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Enbridge Gas Distribution
500 Consumers Road
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Canada

January 23, 2018

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("Enbridge")
Cap and Trade Application ("Application")
Ontario Energy Board ("Board") File Number EB-2017-0224
Interrogatory Responses

Further to Enbridge's letter dated January 19, 2018, enclosed please find six copies of Enbridge's response to the following interrogatories:

- Exhibit I.C.EGDI.STAFF.5, plus attachments; and
- Exhibit I.C.EGDI.CCC.10.

Exhibit I.C.EGDI.STAFF.5, Attachment 4 has been provided to the Board in confidence under separate cover due to the commercial sensitive information included in the attachment.

These interrogatory responses are being filed through the Board's Regulatory Electronic Submission System and will be available on the Enbridge website at www.enbridgegas.com/ratescase.

Please contact the undersigned if you have any questions.

Yours truly,

(Original Signed)

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. D. Stevens, Aird & Berlis LLP
All Interested Parties EB-2017-0224 (via email)

STAFF INTERROGATORY #1

INTERROGATORY

Ref: Exhibit C / Tab 5 / Schedule 1 / p. 15, #38
Exhibit C / Tab 5 / Schedule 2 / p. 26, Table 3

Preamble:
Enbridge Gas notes that it considered the results of the OEB's Marginal Abatement Cost Curve (MACC) in its 2018 Compliance Plan filing. Enbridge Gas acknowledges that the MACC identified a range of carbon abatement costs associated with RNG in the range of $77 to $1,990 per tonne of CO_2e, which is significantly more expensive on a cost per tonne basis than customer abatement programs identified on the MACC.

Enbridge Gas also concluded that "additional DSM programs would not be cost-effective; in some cases the marginal costs of new programs may be higher than the cost of compliance instruments."

In addition, in Table 3 of Exhibit C, Tab 5, Schedule 2, Enbridge Gas states that "analysis of the MACC study results as compared to the Company's DSM plans [shown in Table 3 below] indicates that Enbridge Gas' current DSM Plan delivers results for ratepayers that are well in excess of what the MACC study would otherwise indicate is cost-effective under a Mid-Range LTCPF scenario."

Questions:

a) Please provide any analysis, with underlying assumptions, that Enbridge Gas has done with respect to the cost-effectiveness of RNG versus other abatement options.

b) Will the OEB's decision to approve/not approve Enbridge Gas' RNG procurement model impact other abatement activities that Enbridge Gas is considering? If so, please discuss how. Please provide all relevant analysis and documentation.
   i. If Enbridge Gas' RNG procurement model is not approved, would Enbridge Gas invest in other abatement activities? Please explain and provide all relevant documentation.

c) Please provide all information, including specific references to the MACC and DSM tables found in Exhibit C, Tab 5, Schedule 2, p. 26, Table 3, that Enbridge Gas used to determine that "additional DSM programs would not be cost-effective; in some cases the marginal costs of new programs may be higher than the cost of compliance instruments."

Witnesses: A. Chagani
D. Johnson
S. McGill

d) Does Enbridge Gas agree that the cost-effectiveness of RNG is predicated on provincial government funding?
    i. If yes, has Enbridge Gas had any discussions with the provincial government in regards to obtaining similar funding to support other abatement opportunities? Please provide all relevant supporting documentation.
        1. Please explain what types of customer abatement activities Enbridge Gas has been discussing with the provincial government.
        2. Please explain whether and how Enbridge Gas would consider these customer abatement activities cost-effective given Enbridge Gas' conclusion that "additional DSM programs would not be cost-effective; in some cases the marginal costs of new programs may be higher than the cost of compliance instruments."
    ii. If no, please explain. Please include supporting analysis and documentation.

RESPONSE

a) The Company has considered the cost of abatement options as is possible, in conjunction with a review of available funding information through GreenOn. In the MACC, the RNG shows to be more expensive on a per tonne basis than other abatement opportunities scoped into that study. Importantly though, Enbridge's proposal for procuring RNG is contingent on available provincial funding, thereby resulting in a net cost of GHG abatement to ratepayers equivalent to that of the purchase of carbon allowances.

b) No, a decision by the OEB to not allow the Company to apply funds being offered by the provincial government to reduce the cost of procuring RNG supplies to the level of the carbon abated cost of traditional gas will not impact other abatement activities that Enbridge is considering.

c) The values for Column 2 in Exhibit C, Tab 5, Schedule 2, page 26, Table 3 are derived from section 2.3 Customer Abatement MACC Results in the Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities (EB-2016-0359) study. Specifically, the estimated abatement associated with Industrial, Commercial and Residential measures that are cost effective relative to the carbon price as defined in the LTCPF Report's Mid-Range Scenario.

Witnesses: A. Chagani
D. Johnson
S. McGill

The values for the Column 6 in Exhibit C, Tab 5, Schedule 2, page 26, Table 3 are the cumulative sum of the proposed targets filed by EGD for 2018-2020.

As the table shows, the proposed cumulative targets for DSM exceeded the cost effective DSM identified in the MACC study, which appears to indicate that, at least in some cases, the marginal costs of new programs may be higher than the cost of compliance instruments.

d) In the absence of other funding mechanisms, Enbridge recognizes that in order to ensure minimal ratepayer impact, government funding will be necessary in order to introduce RNG supplies into Ontario's gas supply portfolio.

   i. Enbridge has had a number of discussions with the provincial government in regards to obtaining funding to support other abatement opportunities. Other abatement activities for which Enbridge has sought funding include: incremental energy efficiency, geothermal, natural gas for transportation and power-to-gas. Please see the attached presentation (Enbridge in Ontario, 27 September 2017). This presentation is representative of the types of initiatives and discussions Enbridge has had with the province on the following initiatives: energy conservation; technology and energy optimization; decarbonizing the natural gas supply, natural gas for transportation and power to gas.

   ii. This is not applicable.

Witnesses: A. Chagani
D. Johnson
S. McGill




Enbridge in Ontario

27 September 2017

ENBRIDGE

The New Enbridge

- **4th largest company in Canada**
- **Operates the longest crude oil transportation system in the North America**
- **Operates Canada's largest energy distribution companies:** Enbridge Gas & Union Gas: serve consumer markets in Ontario, Quebec & New Brunswick and New York
- **Canada's second largest investor in renewables** (wind, solar, hydroelectric, geothermal etc.)

Enbridge in Ontario

Delivers 95% of Ontario's natural gas and 96% of its petroleum products

Key Projects of Interest:

Natural Gas Rural Expansion: $100M expansion program to add rural communities and economic development projects; applications due in July.

Line 10: replacement of 35km of Line 10 segment near Hamilton, approved by NEB in 2017.

East-West Tie Transmission: upcoming application to the OEB.

Natural Gas
3.5 M customers, heating more than 75% of Ontario homes, through two utilities

Renewables
7 projects: wind, solar and hydroelectric (490 MW).

Liquids Pipelines
3 pipelines which move 491,000 barrels per day.

Infrastructure
~$14 billion (2016) between Enbridge Gas Distribution and Union Gas

Property Taxes
Pays more than $127 million in property and other taxes each year.

Employment
Over 4,500 Ontario-based permanent and temporary staff.

Utility Integration

One Company. One Team. One Message.

- With the recent merger of Enbridge Inc. and Spectra Energy, the two leading Ontario natural gas utilities, Union Gas and Enbridge Gas Distribution, are now part of the same company, Enbridge Inc.

- In order to lower customer energy costs and increase operational efficiency over the long term, Enbridge Gas Distribution and Union Gas plan to apply to the OEB for approval to integrate the two utilities. This will allow us to focus on doing what's right for our customers.

- The Merger will save money for our 3.5 million Ontario customers while maintaining the safe, reliable delivery of affordable natural gas.

- We know that energy affordability and the safe, reliable delivery of natural gas are important to our customers. With this integration, customers will benefit from long-term rate stability, our continued outstanding quality of service and pursuit of efficiencies.

uniongas
An Enbridge Company

ENBRIDGE
Life Takes Energy™

Enbridge – Part of the Solution

Supporting the Transition to the Low Carbon Economy

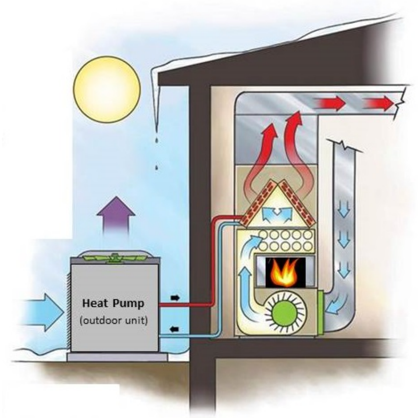
Energy Conservation

Average Residential Customer Usage Reduced Natural Gas use by 21%

Residential Customers save $2.67 for each dollar spent on natural gas conservation
(Environmental Commissioner of Ontario, 2016)

Ontario
HOME ENERGY CONSERVATION INCENTIVE PROGRAM
With funding from Ontario's Green Investment Fund

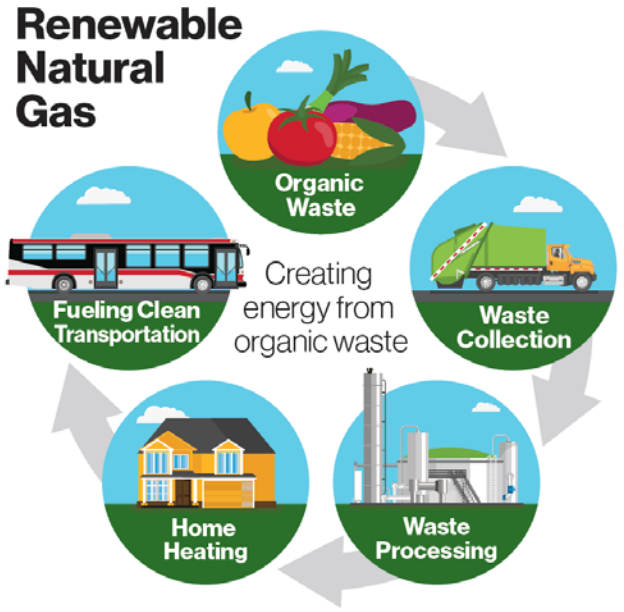
Technology & Energy Optimization



Source: www.familyhandyman.com

- Rely on natural gas on coldest days
- Use air source heat pump on most days
- 60% reduction in GHG's
- Less than ½ lifecycle cost of full electric air source heat pump

Decarbonize the Gas Supply with Renewable Natural Gas & Hydrogen



Energy Conservation

Proven Leadership, Expertise & Speed

Conservation remains the lowest cost solution to reducing emissions and saving customers money. Ontario should use 'GreenON' to enhance the utilities' conservation initiatives.

$ **Residential Customers save $2.67 for each dollar spent on natural gas conservation**
(Environmental Commissioner of Ontario, 2016)

Average Residential Customer Usage Reduced 21% (1995-2015)

Moving forward:

- Reach of the gas utilities: 3.5M customers (78% of homes); New GIF program reaches all Ontarians
- Enbridge's proposals to partner with GreenON beyond the existing Green Investment Fund Partnership would allow further cost-effective opportunities to further reduce emissions by leveraging Enbridge's business model, relationships, expertise and speed
- Enbridge's conservation teams at Enbridge Gas and Union Gas can ensure alignment with government, participation from market players and we can be in the market quickly.

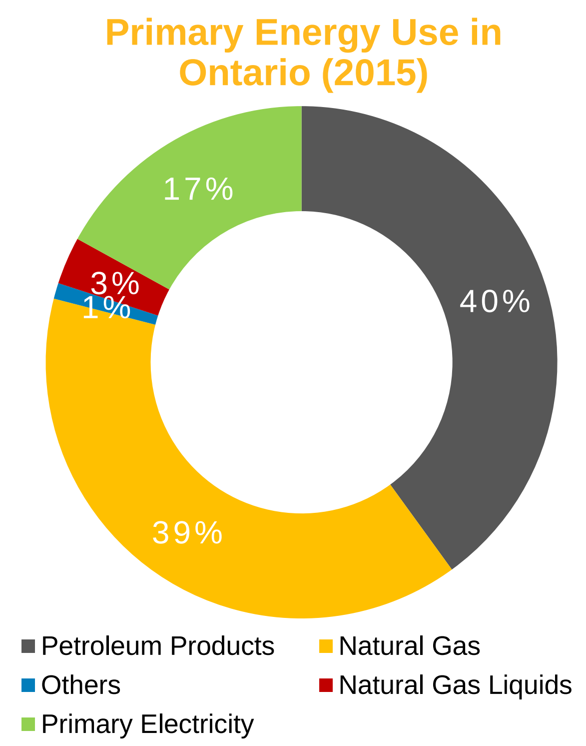
Technology & Energy Optimization

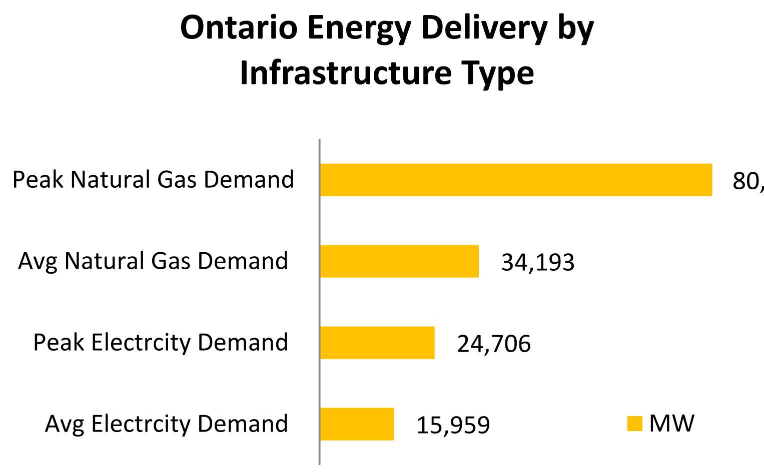
Electrification?

- **While Ontario strives towards its ambitious emission reduction objectives it needs to ensure that our energy systems are as reliable and affordable as possible for consumers.**

- Ontario’s natural gas distribution and storage network delivers more than three times the energy on a peak day (equivalent to ~80,000 MW) compared to the electricity system (24,700 MW).

