Nodal Pricing in Ontario –

Implications for Solar PV

April 20th, 2007

Sarah J. Brown
Undergraduate Student,
Faculty of Environmental Studies,
University of Waterloo
s6brown@fes.uwaterloo.ca

Ian H. Rowlands
Associate Professor,
Faculty of Environmental Studies
University of Waterloo
Waterloo, ON, N2L 3G1
irowland@fes.uwaterloo.ca
(519) 888-4567, ext. 32574

**DRAFT – PLEASE DO NOT QUOTE OR CITE WITHOUT PERMISSION.
COMMENTS GRATEFULLY RECEIVED.**

Acknowledgements: This work was funded in part by the Solar Buildings Research Network under the Strategic Network Grants Program of the Natural Sciences and Engineering Research Council of Canada. This support is gratefully acknowledged. Appreciation, as well, to Prof. Peter Lafleur, Trent University, for access to solar radiation data.

Introduction and background

Solar photovoltaic (PV) systems are a distributed form of generation. The value of energy production by this method includes the avoidance of distribution and transmission costs; reduction of generation capacity capital costs as well as operation and maintenance costs; reduction in generation fuel costs; avoidance of emissions; and an increase in system reliability (Duke et. al., 2005; Alderfer et. al., 2000; CanSIA, 2005). These traits are particularly valuable in the current electricity situation in Ontario (Canada), where an $80 billion plan for electricity supply expansion – developed by the Ontario Power Authority (OPA) – is currently underway. Indeed, congestion in key urban areas in southern Ontario – something that PV can potentially serve to alleviate – is one of the key electricity challenges facing Ontario (with the cost, for example, of a high voltage transmission line from the Lake Huron shoreline in Bruce County to Milton placed at $600 million) (OPA, 2007).

But electricity markets in Ontario do not generally serve to recognize these additional benefits and thus neither do they encourage increased use of solar PV. At present, so-called ‘uniform pricing’ is the dominant approach – for it is reflected in the Hourly Ontario Energy Price (HOEP), which calculates one price for electricity, regardless of where it is ‘produced’ or ‘consumed’. 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 (Dietrich et. al., 2005).

By contrast, zonal pricing attempts to assign congestion costs by dividing the market into several zones and setting the price for each zone by aggregating all of the nodal prices into one price at a respective reference node. This kind of approach is advantageous over uniform pricing in that it becomes easy to detect any exercise of market power and suppliers are exposed to demand elasticity (Johnsen et. al., 1999). However, it still does not account for differences in congestion within large zonal areas. 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 (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 (IMO, 2003). Dietrich et. al.

(2005) contend that nodal pricing is theoretically the most efficient mechanism considering both economic factors and the physical laws of electricity networks. Moreover, it is increasingly becoming the benchmark of electricity pricing in both American and European markets. Jurisdictions that are currently using, or plan to soon implement, nodal pricing systems include New Zealand (since 1997), New York (1998), New England (2003) and California (2007) (Dietrich et. al., 2005). Some study began in 2002 regarding the potential of using the nodal pricing approach in Ontario (under the remit of the Independent Electricity System Operator (IESO)) (IMO, 2003). As recently as fall of 2006, the IESO conducted a Locational Marginal Pricing study using historical shadow prices from the constrained algorithm to provide some insight into what locational prices might look like in Ontario (IESO, 2006a). Despite this work, the nodal pricing approach does not appear to be on the province's agenda for near future market conditions in Ontario.

Rationale

During an analysis of market-based price differentials in October 2004, the California ISO found that locational marginal prices within major zones were generally very similar during most hours; however, during hours of high loads, congestion caused price differences within these zones. It was also found that local transmission constraints were more common during summer system peak loads of July, August, and September 2004 (California ISO, 2006). Furthermore Rowlands (2004) concludes that solar radiation values coincide closely with peak electricity market demand in Ontario and, though to a somewhat lesser extent, peak electricity market prices during the summertime in the province. Marnay et. al. (1997) also argued that PV systems can provide a distributed source of electricity at times of high electricity demand. The Rocky Mountain Institute (2002) found that a consistent result from area- and time-specific cost analyses was 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. (In our study, we will assume distribution utility costs to be represented as part of nodal price differences.)

