Marginal Greenhouse Gas Emission Factors for Ontario

Electricity Generation and Consumption

Prepared for:

Enbridge Gas Inc.

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Executive Summary

Broadly, the objective of climate change policy for energy use is to reduce the amount of greenhouse gas emissions produced while meeting the energy need of the consumer. Greenhouse gas emission factors indicate the volume of emissions attributable to a unit of energy use or activity. Two types of emission factors, namely Average Emission Factors (AEFs) and Marginal Emission Factors (MEFs), are used to evaluate the impact of various technologies, policies and program.

Use of the appropriate type of emission factors is essential. Using AEFs to assess policy or programs in the electricity sector can produce misleading results because AEFs do not consider the time-dependant impacts of electricity generation and consumption; MEFs are better suited for this purpose. When assessing policy and program, it is important to understand the relationship between fuel consumption, electricity generation and electricity consumption on an hourly, daily and seasonal basis. A misinterpretation of these factors could lead to unintended consequences that could result in a net increase in GHG emissions. For example, electrification of space heating increases electricity consumption during peak demand periods when MEFs could be much higher than AEFs – an important factor in evaluating net GHG emission impacts.

This report documents Power Advisory's estimates of MEFs for electricity generation and consumption for Ontario. The objective of this report is to provide Ontario stakeholders with an overview of Power Advisory's marginal emissions factor methodology and guidelines for their use. Ultimately, the goal of the report is to provide clarity and confidence for use when assessing activities that could reduce greenhouse gas emissions in Ontario.

Power Advisory's marginal emission factor estimates are based on the relationship between Ontario demand; gas-fired generation; energy production from all sources of generations; and imports & exports with neighbouring jurisdictions. Most of Ontario's generation (i.e., nuclear, hydro, wind, solar and bioenergy) has no emissions; therefore, emissions due to Ontario's electricity system come from two main sources:

- Natural gas-fired generators in Ontario
- Emissions associated with electricity imports.

The MEFs account for emissions from both gas-fired generation located in Ontario and imports from neighbouring jurisdictions, including how these inputs will change over time due to refurbishment of nuclear fleet and shutting down of Pickering nuclear station.

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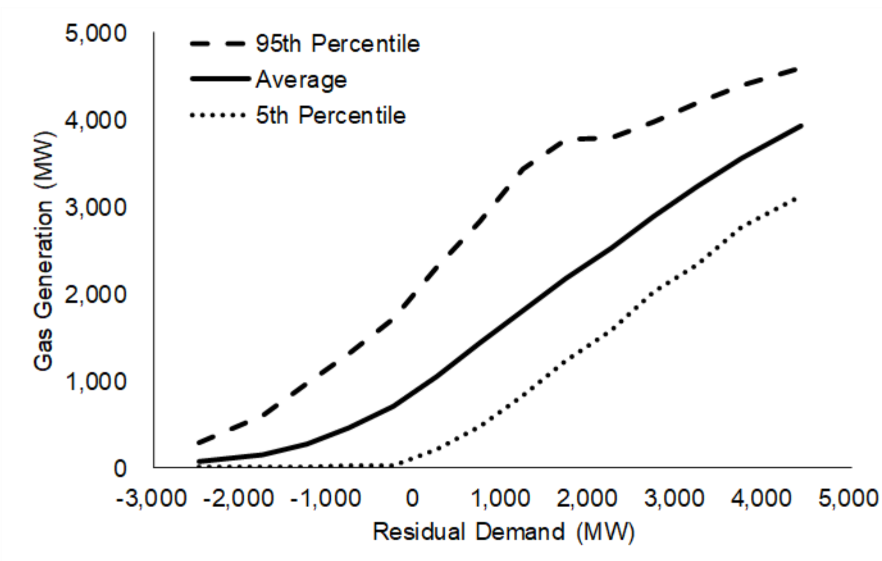
The process for estimating emission factors involved several steps:

1. Forecast demand and less flexible generation (nuclear, some hydroelectric, wind, solar and bioenergy) for each hour in the forecast period and calculate the difference between the two, which is referred to as Residual Demand
2. Quantify the relationship between Residual Demand and Fossil Generation & Net Imports (i.e., gas-fired generation)
3. For each hour of the forecast period, estimate the impact that a 1-MWh change in Residual Demand would have on Fossil Generation, Net Imports, and GHG emissions

The results of the analysis produce the following relationship between Residual Demand and Fossil generation in Ontario (see figure below). Change in Residual Demand in each hour results in a change of Fossil Generation. The difference in Fossil Generation between the initial and final Residual Demand for a given hour is the net impact on greenhouse gas emissions.



Hourly Fossil Generation vs. Residual Demand, base years 2015-2019

Ontario's fleet of large gas generators is estimated to have a GHG emission factor of 0.412 tonnes/MWh. The MEF varies between 0 and 0.412 tonnes/MWh, depending upon the above correlation. Power Advisory forecasted MEFs for every hour from 2020 – 2040. Contact information to get this data file is available at the end of this report. The MEFs are also summarized by both season and time-of-use period for the forecasted period of 2020 – 2040. The overall MEF for all 20 years is projected to be 0.32 tonnes/MWh.

Overall, Power Advisory hopes this report and the marginal emission factor estimates will assist stakeholders in determining the optimal strategy for reduce greenhouse gas emissions.

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Table of Contents

1. Introduction 1
1.1 The Importance and Use of Marginal Emission Factors 1
1.2 Ontario's Electricity System and Outlook 2
2. Methodology 4
2.1 Overview 4
2.2 Step 1: Residual Demand 5
2.3 Step 2: Relationship Between Residual Demand and Gas Generation 6
2.4 Step 3: Forecast Gas Generation, Net Imports and GHG Emissions 8
2.5 Other Methodologies for Estimating Marginal Emission Factors 11
3. Marginal Emission Factor Estimates and Applications 13
3.1 Mean Marginal Emission Factors 13
3.2 How Marginal Emission Factors Are Being Used 15
3.2.1 Example: Combined Heat and Power for a New High-Rise Building 15
4. Guidelines for Using Marginal Emission Factors 18

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1. INTRODUCTION

1.1 The Importance and Use of Marginal Emission Factors

There is a growing global consensus for the reduction of greenhouse gas (GHG) emission to combat the negative impacts of climate change. Many measures have been proposed to reduce GHG emissions. For example, replacing incandescent light bulbs with high-efficiency Light Emitting Diodes (LEDs), reduces the use of electricity and the emissions associated with generating that electricity. On the other hand, replacing cars powered by conventional gasoline engines with plug-in electric vehicles (PEVs) increases the use of electricity (and the emissions associated with generating electricity). However, net emissions may decrease if the reduction of emissions from gasoline engines is greater than the increase in emission from greater electricity production. It is important to understand the relationship between fuel consumption, electricity generation and electricity consumption on an hourly, daily and seasonal basis. A misinterpretation of these factors could lead to unintended consequences that could result in a net increase in GHG emissions.

Greenhouse gas emission factors indicate the amount of emissions attributable to a unit of energy use or activity. Two types of emission factors are commonly used:

- **Average Emission Factors** (AEFs) are the ratio of all emissions resulting from a certain activity (e.g., transportation, or electricity consumption) to some measure of that activity (e.g., kilometers travelled, or MWh consumed). The primary use of Average Emission Factors is to develop inventories of GHG emissions – i.e., total emissions and where they come from.