- The most desirable and cost effective electrification utilizes existing infrastructure and does not create the need for new capacity resources, while at the same time displacing fuels to reduce emissions. (eg. electric cars vs home heating)





Decarbonizing Ontario's Natural Gas Supply

Renewable Natural Gas

- Renewable Natural Gas (RNG) is created by upgrading biogas that can be found on farms, landfills and food processing facilities to a quality that meets pipeline injection specifications. RNG can be transported throughout the natural gas distribution system.

- RNG is non-emitting, and would allow the province to reduce building emissions significantly, without having to build new transmission or distribution, at a fraction of the cost of electrification.

- RNG could provide 8 MT CO2e emission reductions by 2030

Energy Costs:	
Traditional Natural Gas	2 cents / kWh
RNG (Low-Cost)	4 cents / kWh
RNG (High-Cost)	8 cents / kWh
Electricity (Mid-Peak)	13 cents / kWh
Electricity (On-Peak)	19 cents / kWh

Natural Gas Transportation

Catching Up on Low-Carbon Vehicles

- While light duty vehicles will be increasingly powered by electricity, natural gas – including increasing amounts of renewable content – is the best solution for lowering emissions with today's medium and heavy-duty vehicles.

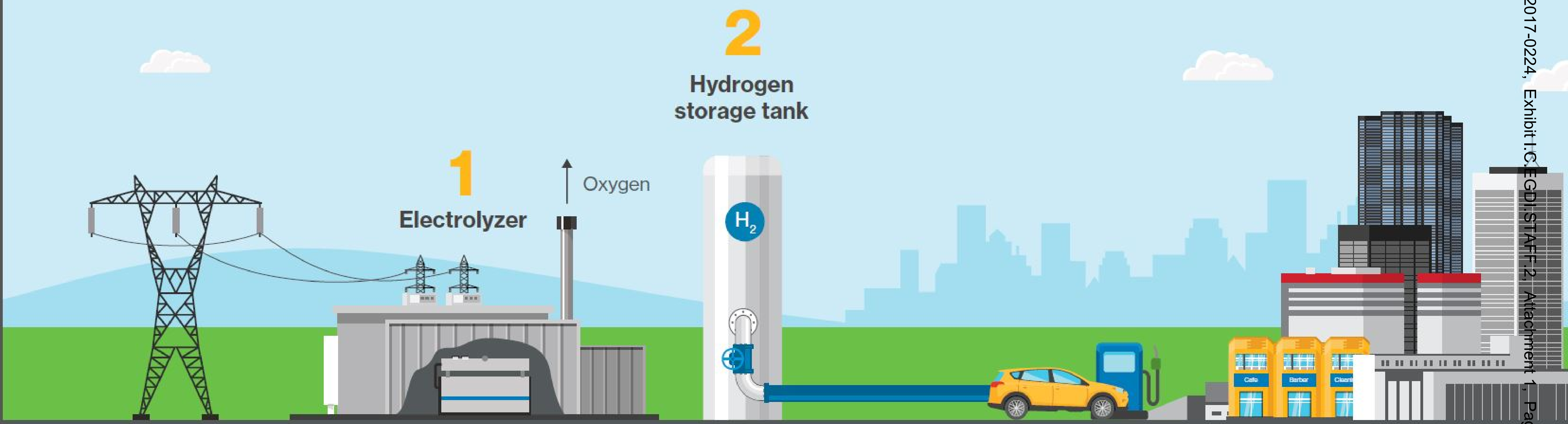
- Natural gas has roughly 20% fewer GHG emissions and is up to 40% less expensive than diesel or gasoline.

- Ontario's proposed Green Commercial Vehicle Program which will provide rebates for heavy-duty natural gas vehicles will help this transition.

- The next step is to support the need for natural gas vehicle refueling infrastructure along the 400-series highways and in urban distribution areas.

Enbridge Invests in Power to Gas

Future State - Using hydrogen to fuel zero-emissions vehicles



1 Since electricity can't be stored, when there is a surplus, an electrolyzer can take the electricity and use it to split water into hydrogen and oxygen. →

2 The hydrogen that is produced is then stored. →

3 Hydrogen can be shipped directly to refueling stations or to industrial and commercial customers.

ENBRIDGE
Life Takes Energy™

STAFF INTERROGATORY #2

INTERROGATORY

Ref: Exhibit C / Tab 5 / Schedule 2 / p. 7

Preamble:
Enbridge Gas acknowledges that the RNG data used in the MACC report was based on a desk top review of studies by ICF dating back to 2011. Enbridge Gas also notes that in pages 50 to 53 of its report, ICF noted a number of limitations and caveats relating to its analysis of RNG potential and costs.

Questions:

a) Please provide any additional information that Enbridge Gas has acquired or developed related to actual RNG costs and production levels in Ontario beyond what was used by ICF to generate the MACC report.

RESPONSE

Enbridge's understanding of RNG costs and production levels in Ontario comes from activities such as review of existing reports (for example, the MACC report, the Fuels Technical Report and the Electrigaz report filed in EB-2011-0242), attendance at conferences, review of industry and market publications, discussions with RNG technology providers, the Canadian Biogas association and discussions with Government officials.

Witnesses: A. Chagani
S. McGill

STAFF INTERROGATORY #3

INTERROGATORY

Ref: Exhibit C / Tab 5 / Schedule 2 / pp. 6-7

Preamble:
Enbridge Gas states that because the early supplies of renewable pipeline fuel will be predominantly derived from waste streams, RNG can help reduce GHG emissions in two ways (two value streams): 1) through the displacement of conventional natural gas (fuel switching value stream) and 2) through the creation of carbon offsets that account for the capture of biogenic methane that would otherwise have been vented to atmosphere as fugitive emissions (methane avoidance offset credits value stream).

Enbridge Gas also states that one key limitation concerning the economic value of RNG in the MACC report is that ICF does not take into account the potential sale of associated emissions reductions derived from offset credits that would be associated with the methane avoidance value stream.

Questions:

a) Please explain how offsets could represent another "value stream".

b) Please explain how this value stream could impact the cost, production level, and timing of RNG development.
   i. Please explain how this impacts Enbridge Gas' potential procurement of RNG, including the cost of RNG and the timing of procurement.

c) What is Enbridge Gas' expected "value of offsets" in \$/tonne of CO_2e? Please explain and provide supporting data and analysis.

d) Please explain how Enbridge Gas expects the "value of offsets" to affect Enbridge Gas' proposed RNG procurement and funding. Please provide all relevant supporting documentation and analysis.

e) Please explain how Enbridge Gas expects the value of offset credits could affect the amount Enbridge Gas would pay to RNG suppliers through its RNG funding model. Please provide all relevant supporting documentation and analysis.

Witnesses: A. Chagani
S. McGill
J. Murphy

f) Please explain whether the Ministry of Environment and Climate Change and/or provincial government has confirmed that offset credits will be available for RNG.

g) Does Enbridge Gas plan to be an offset project developer and/or offset supplier?
   i. If yes, please confirm that the laws and regulations governing cap and trade and offset credits in Ontario would allow a capped participant such as Enbridge Gas to undertake this business activity. Please explain whether Enbridge Gas would undertake this business activity through an affiliate or as a regulated utility.
   ii. If no, please explain how Enbridge Gas could take advantage of the offset value stream and how this value stream could affect the cost of RNG that Enbridge Gas would procure.

RESPONSE

a) When methane is captured from sources such as landfills and digesters and turned into RNG, there are two value streams that may be created: renewable natural gas and offset credits. Offset credits can only be generated from projects that meet the eligibility requirements of the Offset Regulation and the applicable offset protocol. In cases where a project does generate offset credits, these are also a commodity that can be sold to participants in the Cap and Trade Program, including capped participants and market participants.

b) The sale of offset credits can reduce the costs of generating the RNG and may make projects more economical. RNG can be sold with or without the underlying offset value. The price to be paid for RNG supplies will be determined through a competitive tendering process and these prices will reflect whether or not the supplies of RNG to be purchased are inclusive of the offset value associated with such gas. At present the province has finalized its offset protocol for RNG derived from Landfill Gas. Other protocols will be required in order to establish the offset value of RNG derived from other sources. Until such time as these protocols are established the prices that the Company will be prepared to pay for RNG supplies will necessarily only reflect the substitution value of the gas and the potential for further offset value may rest with the RNG producer / supplier.

c) For analysis purposes Enbridge has assumed that RNG coming from landfill gas projects will not generate offset credits. This is because the protocol only allows offset credits to be generated from landfills under certain size thresholds, and therefore most landfills in Ontario are unlikely to be able to generate offset credits. In the absence of the remaining offset protocols, Enbridge is unable to determine which projects may generate offset credits at this time, and therefore does not have an expected value of offsets.

d) At this time, Enbridge does not expect the value of offsets to affect the RNG procurement or funding. When there is an assessed offset value, this would be negotiated in the pricing of contracts at that time.

e) Please see the Company's response to part d of this question above.

f) On January 1, 2018, the Ontario Offset Credits Regulation came into effect, along with Ontario's first offset protocol, the Landfill Initiative Protocol. Eligible landfills, meaning those that meet the criteria in Section 4 of the protocol, may generate offset credits if the methane in the landfill gas is destroyed by an eligible destruction device, which is a device that is set out on Table A.1 of the protocol. Table A.1 includes "injection into natural gas transmission pipeline"[1] as an eligible destruction device. Enbridge understands this to mean that at eligible landfills, landfill gas that is treated/upgraded into RNG and injected into natural gas distribution pipelines may generate offset credits. As discussed in the response to Energy Probe Interrogatory #2 filed at Exhibit I.C.EGDI.EP.2, two additional offset protocols are being developed that may include renewable natural gas.

g) If Enbridge was to act as an offset project developer/supplier, this might be done as a means to satisfy the Company's own compliance obligations. Because of this, Enbridge is not permitted to respond to the specifics of this question for reasons of confidentiality as set out in the Climate Change Mitigation and Low-carbon Economy Act, Cap and Trade Regulation, and/or the Report of the Board in respect of the Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities (EB-2015-0363). Information pertaining to this question is provided confidentially in Exhibit C, Tab 4, Schedule 1.

[1] In the landfill initiative protocol, natural gas transmission pipeline has following definition: "the same meaning as "pipeline transportation system" in O.Reg. 143/16". In O.Reg. 143/16 the definition of pipeline transportation system is "a facility consisting of a system of pipelines in Ontario, or a part of such a system, that transports natural gas and its associated installations, including storage installations but excluding straddle plants or other processing installations". This should be interpreted to include natural gas distribution pipelines.

Witnesses: A. Chagani
S. McGill
J. Murphy

STAFF INTERROGATORY #4

INTERROGATORY

Ref: Exhibit C / Tab 5 / Schedule 2 / p. 7, #19-21

Preamble:
Enbridge Gas states that in addition to ICF not considering the potential sale of offset credits associated with methane avoidance, the MACC report also "did not take into account the economic benefit resulting from the use of existing infrastructure and customer owned assets (furnaces, boilers, water heaters etc.) in the reduction of GHG emissions through the consumption of RNG."

Questions:

a) Please explain what Enbridge Gas believes the "economic benefit" would be as a result of using existing infrastructure and customer owned assets.
    i. Please explain how this is a prudent investment for ratepayers. Please provide supporting data and analysis.

RESPONSE

The introduction of RNG supplies to the Ontario natural gas distribution, transmission and storage system will allow existing infrastructure and customer owned assets to be utilised to their maximum potential while reducing carbon emissions associated with their use. Using these assets to their maximum potential will continue to maximize their economic efficiency. With respect to customer owned assets, RNG enables the reduction of customer GHG emissions without the customer having to replace or upgrade their heating or water heating equipment thereby conferring an economic benefit upon them as a result of the avoidance or deferment of the cost of replacing or upgrading gas consuming appliances. This is consistent with the Province's 2017 Long Term Energy Plan, page 114. To a limited extent, the Province has indicated a willingness to fund the cost differential between traditional gas supplies and RNG supplies such that ratepayers will be held harmless.

Witnesses: A. Chagani
S. McGill

STAFF INTERROGATORY #5

INTERROGATORY

Ref: Exhibit C / Tab 5 / Schedule 2 / pp. 9-10, #25-26

Preamble:
Enbridge Gas states that it is seeking the Board's approval of the use of long term gas cost forecasts in respect of RNG procurement volumes in the derivation of the PGVA Reference Price, as well as the Board's acceptance of the Long-Term Carbon Price Forecast (the "LTCPF") as part of its RNG Procurement Model.

Enbridge Gas also describes various steps that it plans to undertake in 2018 with respect to the procurement of RNG supplies, including an RFP process, negotiating and entering into a contractual arrangement with the Province, calculating the difference between the cost of the RNG purchased and the carbon abated cost of natural gas using the LTCPF and a forward price forecast for the commodity.

Questions:

a) Please describe what the provincial government has agreed to do with regards to RNG funding, including the terms it has agreed to and the length of time the government has committed to funding Enbridge Gas' RNG procurement. Please provide all supporting documentation.

b) Please explain how Enbridge Gas has ensured, or will ensure, that any funding agreement with the government includes a guarantee of sufficient funding for the length of any RNG supply contract term. Please provide details and supporting documentation.

c) Please explain what steps Enbridge Gas has taken, or intends to take, to ensure that, in the event that provincial funding were to be discontinued for RNG, ratepayers will not be left paying amounts for RNG in excess of the cost of conventional natural gas plus the price of carbon. Please provide details and supporting documentation.

d) Please explain whether Enbridge Gas will ensure, or intends to ensure, that agreements with RNG suppliers include a term that would deem an ending of provincial funding to constitute force majeure. Please provide details and supporting documentation.

e) Please describe what RNG procurement terms and conditions Enbridge Gas expects to negotiate in the RFP process.

f) Please indicate the status of any ongoing RFP process related to RNG procurement.

RESPONSE

a) The Company and the provincial government have not yet concluded negotiations concerning the province's financial support of the Company's RNG procurement proposal. Documents and presentations outlining and informing the Company's discussions with Government to date have been listed below and attached to this Exhibit.

