Nodal Pricing in Ontario, Canada: Implications for Solar PV Electricity

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Abstract:
This article investigates the extent to which the value of solar electricity (that is, electricity generated by photovoltaics), a form of distributed generation, would be higher under a nodal pricing system as compared to a uniform pricing system. More specifically, solar radiation and electricity market data for the period 1 January 2005 to 31 December 2006 are examined for locations near Mississauga, Ontario and Kingston, Ontario. The Hybrid Optimization Model for Electric Renewables (HOMER) program is used for the simulation of solar electricity output. For Mississauga, the average monthly value of the solar electricity based on Ontario's uniform pricing system (the Hourly Ontario Energy Price, or HOEP) was C$20.62. Based on nodal pricing, the average monthly value was C$27.20 per month (32% higher). For Kingston, the average monthly value of the solar electricity based on HOEP was C$23.78 per month. Based on nodal pricing, the average monthly value was C$36.03 (52% higher). Over the two-year period, the monthly differences were greatest during the summer, with a 53% spread in June in Mississauga and a 106% spread in May in Kingston. As debates regarding electricity futures progress, the importance of proper valuation of alternative generation sources continues to be critical. This research aims to contribute to discussions regarding the extent to which a nodal pricing system could facilitate the contribution of solar electricity to a sustainable electricity system in Ontario.

Keywords:
Canada; Distributed Generation; Electricity; Markets; Nodal Pricing; Photovoltaics

1. Introduction

Access to energy is recognized by the United Nations as an indicator of societal health and developmental progress [1]. Industrialized nations, in particular, have built economies and lifestyles that depend heavily on access to reliable electricity. When this access to electricity is compromised, there are significant economic and societal impacts (as were experienced following the wide-scale blackouts that occurred in 2003 throughout areas of Canada, the United States and Europe) [2]. A common challenge facing operators of electricity systems around the world is the congestion of supply resources due to high demand and strained transmission and distribution infrastructure [e.g., 3, p. 36]. Alleviating transmission congestion is an important part of maintaining reliability of the power grid, especially during extreme weather conditions. Low emission solutions to this challenge are attractive due to the increasing concern over air quality issues at both local and global levels (i.e., smog and climate change, respectively).

Distributed generation is defined as "the small-scale production of electricity at or near customers' homes and businesses" [4]. It has been identified as a way to "help improve transmission and distribution reliability by reducing losses and congestion on the power lines" [5, p.1]. Distributed generation allows for the close matching of energy output to a specific local load, thus avoiding, or at least deferring, the need to invest in central generation, transmission and distribution infrastructure [6]. Along with this, the value of distributed energy production can be counted in other non-traditional ways, including the reduction of generation capacity capital, operation and maintenance costs, the potential avoidance of emissions, and the increase in system reliability [7-9].

These traits are particularly valuable in the current electricity situation in Ontario (Canada) where electricity demand growth in the last decade has resulted in the need for costly transmission upgrades in order to maintain grid reliability and sustainability (for example, the proposed C$600 million development of a high voltage transmission line from the Lake Huron shoreline in Bruce County to the Town of Milton) [10].

In a consultant's report commissioned by the California Energy Commission, it was found that "utilities facing costly and controversial transmission upgrades could realize substantial savings if well-placed [distributed generation] can defer or minimize such projects by providing transmission system benefits" [11, p. 117]. Furthermore, the Rocky Mountain Institute found that transmission and distribution costs vary widely over time and place, and that this is a good reason for targeting distributed generation projects in areas where the distribution utility costs are relatively high [12].

Low emission, renewable energy generation sources, in particular solar photovoltaic (PV) systems, have the greatest potential to become cost-effective when situated as a distributed resource, as compared to deployment as a central station energy supply option. It is imperative to capture the non-traditional benefits of distributed solar PV applications in order for the technology to become a cost-effective and commercially viable component in grid-supplied electricity [13].

Given this, the purpose of this article is to determine the extent to which the value of solar electricity (that is, electricity generated by solar PV systems), a form of distributed generation, would be higher under a pricing scheme that captures some of its non-traditional or distributed benefits. More specifically, we investigate a pricing scheme that considers locational constraints (as compared to a uniform pricing regime). A common method of locational pricing is 'nodal pricing', which is a market design that takes into account the locational factors of energy production and consumption at any given location on the grid. This research aims to contribute to discussions regarding the extent to which a nodal pricing system in the province of Ontario (Canada) could facilitate the contribution of solar electricity to a sustainable electricity system.

The article is divided into seven main sections. After this introduction, the Ontario context is set in Section 2. Following this, Section 3 explores the difference between uniform pricing and locational pricing, and also considers experiences with nodal pricing in jurisdictions around the world. Section 4 describes the data collection and preparation that were required for the analysis. In Section 5, the values of solar electricity outputs under uniform and locational pricing schemes are compared and investigated. The results are discussed in Section 6 and finally, implications for policy and future research are highlighted in Section 7.

2. The Ontario Context

The article is focused on Ontario, Canada's most populous province. Ontario is Canada's second largest generator of electricity (of 10 Canadian provinces). Managed by the province's Independent Electricity System Operator (IESO), Ontario's electricity supply system was restructured and opened to some competition and market forces in 2002. In 2005, total Ontario electricity demand was 157 TWh [14], with nuclear generating stations making the largest contribution to the province's electricity supply (54.1%), while hydroelectric (22.3%), coal (16%), and natural gas (6.4%) stations were also major contributors. Other supply sources, including renewables, accounted for the remaining 1.2% [15].

Ontario's electricity system has experienced a fundamental change in the past decade, moving from a winter peaking situation to a summer peaking one. This is attributed mainly to an increased demand for air conditioning in the summer and a decrease in the use of electricity for heating purposes in the winter [16]. Peak winter demand in 2006 was 23,052 MW (16 January), while peak summer demand in the same year reached 27,005 MW (1 August); this represented an all-time record [17, 18]. Ontario's peak electricity demand is rising at a faster rate than Ontario total electricity demand (which itself is also rising) [19], and 15 of the top 20 recorded dates for Ontario peak electricity demand occurred in 2005 and 2006 [18]. Despite increasing demand, Canada's electricity prices continue to be among the least expensive of countries in the developed world [19].

