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Quantification of high temporal and spatial scale GHG emissions from electricity generation: method and case study

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Abstract: *This paper presents a method to quantify greenhouse gas (GHG) emissions of an electrical grid user via generator data using hourly timesteps. This method allows energy modellers to more accurately calculate GHG emissions on an hourly basis. This is an improvement over current method that calculate on an annual basis which may lead to significantly different emission calculations for buildings with temporal electrical load variations. The proposed methodology is relevant for any mixed electrical grid and is demonstrated using Ontario data. A case study of a university building is utilized to show the difference between annual and hourly emission calculations. Furthermore, this paper discusses the use of a federal, provincial, and municipal geographic frame of reference when segmenting the electrical grid. The current case study demonstrates an increase in GHG emissions costs of 53% when comparing annual versus hourly methods at the provincial level.*

Introduction

The Government of Canada is moving forward with carbon pricing (Government of Canada, 2017). In 2015, Environment and Climate Change Canada (2017) reported that 11% of Canada's greenhouse gas (GHG) emissions came from the electricity sector, the fourth largest source. Historically, the electrical grid's carbon footprint has been calculated via an emission factor (EF) converting electricity use (GWh) into tonnes of carbon dioxide emissions equivalent (t CO_{2e}). For this paper, all GHG emissions will be presented in carbon dioxide equivalent (CO_{2e}). CO_{2e} is an equivalency measure of the amount of carbon dioxide needed to produce similar greenhouse effects from other sources (Government of Canada, 2017).

The United States Environmental Protection Agency (EPA) (2017) defines EFs as representative values that attempts to relate the quantity of a pollutant released into the atmosphere with an activity associated with the release of that pollutant. The electrical grid energy mix is the main source of information to dictate EFs. The Independent Electricity System Operator (IESO) reports that approximately 71% of Ontario electric generation infrastructure has zero GHG emissions sources. Much of generation in Ontario is from nuclear stations and hydro dams (Independent Electricity System Operator, 2017). The rest of the electricity generation is mostly from the combustion of fossil fuel which emits carbon dioxide (CO_2), water (H_2O), methane (CH_4), and nitrous oxide (N_2O) (Farhat & Ugursal, 2010) with a fraction from renewables such as solar and wind.

EFs have historically been calculated using two methods. The first, defined in Equation 1, is the average mass of GHG emissions (t CO_{2e}) from producing one unit of electricity (GWh) (Farhat & Ugursal, 2010). For instance, to calculate the EF (t CO2e/GWh) of a province, the values for emissions from generation (t CO2e/year) and electrical generation are those of within that province (GWh/year).

$$EF = \frac{GHG\ emissions\ from\ electricity\ generation}{Total\ electricity\ generation} \quad (1)$$

Equation 1 introduces some error into emission factors by neglecting transmission and distribution losses, neglecting supply differences from one province to another, and is an under-estimate of GHG emissions. The overall transmission and distribution losses for Ontario is estimated to be 6% (Farhat & Ugursal, 2010). The second method to calculate EFs, defined in Equation 2, Farhat & Ugursal (2010) considers GHG emissions from only fossil fuel power plants.

$$EF = \frac{GHG\ emissions\ from\ fossil\ fuel\ plants}{Total\ electricity\ generation\ from\ fossil\ power\ plants} \quad (2)$$

Equation 2 considers transmission and distribution losses but is an overestimate used often for electricity savings. Farhat and Ugursal (2010) note that the difference between methods can be substantial with the Ontario value from Equation 1 being 199 t CO_{2e}/ GWh and the value from Equation 2 being 862 t CO_{2e}/GWh for the period of 2004-2006.

Environment Canada utilizes a simplified emissions estimation method based on fuel consumption from the electricity generation sector (Gordon & Fung, 2009). Fuel-based methods only estimate an annual average, which does not properly represent the energy mix variation seen hourly in Ontario. Table 1 shows that an EF is released by Environment Canada each year (Environment Canada, 2016). Equation 3 is the currently accepted method of

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calculating CO_{2e} emissions from grid-purchased electricity where an EF is applied to the quantity of electricity consumed (Frommann & DiValentino, 2012; Brander, Sood, Wylie, Haughton, & Lovell, 2011; Environment and Climate Change Canada, 2017). Equation 3 is used to calculate the emissions based on the value of EF that is calculated using Equation 1.