1. February 18, 2016 – Enbridge meeting with Ministry of Energy ("MOE") on reducing emissions with RNG. Please refer to Attachment #1 to this Exhibit.

2. June 7, 2017 – Enbridge presentation at the Ministry of the Environment and Climate Change's ("MOECC") Organics Working Group on RNG, Decarbonizing the Gas Supply: Renewable Natural Gas & Hydrogen. Please refer to Attachment #2 to this Exhibit.

3. June 13, 2017 – Discussion between Enbridge personnel and personnel from the MOE and MOECC (discussion only, no attachment).

4. June 21, 2017 – Enbridge and Union Gas meeting with MOECC regarding the Landfill Gas Protocol (discussion only, no attachment).

5. July 26, 2017 – Enbridge and Union Gas Limited ("Union Gas") meeting with MOECC and MOE regarding RNG, Integration of Renewable Natural Gas. Please refer to Attachment #3 to this Exhibit.

Witnesses: A. Chagani
S. McGill

6. August 29, 2017 – Enbridge and Union Gas meeting with MOECC regarding RNG, Integration of Renewable Natural Gas. Please refer to Attachment #4 to this Exhibit.

7. November 15, 2017 – Enbridge and Union Gas meeting with the MOE and MOECC, Integration of Renewable Natural Gas. Please refer to Attachment #5 to this Exhibit.

8. November 22, 2017 – Enbridge and Union Gas submitted a list of RNG-ready projects to the MOECC and MOE. Please refer to Attachment #6 to this Exhibit.

9. December 12, 2017 – RNG Technical Meeting with Ontario Ministry of Agriculture, Food and Rural Affairs (“OMAFRA”) (discussion only, no attachment).

10. January 9, 2018 – Enbridge and Union Gas submitted a Draft RNG Implementation Discussion Document to the MOECC. Please refer to Attachment #7 to this Exhibit.

b) The Company will not proceed with the RNG procurement program unless it can be ensured that the funding agreement with the government includes a guarantee of sufficient funding for the length of any RNG supply contract term.

c) It is the Company’s intention to secure funding for the duration of the 10-year contracts, prior to signing contracts.

d) As indicated in the responses above to b and c, the Company will not enter into contracts unless the funding has been secured for the duration of the contracts.

e) Enbridge is currently developing its RFP; however, the Company expects it to include RNG price, term of supply agreement, delivery requirements and other contract terms and conditions.

f) Enbridge is currently in the early stages of developing its RNG RFP requirements. The Company expects to complete the RFP process in early 2018.

Witnesses: A. Chagani
S. McGill

Enbridge: Reducing Emissions with Renewable Natural Gas

February 3rd, 2016

Enbridge Gas Distribution

Enbridge – An Early Mover on Emission Reductions

– Enbridge's energy efficiency (DSM) programs between 1995 and 2014, have resulted in reductions of *18 million tonnes CO_2e*. This is equal to removing 3.5 million cars from the road for a year

– Cast iron replacement program – reduced fugitive GHG emissions by approximately 0.144 Mt CO_2e

– Today 75% of Enbridge Gas Distribution's 648 fleet vehicles run on natural gas, reducing emissions by 400 tonnes of CO_2e per year (over gas/diesel)

– Invested in leading green energy technology: Canada's Morgan Solar (industry leader in concentrated photovoltaics), Canada's Temporal Power (leader in 'flywheel' energy storage technology); launched North America's first low-flow technology hydroelectric dam at Wasdell Falls, Ontario.

– Partnered with Hydrogenics to develop a Power-to-Gas, energy storage plant to provide "green hydrogen" in the GTA. By 2017, it will convert off-peak, surplus renewables (wind, hydro, etc.) to green gas for storage. Once stored as a gas, this renewable energy has multiple pathways back to consumers as zero-carbon fuel for home heating, transportation of dispatchable power.

Fitting Natural Gas into the Cap & Trade Landscape

Supporting Cap and Trade / Collaboration with Government to Reduce Emissions

- Enbridge supports Ontario’s proposed Cap and Trade Program, and we look forward to a partnership with the province to help meet our GHG reduction targets and economic goals
- **It is critical that cap-and-trade proceeds are recycled into GHG-reducing initiatives in the sectors from which they are collected**
- Reinvesting Cap and Trade proceeds into the natural gas sector will help to transition the market and protect ratepayers from rapid and significant cost escalations
- For the natural gas sector, this means **empowering utilities to make new investments in the following key areas, including renewable natural gas;**

Fitting Natural Gas into the Cap & Trade Landscape

Investment in four key areas can drive 21 MT of annual reductions

- **Reducing per-customer consumption with more conservation/CHP (~9Mt CO2e)**
  - The most cost effective way to reduce per-customer consumption, which simultaneously reduces emissions and customer bills. Customers saved $2.43 for every $1 spent by Enbridge on DSM
  - Need ensure that incremental conservation spending is delivered by existing utility experts with proven track records and strong customer relationships
- **Greening the natural gas supply (~8Mt CO2e)**
  - Renewable natural gas (RNG) has untapped and significant emission reduction potential, and could meet up to 18% of Ontario's demand by 2035. Future innovation could grow this number further.
- **Fuel switching in the transportation sector (~3Mt CO2e)**
  - Natural gas has up to 25% lower GHG emissions and is up to 40% less expensive than diesel or gasoline. Access to refueling stations in Ontario is limited, while government incentives exist in Quebec, BC, New York, Pennsylvania, Ohio, Illinois and other areas
- **Make Investments in innovation (to close the gap)**
  - Innovation levy or similar mechanism to make these investments possible

ENBRIDGE

Ontario's Emission Reduction Forecast (2017-2030)

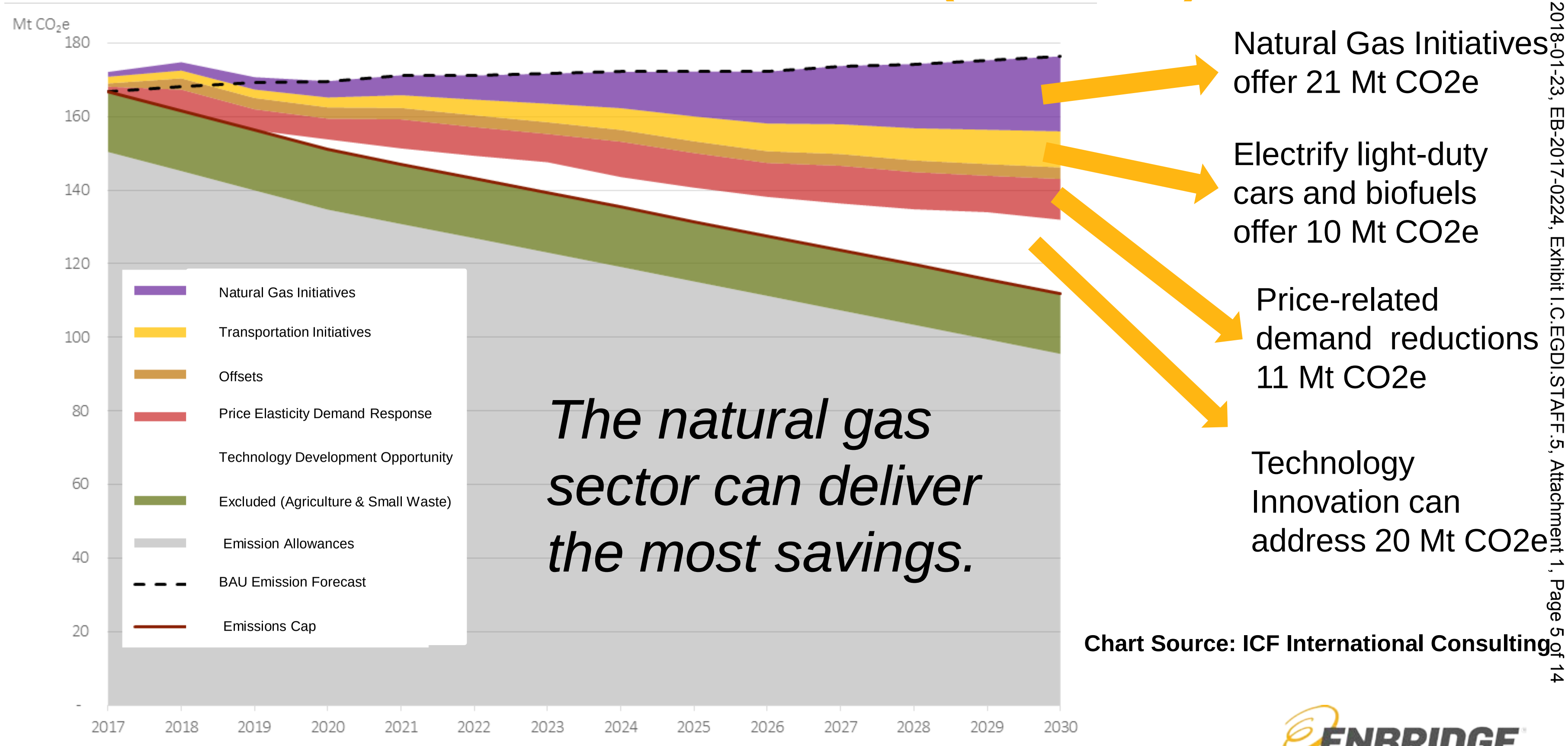
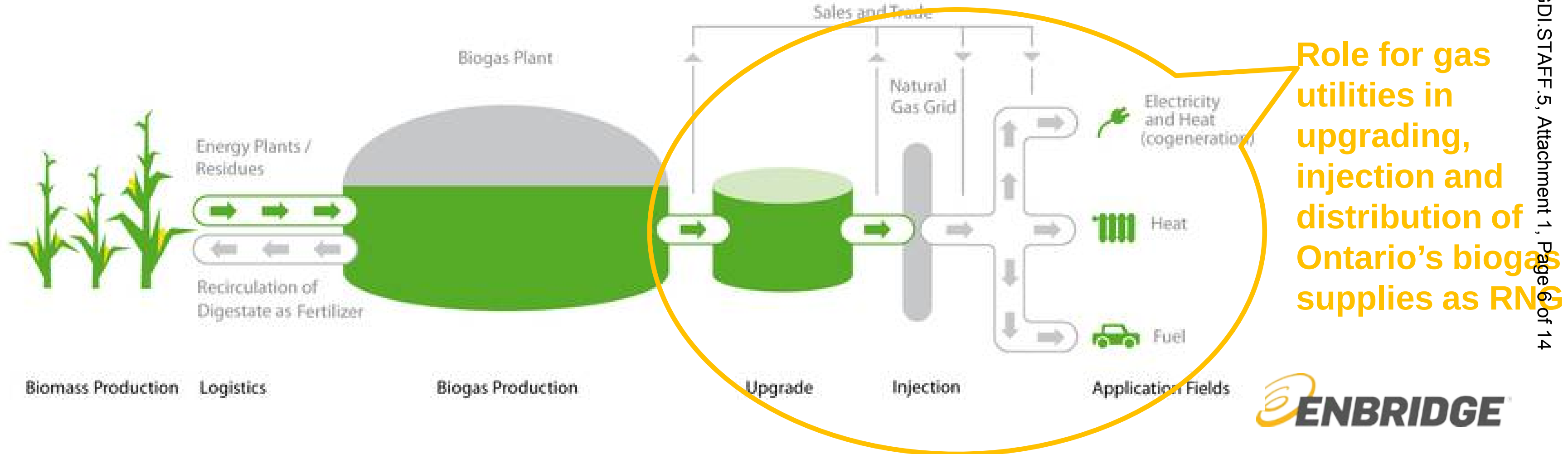


Chart Source: ICF International Consulting

Greening the Natural Gas Grid: Powering Ontario on Waste

RNG (Renewable Natural Gas) part of a diversified supply meeting Ontario's renewable energy needs

- Created from local supply (i.e. landfill, municipal organic waste; agricultural waste: cow or chicken manure; wastewater or treatment facilities)
- Local employment opportunities and partnerships with agriculture, forestry, waste and sewage sectors
- Once injected into natural gas pipelines, multiple paths to consumer exist for this renewable energy
  - Renewable home heating, fuel for city bus and truck fleets (i.e. Hamilton) or CHP

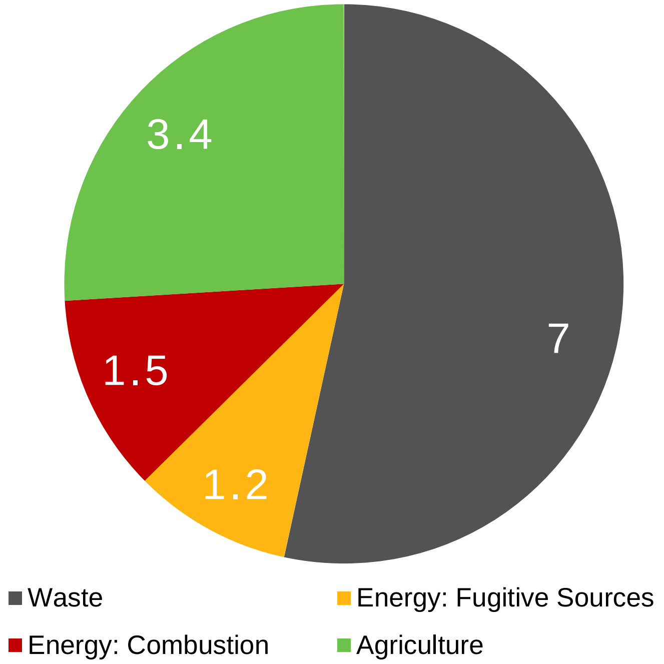


ENBRIDGE

Maximize Emission Offsets/GHG Reductions under Cap & Trade

- Ontario emits 13.1 Mt CO2e each year as methane from landfill waste (7 Mt) and livestock (3.4 Mt)
- Wastewater treatment and source separate organic (SSO) a growing source of methane
- Methane management (e.g. flaring) can be a source of emission offsets from livestock, SSO, etc.
- As an alternative to venting, or flaring - the cleanup and injection of this renewable biogas into pipelines is significantly better for the environment, and is considered carbon neutral in leading jurisdictions.
- Today, we incent biogas to power (~ 35% efficient). As alternative, upgraded this to RNG and ~ 90% of this renewable energy is delivered to consumers directly offsetting conventional natural gas.