In 2004, Ontario's electricity supply system was responsible for 34.6 Mt of greenhouse gas emissions (carbon dioxide equivalent), which accounted for 26.6% of Canada's electricity-related greenhouse gas emissions, and 4.6% of Canada's total greenhouse gas emissions (which were 758 Mt carbon dioxide equivalent in 2004) [20]. Considering Canada's obligation to lower its greenhouse gas emissions under the terms of the Kyoto Protocol, Ontario is a strong candidate for greater use of renewable resources in its electricity supply system. Additionally, the Government of Ontario has committed to a complete phase-out of coal-fired generating stations as soon as possible, thus increasing the need to develop alternate generation supply sources.

Congestion in key urban areas in southern Ontario, and associated distribution and transmission issues, are major electricity challenges facing the province. In June 2007, the IESO reported that in areas of the grid where projected extreme weather demand load was expected to approach or exceed the capability of the transmission facilities, congestion of low-priced supply resources could well result. This would necessitate the use of higher-priced resources instead; thus, costs to market loads would rise. The IESO also reported upon the "increased risk of load interruptions" [21, p. 23].

The Ontario Power Authority (OPA) released a discussion paper in November 2006 that identifies a number of transmission issues facing the Greater Toronto Area (GTA), in particular the downtown Toronto core. These include "the shortage of local generation, risks associated with having only two major supply corridors, and the difficulty and expense of developing new infrastructure in heavily built-up urban areas" [22, p. 3]. As of July 2007 (the time of this writing), virtually all of the power consumed in Toronto was generated outside of the city and the capacity of transmission lines required to bring in this externally generated power was not sufficient to meet peak demand [23]. (Toronto's peak demand in August 2006 was 5,018 MW [24].) The anticipated commissioning of the Portlands Energy Centre on Toronto's waterfront is expected to help to alleviate transmission congestion by providing a modest level of local generation (planned at 550 MW). Promotion of other local generation sources, such as solar electricity, would have similar benefits. In addition to the GTA, the OPA identifies a number of other regions in southern Ontario that currently or will soon have transmission-related reliability and supply adequacy issues [22].

In Ontario, transmission congestion tends to be heaviest during the summer, which is also when solar radiation values coincide closely with peak electricity market demand and, though to a somewhat lesser extent, peak electricity market prices [16]. Marnay et. al. argue that solar PV systems can provide a distributed source of electricity at times of high electricity demand [25]. In an analysis of market-based price differentials, the California Independent System Operator found that local transmission constraints were more common during the summer system peak loads of July, August, and September [26]. Given this, the potential of solar electricity to be a valuable part of the solution for the energy transmission and congestion issues facing Ontario appears high.

3. Nodal Pricing: Experiences and Assessment

Electricity markets in Ontario currently operate under a uniform pricing system, which is reflected in the Hourly Ontario Energy Price (HOEP). HOEP is a single price for electricity across the province that is determined through a process of bids and offers against a model of the grid that does not account for locational constraints. The costs associated with locational constraints are recovered as uplifted costs through a separate process called congestion management settlement credits (CMSC) [27]. Operating under such a system, the electricity market does not generally serve to recognize some of the additional benefits of distributed generation. Traditionally, electricity market managers have found such a system to be attractive, for it is quite simple; however, it works efficiently only in the absence of congestion [28].

An alternative method to uniform pricing is locational pricing, which can be defined in the broadest sense as any pricing algorithm that considers the locational constraints of providing electricity. More specifically, there are two methods of locational pricing that are most commonly referred to: zonal pricing and nodal pricing.

Zonal pricing attempts to assign congestion costs by dividing the market into several zones in which the locational prices are usually similar. The zonal price is calculated by averaging all of the prices at individual locations (or ‘nodal prices’ as described further on) within the zone and this is used to pay all suppliers and charge all consumers within the zone [27]. This kind of approach is advantageous over uniform pricing in that it “makes any exercise of market power easier to detect and exposes suppliers to demand elasticity” [29, p. 2]. However, it still does not account for differences in the levels of congestion within large zonal areas. The California Independent System Operator performed an analysis on October 2004 data that found locational marginal prices within major zones to be generally very similar during most hours; however, congestion caused price differences within these zones during hours of high loads [26]. It has been argued that the idea of aggregating several similar nodal areas into larger zones is inappropriate in the sense that it treats “fundamentally different locations as though they were the same” [30, p. 1]. Furthermore, Hogan contends that zonal pricing spreads higher costs over a societal base, and that it also tends to remove incentives for energy efficiency or distributed generation [30].

Nodal pricing, also known as locational marginal pricing (LMP), is similar in concept to zonal pricing but has more specific locational price assignments. Nodal pricing is the cost of serving the next MW of load at a given location or ‘node’. Nodal pricing takes three components into consideration: the marginal cost of generation, the marginal cost of losses and the marginal cost of transmission congestion [31]. Under this pricing mechanism, buyers and sellers realize the actual cost to deliver electricity based on their location on the transmission grid [32]. Green contends that nodal pricing makes the system less vulnerable to the exercise of market power and also sends better investment signals [33].

Nodal prices “reflect the relative scarcity of transmission capacity at each point of the grid” [28, p. 105], and thus, a system based on these prices provides incentives for efficiency both in the short-term and in the long-term. At congested nodes on the grid, transmission becomes relatively expensive and higher prices result. This provides an incentive to decrease demand in these locations, which in turn alleviates congestion in the short-term. Higher prices also provide an incentive to invest resources into supply and infrastructure in congested areas, contributing to the long-term efficiency of the grid [28].

