role of market structure on price volatility. Section 6 summarizes the main findings of this paper.

2. Analysis measures and methodology

2.1. Historical volatility

Let denote p_t as the spot price for a commodity at time t. The arithmetic return over a time period h is defined as

$$R_{t,h} = \frac{p_t - p_{t-h}}{p_{t-h}} \tag{1}$$

and the logarithmic return, over the time period h, is defined as

$$r_{t,h} = \ln\left(\frac{p_t}{p_{t-h}}\right) = \ln(p_t) - \ln(p_{t-h}). \tag{2}$$

When returns are small, the arithmetic and logarithmic returns are close, given the fact that

$$r_{t,h} = \ln\left(\frac{p_t}{p_{t-h}}\right) = \ln(1 + R_{t,h}) \approx R_{t,h}. \tag{3}$$

Most volatility analysis studies consider the logarithmic return over arithmetic return (Jorion, 2001; Christoffersen, 2003); hence, logarithmic return is used in the present work as well.

If the return values are identically and independently distributed (i.i.d.) over a time window T, one can present them as

$$r_{t,h} = \hat{\mu}_{h,T} + \hat{\sigma}_{h,T}\varepsilon_t, \tag{4}$$

where $\hat{\mu}_{h,T}$ is the conditional mean return; $\hat{\sigma}_{h,T}$ is the conditional return variance; and the random variable ε is a mean zero, unit variance, i.i.d. innovation. $\hat{\sigma}_{h,T}$ is referred to as the historical volatility over the time window T; in other words, historical volatility is defined as the standard deviation of arithmetic or logarithmic returns over a time window T. Given the return values, the estimated value of $\hat{\sigma}_{h,T}$ can be calculated as

$$\sigma_{h,T} = \sqrt{\frac{\sum_{t=1}^{N_o}(r_{t,h} - \overline{r}_{h,T})^2}{N_o - 1}}, \qquad (5)$$

where $\sigma_{h,T}$ is the estimated value of historical volatility, N_o is the number of $r_{t,h}$ observations, and $\overline{r}_{h,T}$ is the simple $r_{t,h}$ average, all of them over the time window T.

In most volatility analysis studies, $h = 1$ is the commonly used time period. However, since electricity market prices usually follow the general trend of electricity demand, it is not surprising to encounter significant price fluctuations when moving from the off-peak hours to the on-peak hours of a day. In Simonsen (2005), the time period h is selected to be 24 h and trans-day price fluctuations are analyzed. In the present study, in order to quantify the price uncertainty to which the market participants are exposed when moving from one week to the next week, trans-week price fluctuations are also considered; thus, $h = 168$ h is considered for the analyses, in addition to $h = 1$, and 24 h.

The definition of historical volatility in (4) is based on the assumption that the logarithmic return observations follow an i.i.d. random variable. In other words, the returns are assumed to behave randomly, having constant

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mean and variance over the time window T. These assumptions are usually true for most stochastic returns in economics and finance, when ignoring small return correlations for the first few time steps (Bouchaud and Potters, 2000; Jorion, 2001; Christoffersen, 2003). However, electricity market prices follow daily, weekly and sometimes seasonal patterns, basically due to the seasonal behavior of electricity demand. As a result, electricity market price returns are highly correlated and do not behave as an i.i.d. random variable. For example, $r_{t,24}$ is calculated for the Ontario electricity market prices using (2), and their autocorrelation functions (Box et al., 1994) for two arbitrary samples of 168 and 24 return observations ($T = 168$ and $T = 24$), are determined and displayed in Fig. 1. Observe in this figure that the returns are correlated for the first 7 lags in the case of $T = 168$, whereas for $T = 24$ the correlations are negligible. Accordingly, when studying electricity market price volatility, the time window T should be selected to be short enough (e.g. 24 h) in order to have negligible return correlations, which is the case in this study. Furthermore, selecting a short time window T allows analyzing the original price time series without considering separation of the periodic and random parts of the price data.

In order to define historical volatility indices in the present study, market price data are dealt with in two different scenarios. In the first scenario, a price time series

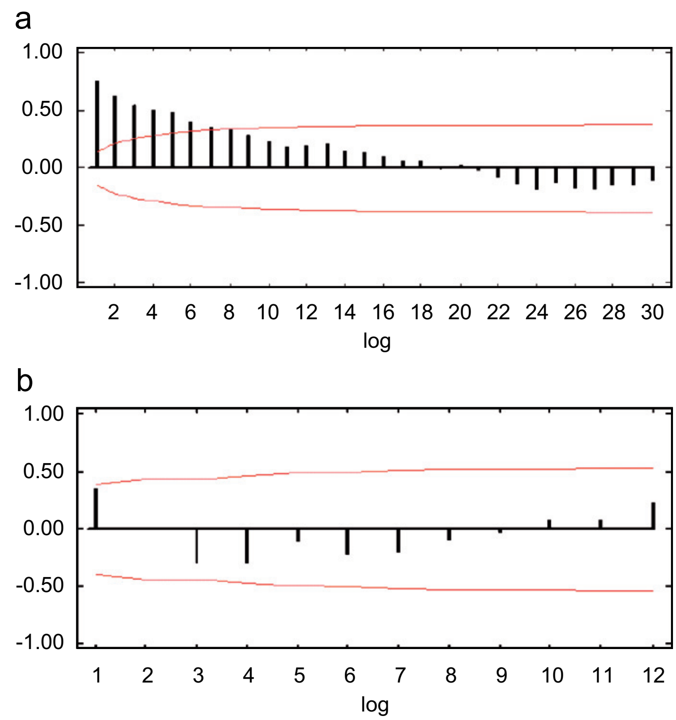

Fig. 1. Autocorrelation functions for the logarithmic Ontario market price returns: (a) $T = 168$; (b) $T = 24$.