- **Marginal Emission Factors** (MEFs), which are the subject of this report, are used to evaluate specific policies or programs. MEFs are the ratio of the increase or decrease in GHG emissions resulting from a unit change. An example would be the net change in emissions from driving one kilometer in a PEV instead of a gasoline-powered vehicle.

Use of the appropriate type of GHG emission factors is essential. Using AEFs to assess policy or programs can produce misleading results because AEFs do not consider the time-dependant impacts of electricity generation and consumption; MEFs are better suited for this purpose. When assessing policy and program, it is important to consider time of use. For example, electrification of space heating increases electricity consumption during peak demand periods when MEFs could be much higher than AEFs – an important factor in evaluating net GHG emission impacts.

This report documents Power Advisory's estimates of MEFs for electricity generation and consumption. The emission estimates are intended for use in evaluating programs, policies and other activities that depend, partially or fully, on electricity supplied from the Ontario electricity grid. The emission factor analysis and this report were developed by Power Advisory under an engagement with Enbridge Gas Inc. The analysis and report reflect Power Advisory's independent views and extensive knowledge of the Ontario electricity sector.

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1.2 Ontario's Electricity System and Outlook

Ontario's bulk electricity system and electricity market are operated by the Independent Electricity System Operator (IESO). The IESO-Administered Market (IAM) supplies Ontario consumers with approximately 135 TWh of electricity through the transmission system; a further 6 TWh/year is generated by embedded generation (i.e., distributed generation delivered to consumers through local distribution systems). Ontario's electricity generation output by fuel type for 2019 is shown in Figure 1 and electricity generation by installed capacity in Figure 2.

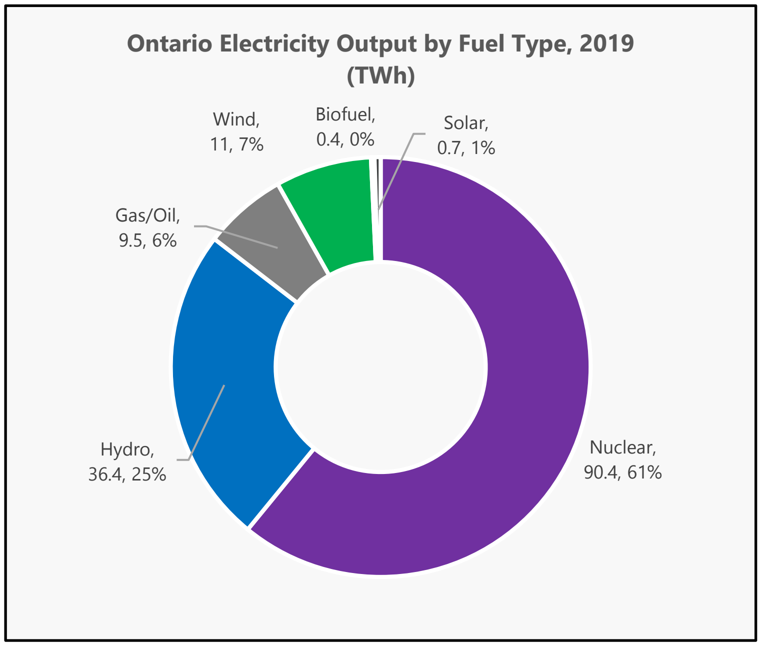

Figure 1: Ontario 2019 Electricity Output by Fuel Type (TWh)[1]

More than half of Ontario's electricity supply comes from three nuclear stations: Pickering, Darlington and Bruce Power. In addition, there has been a surplus of supply in Ontario over most of the past decade. Supply surplus results in reduced usage of gas-fired generation assets that are commonly used to meet peaking demand needs.

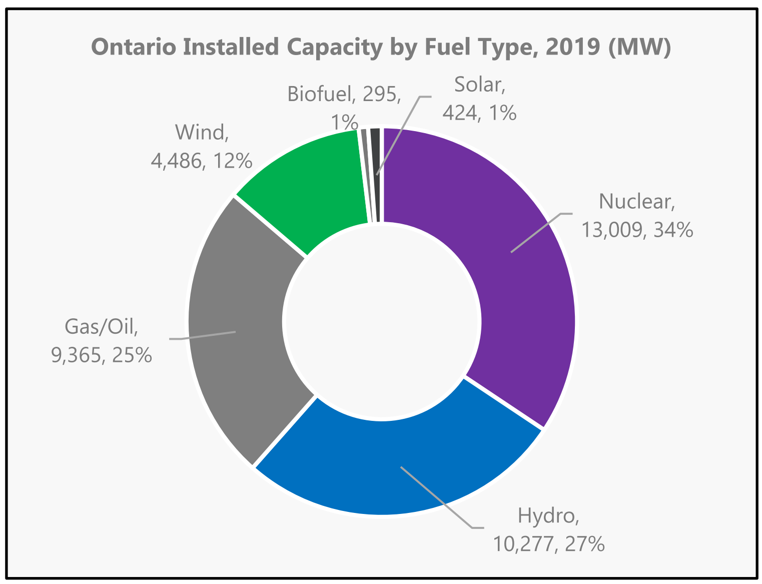

Figure 2: Ontario 2019 Installed Capacity by Fuel Type (MW)[1]

Ontario's electricity supply mix is expected to change over the next two decades. The Pickering Nuclear Station is scheduled to retire at the end of 2025 and 10 nuclear generation units at Bruce Power and Darlington will be taken out of service for refurbishment[1]. Each unit will be out of service for up to 4 years and as many as four units may be out at one time. During the refurbishment, gas-fired generation will operate more often to replace energy from the out-of-service nuclear units. Figure 3 below shows Power Advisory's forecast of Ontario supply and demand.

[1] Information on the refurbishment projects can be found for Darlington at https://www.opg.com/strengthening-the-economy/our-projects/darlington-refurbishment/, and for Bruce at https://www.brucepower.com/life-extension-program-mcr-project/ .