According to van Sambeek, the use of distributed generation can lower nodal prices for the benefit of all users of a transmission grid, not just those located in areas that experience heavy congestion [6]. More specifically, distributed generation can significantly reduce local congestion which frees up available transmission capacity, which in turn lowers the shadow value of transmission capacity and consequently the nodal spot price. Removing a congestion constraint also allows for a less expensive dispatch pattern to be followed and there is a reduction in nodal spot prices and marginal transmission costs over the congested line as well as over other affected parts of the grid [6].

Nodal pricing is increasingly becoming the benchmark of electricity pricing in many American and European markets. Ontario is adjacent to five independent system operators (ISO) and actively trades with these jurisdictions in the North American electricity market. As of 2007, four of these five were using nodal pricing systems: New York ISO (since 1999), ISO New England (since 2003), Pennsylvania-New Jersey-Maryland (PJM) Interconnection (since 1998) and the Midwest ISO (since 1995); Hydro-Québec is the sole exception [32]. Other examples also exist. The California ISO, for instance, has a proposed market design program in place to move from a zonal-based pricing approach to a nodal pricing scheme (among other system design changes) in November 2007 [32]. Based on their experiences with different pricing systems, the California ISO has found nodal pricing to be “the preferred method for dealing with transmission traffic jams and determining the least cost method for meeting electricity demand” [34, p.1].

In Ontario, some study regarding the potential of using the nodal pricing approach began in 2002 (under the remit of the Independent Electricity System Operator (IESO)) [31]. Further to this, in 2006, the IESO commenced a locational marginal pricing (LMP) study using historical shadow prices from the constrained algorithm to provide some insight into what locational prices might look like in Ontario [35]. At this time, the reasons for studying locational pricing included stakeholder interest, increasing complexity of congestion management settlement credits, preparation for price calculation, design of day-ahead market structure and a recommendation in the latest market surveillance panel report to introduce locational pricing [27]. The Stakeholder Advisory Committee reviewed the status of the IESO's LMP study in November 2006 and acknowledged several factors, both behavioural and mechanical, that make a direct comparison of locational prices and HOEP problematic. As of 2007, the IESO was continuing to pursue ways "to improve some of the mechanical factors and to better understand the behavioural factors in order to enable more informed future decisions on locational pricing" [36, p.1]. Nodal pricing data were still being collected and published by the IESO, but for informational purposes only.

4. Data Collection and Preparation

For 2005 and 2006, hourly global solar radiation data were gathered from two weather stations in Ontario, as shown in Figure 1 (Mississauga and Kingston); HOEP data were obtained from the IESO; and, hourly nodal prices were acquired from the IESO for the Darlington Nuclear Generating Station in Clarington, Ontario and the Lennox Generating Station in Bath, Ontario. The years of 2005 and 2006 have been chosen in an attempt to most accurately represent the current state of congestion and transmission constraints that exist in the province of Ontario. Note that when values are reported at a particular time, they represent the value for the hour up to, and including, that time.

Fig. 1. Locations of global solar radiation data collection

Global solar radiation data – Global solar radiation is a measure of all incoming radiation incident on the earth's surface. Global solar radiation in Mississauga was measured at the University of Toronto at Mississauga's (UTM) Erindale weather station (43 deg 33' N latitude and 79 deg 40' W longitude). Raw data were downloaded from the UTM website [37]. Kingston global solar radiation data were measured at the Queen's University Live Building **(**44 deg 13' N latitude and 76 deg 29' W longitude). Raw data were downloaded from the Queen's University Live Building website [38]. In both locations, a flat plate collector was used to record hourly values of solar radiation. A Kipp & Zonen pyranometer was used in Mississauga. In Kingston, a Li-Cor pyranometer was used prior to October 2005 and a Vantage Pro solar sensor (part of a Davis Weather Instruments package) was used from October 2005 onward.

Global solar radiation data sets were manipulated in preparation for input to a simulation program which would provide simulated solar electricity production as an output. For the chosen program, a data set of hourly global solar radiation values in W/m^2 for one year (8,760 values) was required. The Mississauga and Kingston global solar radiation data sets were modified by replacing all recordings that had a negative value (experienced in the overnight hours) with a value of 0 W/m^2. It is common for pyranometers to record negative values at night.[1] For the purpose of this study, the negative values were replaced with zeros in order to avoid calculating negative revenues at night, which would not occur in reality. Additionally, there were two gaps in data collection at the Mississauga weather station. One occurred over 35 days from 26 May 2005 to 30 June 2005, when the solarimeter was sent away for calibration. The other was caused by a changeover of data logger and logging program and occurred over eight days, 26 June 2006 to 4 July 2006. A correlation analysis was performed to determine the adequacy of global solar radiation measured at an alternative weather station approximately 70 kilometres to the west.[2] The data at each of the stations for three weeks prior to and three weeks after the missing data gap were compared. A strong linear relationship with a correlation

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[1] The pyranometer sensor is exposed to sunrays. The irradiance values thus obtained are a function of the temperature difference between the sensor material and the case surrounding it. During daytime, the sensor temperature varies with sunlight, but the temperature of the case is same as that of the ambient temperature. During nighttime, no sunrays are absorbed by the sensor. There is a possibility that the temperature of the sensor might be lower than the case temperature. Hence the pyranometer may show small negative values at night [39].

[2] University of Waterloo Weather Station located at 43 deg 28' N latitude and 80 deg 33' W longitude using a Kipp & Zonen pyranometer [40].

coefficient of 0.92 was found. Thus, the alternative global solar radiation data were applied to the dates where recordings were unavailable from the Mississauga weather station. This is recognized as a limitation to the analysis.

The Hybrid Optimization Model for Electric Renewables (HOMER) program, developed by the United States National Renewable Energy Laboratory (NREL), was used for solar electricity output simulation. Although HOMER is primarily used as an economic optimization model [41-43], for our purposes it was useful in providing estimated solar electricity output on an hourly basis based on inputs of panel and inverter specifications, hourly solar radiation data and latitude and longitude of the weather station. For this study, a simulated solar electricity output was generated for a 3 kW solar system connected to the grid with panels at a tilt angle of 30 degrees and an azimuth of 0 (due south).