Table 1: Yearly emission factor for Canada and select provinces (t CO_{2e}/ GWh)

Location	2010	2011	2012	2013	2014	2015
Canada	210	180	180	160	150	152
Ontario	140	100	100	80	40	43
Quebec	3.0	2.6	3.3	2.5	1.6	1.8
Manitoba	2.8	3.8	3.4	3.2	3.5	4

$$\text{CO2e Emissions (t CO2e)} = \text{Purchased Electricity (GWh)} \times \text{EF}\left(\frac{\text{t CO2e}}{\text{GWh}}\right) \quad (3)$$

The shortcoming with Environment Canada's method is that it does not consider the timing at which the electricity was consumed. In Ontario, the base load is met largely with nuclear and hydro power whereas the peak loads are mostly met with natural gas-fired powerplants. This translates to peak load times having higher EFs and higher costs. Using 1 kWh of electricity early morning when total market load is lowest is less carbon intensive than using 1 kWh of electricity in the afternoon when the province is most active. California's Energy Efficiency for Residential and Non-residential Buildings adopted time-dependent valuation (TDV) to promote the reduction of peak demand (MacCracken, 2006). The California Energy Commission states that the concept behind TDV is that energy efficiency measure savings should be valued differently depending on which hours of the year the savings occur, to better reflect the actual costs of energy to consumers, to the utility system, and to society (Price, Mahone, Schlag, & Suyeyasu, 2011). As of 2017, the Government of Canada does not utilize TDV. The implementation of TDV in California reported EFs on an hourly basis, however, it was implemented on a yearly basis ignoring daily, monthly, and seasonal variations. Most of California is in ASHRAE climate zone 3 (warm), whereas Ontario is in zone 6 (cold) and zone 7 (very cold) which can cause more of a seasonality discrepancy in EFs (National Renewable Energy Laboratoty, 2009) (ASHRAE, 2007). Similarly, Graff Zivin et al. (2014) developed a methodology which estimated the emissions of electrical demand across the United States and found substantial variations dependant on locations and times of day. Table 2 shows the large variance found in the study with some sample hour and locations (Graff Zivin, Kotchen, & Mansur, 2014). Figure 1 displays the regions defined by the North American Electric Reliability Corporation (NERC) (2017).

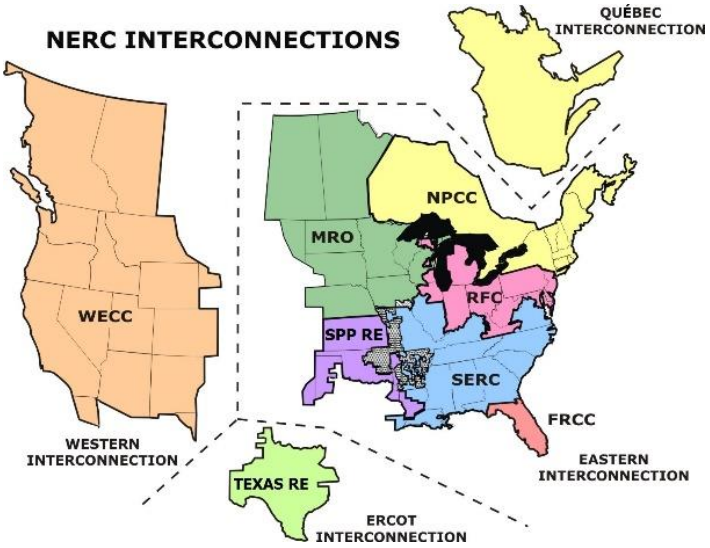

Figure 1: NERC interconnections map

Table 2: Hourly emission factors for USA (t CO2e/GWh)

Hour	NPCC	Eastern	Western	USA
12 AM	530	695	420	640
4 AM	730	735	400	680
8 AM	620	605	340	585
12 PM	760	635	440	600
4 PM	700	595	400	555
8 PM	555	590	405	545

With a lack of emission data on Ontario's generation stations, Gordon and Fung (2009) created a method to produce seasonal EFs with TDV to replace the annual method. Their results demonstrated a large difference between EFs throughout the year. They recommended that better accuracy could be reached by creating monthly EFs. The Canadian Energy Research Institute use dispatch models with 25 time-slices representing a peak demand period, and a reference day in each season split into six daily demand slices (Canadian Energy Research Institute, 2017). Moreover, optimal accuracy in emission calculations requires hourly precision as emission intensities of large-scale electrical grids change by the hour (Frommann & DiValentino, 2012).

This paper is intended to demonstrate the limitation of using EFs to audit an Ontario electricity user's carbon dioxide emission by comparing different methods used in the past and a proposed data-driven method utilizing public data available from the Independent Electricity System Operator (IESO). Previous methods are believed to not be

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representative due to simplifications in daily, monthly, and seasonal variability while also using too large of a frame of reference.

This paper lays out a methodology that reports an electric grid user's carbon footprint by using hourly generator data to calculate the local energy mix and applying it to the hourly electrical load. Furthermore, this paper demonstrates the large difference from a federal, provincial and municipal view of the problem. This new approach allows energy modellers to more accurately quantify GHG emissions using simulation results or measured energy use data.

Methodology

The methodology proposed to calculate an electrical user's carbon emissions will be completed with four frames of reference. These frames of reference were chosen to showcase the case study buildings' actual location and another municipal location which has a higher GHG intensive grid.