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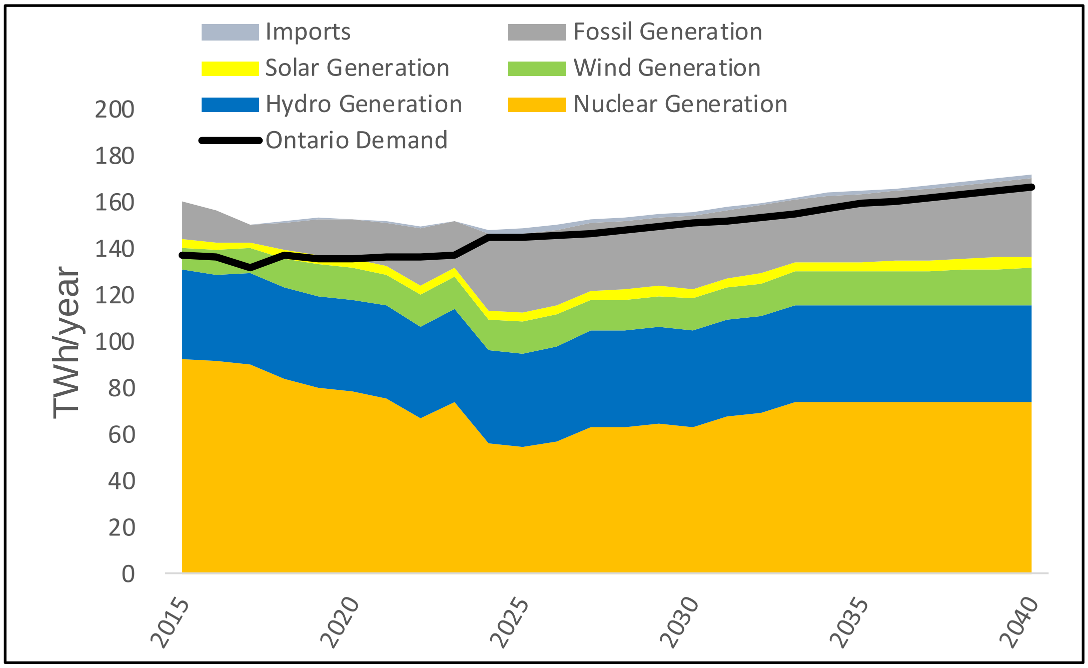

Figure 3: Ontario Electric Energy Supply and Demand

Most of Ontario's generation (i.e., nuclear, hydro, wind, solar and bioenergy) has no emissions; therefore, emissions due to Ontario's electricity system come from two main sources:

- Natural gas-fired generators in Ontario
- Emissions associated with electricity imports.

Natural gas-fired generation currently supplies only a moderate share (around 12%) of Ontario's electric energy, but it plays a crucial role in balancing supply and demand. For example, when the IESO schedules supply for dispatch to meet forecasted demand they must ensure that there is enough generation that can ramp (i.e., increase or decrease output) fast enough to follow variations in electricity consumption patterns. In Ontario, ramping primarily comes from gas-fired generation and hydroelectric generation.

Ontario's electricity grid is well interconnected with neighbouring jurisdictions across 26 interties to two provinces (i.e., Manitoba and Quebec) and three states (i.e., Minnesota, Michigan and New York). Ontario schedules imports and exports on an hourly basis. Depending on the source of imports they can be considered to increase Ontario's GHG emissions.

The MEFs developed by Power Advisory account for emissions from both gas-fired generation located in Ontario and imports from neighbouring jurisdictions, including how these inputs will change over time.

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2. METHODOLOGY

2.1 Overview

GHG emissions in Ontario's electricity system come from two main sources: gas-fired generators in Ontario, and emissions associated with electricity imports from other jurisdictions. In general, both tend to be high when demand is high or less flexible generation[2] is low, and both tend to be low when demand is low or less flexible generation is high. The relationship is not exact: hours with very similar demand and supply of less flexible generation can see very different amounts of both gas-fired generation and imports. These differences are due to a number of factors:

- Gas-fired generation attributes (e.g., ramp rate) and maintenance schedules (e.g., planned outages);
- The availability and price of imports; and
- The availability of export opportunities (e.g., gas-fired generation output exported to higher price neighbouring jurisdictions in a given hour).

Power Advisory's MEF estimates are based on quantifying and extrapolating these patterns. The process for estimating emission factors involved several steps:

1. Forecast demand and less flexible generation for each hour in the forecast period and calculate the difference between the two, which is referred to as Residual Demand[3]
2. Quantify the relationship between Residual Demand and Gas Generation[4]
3. For each hour of the forecast period, estimate the impact that a 1-MW change in Residual Demand would have on Gas Generation, Net Imports[5], and GHG emissions

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[2] Less flexible generation is defined as the sum of transmission-connected nuclear, hydroelectric, wind, solar and bioenergy projects; it also excludes embedded generation. A case could be made for distinguishing between baseload and peaking hydro, treating the latter separately rather than including it in less flexible generation. However, as discussed in a footnote 11 below, this would not significantly affect the results.

[3] For the purposes of this report, "**Residual Demand**" is defined as Ontario electricity demand minus less flexible generation. All amounts are hourly, and historical values are based on data published by the IESO. Ontario Demand is reported in the IESO's Ontario and Market Demand reports. Hourly generation for almost all of Ontario's transmission-connected generators is reported in the IESO's Generator Capability and Output reports. Both sets of reports are available at http://ieso.ca/en/Power-Data/Data-Directory in the "Featured Reports" section.

[4] Fossil Generation is defined as transmission-connected generation using natural gas, oil or coal as fuel.

[5] Net Imports is imports into Ontario minus exports out of Ontario. In many hours it is negative (i.e., exports exceed imports).

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The following sections describe each step in more detail. The resulting hourly MEFs can either be summarized by hour of the day, season, time-of-use period, etc., or used as is for more detailed analysis.

2.2 Step 1: Residual Demand

Residual Demand represents the imbalance between Ontario's need for electricity (at the transmission level) and what is available from its own nuclear, hydro, wind, solar and bioenergy generators. This imbalance can come from only two sources: Gas Generation and Net Imports. In many hours, Residual Demand is negative, meaning that even if there were no Gas Generation in that hour, Ontario would have a surplus available for export.

Power Advisory maintains a wholesale market forecast model that forecasts hourly operation of Ontario's electricity system. The wholesale market forecast model includes an electricity demand forecast and a supply forecast. Residual Demand is calculated as the difference between forecast Ontario electricity demand and forecast less flexible generation. Table 1 below summarizes the primary inputs for the forecast model

Table 1: Forecast of Residual Demand Inputs

Demand Forecast Inputs	Supply Forecast Inputs
• Organic growth in electricity demand; • Expected levels of conservation and demand management; and • Growth in demand from emerging technologies (e.g., electric vehicles and heat pumps).	• The availability of Ontario's nuclear fleet (i.e., retirement and refurbishment); • Existing generation including Ontario Power Generation's (OPG's) rate-regulated assets and generation currently under contract with the IESO; • Committed contracts for transmission-connected generators not yet in service; and • Development of new generation to meet supply adequacy needs.

Not all gas-fired generation is dispatchable: there are some cogeneration facilities that run almost all hours of the year to supply thermal energy to their load hosts. Some of these facilities have both a constant, baseload level of generation in virtually all hours, and dispatchable capacity above this baseload level operates primarily when Residual Demand is high. Power Advisory's analysis included identifying those facilities and estimating how much of their generation in each hour of 2015-2019 was baseload vs. dispatchable. Baseload generation was added to less flexible generation (which means it reduced Residual Demand). Only dispatchable generation was included in Gas Generation with the following attributes:

- At very low levels of Residual Demand, (dispatchable) Gas Generation falls to zero.
- Dispatchable generation affects forecasts of Residual Demand. Several cogeneration facilities retired or converted to dispatchable-only operation during the 2015-2019

period when their original Power Purchase Agreements expired. All of the remaining gas-fired generators with a baseload component are expected to retire, or convert to dispatchable-only operation, during the forecast period.