Hourly Ontario Energy Price (HOEP) data – This data set held hourly electricity market prices for the years of 2005 and 2006. HOEP represents the payment for the energy component of electricity that would be made to electricity suppliers during any given hour in the province of Ontario. HOEP data were obtained from the Market Data section of the IESO website [44].

Nodal price data – The Ontario electricity grid is divided into ten zones, as shown in Figure 2. The IESO publishes price data for a representative node within each zone. For this study, hourly nodal price locations with complete 2005 and 2006 data that were closest to the two weather stations were identified. Nodal prices at the Darlington Nuclear Generating Station, located 82 kilometres east of Mississauga in Clarington, Ontario, are published by the IESO as the representative node for the Toronto zone. Nodal prices at the Lennox Generating Station, located 23 kilometres west of Kingston in Bath, Ontario, were obtained directly from the IESO. It is a limitation of this study that the locations of solar electricity data and the nodal prices are not identical, for it is recognized that nodal prices can vary widely within zones as well as between them; however, these approximations were as close as possible given the available resources. It should also be noted that the nodal prices are published by the IESO for information purposes only and that the IESO notes that they should not be considered to be a true reflection of future pricing [45]. Nevertheless, they are still useful in providing insight into what locational prices might look like in Ontario [35].

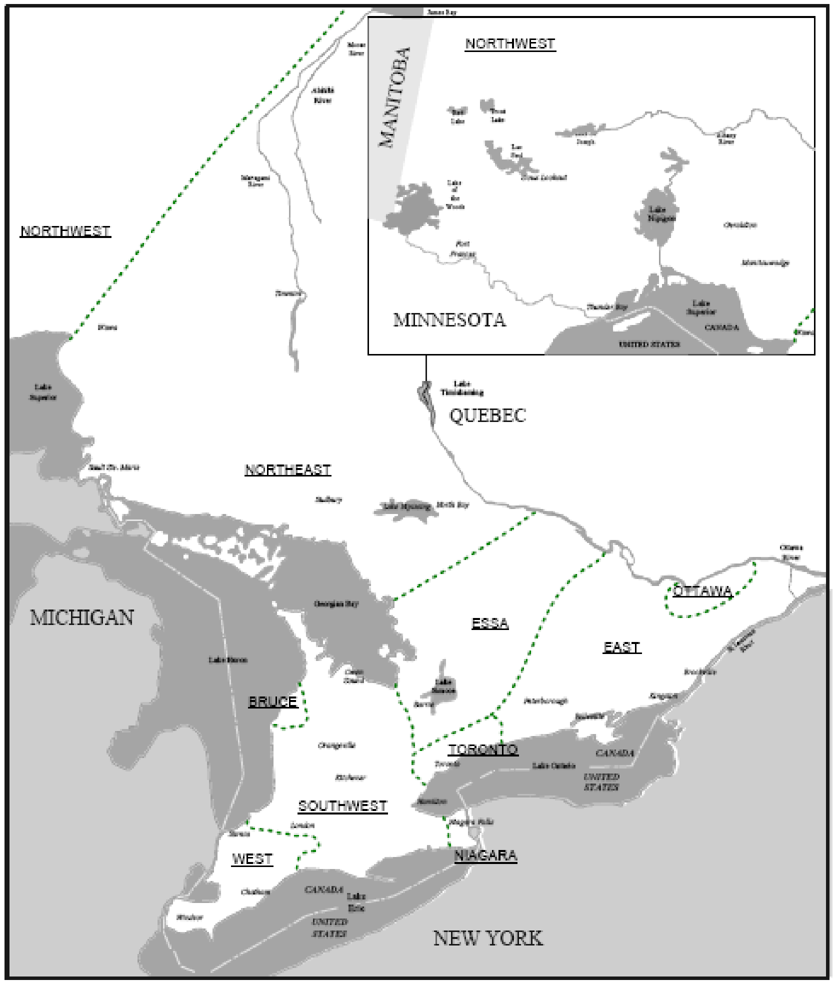

Fig. 2. IESO Transmission Zones

Source: [46]

5. Results

The total yearly simulated solar electricity output at the Mississauga location was 3,315 kWh in 2005 and 3,494 kWh in 2006, while for the Kingston location, the corresponding figures were 4,334 kWh and 3,705 kWh, respectively. Figure 3 provides a monthly breakdown of these values. While the 2006 output figures for the two locations are relatively similar, the 2005 figures differ more significantly. There are at least two possible explanations for this. For one, the particular weather conditions in Kingston may have caused more solar radiation to be incident on the ground in that location. And second, a new sensor was installed at the Queen's University Live Building in the fall of 2005. This sensor may not have been aligned nor calibrated the same as the previous one [47]. Regardless, because our primary comparison in this article is between alternative pricing systems for a given level of solar PV electricity production at any given point in time, we nevertheless believe it worthwhile to proceed given this limitation.