Methane Emissions – Ontario (2012) (CO2e Mt)



* Environment Canada's "National Inventory Report 1990–2012: Greenhouse Gas Sources and Sinks in Canada", published in 2014.

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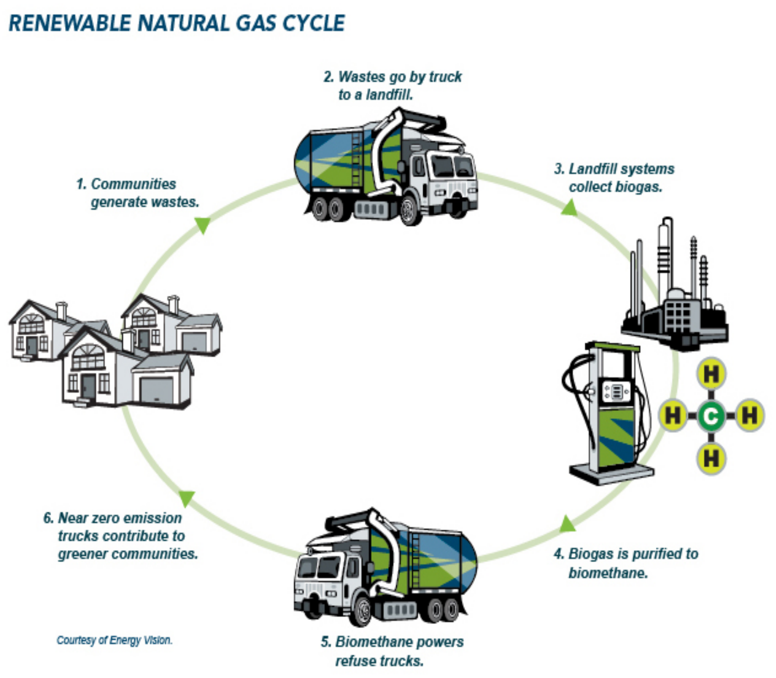
Greening the Natural Gas Grid Continued

The future of waste collection with RNG



– Incorporating Renewable Natural Gas (RNG) in Ontario's pipeline network has significant benefits:
  - less expensive than renewable electricity
  - not intermittent / does not need to be backed up
  - It can easily be stored

– While the province moved quickly in announcing support for more DSM and NGVs to lower GHGs, acceptance and support of RNG has lagged behind.

– Ontario has made significant investment in renewable electricity. With the electricity grid largely decarbonized, more focus should be shifted to greening the natural gas grid – RNG offers a much larger emission reduction profile (vs. renewable electricity) and it is significantly less expensive.

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Greening the Pipeline Grid: Environmental Endorsements

Support for RNG

"…renewable natural gas can provide a double benefit in reducing greenhouse gas (GHG) emissions. First, the carbon dioxide emitted during combustion equals the amount that was removed from the atmosphere by the bioenergy source during its lifetime. Second, the collection of the source material can prevent methane, a much more potent greenhouse gas than carbon dioxide, from escaping into the atmosphere.

- **Environmental Commissioner of Ontario (2012)**

"RNG is a renewable, non-intermittent form of energy generated from waste. Unlike some other forms of renewable energy, it can be stored and dispatched as necessary through injection into the natural gas distribution system…. RNG will reduce Ontario's GHG emissions by reducing methane emissions through natural decay and by replacing conventional natural gas. This will contribute directly to Ontario's GHG reduction targets of 15% by 2020 and 80% by 2050.

…. RNG Program enables capture and redirection of methane that would otherwise be released into the atmosphere with the effect of creating 21 times more greenhouse gases ("GHGs")…. RNG results in a "made in Ontario" energy supply that provides economic benefits through local job creation."

- **Ontario Sustainable Energy Association (2011)**

January 29th, 2016

Support from OMAFRA

Support for RNG from OMAFRA's Website

Environmental and Societal Benefits of Using RNG from Farm and Food-Based Biogas Systems

– "In addition to the climate change benefits associated with using methane from a non-fossil fuel source, when markets for RNG can be found, the operation of farm and food-based biogas systems results in benefits that include:

– **Emissions reduction:** the storage, land application, or disposal of untreated manure and food waste can produce greenhouse gas or smog-forming emissions. By harvesting the carbon in a biogas system and using it as Renewable Natural Gas, emissions from conventional processes are avoided.

– **Avoid land filling:** By using food waste as a biogas input, food waste and food processing by-products that are currently land-filled can be diverted. While a portion of the methane emissions from landfills can be captured once a landfill is capped, it is much more efficient to harvest this methane directly and fully in a biogas system."

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January 29th, 2016

RNG – A Revenue Stream for Key Sectors

Recent Endorsements from the Agricultural and Waste Management Sectors

- "The development of a carbon allowance market… will improve the economics of a number of industry options that if implemented would help the province meet its climate change mitigation goals. These include capture and cleaning of gases from landfills, digesters, and EfW facilities for injection in to the natural gas pipeline system.
- The government could encourage the establishment of Ontario capacity for renewable natural gas supply by providing price signals to cover any gap between the allowance price and the opportunity cost of such investments." - **Ontario Waste Management Association (OMWA) 2015**
- "Biomass based products have the potential to create significant growth for Ontario's agri-food sector while providing a renewable source of biologically-derived natural gas [RNG]…. Ontario needs to encourage these new bio-based technologies to ensure future energy competitiveness."
  - **Ontario Federation of Agriculture, Pre-Budget Submission (2016)**

Catching up with Leading Jurisdictions

RNG (Renewable Natural Gas) to Meet Ontario's Energy Needs

- 2009: Enbridge proposed to own/operate assets to produce/distribute RNG - OEB ruled that the production of renewable energy is seen as a competitive market activity

- 2011: Enbridge proposed to acquire RNG as part of their supply portfolios - OEB ruled it had jurisdiction, was a novel application, but, needed more on cost-benefit analysis

Other Jurisdictions

- 2011: FortisBC launched RNG offering for residential customers targeting RNG supplies from landfills, agriculture, waste treatment facilities, and dairy farms. FortisBC' s renewable natural gas offering was granted Carbon Neutral Product status by Offsetters, Canada's leading carbon management solutions provider.
- 2012: Germany operates over 80 RNG facilities and over 100 RNG vehicle refueling stations
- 2013: Quebec's BFI Canada launches largest RNG transformation project in Canada
- 2014: California Gas utilities develop RNG facilities under state's "Directed Biogas" program

A functioning RNG market has not yet materialized in Ontario. The province risks losing ground to competing jurisdictions like CA, and QC; but, a renewable portfolio standard (RPS), administered by natural gas utilities, could support RNG developments

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Next Steps:

- Government should express policy support for renewable natural gas as part its plan to reduce emissions in the larger energy economy (e.g. home heating, heavy-duty transportation, etc.) As part of the forthcoming Climate Change Action Plan, mandate a specific RNG target by a specific date.

- To support the RNG target, establish a renewable portfolio standard (RPS) for Ontario’s natural gas utilities. Unlike a Feed-in-Tariff, an RPS framework will allow gas utilities to actively manage the sourcing of RNG while driving costs down.

- Within the RPS framework, incent i) utility procurement of diversified green gas supplies from the marketplace, and ii) development of a utility upgrading service to convert biogas to RNG.

- Evaluate the opportunity for Ontario’s “use-of-proceeds”, under cap-and-trade, to support the development of a healthy and robust RNG market. This can complement an RPS for renewable natural gas by helping to driving down the costs for this emerging renewable energy supply. Ontario’s Green Investment Fund, could also be considered to help advance the early market.

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Questions?

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Decarbonizing the Gas Supply:

Renewable Natural Gas & Hydrogen

ENBRIDGE

External Affairs Canada

June 07, 2017

Enbridge: An Evolving Energy Company

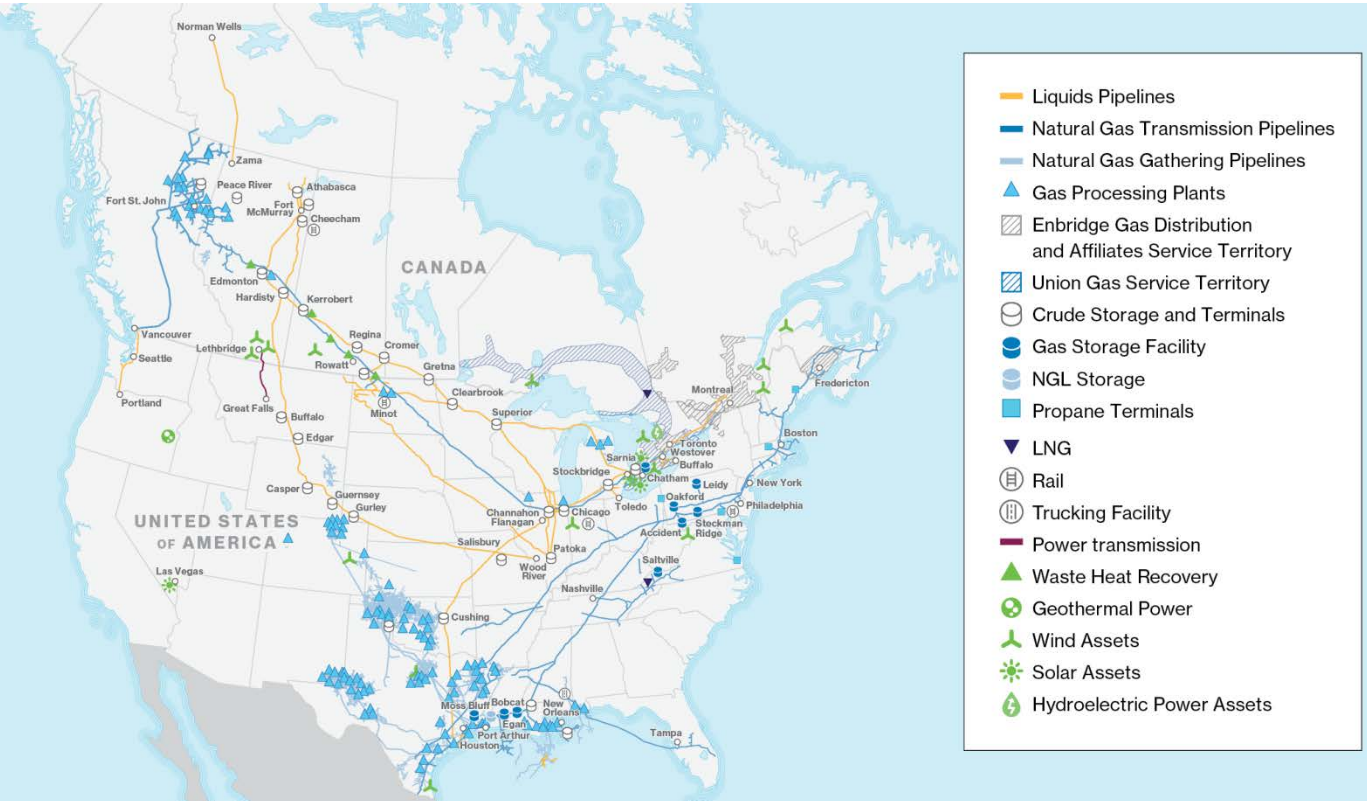
Helping to deliver 75% of Ontario's total energy use each year

Who is Enbridge?

- 4th largest company in Canada
- Operates the longest **crude oil** transportation system in the North America
- Operates Canada's largest energy distribution companies: **Enbridge Gas & Union Gas**; serve consumer markets in Ontario, Quebec & New Brunswick and New York
- Canada's second largest investor in **renewables** (wind, solar, hydroelectric, geothermal etc.)

Enbridge in Ontario:

- Delivers 95% of Ontario's natural gas to 3.5M customers (75% of homes); delivers 96% of Ontario's crude oil
- 3 wind farms, 3 solar farms, a hydroelectric dam & hydrogen facility



An Enbridge Company

Enbridge Gas Distribution Inc.

Why Renewable Natural Gas & Hydrogen?