2.3 Step 2: Relationship Between Residual Demand and Gas Generation

On average, electricity production by Gas Generation increases as demand increases and power from less flexible generation (such as nuclear and renewables) decreases. To quantify this relationship, all hours from Base Years[6] were grouped based on Residual Demand in that hour (i.e., all hours with Residual Demand less than -2,000 MWh were put in one group, all hours with Residual Demand between -2,000 and -1,500 MWh in another group, etc.).[7] For each group, both average Residual Demand and average Gas Generation was calculated. The results are shown in Figure 4 below; the 5th and 95th percentile of Gas Generation in each group are shown for reference.

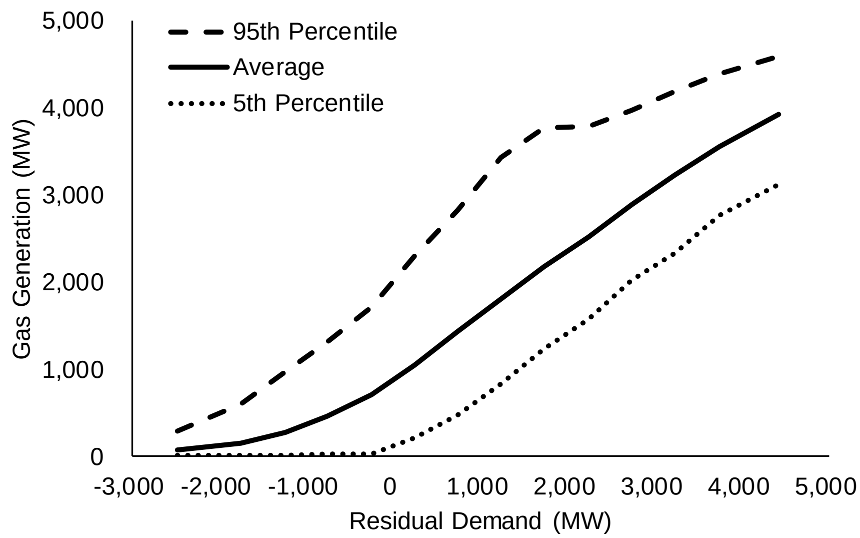

Figure 4: Hourly Gas Generation vs. Residual Demand, 2015-2019

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[6] Five Base Years (2015-2019) were used to represent a range of supply, demand, weather and price scenarios. Years earlier than 2015 are considered less indicative of current and future market operations because of market rule and other changes.

[7] The use of 500-MWh intervals was selected for a balance between precision and accuracy. Smaller intervals would have provided more detailed information about the shape of the curve; however, if the intervals were too small there would not be enough hours to provide a meanful average within each group.

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The resulting curve from the Gas Generation and Residual Demand relationship has an S-shape:

- When Residual Demand is low, the slope of the curve is quite shallow; at very low levels, the curve is flat, with a slope of zero. Within this group of hours, reductions in Residual Demand have little correlation with Gas Generation. Instead, Ontario's electricity system adjusts through either higher exports or increased curtailment of internal supply (i.e., nuclear, hydro, wind and solar).
- The slope of the curve is highest at intermediate levels of Residual Demand, reflecting that fact that gas-fired generation is dispatched to serve growing demand.
- At high levels of Residual Demand, the slope decreases slightly. There is a limit to how much Ontario gas-fired generators can produce; any additional supply needs must be met by importing electricity from other jurisdictions.

The resulting curve of average Gas Generation vs. average Residual Demand in each group can be approximated closely to a series of four straight lines (shown in red on Figure 5 below):

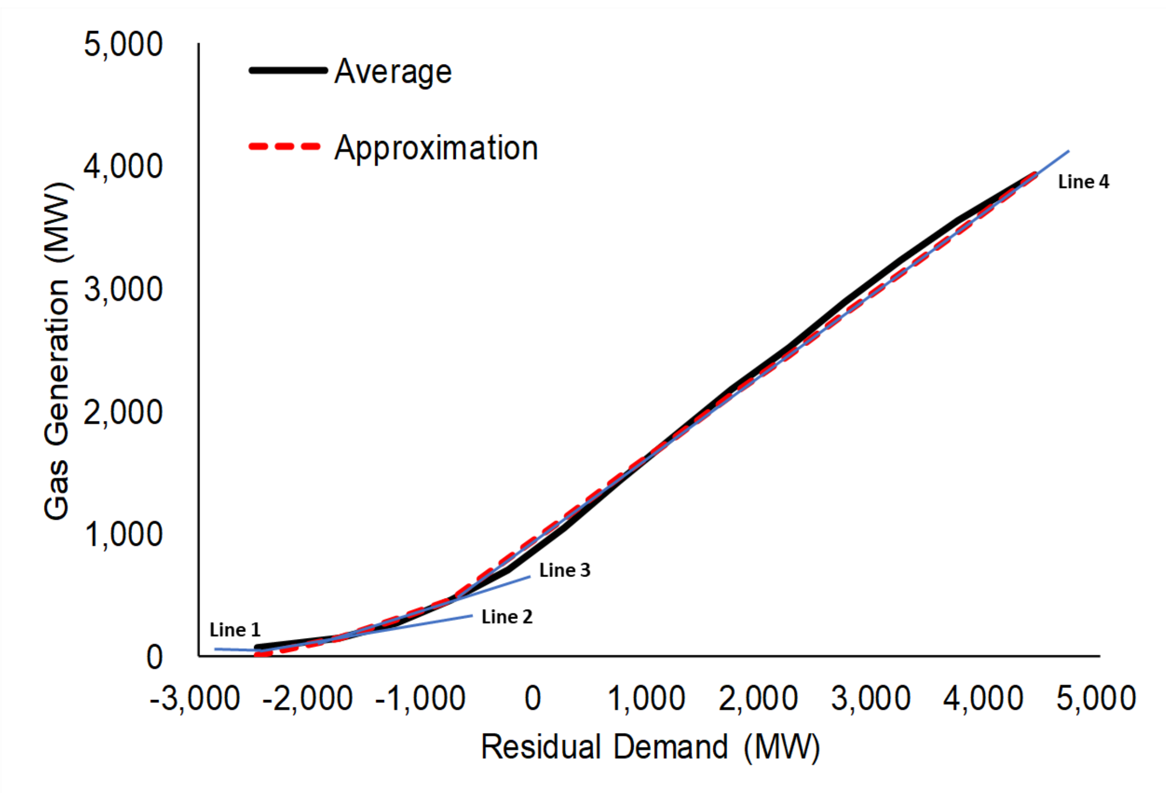

Figure 5: Approximation of Gas Generation vs. Residual Demand

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- Line 1 for Residual Demand below -2,500 MW, with a slope of zero (i.e., changes in Residual Demand do not result in changes in Gas Generation);
- Line 2 for Residual Demand between -2,500 and -1,750 MW, with a slope of 0.19 (i.e., Gas Generation increases by 0.19 MW for each 1-MW increase in Residual Demand);
- Line 3 for Residual Demand between -1,750 and -750 MW, with a slope of 0.32; and
- Line 4 for Residual Demand above -750 MW, with a slope of 0.67.