Scenario 1 daily aggregation, 2 hourly volatility

is treated as a whole signal for all 24 h of a day, and volatility indices are calculated to analyze overall price behavior. In the second scenario, a price time series is broken up into 24 time series corresponding to each of the 24 h to provide insight into the risks associated with the price at each particular hour of a day.

2.1.1. Scenario 1

In this scenario, the time window T is selected to be 24 h (one full day) and the historical volatility for each studied day, i.e. $\sigma_{h,24}(d)$, is determined as

$$\sigma_{h,24}(d) = \sqrt{\frac{\sum_{t=1+24\times(d-1)}^{24\times d}(r_{t,h} - \overline{r}_{t,h})^2}{23}}, \qquad (6)$$

where $d \in \{1, 2, 3, \ldots, 366\}$ is the index of studied days, and $\overline{r}_{t,h}$ is the logarithmic returns average over each day. In this scenario, hourly ($h = 1$), daily ($h = 24$), and weekly ($h = 168$) logarithmic returns are the basis of analysis, and the averages of $\sigma_{h,24}(d)$ over all studied days, i.e. $\overline{\sigma}_{h,24}$, $h = 1, 24, 168$, are used as volatility indices.

Observe that the index $\overline{\sigma}_{1,24}$ is the average standard deviation of price fluctuations in subsequent hours; in other words, this index quantifies the price changes from one hour to another during a day. Similarly, $\overline{\sigma}_{24,24}$ is the average standard deviation of overall price fluctuations in subsequent days; thus, this index basically measures the overall change in hourly prices from one day to another. Finally, $\overline{\sigma}_{168,24}$ quantifies the price changes in subsequent weeks.

2.1.2. Scenario 2

In this scenario, the logarithmic return for hour j, day k, over a time period h, is defined as

$$r^j_{k,h} = \ln\left(\frac{p^j_k}{p^j_{k-h}}\right) = \ln(p^j_k) - \ln(p^j_{k-h}), \tag{7}$$

where p^j_k refers to price at hour j on day k. Choosing $h = 1$ in (7) implies that market prices at hour j for two consequent days are compared. By considering a 7-day time window (one full week), i.e. $T = 7$, and $h = 1$, historical volatility for hour j for week w can be determined as follows:

$$\sigma^j_{1,7}(w) = \sqrt{\frac{\sum_{t=1+7\times(w-1)}^{7\times w}(r^j_{k,1} - \bar{r}^j_{k,1})^2}{6}}, \tag{8}$$

where w is the index of each studied week, $j \in \{1, 2, 3, \ldots, 24\}$ is the index of hour, and $\bar{r}^j_{k,1}$ is the return average over the 7-day time window for hour j. The average of $\sigma^j_{1,7}(w)$ over all studied weeks, i.e. $\bar{\sigma}^j_{1,7}$, is used as the volatility index for price at hour j. In fact, this scenario quantifies the fluctuations of price at a particular hour in subsequent days over a 7-day period.

2.2. Price velocity

The authors in Alvarado and Rajaraman (2000), Benini et al. (2002) and Simonsen (2005) employ the historical volatility concept in order to analyze electricity market prices volatility. On the other hand, the authors in Li and Flynn (2004), define *price velocity* for quantifying price uncertainty. Thus, let define the absolute value of the difference between two prices which are an h time period apart as

$$\delta_{t,h} = |p_t - p_{t-h}|. \tag{9}$$

The following two volatility measures are defined in Li and Flynn (2004) for electricity market prices, i.e. daily velocity based on overall average price (DVOA) and daily velocity based on daily average price (DVDA):

$$\mathrm{DVOA}_{d,h} = \frac{\text{Daily Average of } \delta_{t,h}}{\text{Overall Average of } p_t}, \tag{10}$$

$$\mathrm{DVDA}_{d,h} = \frac{\text{Daily Average of } \delta_{t,h}}{\text{Daily Average of } p_t}, \tag{11}$$

where d is the index of studied day. The averages of $\mathrm{DVOA}_{d,1}$ and $\mathrm{DVDA}_{d,1}$ over the studied days, i.e. $\overline{\mathrm{DVOA}}_1$ and $\overline{\mathrm{DVDA}}_1$, are employed in Li and Flynn (2004) to compare price uncertainty across 14 electricity markets worldwide.