1. Federal: Canada
2. Provincial: Ontario
3. Municipal: Ottawa
4. Municipal: London

The federal frame of reference will be utilized as a reference case. In this instance, Equation 3 will be utilized using the 2015 EF from Table 1 to be processed through MATLAB (Environment Canada, 2016; Frommann & DiValentino, 2012). To compare the difference utilizing energy production with EFs versus utilizing lifecycle GHG intensity (t CO_{2e}/GWh) with Energy Mix (EM) model and the by-the-hour model, Equation 4 is processed through MATLAB to calculate EM models. The annual energy mix model is implemented on a yearly basis, thus ignoring hourly variances, with *j* representing the various generator types (i.e. solar, wind, hydro, etc.).

$$CO2e\ Emissions = \sum_{j=1}^{N} Building\ Load \times Percentage\ of\ Energy\ Mix(j) \times Lifecycle\ GHG\ Intensity(j) \quad (4)$$

For the provincial models, IESO's generator energy output and capability data was used. This data was utilized to present the energy output of all 159 generating facilities with a minimum output capability of 20 MW or more in Ontario. The generators were separated into the following categories; solar, wind, biofuel, natural gas, hydro, nuclear, and coal.

For the municipal models, IESO's Zonal Map data was used, which segments Ontario into 10 local regions: Bruce, East, Essa, Niagara, Northeast, Northwest, Ottawa, Southwest, Toronto, and West. Figure 2 shows the physical boundaries of these sections. Table 3 gives general information on these regions out of province connections and resources from the IESO. There are five additional sections created to simulate the import and export of electricity from Ontario to surrounding regions: Manitoba, Michigan, Minnesota, New York, and Québec.

Table 3: General information of Ontario's electrical zones

Zone	Import/Export Connections	Ratio of Peak Supply to Peak Demand
Bruce	n/a	Much higher than peak demand
East	Québec and New York	Exceed peak demand
Essa	n/a	Much less than peak demand
Niagara	New York	Much higher than peak demand
Northeast	Québec	Exceeds peak demand
Northwest	Manitoba and Minnesota	Generally, exceeds peak demand
Ottawa	Québec	Much less than peak demand
Southwest	n/a	Generally, balanced with peak demand
Toronto	n/a	Less than peak demand
West	Michigan	Generally, exceeds peak demand

Using the data provided and the map shown in Figure 2, a model was created separating each region into nodes with a sink representing the areas demand and multiple sources representing the various generators in the area (Independant Electricity System Operator, 2017). Several assumptions were made to reconcile the energy accounting. First, each node answers its demand if possible with the generators within their area. Second, any excess or deficit energy from a node is then transformed into their export or needed import. Once electricity is generated we do not have data on its exact path and ultimately which load it serves.

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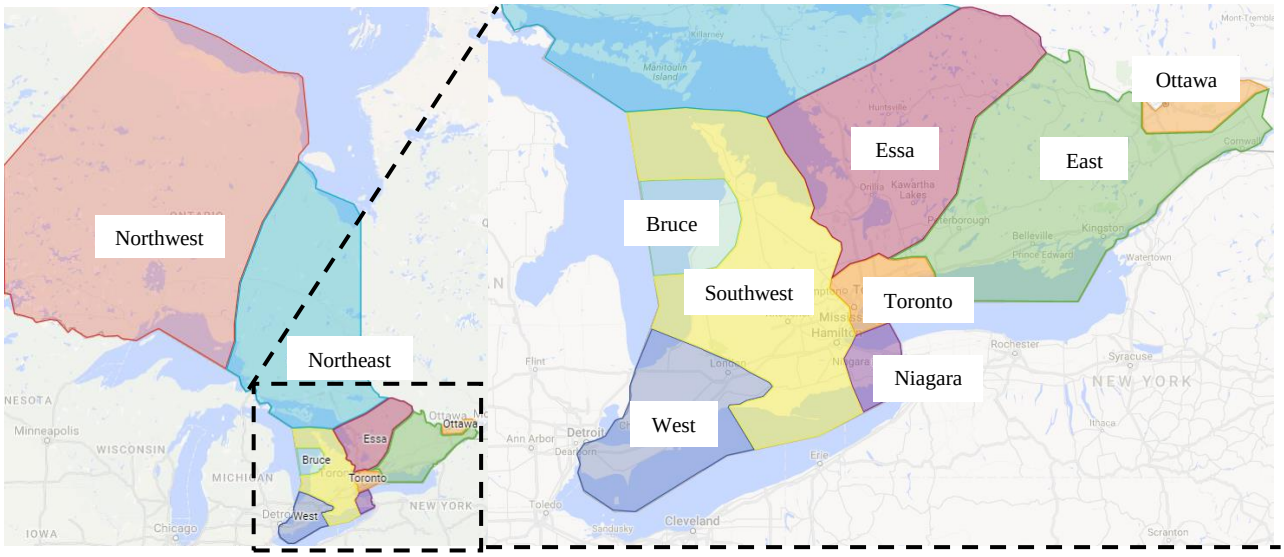

Figure 2: Physical boundaries of Ontario's electrical zones

Thus, thirdly, due to the uncertainty of which generator serves which load, a modelling assumption was made where the local load is met in the following order of technologies:

1. Solar
2. Wind
3. Biofuel
4. Natural Gas
5. Hydro
6. Nuclear
7. Coal

The order that the load is met uses renewables first due to their intermittent nature and to reward jurisdictions that have invested in these technologies, whereas, hydro and nuclear generators are utilized towards the end of the list as they typically meet Ontario's base load. Furthermore, coal is used last as it is only seen in minimal amounts from imports. The implications of this order is discussed in the Results section of the case study.