In areas of the IESO-controlled grid where the projected loading is expected to approach or exceed the capability of the transmission facilities, congestion of low-priced resources could result and thus, have to be replaced by higher-priced resources, increasing costs to market loads. There is also an increased risk of load interruptions (IESO, 2006b). The September 2006 18-Month Outlook from Ontario's Independent Electricity System Operator concludes that "the magnitude of resource deficiencies under both normal and extreme weather emphasizes the continued need for additions of reliable supply and demand response within Ontario" (IESO, 2006b). In the most recent 18-Month Outlook – released in March of 2007 – the IESO finds that even in the best scenario, which assumes normal weather and the availability of planned resources, there will still be 10 weeks of the period during which reserves are lower than required, thus necessitating the cancellation of planned outages or the potential use of imports. Furthermore, the Ontario Power Authority (OPA) released a discussion paper in November 2006 that points out that there are a number of transmission issues facing the Greater Toronto Area (GTA) and, in particular, the downtown Toronto core such as "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." Currently, all of the power consumed in Toronto is generated outside of the city and the capacity of transmission lines required to bring in this externally generated power is not sufficient to meet peak demand (Ontario Ministry of Energy, 2007). Commissioning of the Portlands Energy Centre, currently under construction on Toronto's waterfront, will help to alleviate transmission congestion by providing local generation supply. Promotion of other local generation sources such as PV energy would have similar benefits towards reducing stress on the transmission infrastructure in Toronto. In addition to the GTA, the OPA (2006) identified Kitchener-Waterloo-Cambridge-Guelph, Windsor/Essex, southern Georgian Bay, Woodstock, Brant, Thunder Bay and northern York Region as large load centres that have, or will soon have, transmission-related reliability and supply adequacy issues.

Given this situation, this research aims to contribute to discussions regarding the contribution of PV to a sustainable electricity system in Ontario, and the extent to which a nodal pricing system in the province could facilitate PV's role. This research indicates that it would be of interest to further study how PV generated energy would reflect a higher value in a pricing scheme that takes into account the location of energy production – such as nodal pricing - and thus, be a valuable part of the solution for the energy transmission issues facing southwestern Ontario.

Data and Methodology

This paper examines the extent to which HOEP understates the value of solar PV electricity by comparing the level of nodal prices to HOEP during periods of high solar radiation. For one week in the summer of 2006, solar radiation data are taken from three locations across Ontario (Peterborough,[1] Mississauga[2] and Waterloo[3]) and market data are taken from the IESO.[4] The period of analysis is from July 30 to August 5, 2006. This period of time was chosen to consider differences between weekday and weekend energy use. This week captures a significant high demand and high price period. The dates of July 31, August 1 and August 2, 2007 constitute three of the top eight recorded dates for Ontario peak electricity demand. The top all-time record was reached on August 1st, 2007 when Ontario demand soared to 27,005 MW (IESO, 2007b)

Solar radiation data - Data from three weather stations across Ontario were examined over a one-week period in August 2006. It was determined that solar radiation reached its daily highest point most often (52.4% of the time) during the noon hour (12:00 p.m. – 12:59 p.m.[5]). The next most likely times for radiation to reach its daily maximum point were the hour directly before (11:00 a.m. – 11:59 a.m. – 14.3%) and the hour directly afterwards (1:00 p.m. – 1:59 p.m. – 14.3%). The daily highest solar radiation value occurred between the hours of 10:00a.m. and 1:59p.m. 90.5% of the time. (For the remainder of the paper we will refer to this time period as 10:00a.m. to 2:00p.m.). Based on these observations we will consider the time period of 10:00a.m. to 2:00p.m. to be the time of day during which maximum solar radiation is most likely to occur. In comparison, the time period twelve hours later of 10:00p.m. to 2:00 a.m. will be considered as a time of day during which zero solar radiation is recorded. The

[1] http://www.trentu.ca/academic/bluelab/trentclimatestation.html
[2] http://eratos.erin.utoronto.ca/UTMMS/
[3] http://weather.uwaterloo.ca/
[4] http://www.ieso.ca
[5] All times are in Eastern Standard Time (EST)

difference between nodal price and HOEP will be compared between these two time periods, as well as compared between the noon hour and the midnight hour.