Observe that when $\overline{\mathrm{DVOA}}_1$ is 0.2 for a specific market, it basically implies that the average intra-day price change has been about 20% of the long-term average price for the studied period. Similarly, when $\overline{\mathrm{DVDA}}_1$ is 0.2, it means that the average intra-day price change has been about 20% of the average daily price. It should be noted that the concept of price velocity differs from historical volatility in the sense that it employs the daily average of price changes to quantify price uncertainty, in lieu of the standard deviation of price returns in historical volatility.

In the present study, the price velocity concept is extended for the time periods $h = 24$ and 168 h in order to analyze trans-day and trans-week price fluctuations. By choosing $h = 24$ or 168 h, $\overline{\mathrm{DVOA}}_{24}$ and $\overline{\mathrm{DVOA}}_{168}$ represent the average changes in prices in subsequent days and average changes in prices for a specific day in subsequent weeks, as a fraction of overall average price, respectively, and similarly for $\overline{\mathrm{DVDA}}_{24}$ and $\overline{\mathrm{DVDA}}_{168}$. Hence, values of $\overline{\mathrm{DVOA}}_h$ and $\overline{\mathrm{DVDA}}_h$ for $h = 1$, 24, and 168 h, are also employed here as volatility indices.

Summarizing, the following volatility indices are used in the present work to compare electricity market price volatility in Ontario and other markets: $\bar{\sigma}_{h,24}$, $\overline{\mathrm{DVOA}}_h$, and $\overline{\mathrm{DVDA}}_h$, with $h = 1, 24, 168$, and $\bar{\sigma}^j_{1,7}$.

3. Price volatility analysis for Ontario's electricity market

Energy and operating reserves markets in Ontario are based on a uniform market clearing price (MCP) that applies to all load zones and generators within the province. The hourly average of the 5 min energy MCPs is defined as the hourly Ontario energy price (HOEP), and forms the basis for many financial settlements. Thus, historical HOEP data for the period of May 1, 2002 to April 30, 2005, are used here to analyze price volatility in the Ontario electricity market. The data are available at http://www.ieso.ca.

The analyzed HOEP data are depicted in Fig. 2, where the HOEP fluctuations over an arbitrary week, are also displayed. Observe from Fig. 2(a) that during the first year of market operation, the prices were higher and more unstable than the next two years. For instance, from the first to the third year, the number of hours during which the HOEP exceeded \$200/MWh was 106, 10, and 3, respectively, and the average HOEP was \$58.4/MWh, \$48.2/MWh, and \$51.2/MWh, respectively. Notice as well the unusual prices during the on-peak and off-peak hours, which are a couple of the features of the Ontario electricity market and happen on both weekdays and weekends, as illustrated in Fig. 2(b).

3.1. Historical volatilities

3.1.1. Scenario 1

Fig. 3 depicts historical volatilities $\sigma_{h,24}(d)$ for $h = 1$, 24, and 168 h. Observe in this figure that the highest HOEP volatiles occurred in February and early March in 2003. The period of January, February, and early March, 2003 was an extremely cold period and natural gas prices were very high. As a result of this, many gas-fired generating facilities experienced difficulties and were unavailable to the market operator. High demand and shortage of supply in this period resulted in unusually high and volatile

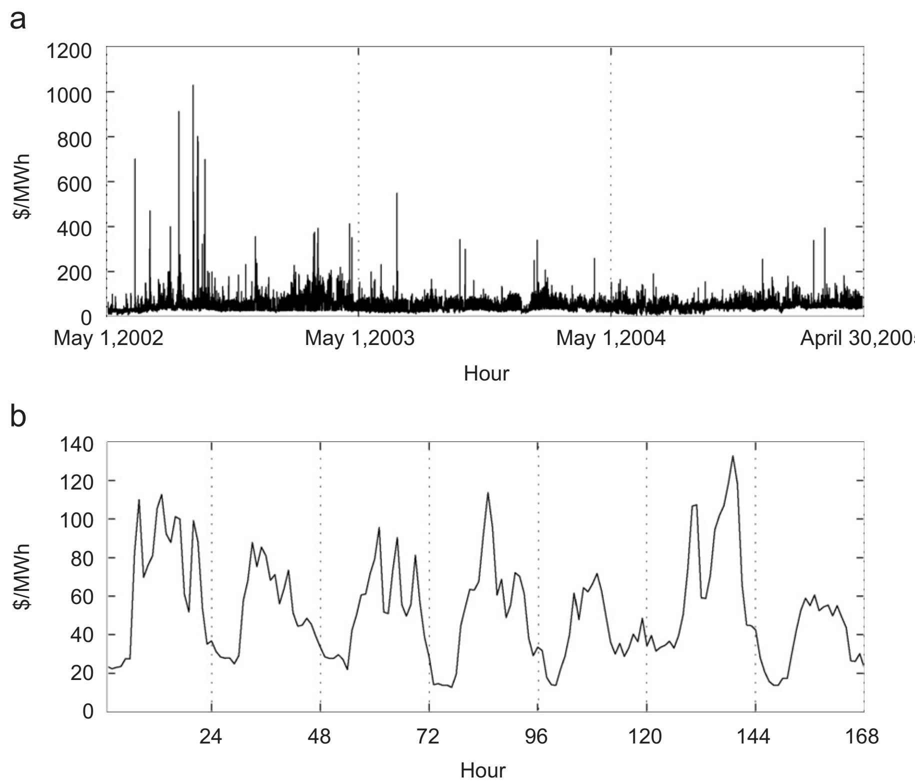

Fig. 2. HOEP: (a) from May 1, 2002 to April 30, 2005; (b) over the week May 17–23, 2004.