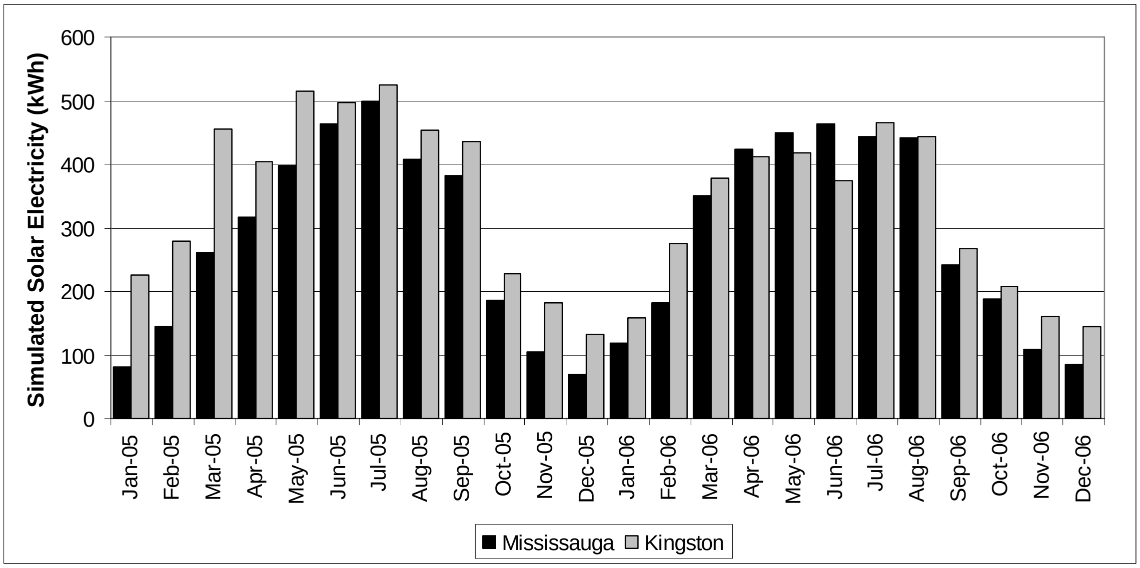

Fig. 3. Monthly simulated solar electricity output, Mississauga and Kingston, 2005 – 2006.

For both locations, hourly solar weighted revenue was calculated based on a uniform pricing system as the product of hourly solar electricity production and HOEP, and then based on a nodal pricing system as the product of hourly solar electricity production and hourly nodal price at the corresponding location.[3] Subsequently, monthly solar electricity production, monthly revenue based on HOEP and monthly revenue based on the nodal price were compared. This allowed for the calculation of an average value of solar electricity in C$/MWh first based on HOEP and then based on nodal prices for each month of 2005 and 2006. In both Mississauga (Figure 4) and Kingston (Figure 5), the total monthly value of solar electricity based on nodal prices was consistently higher than the value based on HOEP, with the most considerable spread occurring in the summer months.

For Mississauga, the total value of the solar electricity over the two year period based on HOEP was C$494.96, or C$20.62 per month. Based on nodal pricing, the total value over the

[3] Recognize that these revenue values are theoretical. In reality, the operator of our modelled PV system would apply for payment under the provincial government's Renewable Energy Standard Offer Program (RESOP) for grid-connected PV systems. For PV systems no larger than 10 megawatts (MW), RESOP provides guaranteed payments of C$0.42/kWh for 20 years.

two-year period was C$652.89, or C$27.20 per month (or 32% higher). The difference in monthly value ranged from nodal-based value being 2% higher than HOEP-based value in December 2006 to 75% higher in June 2005.

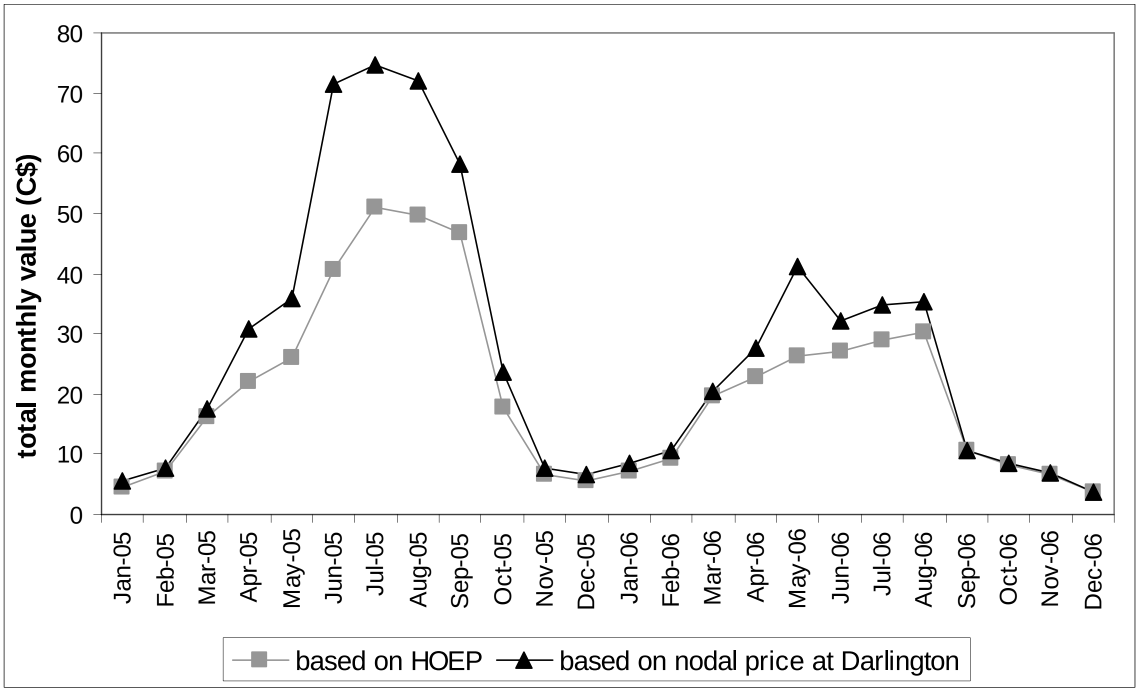

Fig. 4. Total monthly value of solar electricity, Mississauga, Ontario, 2005 – 2006