The slopes of each line segment show how Gas Generation changes in response to changes in Residual Demand. In addition, the line segments show how Net Imports change because Residual Demand is equal to Gas Generation plus Net Imports. For example, at the low end (in the range covered by Line 2), a 1-MWh increase in consumption (or a 1-MWh decrease in less flexible generation) is met by a 0.19-MWh increase in Gas Generation and a 0.81-MWh increase in Net Imports. In the high range (Line 4), a 1-MW increase in demand is met by a 0.67-MWh increase in Gas Generation plus a 0.33-MWh increase in Net Imports.

2.4 Step 3: Forecast Gas Generation, Net Imports and GHG Emissions

Ontario's fleet of large gas generators is estimated to have an emission factor of 0.412 tonnes/MWh, meaning that every 1 MWh increase (or decrease) in gas generation increases (or decreases) GHG emissions by, on average, 0.412 tonnes. This emission factor was derived by dividing the fleet's total emissions by its total output for the five Base Years (2015-2019), as shown in Table 2. The input data was taken from two sets of IESO data:

- The IESO's 2020 Annual Planning Outlook,[8] Figure 32 provides estimates of historical electricity sector GHG emissions. During the five Base Years, the only fossil fuel used in significant amounts in transmission-level generation was natural gas.
- The IESO's "Generator Output and Capability Reports[9] provide information on the actual output of all transmission-connected generation plants over 10 MW, including all significant gas generators.

[8] http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook. The data used to create the figure is available in spreadsheet form.

[9] http://reports.ieso.ca/public/GenOutputCapability/. Only 90 days of historical data is available on-line, but additional data can be obtaining by contacting the IESO's Customer Service department.

Table 2: Emission Factor for Ontario Gas Generation

Base Year	Electricity Sector GHG Emissions (million tonnes)	Gas Generation (TWh)	Emission Factor (tonnes/MWh)
2015	6.3	15.66	0.402
2016	5.5	13.01	0.423
2017	2.5	6.07	0.412
2018	4.0	9.88	0.405
2019	4.1	9.84	0.417
Average	**4.5**	**10.89**	**0.412**

Ontario's two least efficient gas plants, Lennox and York Energy Centre, operated very rarely in the Base Years, but are expected to operate much more frequently over the forecast period as nuclear retirement and refurbishment decreases baseload supply and increases Residual Demand. It could be argued that a higher gas emission factor should be used at very high levels of Residual Demand, when these two plants tend to come on-line contributing to higher emissions. This factor has not been factored into the MEF calculations.

An emission factor was also estimated for imports. Emission factors for imports from neighbouring jurisdictions could be derived from the supply mix in those jurisdictions (e.g., Quebec's generation resources are primarily hydroelectric). This approach however does not recognize the flow of electricity across multiple jurisdictions. Ontario is part of the eastern interconnection that includes electricity network across the eastern part of Canada and the US. The eastern interconnection supplies over 700 GW of electricity demand and has robust electricity trade between jurisdictions. From a broader geographical perspective, every MWh of electricity that one jurisdiction exports to Ontario, especially during peak demand hours, is less electricity that could be exported to another jurisdictions. In addition, imports to Ontario are a function of market dynamics in neighbouring jurisdictions in addition to market opportunities for electricity trade with Ontario. Determining specific import expectations by neighbouring jurisdictions would require detailed outlooks for each neighbouring jurisdiction in addition to potentially other jurisdictions within the eastern interconnect. That undertaking would be overly complex. Instead, Power Advisory has assumed a global view of emission factors for imports to Ontario that is an amalgamation of supply mixes across neighbouring jurisdictions.

Power Advisory estimated a series of emission factors attributable to net imports. The starting point was as 2017 report produced to support Ontario's Cap and Trade Program,[10] which

[10] "2017 Default Emission Factors for Ontario's Cap and Trade Program", available at https://www.ontario.ca/document/default-emission-factors-ontarios-cap-and-trade-program/2017-default-emission-factors. Although these emission factors no longer have any legal effect because Ontario's cap-and-trade program has been cancelled, the research and analysis on which the estimates were based remain valid.

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estimated emission factors for each of the jurisdictions surrounding Ontario. For 2020, a weighted average of the on-peak emission factors was calculated, using as weights the peak demand of each jurisdiction; the result was 0.58 tonnes/MWh (i.e., each MWh of imported electricity when imports exceed exports is assumed to result in 0.58 tonnes of GHG emissions). For later years, the calculations recognized that these emission factors are likely to fall, both because coal generation (which contributed to the high emission factors for MISO and PJM) is being phased out, and that there will be some development of true carbon-free peaking capacity (such as batteries charged with carbon-free electricity). Import emission factors are reduced to 0.17 tonnes/MWh by 2050. Exports were assumed to have no impact on the emissions attributable to Ontario.[11]

For each hour in the Forecast Period, the Residual Demand for that hour (estimated in Step 1 above) and the four line segments that approximate the relationship between Gas Generation and Residual Demand (developed in Step 2 above) were combined to estimate a typical level of Gas Generation for that hour. Net Imports for each hour were then calculated as the difference between Residual Demand and Gas Generation.[12] This was used to determine whether the province was forecast to be a net importer or a net exporter in that hour, which is a significant factor in the calculations below.

For each hour, marginal emissions from a 1-MWh increase (or decrease) in Residual Demand was estimated by calculating marginal emissions from the associated increase in Gas Generation and, if Net Imports were positive, the marginal emissions associated with imports. As an example, consider an hour in which Residual Demand is 1000 MW. Using Line 4 for the approximation, Gas Generation is estimated to be 1,632 MW. Subtracting Gas Generation from Residual Demand, Net Imports are estimated to be minus 632 MW, and the province is assumed to be a net exporter. The marginal emission factor from Gas Generation is 0.67 MWh of Gas Generation per MWh of Residual Demand (the slope of Line 4) times 0.412 tonnes of GHG emissions per MWh of Gas Generation. This gives a marginal emission factor of (0.67 x 0.412= 0.28) tonnes of GHG emissions per MWh of Residual Demand.

Imports are assumed to contribute to Ontario's marginal emissions only when Net Imports is positive, which occurs only when Residual Demand is very high – specifically, when it exceeds

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[11] Ontario exports of low or no emissions electricity generation may reduce emissions in neighbouring jurisdictions to which they are delivered, but these were not credited to Ontario.

[12] This implicitly assumes that when Residual Demand is very high, such that Ontario is importing more than it is exporting, there are only two sources of supply to meet a further increase in Residual Demand: additional fossil generation and additional imports. As noted in a footnote above, it could be argued that peaking hydroelectric generation should be treated as a third potential source of supply, rather than being including in less flexible generation. However, Power Advisory analysis has found that hydro generation in Ontario reaches its peak when Residual Demand is approximately 2,000 MW, well less than the level at which net imports become positive. In general, when Residual Demand reaches 4,000 MW or higher, all available peaking hydro is already operating, leaving fossil generation and imports as the only remaining sources of significant amounts of additional supply.

2,900 MW. At that point, each 1-MWh increase in Residual Demand is estimated to increase Gas Generation by 0.67 MWh (the slope of Line 4, which applies when Residual Demand is greater than -750 MW); the rest of the increase in Residual Demand is met by a 0.33-MWh increase in imports.

Each hour in each year was assigned to one of five possible values. As an example, the possible values for 2030 are shown in Table 3 below, based on the import marginal emission factor for that year (0.44 tonnes/MWh).