Due to discrepancies in sources and sinks due to system losses and embedded generation, an additional node was added to balance the system. The balance node was added as a bidirectional connection with the Bruce node to isolate it from the whole system as Bruce does not import and only exports to the Southwest node. Furthermore, the balance node is assumed to only import or export nuclear energy to simplify the model. The balance node represents on average 1% of the Ontario demand. The final directional nodal model can be seen in Figure 3 where the blue nodes represent the local zones of Ontario whereas the white nodes represent the out-of-province zones; finally, the grey node represents the balance node.

The hour-the-hour model creates an energy mix percentage from the Generator Output and Capability data from the IESO. For imports, Table 4 and Table 5 provide the energy mix for neighbouring Canadian Provinces and U.S. States (U.S. Energy Information Administration, 2017; Independent Electricity System Operator, 2017; Natural Resources Canada, 2017). Table 4 is also used for the EM models at the federal and provincial frame of reference.

For each kWh of electricity produced from a certain technology, a lifecycle GHG EF will be applied. The lifecycle GHG EF used for all nodes comes from Mallia and Lewis' 2013 study from Ontario and shown in Table 6.

A linear program solver calculates the energy trading between nodes. MATLAB is used for its linear program solving abilities. MATLAB's built-in function of linprog solves Equation 5 with a dual-simplex algorithm where *f*, *x*, *b*, *beq* are vectors, and *A* and *Aeq* are matrices (The MathWorks, Inc., 2017).

$$\min f^{T} x : A * x \leq b \, , Aeq * x = beq \qquad (5)$$

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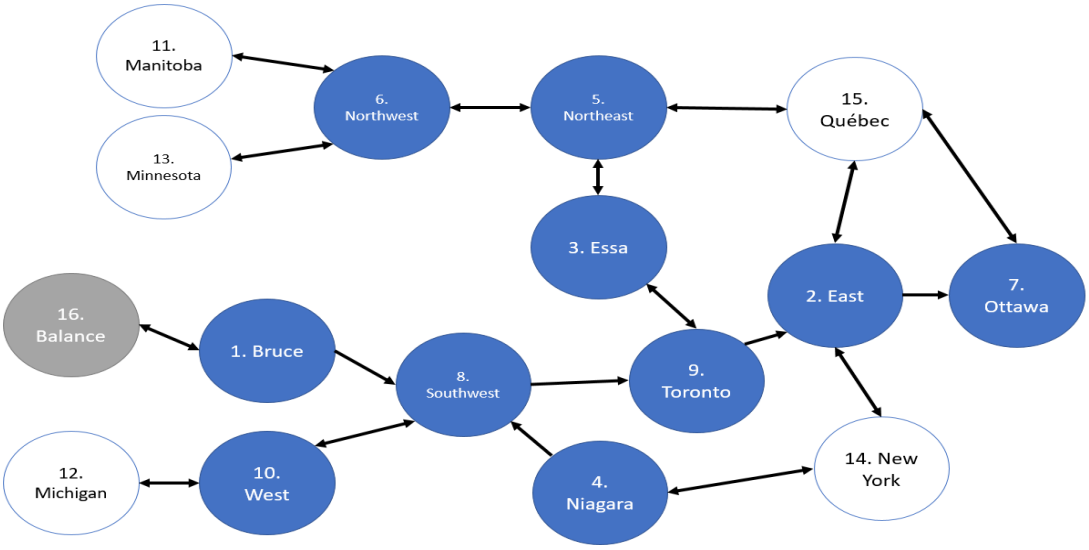

Figure 3: Nodal system of Ontario's grid

Table 4: Energy mix of Canadian provinces in 2014

Location	Natural Gas	Coal	Nuclear	Hydro	Non-hydro Renewables
Canada	10.2%	9.5%	15.9%	59.3%	5.1%
Ontario	10%	n/a	60%	24%	6%
Quebec	n/a	n/a	n/a	97%	3%
Manitoba	n/a	n/a	n/a	98%	2%

Table 5: Energy mix of U.S. states in 2017

Location	Natural Gas	Coal	Nuclear	Hydro	Non-hydro Renewables
Michigan	21%	42%	28%	2%	7%
Minnesota	12%	38%	22%	2%	26%
New York	36%	1%	33%	25%	5%