HOEPs even in the off-peak hours (MSP, 2002–2005). Notice as well that the historical volatilities are relatively higher during the high demand periods than the low demand periods, as expected.

Table 1 shows volatility indices $\overline{\sigma}_{h,24}$, $h = \{1, 24, 168\}$, for the entire 3-year period and for each of the 3 years of market operation. Observe that these volatility indices have declined from the first year to the third year, with the first year showing the highest volatility. This improvement can be attributed to the amendments made to the market rules and regulations, and also is a matter of market maturity. Furthermore, the values of trans-day and trans-week volatility indices, i.e. $\overline{\sigma}_{24,24}$ and $\overline{\sigma}_{168,24}$, are higher than the value of intra-day volatility index, i.e. $\overline{\sigma}_{1,24}$. This basically implies that, on average, the trans-day and trans-week price changes fluctuate in a wider range than the intra-day price changes.

Historical volatilities are studied in Simonsen (2005) for the Nordic electricity market over a 12 years period ending May 2004; only the time period $h = 24$ is considered, yielding $\overline{\sigma}_{24,24} = 0.16$ (12-year average). This level of price volatility is then compared with average historical volatilities for some other markets, such as stock indices ($\overline{\sigma}_{24,24} = 0.01 - 0.015$), crude oil markets ($\overline{\sigma}_{24,24} = 0.02 - 0.03$), and natural gas markets ($\overline{\sigma}_{24,24} = 0.03 - 0.05$). Comparing this volatility index value with the one obtained here for the HOEP, i.e. $\overline{\sigma}_{24,24} = 0.3203$, clearly reveals the significantly higher price volatility of the Ontario electricity market.

3.1.2. Scenario 2

In this scenario, $\sigma^j_{1,7}(w)$, for $j = 1, 2, 3, \ldots, 24$ and $w = 1, 2, 3, \ldots, 156$, are calculated using (8), with the corresponding three-year averages with respect to w, i.e. $\overline{\sigma}^j_{1,7}$, being displayed in Fig. 4. Observe in this figure that $\overline{\sigma}^j_{1,7}$s fluctuate across the different hours, with hours 5 and 8 having the lowest and the highest index values, respectively. Furthermore, prices at the on-peak hours 7–21 are the most volatile, while prices at off-peak hours 22–24 and 1–6 are the least volatile, as expected. However, it should be noted that the price volatility at off-peak and on-peak hours are both significantly high.

3.2. Price velocities

Table 2 shows the values of $\overline{\mathrm{DVOA}}_h$ and $\overline{\mathrm{DVDA}}_h$, $h = 1$, 24, and 168 h, for the HOEP over the 3-year period, as well as for each of the 3 years. These results demonstrate that the $\overline{\mathrm{DVOA}}_h$ and $\overline{\mathrm{DVDA}}_h$ values have also declined over the years, which is consistent with the findings of historical volatility. Furthermore, $\overline{\mathrm{DVOA}}_h$ and $\overline{\mathrm{DVDA}}_h$ have the highest values for $h = 168$ h, and the lowest values for $h = 1$ h; from this, it can be inferred that the average trans-day and trans-week changes in prices are higher than the average intra-day changes in prices.

Values of $\overline{\mathrm{DVOA}}_1$ and $\overline{\mathrm{DVDA}}_1$ for the Scandinavia, Spain, California, New Zealand, the UK, Leipzig (Germany), New England, Australia (New South Wales, Victoria, South Australia, Queensland), Alberta (Canada),