Table 3: Ontario MEF by Residual Demand Range

Range of Residual Demand	Marginal Emissions from Gas Generation (tonnes/MWh)	Marginal Emissions from Imports (tonnes/MWh)	Ontario MEF (tonnes/MWh)
Less than -2,500 MWh	0	0	0.00
-2,500 to -1,750 MWh	0.19 x 0.412 = 0.08	0	0.08
-1,750 to -750 MWh	0.32 x 0.412 = 0.13	0	0.13
-750 to 2,900 MWh	0.67 x 0.412 = 0.28	0	0.28
Greater than 2,900MWh	0.67 x 0.412 = 0.28	0.33 x 0.44 =0.15	0.42

One of these five emission factors (0.00, 0.08, 0.13, 0.28, or 0.42 tonnes/MWh) is assigned to each forecast hour, depending on the forecast of Residual Demand in that hour. (The fifth emission factor will vary by year because the import marginal emission factor is forecast to decline over time.) These emission factors represent typical changes in emissions due to changes in either demand or Less Flexible Generation under the expected system conditions.

2.5 Other Methodologies for Estimating Marginal Emission Factors

At least two other estimates of MEFs for Ontario's electricity system have been produced, one by the IESO[13], the other by The Atmospheric Fund (TAF), an agency of the City of Toronto[14]. Both produce estimates that are significantly lower than Power Advisory's estimates, but both suffer from methodological flaws.

- The IESO's estimates are based on a model of Ontario's electricity system that does not accurately reflect how gas generation is dispatched in real-time. In practice, it is normal for large amounts of gas-fired capacity to be operating even when the province's

[13] http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/APO-Avoided-Emissions-2020.xlsx?la=en. Power Advisory's understanding of the IESO's methodology for calculating marginal emission factors is based on a telephone conversation with Mike Risavy, Manager, Reporting & Economic Analysis, Power System Planning, on April 30, 2020, and by analysis of the published results.

[14] https://taf.ca/publications/a-clearer-view-on-ontarios-emissions-2019/

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baseload generation exceeds its demand, but the IESO's model does not reflect this. As well, the IESO does not attribute any emissions to imports, with the result that in some years, MEFs during peak hours are forecast to be much lower than those in off-peak hours.

- TAF uses historical data to estimate MEFs, but their analysis identifies the marginal resource in each hour based on only increases in generation. For example, if wind speed, and thus wind generation, increase across the province, then wind is identified as the (or one of the) marginal resource(s) in that hour, resulting in a very low MEF for that hour. In reality, wind generation is essentially a given (except that it can be curtailed in certain conditions), and any change in consumption or generation would displace gas generation or imports, not wind. TAF also does not attribute any emissions to imports.

3. MARGINAL EMISSION FACTOR ESTIMATES AND APPLICATIONS

3.1 Mean Marginal Emission Factors

The marginal emission factor estimates resulting from the above methodology can be summarized in different ways for different applications. For example, the mean MEF in 2020 is forecast to be 0.17 tonnes/MWh, as shown in Table 4 below. The averages in that table were calculated giving equal weight to all hours in each year. The mean MEF across all hours would be useful in evaluating a program or activity that would have the same effect in all hours. However, most activities vary based on time of day, weather, season and other factors, so evaluation should take these differences into account.

Figure 6 below shows MEFs in 2020 averaged by season and hour of the day. MEFs for this particular year are expected to be highest in the summer (except early morning) and lowest in the spring. In all seasons, there is significant variation by time of day, with the highest MEFs occurring in the early evening.

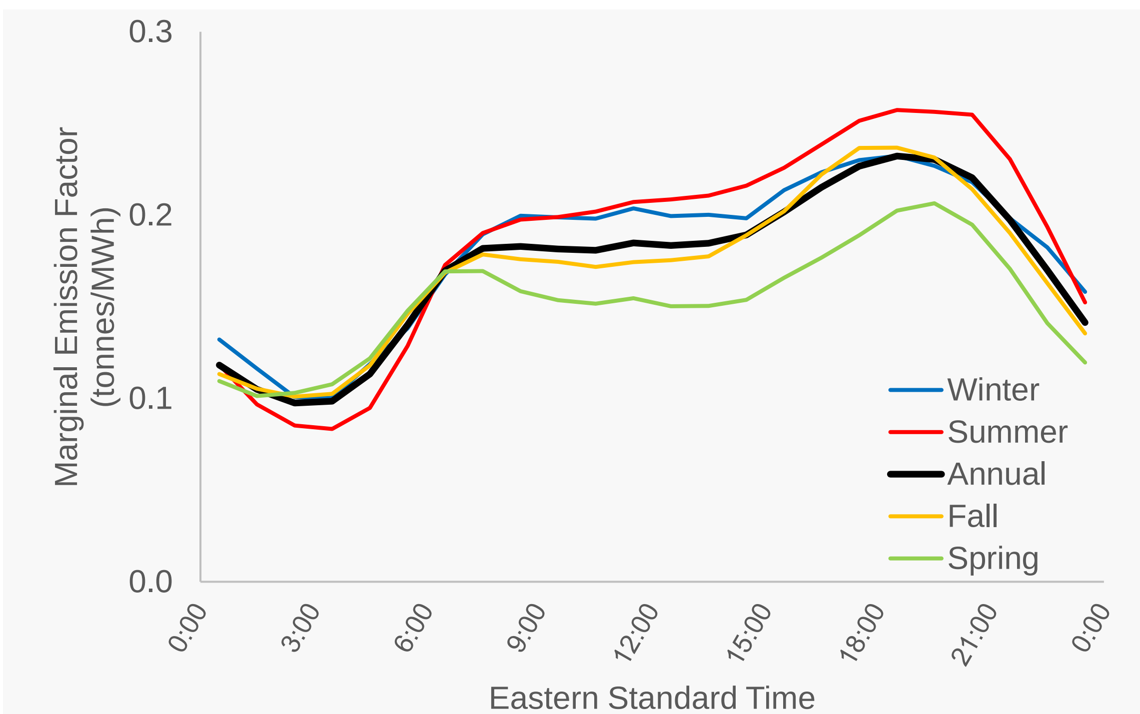

Figure 6: Marginal Emission Factors Averaged by Season and Time of Day, 2020

MEFs will change over time as Ontario's demand and generation supply changes. Figure 7 below shows mean MEFs over the forecast period. Mean MEFs are expected to jump in 2025 when the

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Pickering nuclear station retires; that will greatly reduce Less Flexible Generation and increase Residual Demand, which in turn will increase Gas Generation and imports in many hours.