Table 6: Ontario electricity generator's life cycle GHG emissions in 2008

Type of Generation	Lifecycle GHG Intensity ($t CO_{2e}$/GWh)
Coal	1,069
Natural Gas	497
Hydro	22
Wind	11
Nuclear	5

For simplification, we solve two different linear programs to estimate the amount of energy from each technology is being transferred between nodes. The first linear program is a simplification in the model where we want to know how much energy is being moved from one node to another and drop the knowledge from what source it is coming from. Except for four node interconnections, all other interconnections are bidirectional giving us a total of 32 connections where energy can be transferred between nodes. Therefore, *f* is a 1x32 vector of ones, *b* is a 32x1 vector of zeros, and *A* is a negative identity matrix of 32x32 to put the restrictions of no negative flows. Equation 6 is the balance node notation to create the equality constraints for Equation 7. For the *Aeq* 16x32 matrix, each node is balanced using the connections as shown in Figure 3 where a 1 represents outbound from the node and -1 represents incoming into the node.

Once solved, the second linear program, considering the seven sources of energy, are set up using the *x* vector of the previous linear program, Equations 8 through 10. Similarly, to the previous problem, *f* is a 1x329 vector of ones, *b* is a 329x1 vector of zeros, and *A* is a negative 329x329 identity matrix of to put the restrictions of no negative flows. The *Aeq* in this case is a 152x329 matrix where each node is balanced using the connections as shown in Figure 3 split into seven lines to represent each technology source. Therefore, Equation 11 demonstrates the equality constraint of the linear program. Once the linear program is solved for all timesteps, Equation 12 is used to calculate the total GHG emissions of the by-the-hour energy mix model where *i* represents the hourly timestep and *j* represents the generator type (e.g., solar, wind, hydro, etc.).

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$$Node\ Generation - Node\ Demand = \sum Export\ Connections - \sum Import\ Connections \tag{6}$$

$$Aeq * x = beq \ \rightarrow$$

$$\begin{bmatrix} 1 & 1 & \cdots & 0 & -1 \\ 0 & 0 & \cdots & 0 & 0 \\ \vdots & \vdots & \ddots & \vdots & \vdots \\ 0 & 0 & \cdots & 1 & 0 \\ 0 & -1 & \cdots & 0 & 1 \end{bmatrix} * \begin{bmatrix} x_{1-8} \\ x_{1-16} \\ \vdots \\ x_{15-7} \\ x_{16-1} \end{bmatrix} = \begin{bmatrix} Bruce\ Generation - Bruce\ Demand \\ East\ Generation - East\ Demand \\ \vdots \\ Quebec\ Export - Quebec\ Import \\ \sum_{Node=1}^{15} beq(1, Node) * -1 \end{bmatrix} \tag{7}$$

$$x_{a-b} = Solar_{a-b} + Wind_{a-b} + Biofuel_{a-b} + Natural\ Gas_{a-b} + Hydro_{a-b} + Nuclear_{a-b} + Coal_{a-b} \tag{8}$$

$$\begin{aligned} Node\ Technology\ j\ Export \\ = Node\ Technology\ j\ Import + \sum Export\ Technology\ j\ Connections \\ - \sum Import\ Technology\ j\ Connections \end{aligned} \tag{9}$$

$$Node\ Import = \sum_{j=1}^{7} Node\ Technology\ j\ Import \tag{10}$$

$$Aeq * x = beq \ \rightarrow$$

$$\begin{bmatrix} 0 & 0 & \cdots & 0 & 0 \\ 0 & 0 & \cdots & 0 & 0 \\ \vdots & \vdots & \ddots & \vdots & \vdots \\ 0 & 0 & \cdots & 0 & 0 \\ 0 & 0 & \cdots & 0 & 0 \end{bmatrix} * \begin{bmatrix} Bruce\ Solar\ Import \\ Bruce\ Wind\ Import \\ \vdots \\ Québec\ Nuclear\ Import \\ Québec\ Coal\ Import \\ Solar_{1-8} \\ Wind_{1-8} \\ \vdots \\ Nuclear_{16-1} \\ Coal_{16-1} \end{bmatrix} = \begin{bmatrix} x_{1-8} \\ x_{1-16} \\ \vdots \\ x_{15-7} \\ x_{16-1} \\ Bruce\ Solar\ Export \\ Bruce\ Wind\ Export \\ \vdots \\ Québec\ Nuclear\ Export \\ Québec\ Coal\ Export \\ Bruce\ Import \\ East\ Import \\ \vdots \\ New\ York\ Import \\ Québec\ Import \end{bmatrix} \tag{11}$$

$$CO2e\ Emissions = \sum_{i=1}^{8760} \sum_{j=1}^{7} Load(i) \times Percentage\ of\ Energy\ Mix(i)(j) \times Lifecycle\ GHG\ Intensity(j) \tag{12}$$

Electrical load data of Richcraft Hall (formerly River Building) from the Carleton University's campus was used to demonstrate the proposed methodology (Carleton University, 2017). Similarly, building performance simulation could be used. This building was chosen due to its large energy swings as seen in its yearly load profile (Figure 4) with an August peak hourly demand of 1,012 kWh and average hourly demand of 310 kWh. Figure 5 shows the average daily load profile of Richcraft Hall which will help demonstrate how daily variances can cause differences between a flat yearly EF and the by-the-hour model (HOMER Pro Microgrid Analysis Tool x64 3.8.5, 2017). Figure 6 shows seasonal variance in the building which follows Ontario's summer peak.