Decarbonizing the Gas Supply

ENBRIDGE Life Takes Energy

Energy Costs:	
Traditional Natural Gas	2 cents / kWh
RNG (Low-Cost)	4 cents / kWh
RNG (High-Cost)	8 cents / kWh
Electricity (Mid-Peak)	13 cents / kWh
Electricity (On-Peak)	19 cents / kWh

- Committed to providing customers with the energy they need and want
- Customers are increasingly looking for cost-effective ways to lower their carbon footprint
- Based on current rates natural gas is 68% more affordable than electricity and 65% less than heating oil
- Upgraded (“scrubbed”) biogas or renewable natural gas (RNG) can be injected into the natural gas grid and is a proven method to decarbonize home heating, transportation and industrial processes
- After conservation, RNG is one of Ontario’s lowest-cost carbon abatement options
- Large municipalities have already approached Enbridge to assist in turning their biogas from landfills, waste water treatment plans and organic programs into RNG for municipal transportation purposes (Hamilton, Toronto, Peel, Durham etc.)
- Hydrogen produced from water & excess renewable electricity can also be injected into the natural gas grid (with some limitations) to further decarbonize traditional natural gas

Next Steps for Utility-led Renewable Natural Gas

Decarbonizing the Gas Supply

ENBRIDGE Life Takes Energy™

- Ontario's Climate Change Action Plan (CCAP) states that Ontario intends to create a renewable content requirement for natural gas and will provide $60M to 100M in support for RNG

- CCAP also supports refueling infrastructure and vehicle subsidies to move heavy-duty diesel transportation to natural gas (15% GHG emission reduction, further with RNG/hydrogen)

- Expect Ontario's Minister of Energy to direct the Ontario Energy Board (OEB) to establish a renewable portfolio standard (RPS) for Ontario's natural gas utilities, providing a mandate to source sufficient RNG to meet a government target (ie. 2% of system supply requirement by 2021 or 5% by 2030)

Next Steps:

- Encourage favourable offset protocols development that support RNG development (landfill gas & organics)

- OEB application and hearing process regarding meeting government targets

- Encouraging Ontario's 'Waste-Free Ontario' strategy to recognize Ontario's significant targets for RNG as part of its organics diversion plan; as well as the need for centralized organics processing where possible

Integration of Renewable Natural Gas

—

A Plan to Harness RNG for Ontarians

Enbridge Gas Distribution / Union Gas Limited
For Discussion

Framework Proposal

To Drive an RNG Market in Ontario

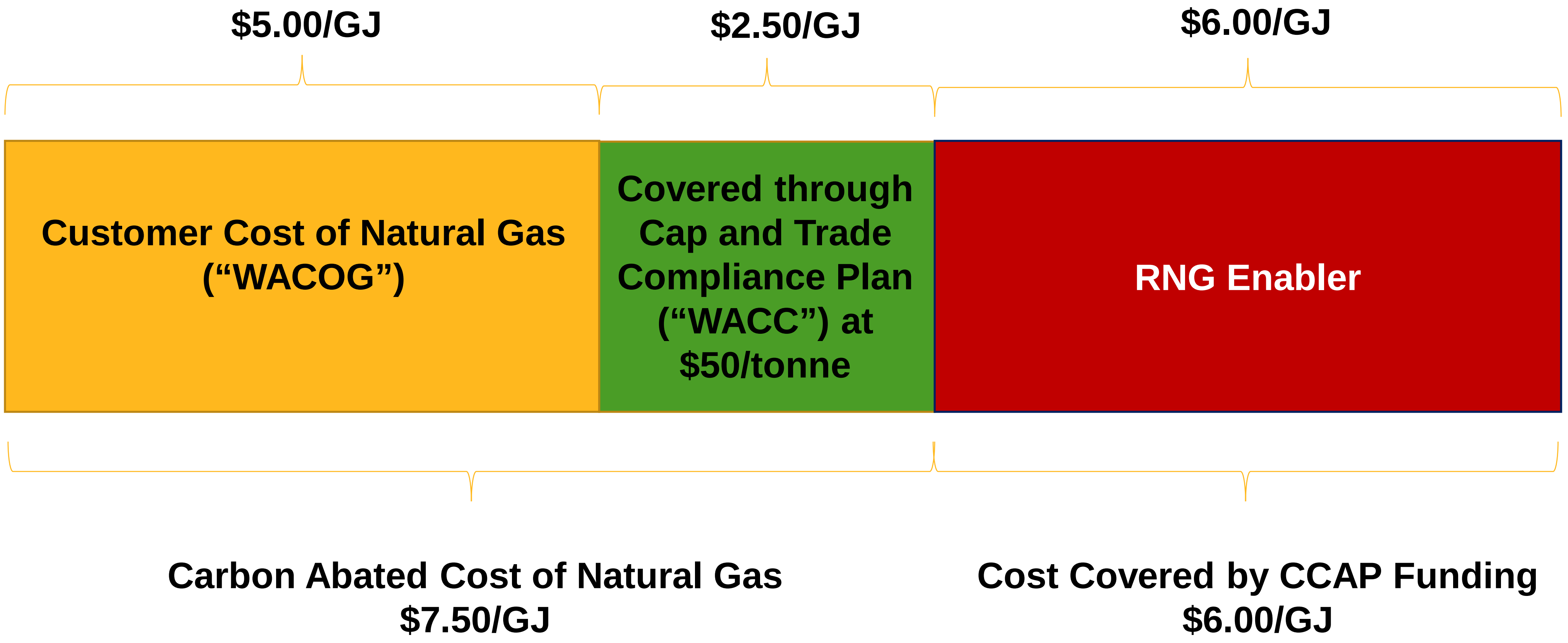
Enbridge and Union Seek

- The ability to administer a competitive procurement process for RNG
- Funding from CCAP to defray the gap between RNG and the carbon abated cost of natural gas for the duration of contracts
- Appropriate treatment of Offsets
  - Recognize the two value streams of RNG
  - Landfill and AD protocols ready for January 1, 2018

RNG Gap Funding Proposal

Illustrative Example

RFP Price of RNG of $13.50/GJ



WACOG is the Weighted Average Cost of Gas, WACC is the Weighted Average Cost of Compliance

RNG Created from CCAP funding and Offset Value

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CCAP Funding Level applied to project term	Percentage of Total Gas Throughput * (fuel substitution only)	Percentage of Total Gas Throughput (offset creation and fuel substitution)	Market for Fuel Substitution and Offset Creation (Annual kilotonnes, PJs)	Carbon Abated CAPP + Offset Funding Over Life of Contract ($/tonne)
$100MM	0.1%	0.2%	335 / 6.8	$30
$200MM	0.3%	0.3%	725 / 14.7	$28
$400MM	0.5%	0.6%	762 / 15.4	$52
$800MM	1.0%	1.1%	1,124 / 22.8	$71

- Higher GreenON funding achieves greater throughput coverage and extends market development window for RNG
- Assumptions
  - Ten year RNG contracts
  - Estimated RNG market costs, Toronto city gate gas costs, Carbon at $50/tonne
  - Conservative estimation of carbon offset creation
  - No financial discounting

*2016 Total Gas Throughput was 925 PJ, System Supply was 430PJ, thus percentages would be 2.1x higher is system gas was the basis

Operational Details

Utility Role in RNG Development

Utilities will administer RNG supply arrangements for GreenON

- Procurement:
  - Conduct procurements for RNG to meet an increasing percentage of gas supply with Ontario based RNG/Green Gas
  - Pre-funding of minimum ten year supply contracts for an initial term
- Facilitation:
  - Promotion of the Ontario RNG industry
  - Gas network access – regulated measurement and injection services
  - Create an optional regulated biogas clean-up rate / service to facilitate RNG
- Compliance:
  - Provide RNG source audit and verification information to ensure strict adherence to target percentage requirements and confirm additionality for offset purposes
  - Calculation and allocation of payments from GreenON

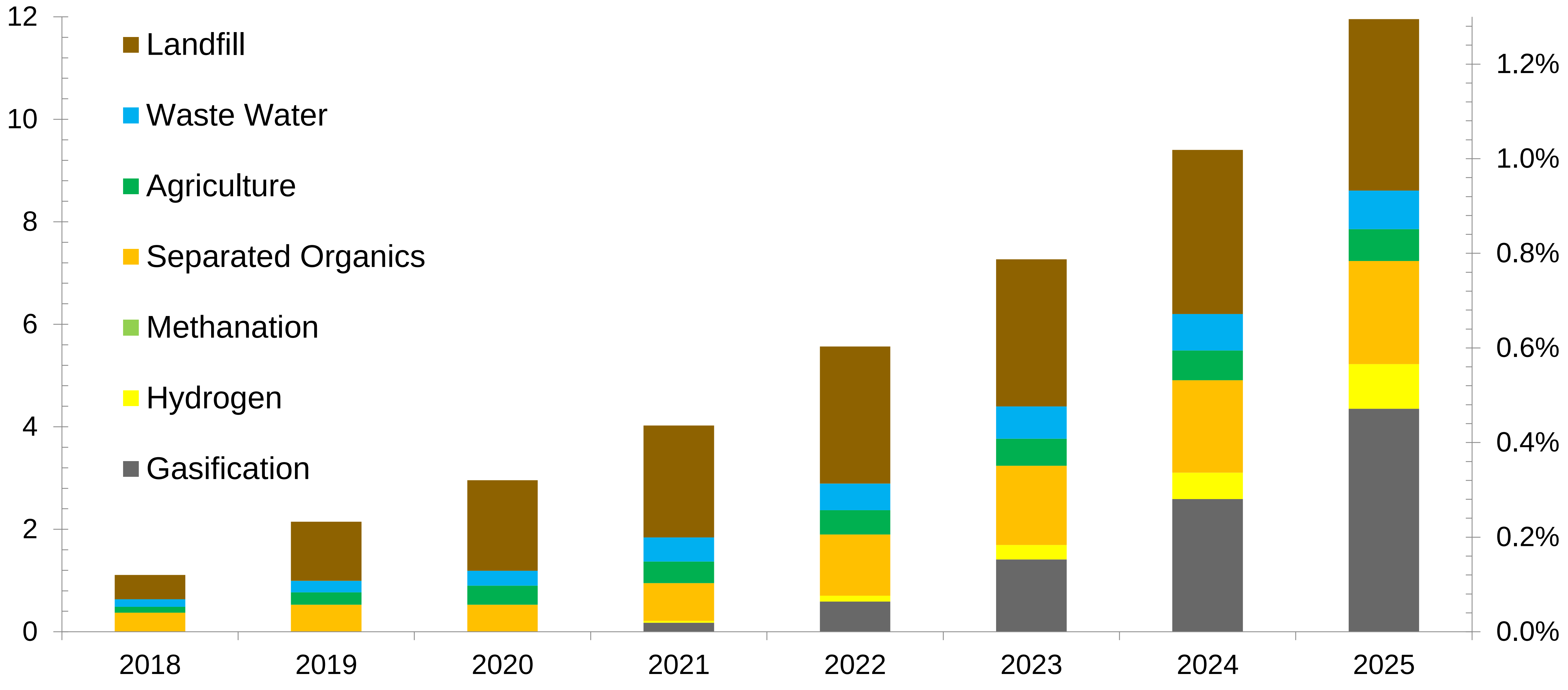
Key Differences between Ontario and Quebec

Early Mover Advantages for Quebec

- Total Gas Throughput: Ontario - 925 PJ, Quebec - 210 PJ
  - 430 PJ of system gas in Ontario, 74 PJ in Quebec
- Quebec is planning to targeted 5% of total gas by 2020
  - Most RNG will be landfill based
  - Quebec is already producing RNG at three facilities
  - 5-6 PJ will be available by 2020
- Ontario has one operating RNG facility
  - Hamilton’s Woodward Street waste water plant can produce between 0.1 – 0.2 PJ/year
    - This is only 0.01% and 0.02% of Ontario’s total gas throughput

Renewable Natural Gas Volumes

PJ Total Supply Potential and Percentage of Total Throughput



Questions

Comparing Abatement Opportunities and their Costs

Estimates on RNG Costs $/tonne

- RNG is a cost effective means to drive abatement in Ontario versus other options such as broad-scale residential electrification
- In fact, the utilities anticipated the cost of RNG from various feedstocks is approximately 15-30% lower than what the OEB commissioned MACC study has anticipated
- The primary difference are from the following observations:
  - MACC did not include offset values against the relevant feedstock streams
  - MACC included smaller landfills and uneconomic waste water facilities
  - MACC did not include economic offsets from waste streams (tipping/gate fees)

Ontario needs market data for RNG to optimize a carbon abatement portfolio

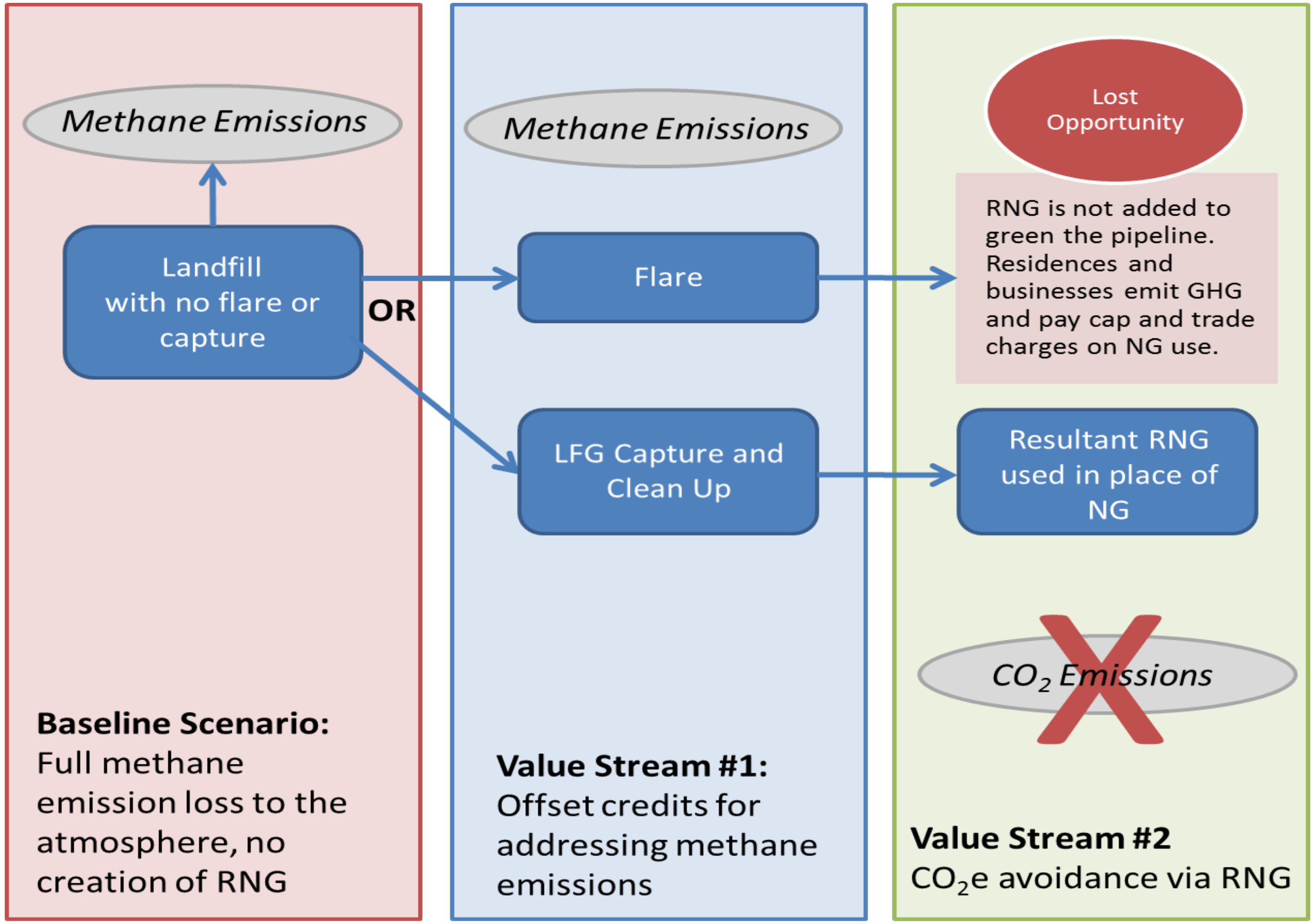
Offset Protocols

Addressing the 'Double Counting' Issue

- Fair offset protocols are critical to ensuring that RNG is valued appropriately; the protocols will inform how much of it we can secure and at what cost, which will impact Ontario's progress on its emission reduction targets