Representative nodal price data – The IESO power grid is divided into ten zones as depicted in Figure 1. The IESO publishes price data for a representative node within each zone. For example, the representative node price for the Toronto zone is measured at Darlington. There are limitations to these data as it is understood that nodal prices can vary widely within zones, as well as between them; however, market data were unfortunately not available at the time of this study for any nodes other than the representative nodes. When these data become available, further work will be required to more thoroughly analyze nodal price differences within zones and how this relates to peak solar radiation and demand.

The price difference between nodal prices and HOEP will be referred to in this paper as the 'residual' and is calculated by:

Residual = Nodal Price – HOEP

Based on this, we can say that when the residual is a positive number, the HOEP undervalues the true nodal price of energy at that place and time. Conversely, when the residual is a negative number, the HOEP is an overestimate of the true nodal cost of energy at that particular location.

Results

On average, over one week, for 49.31% of the time between 10:00a.m. and 2:00p.m., representative nodal prices were higher than HOEP over fifteen zones in Ontario, as shown in Table 1. This is as compared with 36.45% of the time between 10:00p.m. and 2:00a.m. The average residual amount during the 10:00a.m. to 2:00p.m. period was $7.50,[6] while the average residual during the 10:00p.m. to 2:00a.m. period was -$5.88. This indicates that from 10:00a.m. to 2:00p.m., which is the period of highest solar radiation, nodal prices are likely to be an average of $7.50 higher than HOEP. Conversely, nodal prices are lower, on average, than HOEP during the time period of 10:00p.m. to 2:00a.m. by a deficit of $5.88.

[6] Unless otherwise indicated, all energy values for price are in terms of Canadian dollars per MWhr.

Figure 1 **IESO Transmission Zones**

Source: IESO

On average, over one week for 60.94% of the noon hours (12:00p.m. – 12:59p.m.), representative nodal prices were higher than HOEP as shown in Table 2. This is as compared with 52.37% of the midnight hours (12:00a.m. – 12:59a.m.). The average residual amount over the noon hours for the week was $11.95, while the average residual over the midnight hours was $4.39. This indicates that during the noon hours, the time of highest solar radiation, nodal prices are likely to be an average of $11.95 higher than HOEP. Nodal prices are still higher, on average, than HOEP during the midnight hour however by a much smaller margin of $4.39.

Southwestern Ontario was identified earlier as an area with particular concerns regarding transmission adequacy and supply reliability, not only now but also into the near future. When we examine the data focussed only on southwestern Ontario, the patterns support nodal price as a more accurate representation of locational price. The six zones that make up southwestern Ontario are represented by nodes at Darlington, Desjoachims, Bruce, Nanticoke, Niagara and Lambton. Over one week for 62.53% of the time between 10:00a.m. and 2:00p.m., representative nodal prices were higher than HOEP as shown in Table 1. This is as compared with 27.38% of the time between 10:00p.m. and 2:00a.m. The average residual amount during the 10:00a.m. to 2:00p.m. period was $22.88, while the average residual during the 10:00p.m. to 2:00a.m. period was -$1.89. This indicates that from 10:00a.m. to 2:00p.m., which is the period of highest solar radiation, nodal prices are likely to be an average of $22.88 higher than HOEP. Conversely, nodal prices are lower, on average, than HOEP during the time period of 10:00p.m. to 2:00a.m, by an amount of $1.89.

On average, over one week for 80.93% of the noon hours (12:00p.m. – 12:59p.m.), representative nodal prices were higher than HOEP as shown in Table 2. This is as compared with 47.62% of the midnight hours (12:00a.m. – 12:59a.m.). The average residual amount over the noon hours for the week was $28.94, while the average residual over the midnight hours was $0.92. This indicates that during the noon hours, the time of highest solar radiation, nodal prices are likely to be an average of $28.94 higher than HOEP. Nodal prices are still higher, on average, than HOEP during the midnight hour, however by the much smaller margin of $0.92.