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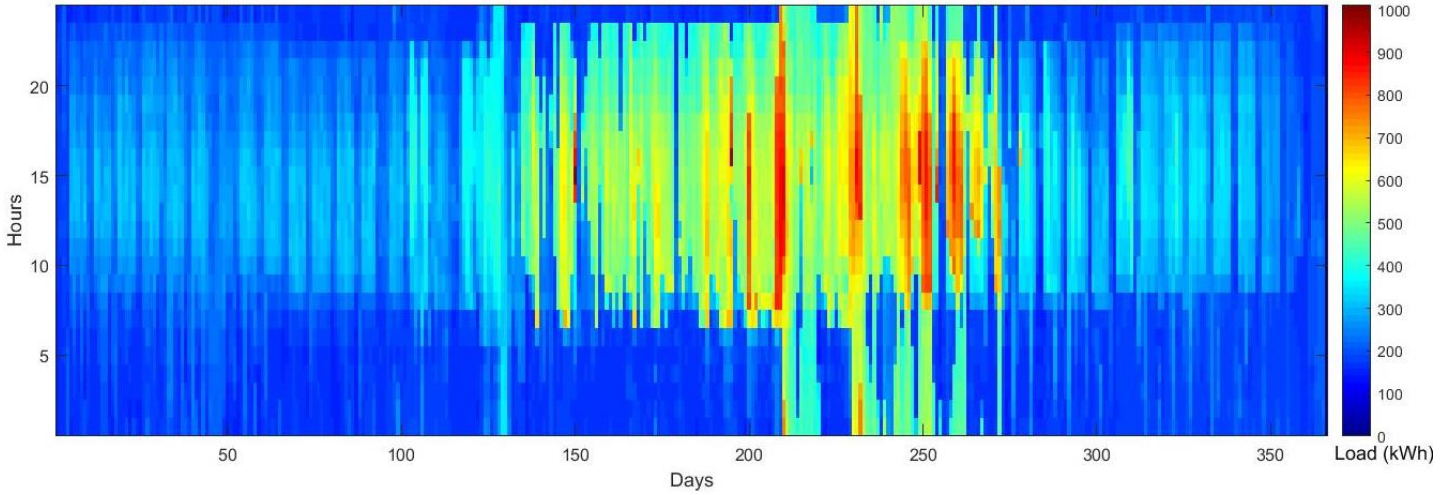