- Two completely distinct streams of emission reductions exist where RNG is created from methane which would have otherwise been vented into the atmosphere:

1. Traditional natural gas is displaced (this benefit exists with all RNG)
2. Methane which would have otherwise been vented is captured and used (the additional benefit which should be offset eligible)



Key Takeaways

- A firm renewable portfolio standard for natural gas requires market data
  - Unlike Quebec, an Ontario based RNG market is yet to be established

- Enbridge can assist in launching a market for RNG by:
  - leveraging the Compliance Framework to determine a carbon abated price of natural gas
  - Establishing a competitive procurement process for long term RNG supply
  - applying CCAP funds and offset protocols to buy down RNG costs to the carbon abated price of natural gas

- Results from the RNG process can inform the setting up of firm renewable portfolio standard for natural gas in Ontario

Integration of Renewable Natural Gas

—

A Plan to Harness RNG for Ontarians

An Enbridge Company

Enbridge Gas Distribution / Union Gas Limited
For Discussion

Driving a Ontario RNG Market

Enabling a Nascent Market

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Enbridge and Union Seek

- *The ability to administer a competitive procurement process for RNG*
- *CCAP Funding will defray the gap for gas customers between RNG and the carbon abated cost of natural gas until a new regulatory framework is in place*

Benefits

- *Fastest route to creating an Ontario RNG market by using existing regulatory frameworks and funding mechanisms*
- *All utility customers (sales and direct purchase) can access RNG at a carbon abated price*
- *Provides price and volume data for informed RNG policy options*

Options for Implementation

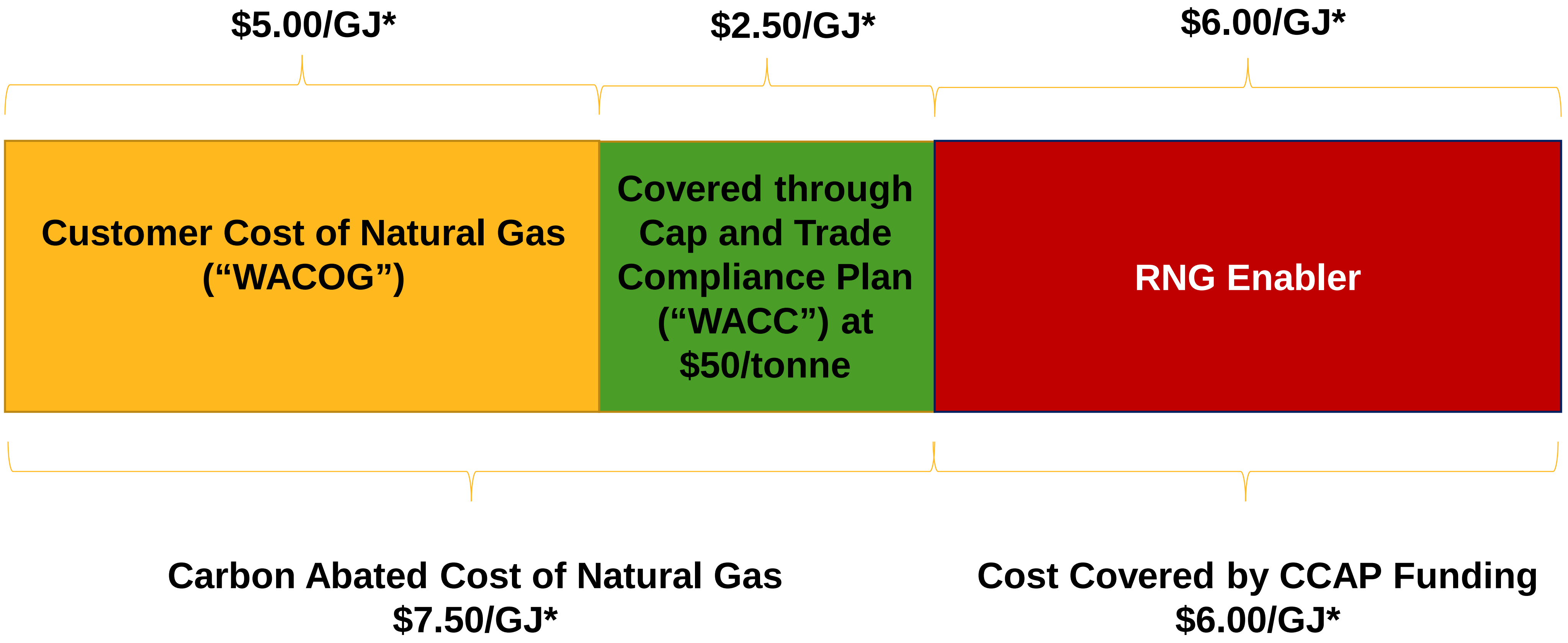
Unintended Cost Consequences

Option	Benefits	Disadvantages	Timing
Status Quo	• None	• There is no Ontario RNG market • Feedstocks will leave Ontario for first mover markets	• Immediately lost market opportunities
Clean Fuel Standard Regulations	• Targeted volumes	• Unknown price impacts for customers	• Regulations - 6 month implementation • OEB proceedings – 1+ year
Renewable Portfolio Standard (RPS) Directive	• Targeted volumes	• Unknown price impacts for customers	• Directive – 3 months • OEB proceedings – 1+ year
CCAP Funded Development	• Data from RFPs • Informed cost of abatement	• First mover advantage to some suppliers	• RFPs could be run in weeks following CCAP funding • Informs future CFS/ RPS

RNG Gap Funding Proposal

Illustrative Example

RFP Price of RNG of $13.50/GJ*



*WACOG is the Weighted Average Cost of Gas, WACC is the Weighted Average Cost of Compliance, *Illustrative Pricing*

RNG Created from CCAP Funding

Investment Drives Low Cost Abatement

CCAP Funding Level applied to project term	Percentage of All Gas Throughput*	Percentage of Residential/Small Commercial* Gas Throughput	Carbon Abated CAPP + Offset Funding Over Life of Contract ($/tonne)
$200MM	0.3%	0.6%	$28
$400MM	0.6%	1.2%	$52
$800MM	1.1%	2.2%	$71

- Higher GreenON funding achieves greater throughput coverage and extends market development window for RNG
- Assumptions
  - Ten year RNG contracts, Carbon costs at $50/tonne
  - Industrial (Direct Purchase) customers are able to voluntarily contract with the utility for RNG at the carbon abated price
  - *Offset Creation and Fuel Substitution

2016 Total Gas Throughput was 925 PJ, System Supply was 430PJ, thus percentages would be 2.1x higher is system gas was the basis

Enabling RNG

Utilities Role in RNG Development

ENBRIDGE
Life Takes Energy™

The Utilities are prepared to make RNG a success in Ontario

- 2011 OEB Application for an RNG Program
  - A comprehensive program to develop an Ontario RNG Industry
  - Contracts, Pricing, Processes and Standards
- Biogas injection standards are ready
- Working with potential RNG suppliers to prepare for system connections
- Creating an optional regulated biogas clean-up rate / service

We will work to ensure that CCAP funding will have immediate effect and provide the best value to ratepayers

Key Takeaways

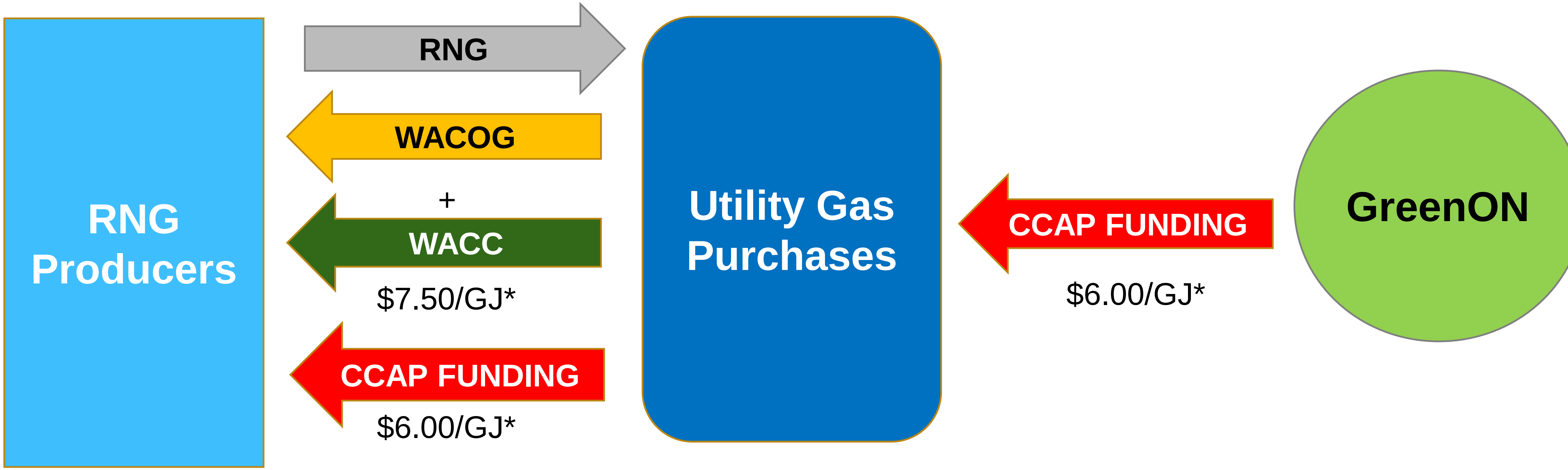
Delivering RNG Effectively to Customers

- Both Clean Fuel Standards or Renewable Portfolio Standards need to be informed by Ontario market data
  - BC and Quebec have viable RNG Markets with data
  - Without long term utility contracts, RNG will be sold into California
- Utilities are working on accelerating RNG production in Ontario
  - Leveraging the OEB Compliance Framework to optimize CCAP funds to buy down RNG costs to the carbon abated price of natural gas
  - Establish competitive procurement processes for long term RNG supply
  - Utility long term contracts will ensure best abatement costs for Ontario
  - Voluntary path for purchase of RNG from utilities is an option for direct purchase/industrials
- Informed implementation of a CFS/RPS 2030 Target

Questions

Operational Model

Option A – Utilities administer and execute with CCAP funding assistance

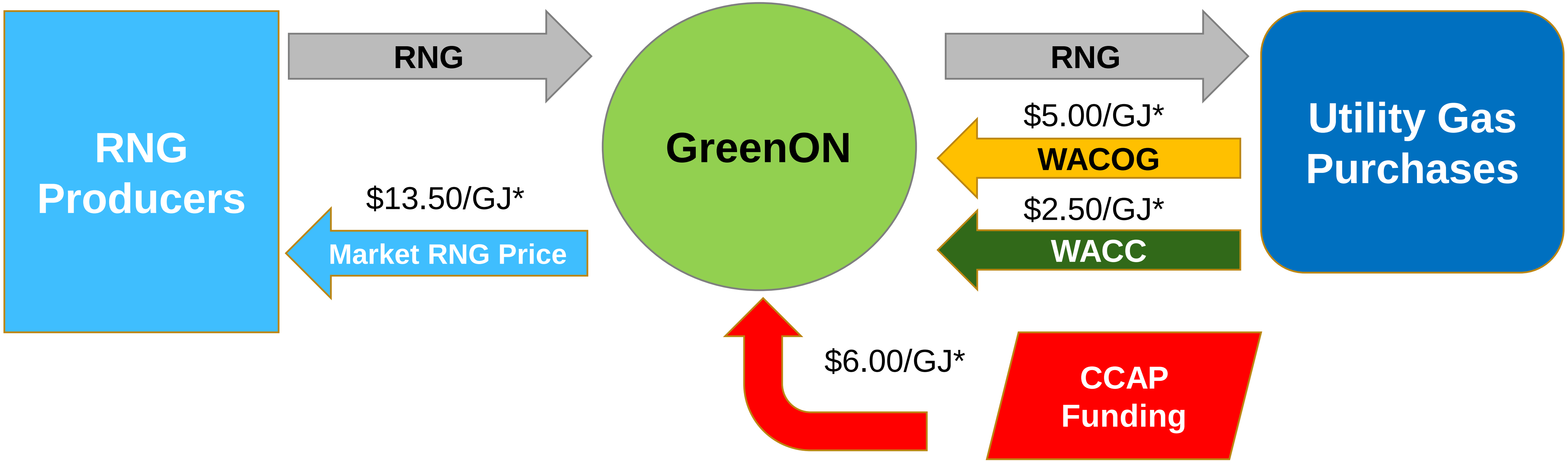


- CCAP will fund RNG for Utilities at $6.00/GJ*
- Utilities will contract for RNG at $13.50/GJ* based on $7.50/GJ* Carbon Abated Cost on Natural Gas plus $6.00/GJ from CCAP

WACOG is the Weighted Average Cost of Gas, WACC is the Weighted Average Cost of Carbon Compliance, *Illustrative Pricing

Operational Model

Option B – Utilities procure RNG from GreenON and facilitate market



- GreenON will contract with RNG producers for supply at market RNG prices at $13.50/GJ*
- GreenON will sell carbon abated gas to the utilities ($5.00/GJ* – WACOG + $2.50/GJ* – WACC)
- CCAP will fund GreenON for difference at $6.00/GJ*

WACOG is the Weighted Average Cost of Gas, WACC is the Weighted Average Cost of Carbon Compliance, *Illustrative Pricing

Key Differences between Ontario and Quebec

Early Mover Advantages for Quebec

- Total Gas Throughput: Ontario - 925 PJ, Quebec - 210 PJ
  - 430 PJ of system gas in Ontario, 74 PJ in Quebec
- Quebec RNG market participation is voluntary and allows for industrial / direct purchase to choose full carbon mitigation
- Quebec is planning to targeted 5% of <u>total</u> gas by 2020
  - Most RNG will be landfill based
  - Quebec is already producing RNG at three facilities with offsets sold to California
  - 5-6 PJ will be available by 2020
- Ontario has one operating RNG facility
  - Hamilton's Woodward Street waste water plant can produce between [redacted]
    - This is only [redacted] of Ontario's total gas throughput