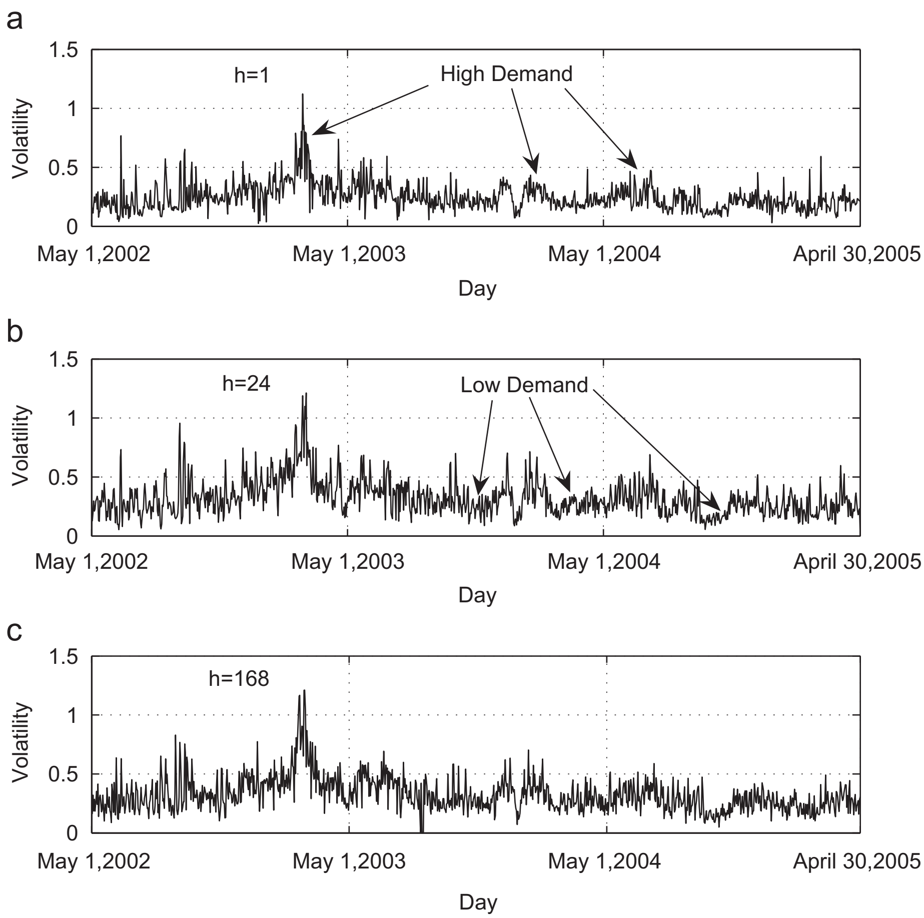

Fig. 3. HOEP volatilities for $T = 24$ and $h = 1, 24, 168$.

Table 1
Historical volatilities for Ontario market

	$\overline{\sigma}_{1,24}$	$\overline{\sigma}_{24,24}$	$\overline{\sigma}_{168,24}$
Year 1	0.2843	0.3771	0.3821
Year 2	0.2477	0.3214	0.3220
Year 3	0.2088	0.2623	0.2613
3-year period	0.2469	0.3203	0.3222

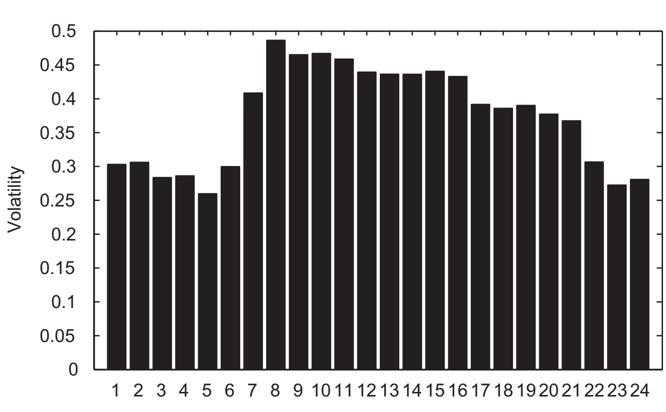

Fig. 4. HOEP volatilities for each hour.

Netherlands, and PJM electricity markets are presented in Li and Flynn (2004). Time duration of the study varies across the markets, all of them ending December 31, 2001. Six of the studied markets, namely, Alberta, PJM, Netherlands, Victoria, South Australia, and Queensland, show higher $\overline{\text{DVOA}}_1$ values than those reported here for the Ontario market. Furthermore, Alberta, South Australia, and Queensland electricity markets show $\overline{\text{DVDA}}_1$ values higher than the corresponding value obtained here for the Ontario market. Despite the differences in time durations of the study presented in Li and Flynn (2004) and the current paper, it can be concluded that the Ontario electricity market is among the most volatile markets from the $\overline{\text{DVOA}}_1$ and $\overline{\text{DVDA}}_1$ point of views.

4. Volatility analysis for Ontario's neighboring electricity markets

The Ontario electricity market is directly interconnected with New York's electricity market and Quebec, as well as with the Michigan, Manitoba, and Minnesota control areas, which are now part of the Midwest electricity market (see Fig. 5). In addition, Ontario is indirectly interconnected with the New England and PJM electricity

Table 2
Price velocities for the Ontario market

	$\overline{\mathrm{DVOA}}_1$	$\overline{\mathrm{DVDA}}_1$	$\overline{\mathrm{DVOA}}_{24}$	$\overline{\mathrm{DVDA}}_{24}$	$\overline{\mathrm{DVOA}}_{168}$	$\overline{\mathrm{DVDA}}_{168}$
Year 1	0.2438	0.1890	0.4208	0.3430	0.5106	0.4379
Year 2	0.1604	0.1719	0.2694	0.2966	0.3083	0.3430
Year 3	0.1463	0.1478	0.2346	0.2421	0.2761	0.2849
3-year period	0.1835	0.1696	0.3083	0.2939	0.3655	0.3557