Figure 4: Richcraft Hall yearly load profile heat map

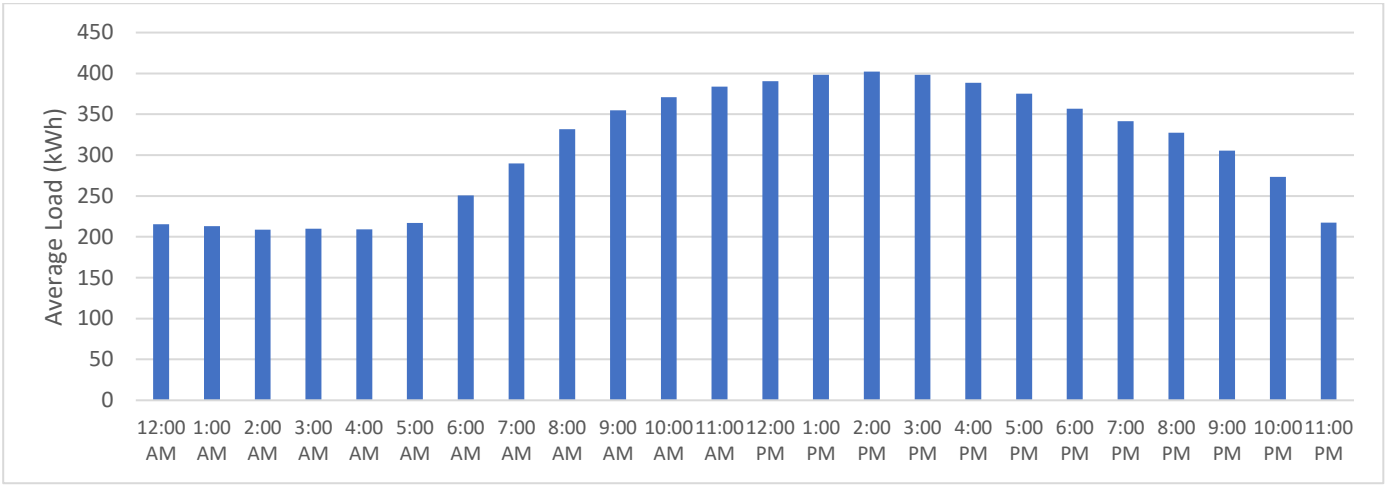

Figure 5: Average annual daily profile of Richcraft Hall

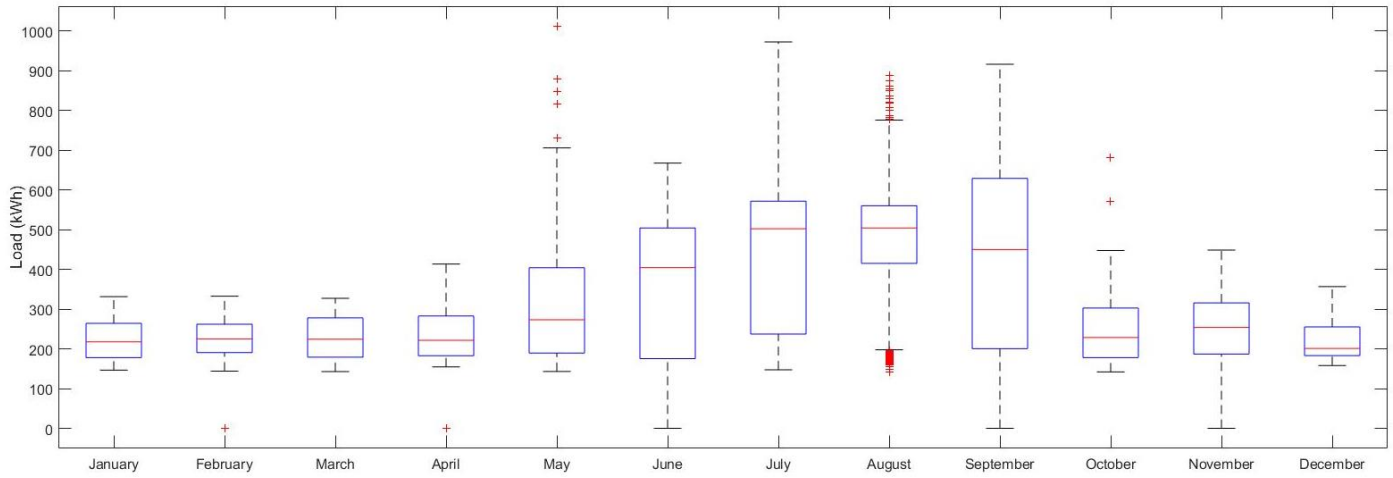

Figure 6: Average monthly profile of Richcraft Hall

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The electrical load used in this paper comes from a submeter of a real-world building, however, any hourly electrical load data from a building simulation could be used.

Results and Discussion

Figure 7 demonstrates the results of the amount of CO_{2e} emitted by the Richcraft Building's electrical load using EF (Equation 3), EM (Equation 4), and by-the-hour model (Equation 12) in our four frames of reference of Canada, Ontario, Ottawa, and London.

We reduce the case study to economic factors to give a sense of scale to the issue for ease of comprehension. To relate this to monetary values, we assume the Government of Canada imposes the 2022 proposed carbon pricing of $50/t CO_{2e} (Government of Canada, 2017). IESO's average electrical pricing data for 2015 from Table 7 was used to calculate the potential yearly bill seen for these buildings loads (Independent Electricity System Operator, 2017). It is approximated that Richcraft Hall had a yearly electrical bill of $284,000 in 2015. Table 8 shows the economic results of the simulation.

Table 7: Ontario average electricity price in 2015

	Average Price in 2015 (cents/kWh)
Hourly Ontario Energy Price (HOEP)	2.36
Global Adjustment (GA)	8.11
Total Price	10.47