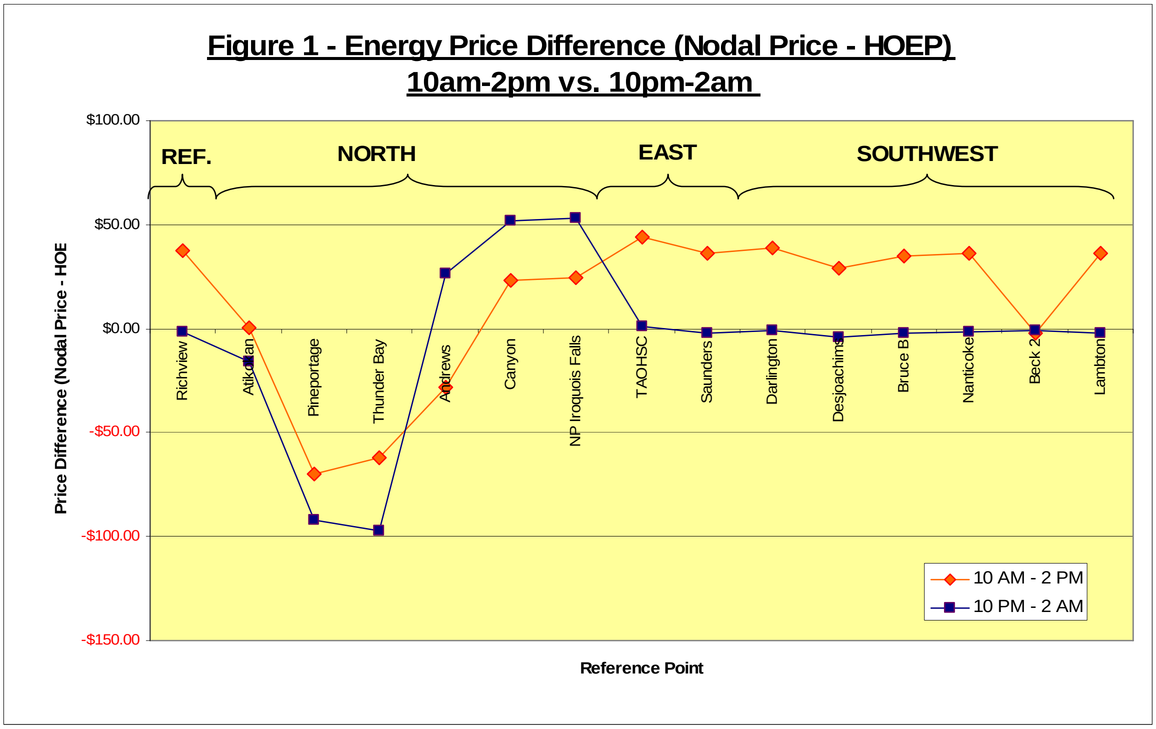
Table 1 Price Differential Analysis for Ontario – 10am-2pm vs. 10pm-2am						
			10 AM – 2 PM		**10 PM - 2 AM**	
	Representative Node	***Zone***	*% of time that hourly nodal > HOEP*	*Average price residual (nodal – HOEP)*	*% of time that hourly nodal > HOEP*	*Average price residual (nodal – HOEP)*
1	*Richview*	*Reference*[1]	67.90%	$31.99	28.60%	-$1.47
2	*Atikokan*	*Northwest*	25.00%	-$4.15	3.60%	-$16.19
3	*Pineportage*	*Northwest*	3.60%	-$74.19	42.90%	-$92.27
4	*Thunder Bay*	*Northwest*	3.60%	-$66.63	42.90%	-$97.37
5	*Andrews*	*Northeast*	25.00%	-$25.35	57.10%	$26.58
6	*Canyon*	*Northeast*	50.00%	$21.91	67.90%	$51.99
7	*NP Iroquois Falls*	*Northeast*	50.00%	$23.09	67.90%	$52.99
8	*TAOHSC*	*Ottawa*	71.40%	$37.98	42.90%	$0.94
9	*Saunders*	*East*	67.90%	$30.50	28.60%	-$2.05
10	*Darlington*	*Toronto*	67.90%	$33.43	32.10%	-$0.89
11	*Desjoachims*	*Essa*	53.60%	$23.93	14.30%	-$3.86
12	*Bruce B*	*Bruce*	67.90%	$30.44	28.60%	-$2.11
13	*Nanticoke*	*Southwest*	64.30%	$29.20	28.60%	-$1.59
14	*Beck 2*	*Niagara*	53.60%	-$10.10	32.10%	-$0.89
15	*Lambton*	*West*	67.90%	$30.40	28.60%	-$1.99
Northern Ontario Average (nodes 2-7)			26.20%	-$20.89	47.05%	-$12.38
Eastern Ontario Average (nodes 8-9)			69.65%	$34.24	35.75%	-$0.56
Southwestern Ontario Average (nodes 10-15)			62.53%	$22.88	27.38%	-$1.89
Total Ontario Average (all nodes)			**49.31%**	**$7.50**	**36.45%**	**-$5.88**