Integration of Renewable Natural Gas

—

A Plan to Harness RNG for Ontarians

An Enbridge Company

Enbridge Gas Distribution / Union Gas Limited
For Discussion

Driving a Ontario RNG Market

Enabling a Nascent Market

Goals:

1. Procure RNG in a timely manner for Ontario gas customers; aware that Ontario's most efficient projects are already being courted by WCI Participants - California & Quebec

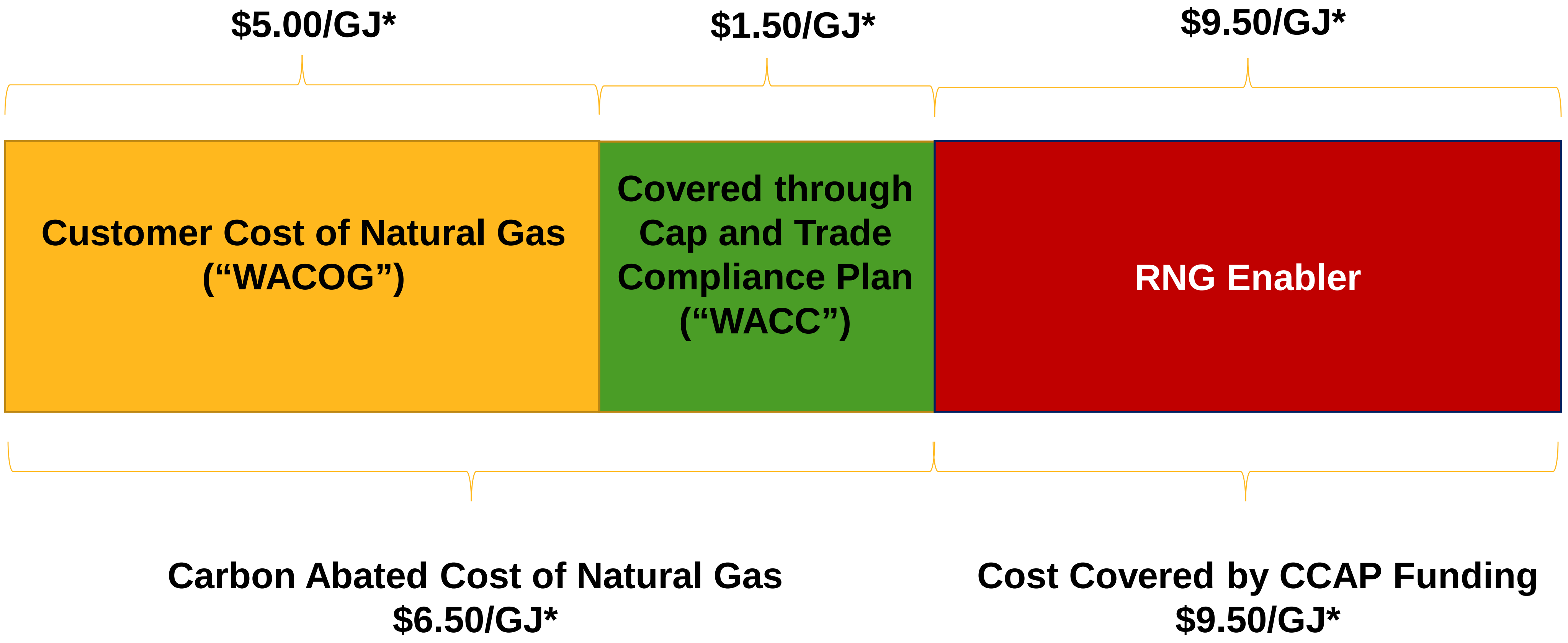
2. Sign contracts in 2018 to provide producers with certainty and Ontarians with the lowest-cost RNG possible resulting in efficient carbon abatement

3. Prevent energy bill increases for Ontario ratepayers by utilizing CCAP Funding to cover cost differential between traditional gas supplies and RNG.

RNG Funding 'Gap'

Illustrative Example

10-year RFP Price of RNG of $16.00/GJ*



*WACOG is the Weighted Average Cost of Gas, WACC is the Weighted Average Cost of Compliance, *Illustrative Pricing*

Timeline to Implementation

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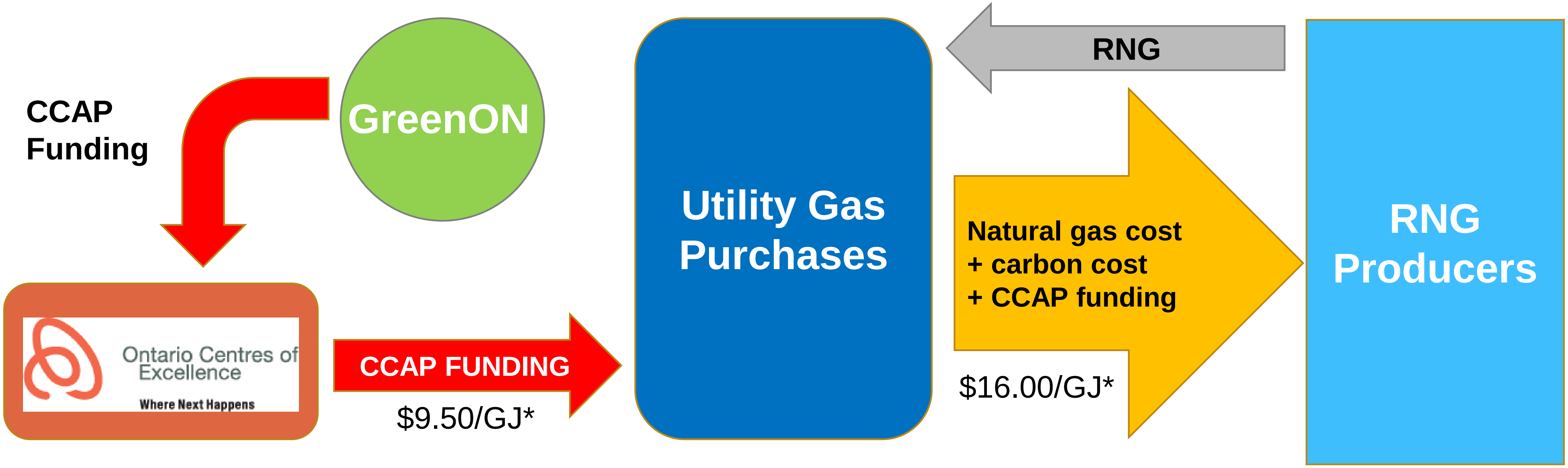
Nov 2017 - Enbridge Gas and Union Gas filed ‘Cap & Trade Compliance Plans’ with the Ontario Energy Board (OEB) requesting early approval to acquire RNG based on 10-year RNG procurement agreements, a 10-year forecast of conventional natural gas prices and the OEB’s 10-year forecast of carbon; pending government funding of the RNG Enabler amount.

Jan 2018 – Enbridge & Union Gas issue an conditional RFP (awards pending OEB approval), for 10-year RNG procurement contracts beginning in 2018. Government announces & flows CCAP funding for RNG to Ontario Centres of Excellence (OCE). Enbridge and Union Gas will make a pro-rata portion of acquired RNG available to other smaller Ontario Gas distributors at cost and industrial (direct purchase) gas users.

Jan/Feb 2018 – OEB makes a determination on gas utilities request for long term contracts for RNG and the use of long term commodity and carbon prices.

Apr 2018 – Enbridge & OCE awards RNG contracts with transparency to OEB; all RNG procured would be made available to all willing gas utilities and industrial (direct purchase) gas users.

Operational Model



- RNG bid at $16.00/GJ*, commodity at $5.00/GJ* and OEB Mid-Range Long Term Carbon Price Forecast at $1.50/GJ* with CAPP funding the difference

***Illustrative Pricing**

Decarbonizing Ontario's Natural Gas Supply

Investment In Renewable Natural Gas Drives Low Cost Abatement

CCAP Funding Level applied to project term	Percentage of System Gas Throughput*	Volumes (PJ)	Carbon Abated CCAP + Offset Funding Over Life of Contract ($/tonne)	MegaTonnes of Carbon abated over 10-year contracts	Number of Potential Projects Asssisted
$100M	0.4%	1.7	$30	3.3	10 to 15
$200M	0.7%	3.2	$34	5.9	20 to 30
$400M	1.3%	5.5	$53	7.6	35 to 50
$800M	2.3%	9.8	$71	11.2	50 to 80

- Higher GreenON funding achieves greater throughput coverage and allows an RFP process to build Ontario's RNG market data

- Assumptions
  - Ten year RNG contracts
  - Industrial (Direct Purchase) customers are able to voluntarily adopt RNG as an abatement option
  - *Offset Creation and Fuel Substitution used for all calculations

2016 Total System Supply was 430PJ

Enabling RNG

Utilities Role in RNG Development

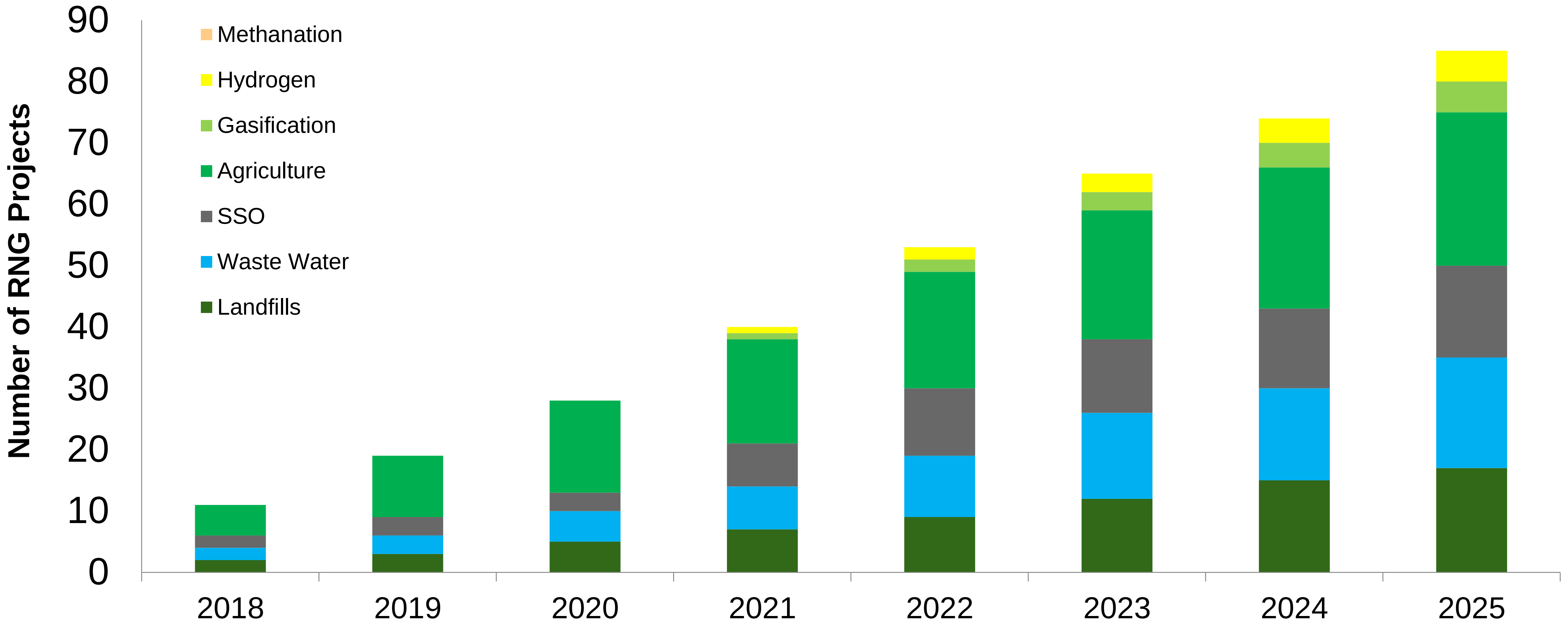
The Utilities are prepared to make RNG a success in Ontario

- 2011 OEB Application for an RNG Program
  - A comprehensive program to develop an Ontario RNG Industry
  - Contracts, Pricing, Processes and Standards
- Biogas injection standards are ready
- Working with potential RNG suppliers to prepare for system connections
- Creating an optional regulated biogas clean-up rate / service
- Ability to run an RFP for gas procurement quickly

We will work to ensure that CCAP funding will have immediate effect and provide the best value to ratepayers

Appendix

Potential Number of Ontario Projects by Contracted Year



Renewable Natural Gas Projects in Ontario

—

Harnessing Ontario's Ready RNG Projects

Enbridge Gas Distribution / Union Gas Limited
For Discussion

Ontario RNG Market Projects

Enabling a Nascent Market

Funding Requirements

Contract Year	Lower	Upper	Volume
2018	$180	$230	2-3 PJ
2019-2020	$190	$230	5-6 PJ
2021+	$400	$450	9-10 PJ

Customer	Type	Region	Size	Contract Year
Municipal	SSO	Central	Medium	2018
Municipal	SSO	Central	Medium	2018
Municipal	Landfill	Southwestern	Large	2018
Municipal	WWTP	Central	Large	2018
Municipal	AD	Central	Medium	2018
Private	Landfill	West Central	Large	2018
Private	AD	West Central	Medium	2018
Private	Landfill	South Western	Large	2018
Municipal	Landfill	South Western	Medium	2018
Private	SSO	South Western	Medium	2018
Private	AG	South Western	Small	2018
Private	AG	South Western	Small	2018
Private	Industrial	South Western	Small	2018
Municipal	WWTP	South Western	Small	2018
Municipal	WWTP	South Western	Small	2018
Municipal	Landfill	Central	Large	2019-2020
Private	AD	Central	Medium	2019-2020
Private	AD	Central	Large	2019-2020
Private	AD	Central	Medium	2019-2020
Private	AD	Eastern	Medium	2019-2020
Municipal	Landfill	Southwestern	Large	2019-2020
Municipal	WWTP	Eastern	Large	2019-2020
Private	AD	Central	Large	2019-2020
Private	AD	West Central	Large	2019-2020
Municipal	SSO	Eastern	Medium	2019-2020
Private	Landfill	South Western	Medium	2019-2020
Municipal	Landfill	South Western	Medium	2019-2020
Municipal	SSO	Northern	Small	2019-2020
Municipal	SSO	South Western	Small	2019-2020
Private	Industrial	South Western	Medium	2019-2020