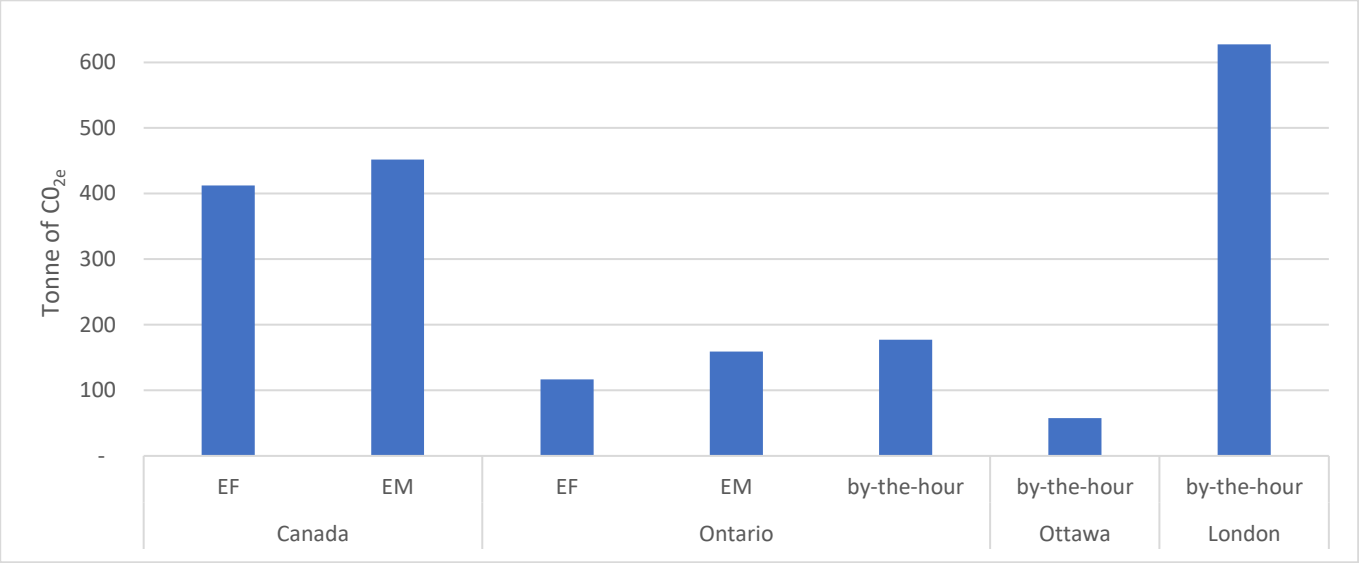

Figure 7: Bar graph of simulation results

Table 8: GHG costs depending on model

Frame of Reference	**Carbon Model**	**Approximate Carbon Cost**	**% Increase on Electricity Cost**
Canada	EF	$20,600	7.25%
	EM	$22,600	7.96%
Ontario	EF	$5,800	2.04%
	EM	$8,000	2.82%
	By-the-hour	$8,900	3.13%
Ottawa	By-the-hour	$2,900	1.02%
London	By-the-hour	$31,400	11.06%

Table 9: GHG sensitivity based on model assumptions

Tonne of CO2e	**Ontario**	**Ottawa**	**London**
Max Value	183.36	183.80	695.49
Min Value	164.08	56.59	627.66
Median	174.42	111.74	661.58

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As shown in Table 8, the EF method estimates a much lower carbon cost than the EM and by-the-hour method. Furthermore, the two-municipal frame of reference shows that there is a large difference dependant on the location of the load. Looking at the Ontario model, there is an increase of 53% in costs when comparing a flat EF model to the proposed By-the-hour model.

The major assumption in modeling the municipal frame of references is the order of technologies in which the local load is met. To verify the sensitivity of these models, the methodology was applied to all 720 possible orders. As shown in Table 9, the model set in Ontario is the least sensitive followed by the model set in London, leaving the model set in Ottawa as the most sensitive. The model applied to the London location is unique as it results in only two different values throughout all 720 iterations. The model set in Ottawa is most sensitive due to its nature as a net importer therefore its load is met from exports of other nodes. Note that the model set in Ottawa may be the most sensitive, however, its maximum value equals the broader model set in Ontario whereas the model set in London always reaches higher GHG emissions than the model set in Ontario. The by-the-hour carbon model only works with hourly and sub hourly results.

Conclusion

The methodology to derive more accurate and higher resolution estimates of GHG emissions associated with electricity use is useful for government, utilities, building owners, and researchers to quantify the real carbon content of electricity use. The by-the-hour methodology would be relevant to any region with mixed electrical generation as seen in the province of Ontario and irrelevant in homogeneous generation areas such as the province of Québec. The case study found that in an Ontario frame of reference, Environment Canada's EF method underestimated the carbon cost of a building by $3,100 compared to the by-the-hour method proposed in this paper. Furthermore, it was found that the sub regions of Ontario can create a large discrepancy in carbon cost showing that if the building was in London, Ontario it would have a carbon cost of $31,400 whereas the same building in Ottawa would have a carbon cost of $2,900. Using this methodology, real opportunity for district energy systems to utilize energy storage arises to lower demand during system wide peaks. This paper presents that location and hourly data of an electrical load is important in calculating the end user's emissions. It should be noted that because Ottawa has the lowest emissions of the municipal regions, this does not mean that we should ignore efficiency measures in this zone as it affects the province. Decarbonization of electricity generation and reducing building peak energy demand are both need to lower overall GHG. It is unclear whether hourly data offer the best results and the content of this paper should be utilized as a reference for comparing the various carbon models. This approach can be translated into policy at the provincial and municipal levels of government. Future work to refine the model may involve applying generator-specific GHG intensity, consideration of generator available capacity, consideration of electrical pricing, consideration of grid losses, consideration of grid line capacity, and consideration of heating loads.

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