[1] The Richview Transformer Station in the Greater Toronto Area is the representative constrained price, or the single price that most accurately reflects the true supply conditions in Ontario at any point in time.

Table 2 Price Differential Analysis for Ontario – Noon Hour vs. Midnight Hour						
			Noon Hour[2]		**Midnight Hour**[3]	
	Representative Node	***Zone***	*% of time that hourly nodal > HOEP*	*Average price residual (nodal – HOEP)*	*% of time that hourly nodal > HOEP*	*Average price residual (nodal – HOEP)*
1	*Richview*	*Reference*[1]	85.70%	$37.61	42.90%	$1.68
2	*Atikokan*	*Northwest*	28.60%	$0.60	0.00%	-$13.50
3	*Pineportage*	*Northwest*	0.00%	-$69.79	57.10%	-$47.42
4	*Thunder Bay*	*Northwest*	0.00%	-$61.84	57.10%	-$45.75
5	*Andrews*	*Northeast*	14.30%	-$28.45	57.10%	$29.48
6	*Canyon*	*Northeast*	57.10%	$23.24	85.70%	$64.76
7	*NP Iroquois Falls*	*Northeast*	57.10%	$24.41	85.70%	$65.86
8	*TAOHSC*	*Ottawa*	100.00%	$43.69	71.40%	$4.17
9	*Saunders*	*East*	85.70%	$36.17	42.90%	$1.09
10	*Darlington*	*Toronto*	85.70%	$39.09	57.10%	$2.28
11	*Desjoachims*	*Essa*	85.70%	$29.36	28.60%	-$1.71
12	*Bruce B*	*Bruce*	85.70%	$34.75	57.10%	$0.51
13	*Nanticoke*	*Southwest*	85.70%	$36.03	42.90%	$1.03
14	*Beck 2*	*Niagara*	57.10%	-$1.91	57.10%	$2.28
15	*Lambton*	*West*	85.70%	$36.31	42.90%	$1.15
Northern Ontario Average (nodes 2-7)			26.18%	-$18.64	57.12%	$8.91
Eastern Ontario Average (nodes 8-9)			92.85%	$39.93	57.15%	$2.63
Southwestern Ontario Average (nodes 10-15)			80.93%	$28.94	47.62%	$0.92
Total Ontario Average (all nodes)			**60.94%**	**$11.95**	**52.37%**	**$4.39**

[1] The Richview Transformer Station in the Greater Toronto Area is the representative constrained price, or the single price that most accurately reflects the true supply conditions in Ontario at any point in time.
[2] Noon hour is from 12:00p.m. to 12:59p.m.
[3] Midnight hour is from 12:00a.m. to 12:59a.m.

The results for an analysis of the residual during the period of 10:00a.m. to 2:00p.m. in comparison with the period from 10:00p.m. to 2:00a.m. show a trend of positive residuals throughout the majority of southwestern zones as shown in Figure 1. An outlier exists for this portion of the graph at the Beck 2 representative nodal point in the Niagara zone.