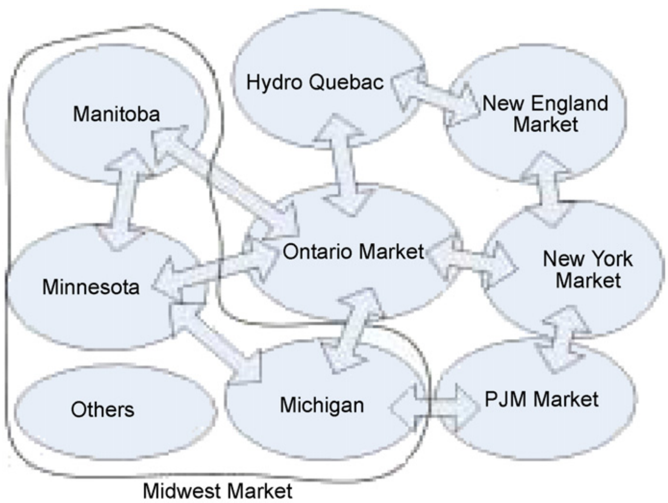

Fig. 5. Interconected markets with the Ontario market.

markets, with energy and operating reserves being actively traded among these three markets. The interconnected electricity markets have facilitated interjurisdiction energy trades in the region, with the supply and demand sides having the option of freely playing in these markets.

The price information regarding Michigan, Manitoba, and Minnesota control areas were only available after April 1, 2005, on which the Midwest market was launched, and hence is beyond the study period of this paper. Furthermore, Quebec has a regulated electricity sector; therefore, no market activity takes place in this province. Hence, New York, New England and PJM markets are the electricity markets studied here.

The year 2004 historical LMP data for 9 pricing points in New England, 9 pricing points in New York electricity, and 15 pricing points in PJM electricity market are used in this study to calculate Ontario's neighboring markets' volatility indices. The studied pricing points include load zones and interfaces with other areas. Since the day-ahead market has the dominant share of energy transactions in these markets, only day-ahead LMPs are considered for the analysis. The presented quantities in this section are the average of the corresponding quantities for all studied pricing points for each market. The data are available at http://www.iso-ne.com, and http://www.pjm.com.

Table 3
Historical volatilities for the Ontario and its neighboring markets prices in 2004

	$\overline{\sigma}_{1,24}$	$\overline{\sigma}_{24,24}$	$\overline{\sigma}_{168,24}$
New England	0.0844	0.0676	0.0722
New York	0.1117	0.0837	0.0907
PJM	0.1637	0.1294	0.1343
Ontario	0.2212	0.2813	0.2805

4.1. Historical volatilities

4.1.1. Scenario 1

The averages of volatility indices $\overline{\sigma}_{h,24}$, $h = \{1, 24, 168\}$, for the studied pricing points in each of the three markets are presented in Table 3. The corresponding indices for the HOEP over the same year are also presented in this table for the sake of comparison. These results show that Ontario market price has the highest historical volatility among the studied market prices, with the New England market showing the lowest historical volatilities. Observe that the intra-day volatilities are higher than the trans-day and trans-week volatilities for the neighboring markets, while for Ontario the opposite is the case.

As an illustration, let us assume that the zero-mean $r_{t,h}$ values follow a normal distribution over the studied time windows. A historical volatility of $\overline{\sigma}_{h,T}$ implies that, on average and with a 95% confidence, one expects that

$$-2\overline{\sigma}_{h,T} \leqslant \ln \frac{p_t}{p_{t-h}} \leqslant 2\overline{\sigma}_{h,T} \tag{12}$$

or

$$p_{t-h}\mathrm{e}^{-2\overline{\sigma}_{h,T}} \leqslant p_t \leqslant p_{t-h}\mathrm{e}^{2\overline{\sigma}_{h,T}}. \tag{13}$$

With $\overline{\sigma}_{24,24} = 0.2813$ for the Ontario market in 2004, prices in a given day could be up to 75.5% higher than the prices in the day before, or they could be 43% lower. These numbers for the New England market are 14.4% and 12.6%, respectively, which reflects a much narrower range for price changes in the New England market.

It is worth highlighting the fact that high levels of price volatility affect price predictability in a market, since the higher the price volatility, the lower the price predictability (Zareipour et al., 2006). The relative low level of price volatility in the New England market has led to a high level of price predictability for this market, which in turn enables market participants to schedule their short-term operation with minimal economic loss (Zareipour, 2006).

4.1.2. Scenario 2

The volatility indices for the price at each specific hour in the three neighboring markets are presented in Fig. 6, along with the corresponding results for the Ontario market. This figure clearly illustrates the fact that for each of the 24 h of a day, Ontario's market prices are more volatile than the prices in the three neighboring markets.