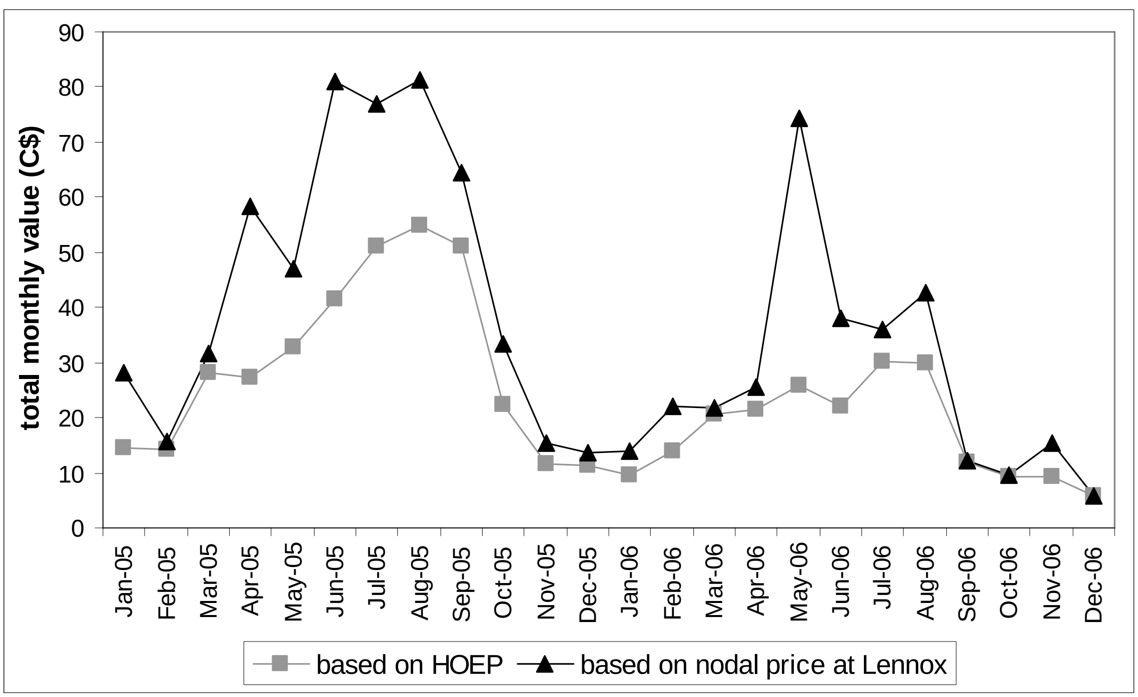

Fig. 5. Total monthly value of solar electricity, Kingston, Ontario, 2005 - 2006

For Kingston, the total value of the solar electricity over the two year period based on HOEP was C$570.72, or C$23.78 per month. Based on nodal pricing, the total value over the two-year period was C$864.69, or C$36.03 per month (or 52% higher). The difference in monthly value ranged from nodal-based value being 2% higher than HOEP-based value in December 2006 to 186% higher in May 2006.

In Figure 4, it is clear that the total monthly value of solar electricity in Mississauga throughout the summer of 2006 is lower than the previous summer at the same location, as well as lower than the figures found in the same time period of 2006 in Kingston. One possible explanation for this is the City of Toronto's active campaign for energy conversation that occurred throughout the summer of 2006. The Summer Challenge conservation program promoted by Toronto Hydro resulted in savings of over 79 million kilowatt hours of electricity in July and August 2006 [48]. With lower demand, lower prices may well have followed.

Given that solar electricity is considered to be most valuable in the summer months - when demand, congestion and solar radiation are highest - the relationship among average hourly solar electricity production, nodal prices and HOEP for this time period (May to August inclusive) in 2005 and 2006 is presented in Figures 6 and 7. Peak solar electricity output coincides closely with peak nodal prices during the midday hours from approximately 10:00 to 15:00 (EST). In Mississauga, solar electricity output reached a peak of 1.88 kWh between 11:00 and 12:00 (EST). The electricity price based on a nodal scheme reached its peak one hour later (13:00 (EST)) at C$122/MWh. In Kingston, solar electricity output reached a peak of 1.83 kWh between 11:00 and 13:00 (EST). The energy price based on nodal pricing reached a peak of C$164.84 at 14:00 (EST).

To further understand how the electricity prices would have compared over the two year period under different pricing schemes, average prices were calculated for three scenarios:

1. **Average market price** - actual average market price of all electricity based on the product of Ontario demand and HOEP;
2. **Solar-weighted (HOEP) price** - average price of solar electricity based on HOEP; and,
3. **Solar-weighted (nodal) price** - average price of solar electricity based on nodal prices.

As shown in Tables 1 and 2, the average market price was lowest of the three at C$61/MWh. For both locations, the solar-weighted price based on HOEP was approximately C$10/MWh higher than the average market price, while the solar-weighted price based on nodal prices ranged from C$25/MWh (for Mississauga) to C$47/MWh (for Kingston) higher than the average market price.