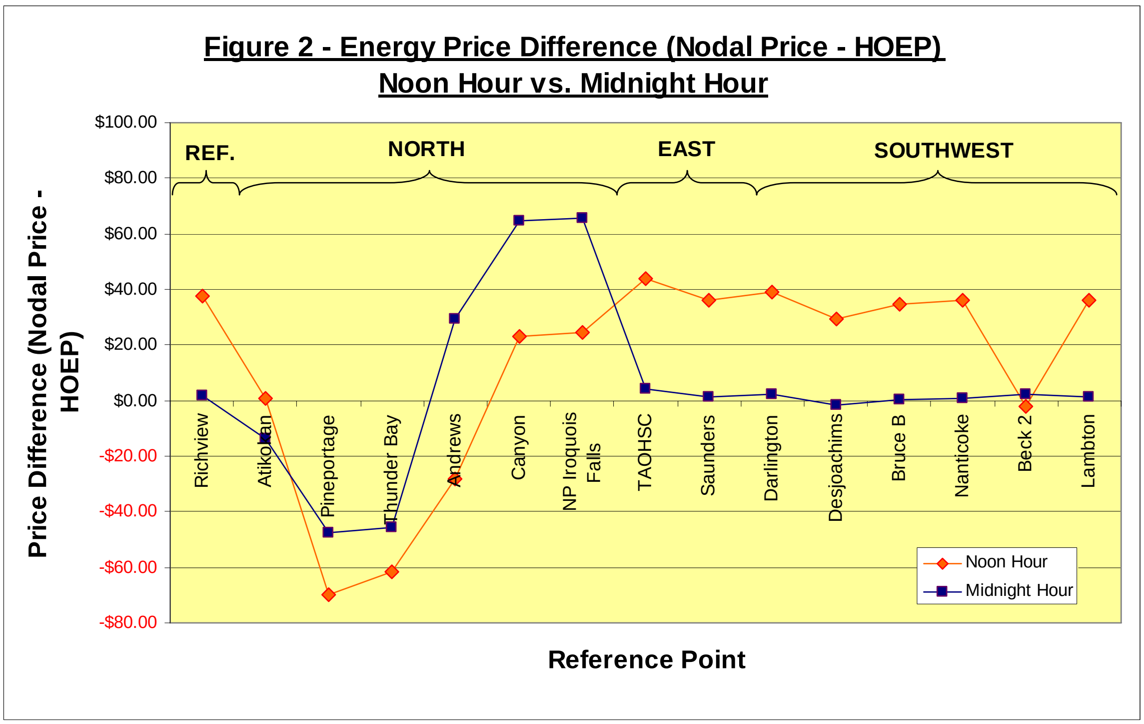


The results for an analysis of the residual during the noon hour in comparison with the midnight hour, also display a trend of positive residuals throughout the majority of southwestern zones as shown in Figure 2. An outlier exists for this portion of the graph at the Beck 2 representative nodal point in the Niagara zone.

Conclusions

Distributed generation sources, such as solar energy, hold more value in areas of high congestion when based on a pricing scheme that takes into account where the energy is produced versus a uniform pricing system such as HOEP. Nodal pricing, also known as locational marginal pricing (LMP), is an example of such a system of pricing that takes into account the location of energy production and is increasingly being used in electricity markets throughout North America and Europe. Placement of PV systems should be encouraged in areas of high congestion such as southwestern Ontario, in particular the GTA. This will help to maintain system reliability, alleviate transmission and distribution costs and offset future capital costs of expanding transmission infrastructure.

This study was limited by the use of only one representative node per zone in the Ontario market. Further study would be useful to more thoroughly analyze nodal price differences within zones and how this relates to peak solar radiation and demand. In a related but separate area of study, more research into storage options for PV energy would be useful when considering how energy generated during peak solar radiation times could be used at times of peak energy demand that occur outside of peak solar radiation times (for example, at supper time).