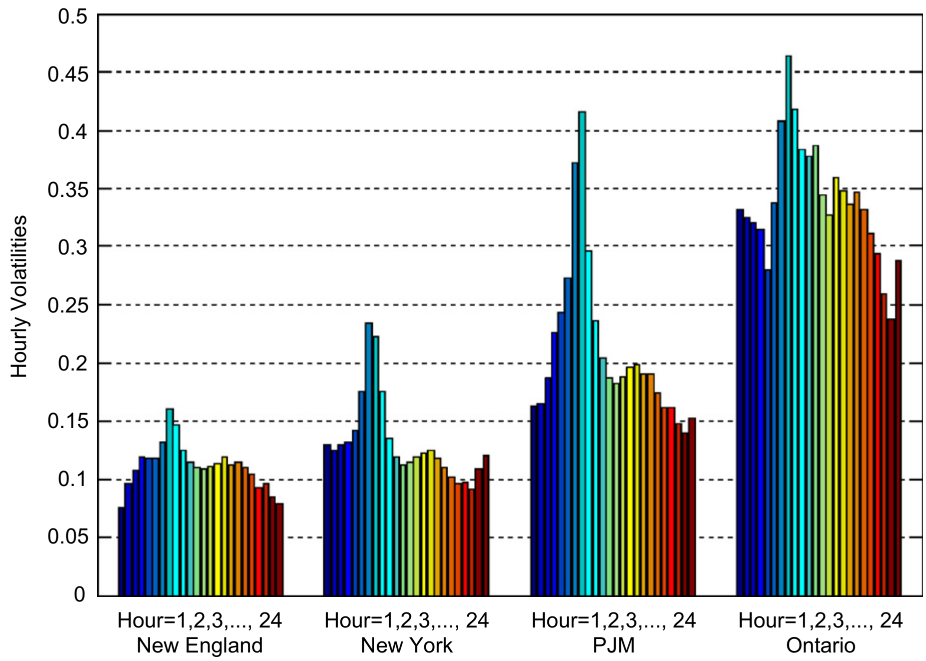

Fig. 6. Historical volatilities for each hour for Ontario and its neighboring markets.

Observe that prices at hours 7, 8, and 9 in the morning are the most volatile prices for all markets, and that the New England market has the lowest volatilities for all hours. In addition, volatilities for the PJM market prices at hours 7, 8, and 9 are somewhat close to those for Ontario; however, Ontario's prices are significantly more volatile at other hours.

Table 4
Price velocities for the Ontario and its neighboring markets in 2004

	$\overline{\text{DVOA}}_1$	$\overline{\text{DVDA}}_1$	$\overline{\text{DVOA}}_{24}$	$\overline{\text{DVDA}}_{24}$	$\overline{\text{DVOA}}_{168}$	$\overline{\text{DVDA}}_{168}$
New England	0.0603	0.0508	0.0976	0.0802	0.1452	0.1282
New York	0.0730	0.0726	0.0932	0.0929	0.1327	0.1283
PJM	0.1129	0.1133	0.1448	0.1489	0.1955	0.1957
Ontario	0.1586	0.1551	0.2541	0.2573	0.2933	0.3005

4.2. Price velocities

Table 4 depicts the average values over the studied pricing points of $\overline{\text{DVOA}}_h$ and $\overline{\text{DVDA}}_h$, $h = \{1, 24, 168\}$, for the mentioned LMPs. Observe from these results that the price velocity indices are also higher for the Ontario market than for the other three markets.

As a simple illustration, a $\overline{\text{DVOA}}_{24} = 0.2541$ implies that the changes in prices over subsequent days was 25.41% of the 2004 HOEP average; hence, with the 2004 HOEP average being \$49.9/MWh, the average change in HOEP in subsequent days could be up to \$12.7/MWh. On the other hand, the 2004 average LMP for the New England market is US\$52.83/MWh; hence, with a $\overline{\text{DVOA}}_{24} = 0.0976$, the average change in New England's day-ahead market LMPs in subsequent days could be up to US\$5.1/MWh, which is less than half of that obtained for Ontario.

5. Market structure and price volatility

According to the volatility analysis presented in the previous sections, price volatility in the Ontario electricity market is significantly higher than price volatility in the New England, New York, and PJM electricity markets. It should also be noted that despite many differences in the detailed market rules and regulations, and in the physical characteristics of the supply and demand sides, the New England, New York, and PJM electricity markets are all based on a standard market design (SMD) structure (Cheung, 2004), which is basically a two-settlement market with nodal pricing. Furthermore, considering that: the PJM electricity market went through various market expansions in 2004; the New England market was a real-time market with a region-wide uniform price, similar to the current Ontario market structure, before the implementation of the SMD structure; and the volatility indices obtained for the New England market are the lowest, very close to those for the New York market. Therefore, only the New England market is selected for the discussions presented in this section.

The New England wholesale electricity market was launched on May 1, 1999, as a single-settlement real-time market. On March 1, 2003, the SMD structure was implemented, which converted the market structure into a new LMP-based market comprising a day-ahead market and a real-time market. The New England market before the implementation of the SMD structure is referred to as the New England Interim Market. More than 31,000 MW of generation capacity along with imports from Canada and New York State serves the New England market demand with a peak demand of 28,127 MW (2006). From the addition of more than 9000 MW of new generation capacity comprising gas-fired generation units from 2000 to 2004, cleaner power has been made available, with the prices declining through this period by 5.7%. Natural gas-fired generators (about 43% of the total capacity) and nuclear generators (about 28% of the total capacity) are the major source of power in this market, with the gas-fired units being the most frequent price setters (NEISO, 2005).