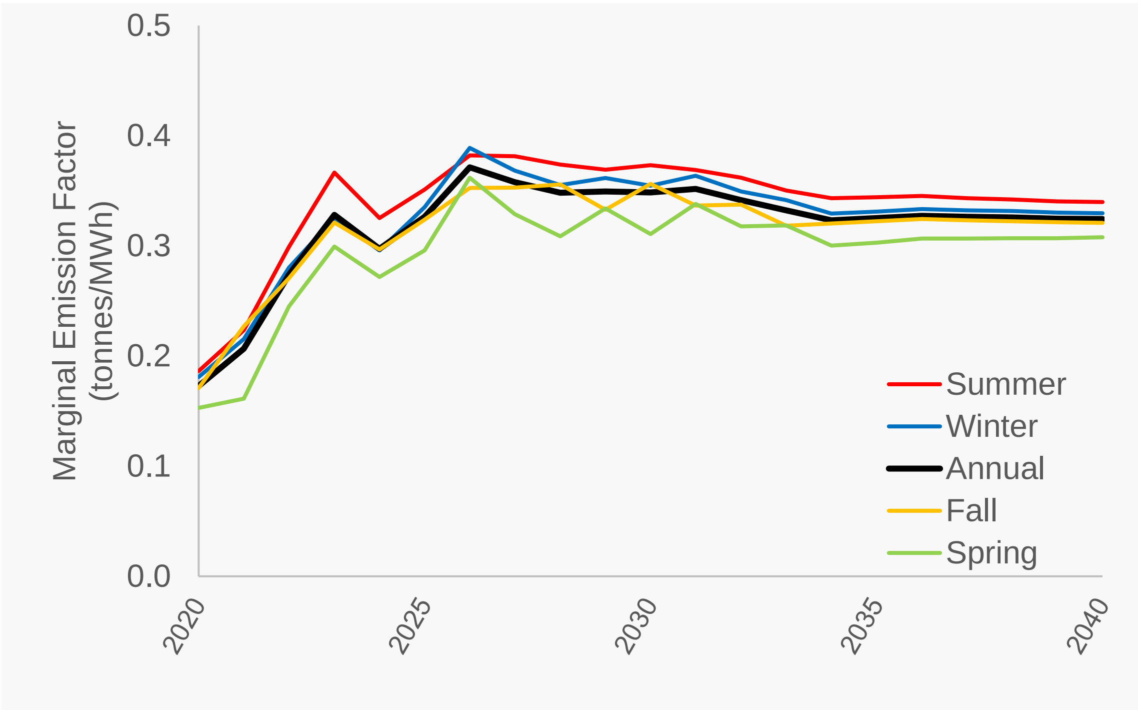

Figure 7: Marginal Emission Factors Averaged by Season, 2020-2040

Table 5 below summarizes MEFs by both season and time-of-use period. Each forecast hour was assigned to one of eight periods:

- Winter (December-March)
  1. On-Peak
  2. Mid-Peak
  3. Off-Peak
- Summer (June-September)
  4. On-Peak
  5. Mid-Peak
  6. Off-Peak
- Shoulder (April, May, October, November)
  7. On- and Mid-Peak Combined
  8. Off-Peak

Time-of-Use periods are based on those used by the Regulated Price Plan, taking into account Daylight Savings Time and the change in the on-peak/mid-peak schedule on May 1 and November 1. Forecast hours were assigned to time-of-use periods based on the Base Year, not the Forecast Year. (The hourly demand patterns used in these calculations reflect the weekends

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and holidays in the Base Years, not the Forecast Years. For example, January 4, 2022 will be a Tuesday, but when using the 2015 Base Year, demand on January 4, 2022 will be estimated based on what actual hourly demand was on January 4, 2015, which was a Sunday. The emission factors for January 4, 2022 are therefore included in the off-peak period when using the 2015 Base Year.)

Table 4: Forecast Marginal Emission Factors by Season and Time-of-Use Period (tonne/MWh)

	Winter			Summer			Shoulder		All
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	On&Mid	Off-Peak	Hours
2020	0.21	0.21	0.15	0.21	0.20	0.17	0.17	0.16	**0.17**
2021	0.23	0.22	0.20	0.24	0.24	0.21	0.20	0.19	**0.21**
2022	0.30	0.28	0.27	0.31	0.30	0.28	0.26	0.25	**0.27**
2023	0.34	0.33	0.31	0.38	0.38	0.35	0.31	0.30	**0.33**
2024	0.32	0.30	0.29	0.34	0.33	0.31	0.29	0.27	**0.30**
2025	0.35	0.34	0.32	0.37	0.36	0.33	0.31	0.30	**0.33**
2026	0.41	0.40	0.38	0.40	0.39	0.37	0.36	0.34	**0.37**
2027	0.38	0.38	0.35	0.40	0.39	0.37	0.35	0.33	**0.36**
2028	0.37	0.36	0.34	0.39	0.39	0.36	0.34	0.32	**0.35**
2029	0.38	0.37	0.35	0.38	0.38	0.35	0.34	0.32	**0.35**
2030	0.37	0.36	0.34	0.39	0.38	0.36	0.34	0.32	**0.35**
2031	0.38	0.37	0.35	0.38	0.38	0.35	0.34	0.33	**0.35**
2032	0.36	0.36	0.34	0.38	0.37	0.35	0.33	0.32	**0.34**
2033	0.36	0.35	0.33	0.36	0.36	0.33	0.32	0.31	**0.33**
2034	0.34	0.33	0.32	0.36	0.35	0.33	0.31	0.30	**0.32**
2035	0.35	0.33	0.32	0.36	0.35	0.33	0.32	0.31	**0.33**
2036	0.35	0.34	0.32	0.36	0.36	0.33	0.32	0.31	**0.33**
2037	0.35	0.34	0.32	0.35	0.35	0.33	0.32	0.31	**0.33**
2038	0.35	0.34	0.32	0.35	0.35	0.33	0.32	0.31	**0.33**
2039	0.34	0.33	0.32	0.35	0.35	0.33	0.32	0.31	**0.32**
2040	0.34	0.33	0.32	0.35	0.35	0.33	0.32	0.31	**0.32**
All Years	**0.34**	**0.33**	**0.31**	**0.35**	**0.35**	**0.32**	**0.31**	**0.30**	**0.32**

When used to evaluate distribution-level activities (e.g., DG-CHP), adjustments should be made to account for transmission and distribution losses.

3.2 How Marginal Emission Factors Are Being Used

3.2.1 Example: Combined Heat and Power for a New High-Rise Building

A Combined Heat and Power (CHP) is an energy efficient technology that generates electricity and captures the heat that would otherwise be wasted to provide useful thermal energy—such as steam or hot water—that can be used for space heating, domestic hot water, and in some application space cooling, and even industrial processes. A CHP system is typically located at facilities where there is a coincident need for both electricity and thermal energy.

Nearly two-thirds of the energy used by conventional grid thermal electricity generation is wasted in the form of heat discharged to the atmosphere or a nearby lake or river. Additional energy is wasted during the distribution of electricity to end users. By capturing and using heat that would otherwise be wasted, and by avoiding distribution losses, CHP can achieve efficiencies of over 75%, compared to about 56% for conventional electricity generation and an on-site boiler. The concept of how CHP saves GHG emissions as compared to separate heat and power (SHP) is illustrated in Figure 8.