References:

Alderfer, R. Brent, M., Eldridge, M., and Starrs T. (2000). Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects. Retrieved on December 4, 2006 from www.eren.doe.gov/distributedpower/barriersreport/

California ISO (2006). Market Redesign and Technology Upgrade Locational Marginal Pricing (LMP) Study 3C: Analysis of Market-Based Price Differentials. Retrieved on December 16, 2006 from http://www.caiso.com/18ad/18ad911a544c0.pdf

Canadian Solar Industries Associations (CanSIA). (2005). Valuing Grid-Connected Solar Electricity: Priming the Market in Ontario._ Retrieved on September 20, 2006 from http://www.cansia.ca/downloads/report2005/C17.pdf

Dietrich, K., Hennemeier, U., Hetzel, S., Jeske, T., Leuthold, F., Rumiantseva, I., Rummel, H., Sommer, S., Sternberg, C., and Vith, C. (2005). Nodal Pricing in the German Electricity Sector – A Welfare Economics Analysis, with Particular Reference to Implementing Offshore Wind Capacities. Trends in German and European Electricity Working Papers. Retrieved on December 18, 2006 from http://www.tu-dresden.de/wwbwleeg/publications/wp_ge_08_dietrich_hennemeier_hetzel_et%20al_nodal_pricing_germany.pdf

Duke, R., Williams, R., and Payne, A. (2005). Accelerating residential PV expansion: Demand analysis for competitive electricity markets, *Energy Policy*, *33*, 1912-29. Retrieved November 26, 2006 from Scholar's Portal Web site: http://scholarsportal.info

IESO. (2006a). Locational Pricing Study. Retrieved April 13, 2007 from http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20061101-LMP-study.pdf

IESO. (2006b). 18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System (October 2006 to March 2008). Retrieved December 4, 2006 from http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2006sep.pdf

IESO. (2007a). 18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System (April 2007 to September 2008). Retrieved March 16, 2007 from http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2007mar.pdf

IESO. (2007b). Ontario Demand Peaks. Retrieved April 11, 2007 from http://www.ieso.ca/imoweb/media/md_peaks.asp

IMO Market Operations Standing Committee. (2003). Proposed Scope for Analysis of Historical Nodal Prices. Retrieved December 4, 2006 from http://www.ieso.ca/imoweb/pubs/consult/mktops/mo_pres_histnodalprices_2003dec03.ppt

Johnsen, T., Verma, S., & Wolfram, C. (1999). Zonal Pricing and Demand-side Bidding in the Norwegian Electricity Market. Retrieved April 11, 2007 from http://www.ucei.berkeley.edu/ucei/PDF/pwp063.pdf.

Marnay, C., Richey, R.C., Mahler, S.A., and Markel, R.J. Energy Analysis Program, Lawrence Berkeley National Laboratory. (1997). Estimating the environmental and economic effects of widespread residential PV adoption using GIS and NEMS', paper presented at the 1997 American Solar Energy Society Meeting, Washington, DC, May. Retrieved on December 4, 2006 from http://eande.lbl.gov/ea/EMS/reports/41030.pdf

Ontario Ministry of Energy. (2007). Transmission System Projects. Retrieved April 11, 2007 from http://www.energy.gov.on.ca/index.cfm?fuseaction=electricity.transmission_projects

Ontario Power Authority (OPA). (2006). Ontario's Integrated Power System Plan, Discussion Paper 5: Transmission. Retrieved January 3, 2007 from http://www.powerauthority.on.ca/ipsp/Storage/32/2716_DP5_Transmission.pdf

Ontario Power Authority (OPA). (2007). Questions and Answers on Bruce Transmission. Retrieved on March 16, 2007 from http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=4063&SiteNodeID=305&BL_ExpandID=

Rocky Mountain Institute. (2002). An Energy Resource Investment Strategy for the City of San Francisco, Scenario Analysis of Alternative Electric Resource Options. Retrieved on November 7, 2006 from http://www.rmi.org/images/other/Energy/E02-16_AnalysisForSF.pdf

Rowlands, I. (2004). Solar PV electricity and market characteristics: two Canadian case-studies, *Renewable Energy, 30*, 815-834. Retrieved November 14, 2006 from Scholar's Portal Web site: http://scholarsportal.info