The current structure of the Ontario electricity market, which is a single-settlement real-time market with a province-wide uniform price, is similar to the New England Interim Market structure. More than 31,000 MW of generation capacity, along with imports from neighboring regions, serve the Ontario demand, with a peak demand of 27,005 MW (2006). Coal-fired generators are the most frequent Ontario market price setters, while expensive gas-fired units are the main price setters during extreme demand hours (MSP, 2002–2005). Observe that the total installed generation capacity and peak load in Ontario and New England electricity markets are in the same order, thus allowing for a more relevant comparison of price behavior between these two markets.

In order to provide a more detailed insight into price volatility in the New England market, the employed volatility indices were calculated for the first three years of the operation of the New England Interim Market, and are presented in Tables 5 and 6. The three-year averages of the respective volatility indices for Ontario are also presented in these tables for comparison purposes. Observe from these volatility indices that price volatility has been high in the New England Interim Market (with a real-time structure), and fairly close to the volatility indices obtained for Ontario. On the other hand, and as expected, after implementation of the SMD structure in New England, price volatility indices have declined significantly for the current New England market, as demonstrated by the results presented in Tables 4 and 3.

Table 5
Historical volatilities for New England's Interim market

	$\overline{\sigma}_{1,24}$	$\overline{\sigma}_{24,24}$	$\overline{\sigma}_{168,24}$
New England	0.2261	0.2866	0.2972
Ontario	0.2469	0.3203	0.3222

Consider the following events which frequently happen in Ontario (MSP, 2002–2005):

- Demand underforecast: A demand underforecast error during the peak hours, even in the acceptable range of 1–2%, may force the market operator to dispatch some of the more expensive units, thus causing unpredictable price spikes.
- Export/import transactions failure: Exports and imports are scheduled 1 h before the dispatch hour in the Ontario market and are considered as fixed load and supply, respectively, in real-time (Zareipour et al., 2005). Any failure in import transactions may force the market operator to instantly dispatch expensive units, which also may cause unusual price spikes. In addition, any failure in export transactions may force the Ontario market operator not to dispatch some of the marginal units, which in turn may cause unusually low prices.
- Error in non-dispatchable generators energy output forecast: In the Ontario market, price-taking self-scheduling generators (e.g. small hydro units) and intermittent generators (e.g. wind farms) forecast their hourly energy output and submit it to the IESO. Analysis of the Ontario market data shows that their real-time available capacity deviates from their forecasted values, sometimes by more than 250 MW. Similar to the demand forecast error or export/import failure situations, dealing with the discrepancy between the forecasted and actual available capacity of the self-scheduling generators in real-time may cause unusually high or low market prices.

Dealing with such unpredictable, and most of the time unavoidable, events in real-time puts upward or downward pressure on market prices, thus leading to high market price volatility. Thus, it can be argued that the real-time nature of the market in Ontario is directly linked with the high levels of electricity price volatility in Ontario.

Observe that in a single-settlement real-time market, the price volatility affects all market participants, whereas in a two-settlement market, most of the eventual real-time demand is cleared in the day-ahead market (on average 97% for the New England market (NEISO, 2005) and 90% for New York market (NYISO, 2005) in 2004), where no physical transactions take place. With the major part of the market demand being cleared 24 h before real-time, market participants have enough time to arrange for their supply and demand obligations, and in case of unpredictable events, only real-time prices may become volatile with a

Table 6
Price velocities for New England's Interim market

	$\overline{\mathrm{DVOA}}_1$	$\overline{\mathrm{DVDA}}_1$	$\overline{\mathrm{DVOA}}_{24}$	$\overline{\mathrm{DVDA}}_{24}$	$\overline{\mathrm{DVOA}}_{168}$	$\overline{\mathrm{DVDA}}_{168}$
New England	0.1483	0.1372	0.2854	0.2563	0.3307	0.3260
Ontario	0.1835	0.1696	0.3083	0.2939	0.3655	0.3557

small group of market players who participate in the real-time market being affected. Therefore, moving from the current single-settlement structure toward a two-settlement market similar to the SMD structure should help to reduce price volatility in Ontario, thus benefiting most market participants.

6. Conclusion

In this paper, various volatility indices were developed based on the historical volatility and price velocity concepts, and price volatility in the Ontario electricity market was quantified accordingly. The employed volatility indices were then applied to several pricing points in three Ontario's neighboring electricity markets, namely, the New England, New York, and the PJM markets. Intra-day, trans-day and trans-week market price fluctuations were considered in calculating the volatility indices, and the determined volatility indices were compared across the studied markets.

Volatility of the Ontario electricity market prices is shown to be significantly higher than price volatility in the New England, New York and PJM electricity markets, as well as in other markets around the world, revealing that Ontario's electricity market prices are among the most volatiles world-wide. It is also demonstrated that while Ontario market participants are exposed to a high level of intra-day price volatility, the trans-day and the trans-week volatilities are even higher, which implies that short-term operation planning is highly risky. Finally, it is argued that high level of price volatility in Ontario is directly linked with the real-time nature of this market, and that moving towards a two-settlement electricity market should mitigate Ontario's electricity price volatility problems.

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