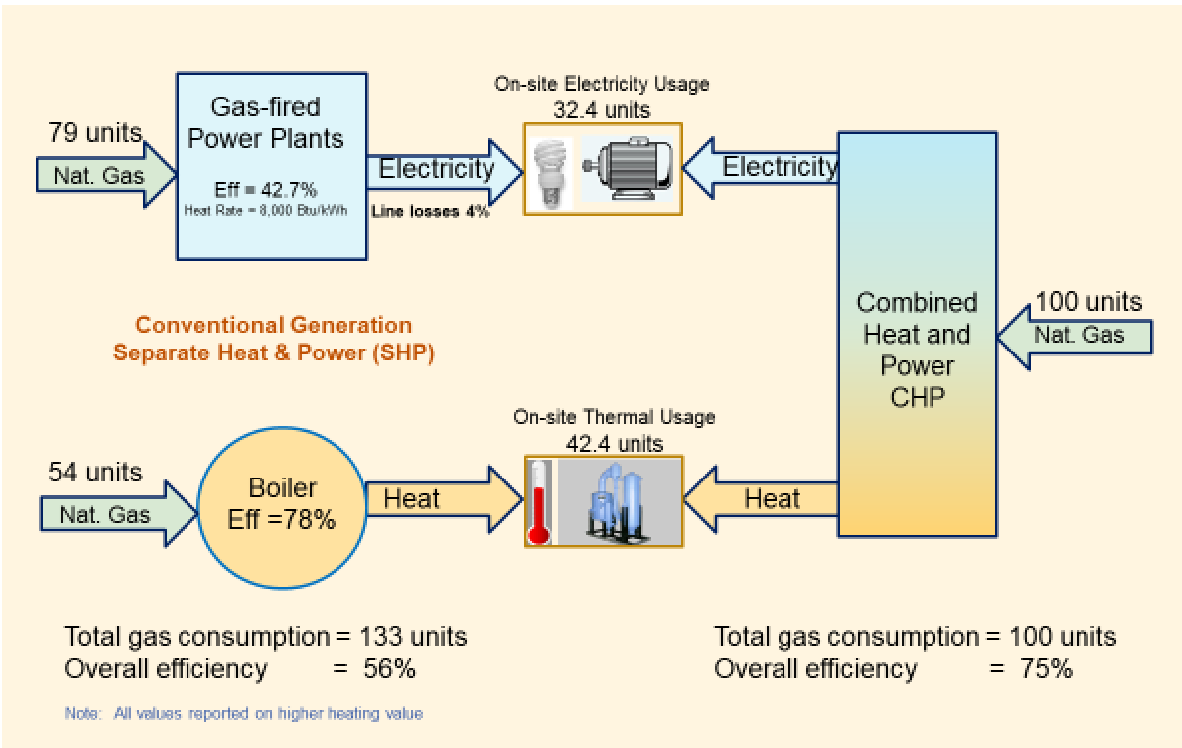

Figure 8: Efficiency of Combined Heat and Power vs. Separate Heat and Power

A case study was performed to evaluate the GHG emissions savings for installing a CHP system at a multi-unit residential building (MURB) using MEFs. An hourly simulation was performed for six scenario to provide 100% of domestic hot water (DHW) load and varying amounts of space heating loads to evaluate net GHG emission change for a proposed building with CHP as compared to a reference building with no CHP, consuming electricity supplied by the grid and

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thermal energy supplied by boilers. The analysis was performed by PowerGENySYS[15] using the hourly marginal emission factors calculated by Power Advisory. The results are summarized in Table 5 below. The analysis shows that a well-designed CHP for high-rise buildings is capable of reducing GHG emissions in all six scenarios. With the use of a single annual average emission factor and without considering future changes in electricity grid emissions, the outcome would have been different. This example shows how important is it to use the MEFs instead of AEFs for new construction.

Table 5: Case Study Results: Multi-Unit Residential Building

	CHP Configuration/Size		Thermal Load		Annual Outputs					GHG Emissions over 20 Yrs		
No.	Internal Combustion Engine (ICE) CHP Plant Configuration	Capacity, kW	DHW, %	Space Heating, %	Operating Hours	Electricity Generation, kWhr	Heat Recovery, mmBTU	Heat Utilized, %	Heat Dump, %	NET Total Emissions Change (OVER 20 YRS) tonnes	NET Avg. Annual Emissions Change, (OVER 20 YRS) tonnes/yr	Meets SB-10 CO2e Emissions Requirement
1	1 x 24 kW	24	100%	0%	7,545	181,078	1,228	99.8%	0.2%	-1,259	-62.95	YES
2	2 x 24 kW	48	100%	25%	6,662	319,793	2,169	95.7%	4.3%	-1,458	-72.90	YES
3	3 x 24 kW	72	100%	50%	6,313	448,482	3,042	88.9%	11.1%	-1,355	-67.75	YES
4	1 x 125 kW	125	100%	60%	4,696	497,847	3,230	81.1%	18.9%	-1,056	-52.82	YES
5	1 x 125 kW	125	100%	70%	4,760	504,656	3,274	81.8%	18.2%	-1,181	-59.04	YES
6	1 x 175 kW	175	100%	100%	2,087	247,228	1,395	81.1%	18.9%	-1,538	-76.92	YES

Source: Combined Heat and Power Systems for New Part 3 Multi-Family Residential Building Designed to Meet SB-10, Division 3, Chapter 1 Emission Requirements: Final Report for Municipal Building Officials, by Sustainable Buildings Canada, January 20, 2020.

[15] POWER GENySYS is a Canadian engineering firm specializing in Combined Heat and Power (CHP) and Combined Heat & Emergency Power (CHeP) systems.

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4. GUIDELINES FOR USING MARGINAL EMISSION FACTORS

When using the MEFs developed by Power Advisory, the guidelines below should be followed:

- MEFs should be used to evaluate the incremental impacts of activities, policies, programs, and measures. To develop inventories of total emissions, AEFs should be used. Power Advisory has not developed AEFs.
- Evaluation of future activities should use forecasts of MEFs that incorporate expected changes in Ontario's electricity system (e.g., changes in supply mix and demand). Using current or historic MEFs would not adequately reflect the future impact of activities. For example, Ontario's MEFs are expected to increase significantly when the Pickering Nuclear Station retires at the end of 2025.
- Summary MEFs (means over time of day, season, time-of-use period etc.) can be used for preliminary analysis of an activity. For more detailed analysis, hourly MEFs should be used. Hourly MEFs for system conditions for five corresponding Base Years (i.e., 2015-2019) are provided. Each set of hourly MEFs can be paired with historical hourly weather and electricity demand data for the corresponding Base Year. To accurately calculate emission impacts, it is recommended that each set of hourly data be used independently, and the results averaged as a final step. Contact information for obtaining hourly MEFs is provided below.
- When evaluating measures that affect supply or demand at the distribution level, such as conservation programs or distributed generation, MEFs should be adjusted for distribution losses. Total distribution losses averaged across all hours are typically around 4%, so when evaluating distribution-level measures, the MEFs could be increased by 4% as a first approximation. This adjustment could be refined based on local[16] and/or time-of-use differences, if information is available.

To obtain the hourly marginal emission factors, please contact:

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Email: aqeel.zaidi @enbridge.com
www.enbridgegas.com

[16] Loss Factors for each of Ontario's Local Distribution Utilities are set by the Ontario Energy Board and published as part of the utilities' rate schedules, which are available at https://www.oeb.ca/industry/applications-oeb/electricity-distribution-rates. These represent average losses for all consumption. Different loss factors are used for small and large customers.

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