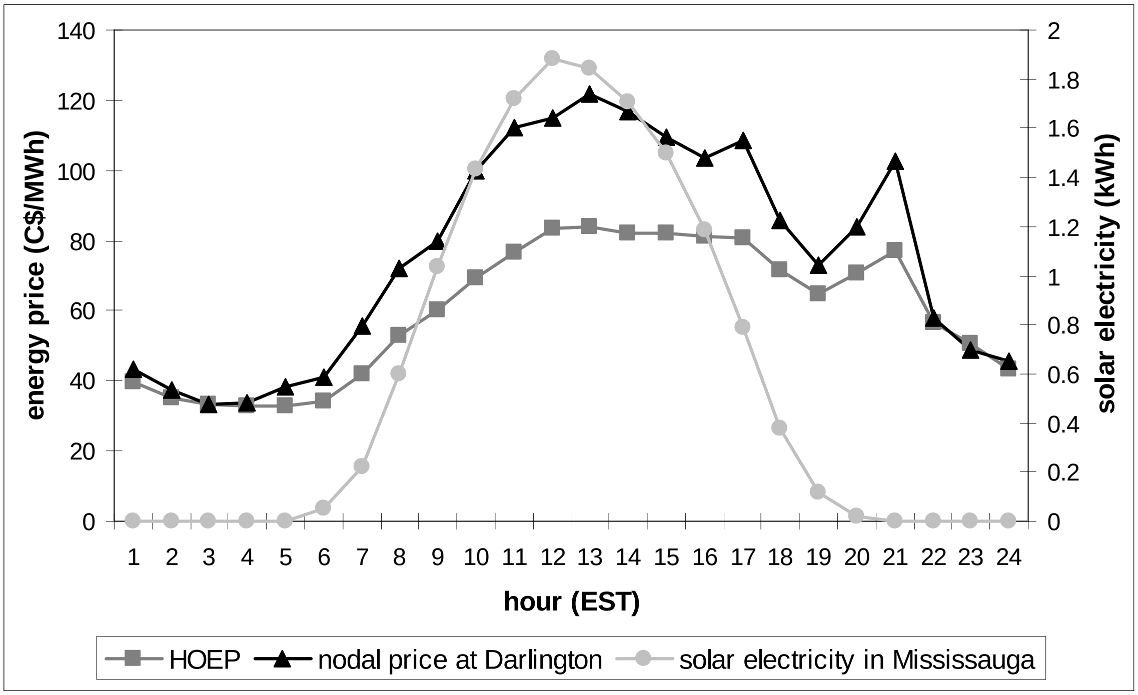

Fig. 6. Average hourly solar electricity output, HOEP and nodal prices, Mississauga, May – August, 2005 – 2006

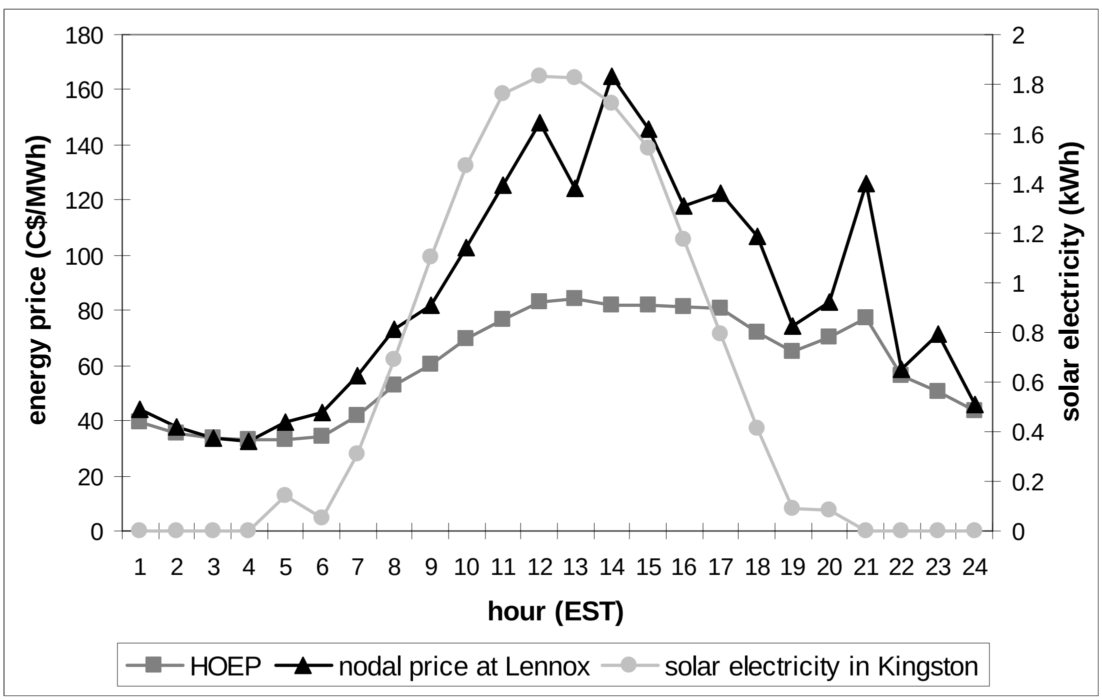

Fig. 7. Average hourly solar electricity output, HOEP and nodal prices, Kingston, May – August, 2005 - 2006

Table 1

Mississauga electricity prices

	2005 - 2006
Average market price (C$/MWh)	60.67
Average solar-weighted (HOEP) price (C$/MWh)	72.69
Average solar-weighted (nodal) price (C$/MWh)	95.89

Table 2

Kingston electricity prices

	2005 - 2006
Average market price (C$/MWh)	60.67
Average solar-weighted (HOEP) price (C$/MWh)	71.00
Average solar-weighted (nodal) price (C$/MWh)	107.57

Focusing again on the summer months, when demand, congestion and solar radiation are highest, Figures 8 and 9 show the average price, solar-weighted (HOEP) price and solar-weighted (nodal) price over the months of May to August in 2005 and 2006. For Mississauga, the solar-weighted (nodal) price is on average 75% higher than the average market price and 22% higher than the solar-weighted (HOEP) price over this time period. The largest difference was found in June when the solar-weighted (nodal) price was 88% higher than the average market price and 23% higher than the solar-weighted (HOEP) price. For Kingston, the solar-weighted (nodal) price is on average 106% higher than the average market price and 21% higher than the solar-weighted (HOEP) price over this time period. The largest difference was found in May when the solar-weighted (nodal) price was 158% higher than the average market price and 21% higher than the solar-weighted (HOEP) price.

6. Discussion

In the cases used in this study, there was found to be consistently higher value under a nodal pricing system for solar electricity produced in areas of high congestion. This reveals that solar electricity was undervalued by the current uniform pricing system. Solar electricity is advantageous in helping to alleviate congestion most importantly because it can be generated in close proximity to loads, thus avoiding line losses and transmission costs. Solar electricity is also preferable due to the fact that its times of high production correspond closely with times of high demand and congestion. These conditions occur generally in the midday hours during the summertime.

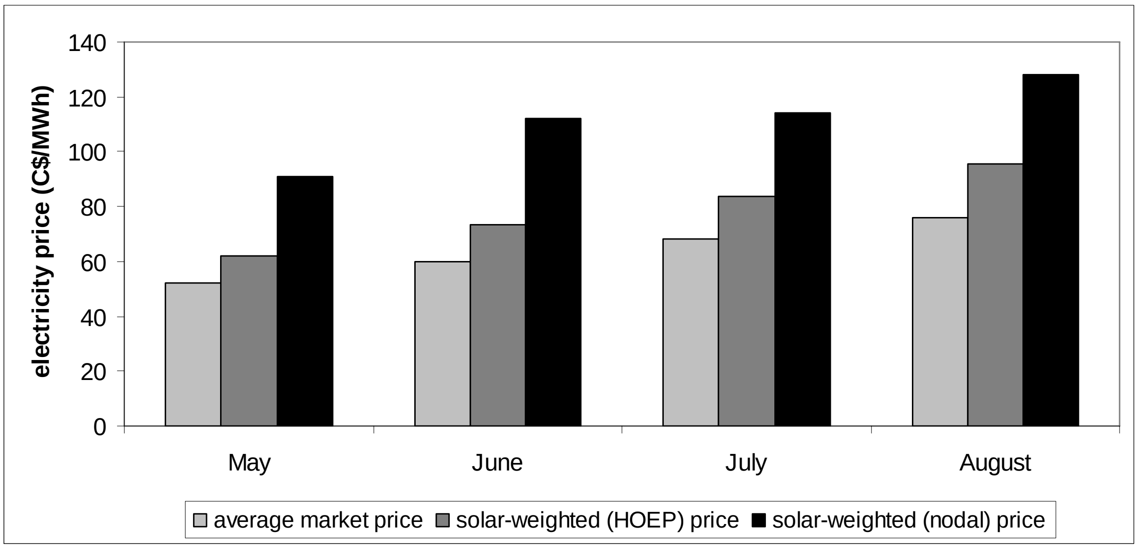

Fig. 8. Average monthly electricity prices, Mississauga, 2005 and 2006

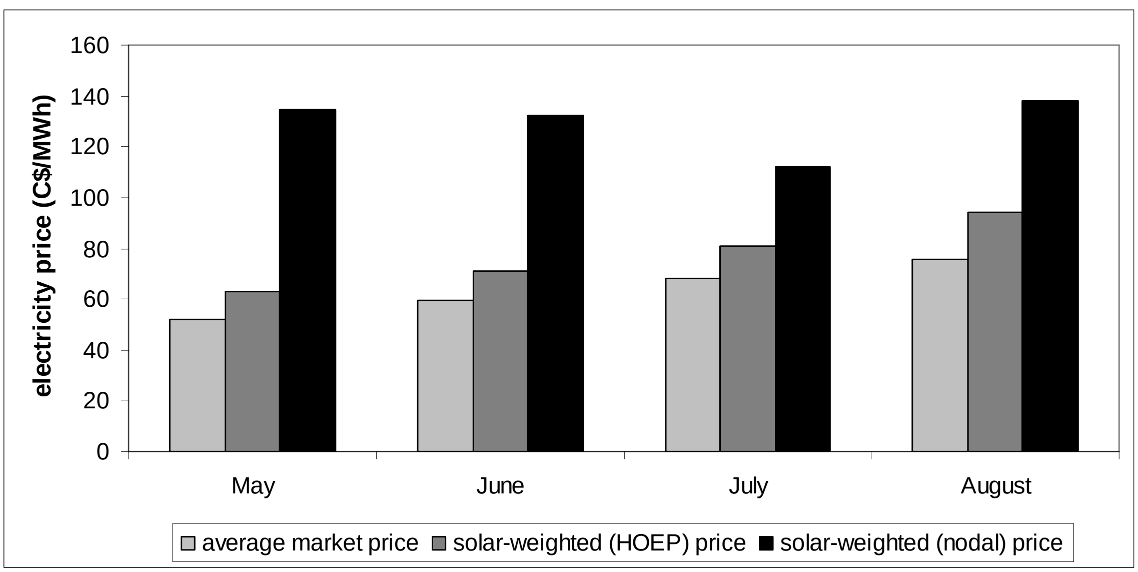

Fig. 9. Average monthly electricity prices, Kingston, 2005 and 2006

By utilizing a nodal pricing system, solar electricity generated in congested areas would be assigned a more accurate market value for the additional benefits it provides. This identification of additional value supports the case for all forms of distributed generation as well as the higher price given for solar PV projects under the Renewable Energy Standard Offer Program (RESOP) in Ontario.

7. Conclusions and Future Research

The results of this study indicate that distributed generation sources, such as solar electricity, can hold more value in areas of high congestion when based on a pricing scheme that takes into account where the electricity is produced (versus a uniform pricing system such as HOEP). Nodal pricing is an example of such a system and is increasingly being used in electricity markets throughout the world. Given this result, the placement of solar PV systems in areas of high congestion in southern Ontario is encouraged. Solar PV has the potential to become a valuable part of the solution for maintaining system reliability, alleviating transmission and distribution costs and offsetting future capital costs of expanding transmission infrastructure in the province. As such, the support given solar PV under the existing RESOP is further justified. Indeed, it could even be suggested that solar electricity produced in areas of high congestion should receive some additional credit under RESOP. This possibility is worthy of further investigation.

This study was limited due to the unavailability of nodal price data and solar electricity output data that are collected at the same location on the grid. Further studies could be improved by using nodal prices and solar PV panel production data that are collected from locations more closely situated to one another, if such data become available.

Another improvement for future research would be increasing the accuracy of the solar electricity simulation modelling, or to use actual solar electricity output data. In the case of the former, Watsun-PV and Natural Resources Canada's ESP-r are possible candidates, although their data input requirements are more sophisticated than those of HOMER. In the case of the latter, with RESOP catalyzing solar PV deployment across Ontario, output data may soon become more readily available. Finally, statistical investigation would also be useful to further explore the trends that have been identified in this preliminary visual exploration of the relationship between nodal prices and solar electricity.

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