*RNG flow date 1-3 years post contract

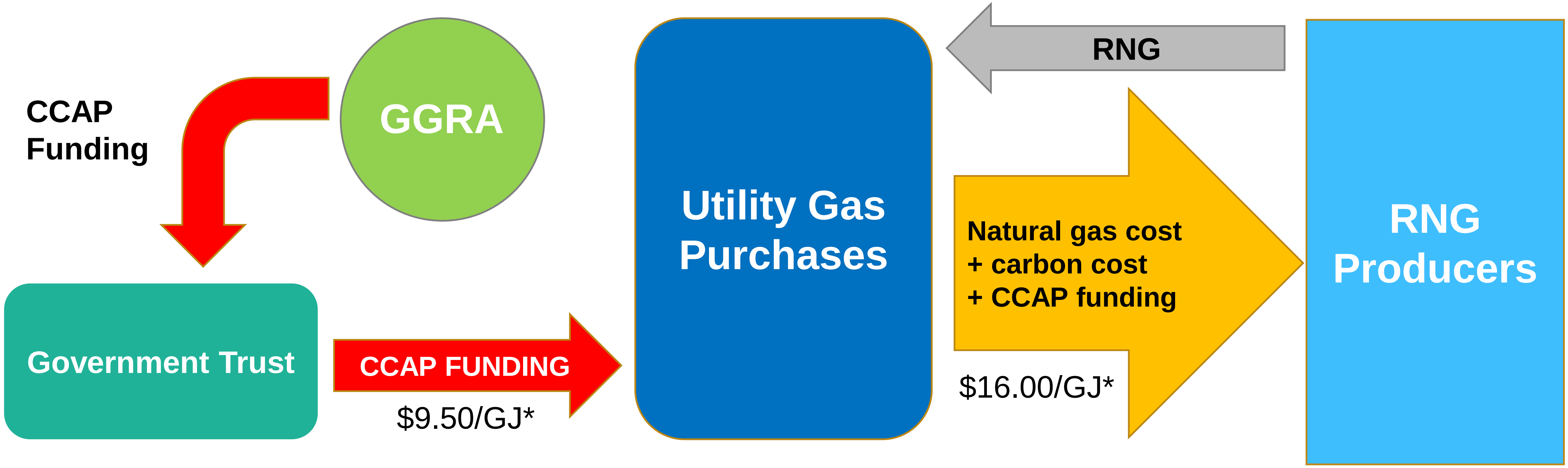
Legend:
Small < 60,000 GJ/yr
Medium 60,000 <> 250,000 GJ/yr
Large > 250,000 GJ/yr

Alternative Implementation to a Trust

Funding Distribution Mechanisms

- Enbridge and Union Gas would be able hold funds from the Province to manage on it's behalf
- A segregated RNG account would be established, with transparent oversight and annual review provided by the Ontario Energy Board
  - This would avoid a costly external trust with no administrative overhead costs
- Funds would be distributed to RNG contract holders
  - Monthly volumetric payments based on delivered RNG
- Full account and records managed in the open OEB process

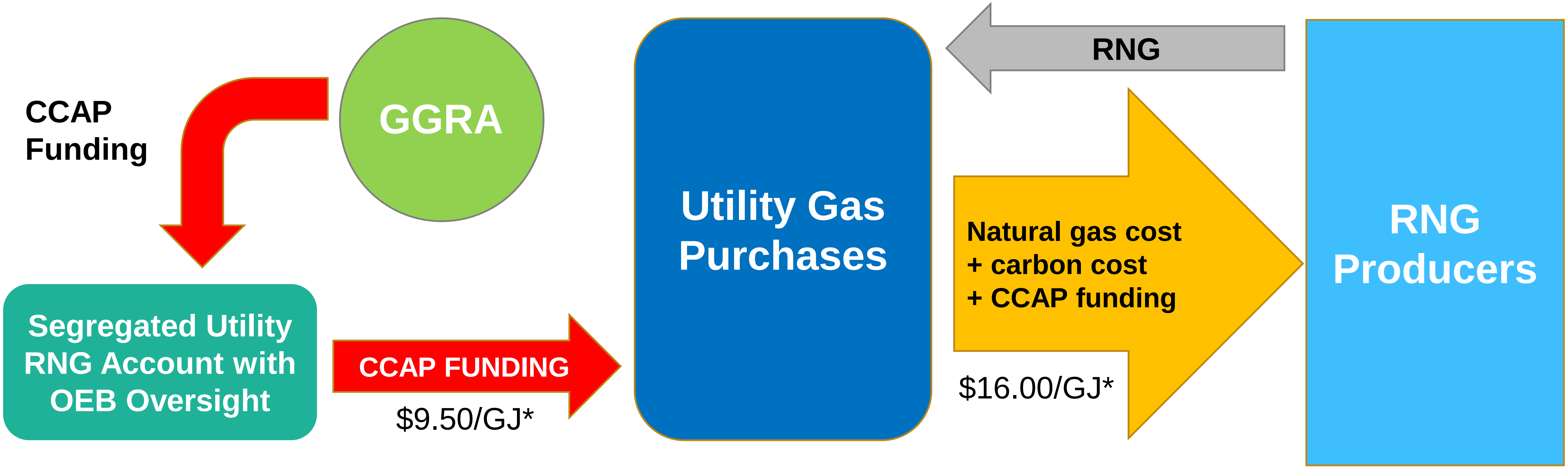
Option A: Operational Model



- RNG bid at $16.00/GJ*, commodity at $5.00/GJ* and OEB Mid-Range Long Term Carbon Price Forecast at $1.50/GJ* with CAPP funding the difference

Illustrative Pricing

Option B: Operational Model



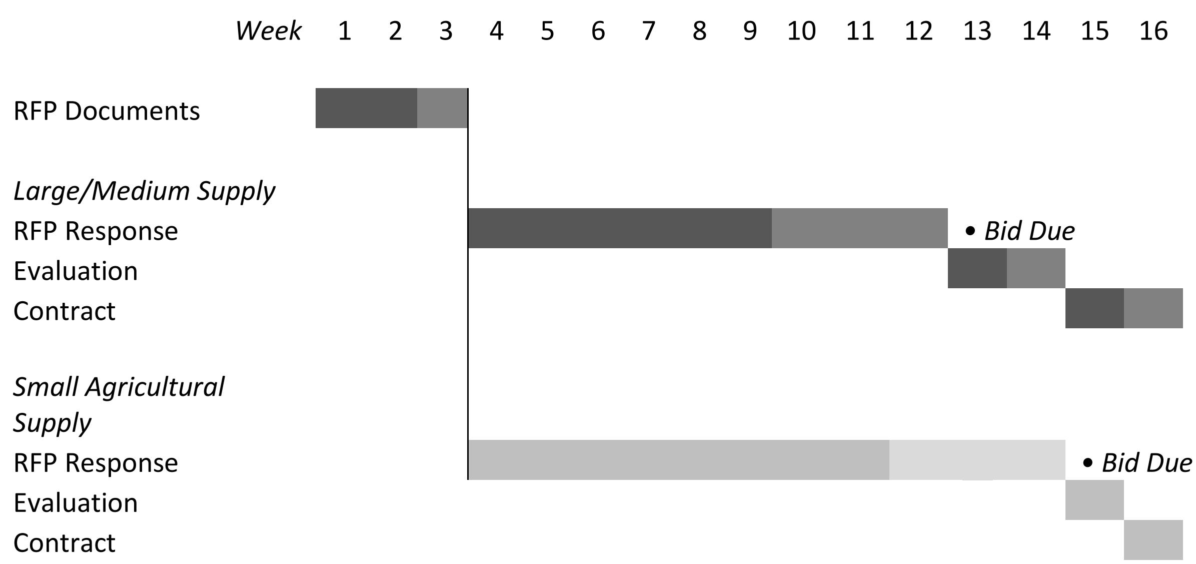
- RNG bid at $16.00/GJ*, commodity at $5.00/GJ* and OEB Mid-Range Long Term Carbon Price Forecast at $1.50/GJ* with CAPP funding the difference

***Illustrative Pricing**

Draft Renewable Natural Gas (RNG) Implementation Discussion Paper

Timeline

1. Requests for Proposal (RFP) documents completed within 2 to 3 weeks
2. RFP Launch process for all suppliers
3. RFP Bid Due Dates for producers
   a. Medium to large suppliers due within 6 to 9 weeks of RFP launch date
   b. Small agricultural suppliers due within 8 to 11 weeks of RFP launch date
4. Evaluation
   a. Medium to large suppliers – 1 to 2 weeks past due date
   b. Small agricultural suppliers – 1 week past due date
5. Contracting
   a. Medium to large suppliers – 1 to 2 weeks from RFP close date
   b. Small agricultural suppliers – 1 week from RFP close date Announcement of Projects selected



Request for Proposals Process

An RFP will be used to gain information on the commitment and project proposals from producers interested in selling RNG to the utilities. The RNG RFP will use the same well-established processes and systems currently used by the utility to purchase natural gas with modifications for biogas.

Information on the RFP for RNG will be communicated to industry groups, interested parties and others via appropriate methods and media, and information will be available on the Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (UGL) websites.

A general information session will be held early in the response period for participants, which will include a formal registration to ensure all communications are provided in an unbiased and timely manner. A question and answer function will be used until the due date of the application, with answers posted for all participants to read.

Producers will respond with information related to their point production. The utilities will be able to evaluate and work with producers to determine utility specific costs which will aid them in responding to the RFP.

Evaluation Steps for RFP

Evaluation of the RFP will be conducted to yield a list of qualified projects using the following process.

1. RFP Submission via Standard Gas Supply Processes
2. Review of Mandatory Elements and Rated Criteria
3. Technical Bid Evaluations
4. Economic Bid Evaluations
5. Initial Award of Contracts

Contract Offer Lists

- Tier 1 List – Selected projects to utilize 100% of Ontario RNG Funding based on cost
- Tier 2 List
  - Projects beyond Tier 1 to provide a project buffer in-case of non-performance of Tier 1 List projects - contracts that have technical, financial or other issues that may result in failure to meet Commercial Operation Date (COD) or
  - If supply dispositions results in additional revenues which will enable more projects
- **Issue conditional contract awards with Tier One List**
- Contact Tier Two List and provide a “reservation” for them to be contacted or automatically considered in the next RFP process

Post Contract Award

- Publish initial list of contracted suppliers, in cost / carbon abatement order
- Obtain producer indemnity letter to cover costs for detailed engineering/design estimates in the event the producer chooses not to move forward with their project
- Meetings with awarded potential suppliers to review estimated utility costs and project details
  - Provide biomethane injection estimated cost information and contract
    - Provide biogas upgrading information and contract as required
  - Discuss initial evaluation of total carbon reduction potential
- Determine any impacts to biomethane supplier of COD of utility services injection, compression and biogas upgrading equipment as required
- Initiate sampling programs
- Revised cost and initial customer input used to revise the projects selected
- Selected projects re-evaluated with updated information

RFP Details/Specifics

- Standard form contracts
  - Enbridge Gas Distribution (EGD): Biogas & Biomethane Contracts
  - Union Gas (Union): Gas Purchase Agreement (GPA)
- Financial Credit Approval forms
- Carbon reduction evaluation
- Additional information requested over standard NG contracts for:
  - Deliverability - Volume breakdowns: annual, monthly, daily, hourly
  - Location of supply / injection location
  - Quality – including sampling and access rights agreements required for measurement
  - Commercial Operation Date of supply
- For Biomethane contracts only, upstream supply agreements and contracts for biogas supply
- Contract duration (term) of biogas/biomethane supply
- All RFP / bid information will be time stamped

RNG Supplier Selection Criteria

Guiding Principal – *The Lowest Total Cost of Carbon Abatement per GigaJoule (GJ) of Energy Delivered*

A scoring matrix will be used with the following criteria:

Primary Attributes

1. RNG energy cost - $/GJ
2. Carbon reduction – Tonnes/GJ

Secondary Attributes

1. Earliest COD
2. Term of RNG supply contract
3. Supply source and location
4. Reliability of supply
   a. operator capability
   b. biogas/RNG source quality
   c. biogas/RNG supply contract or supply control level

Mandatory Requirements

1. Supply into an Ontario Energy Board regulated Ontario Gas Distributor
2. Completion of entire application
3. Credit information

Other Criteria which may be applied as decided between MOE/MOECC/Utilities

1. Allocations based on:
   a. Raw Biogas Sources
      i. Agricultural Anaerobic Digesters [AD] > 50% farm based materials
      ii. Commercial Anaerobic Digesters [AD] <50% farm based materials
      iii. Landfills
      iv. Source Separated Organics [SSO]
      v. Waste Water Treatment Plants [WWTP]

b. Supply Size
    i. Large > 250,000GJ/Year
    ii. Medium 60,000 to 250,000GJ/Year
    iii. Small < 60,000 GJ/Year
    iv. Other – extra small
c. Ownership
    i. Private / Commercial
    ii. Family Farm (non-corporate)
    iii. Public / Municipal
d. Prior Funding / Grants
    i. Screen for value of funds
    ii. Screen for nature of grant

RNG Supply Contract Length

The Supply Contract would be valid from the first day of production of RNG delivered into the systems of an Ontario based gas distribution utility until at a maximum of the tenth anniversary of this date.

Other RNG Contract Features

Payment for RNG

- Pricing at a fixed level (could be indexed – partially or fully to inflation)
- Payment for volumes delivered to distribution system, up to a maximum amount determined by the purchase agreement

Quality Compliance / Volumes

- Compliance with published utility gas specifications
- Purchase of all compliant quantities delivered to injection / measurement station
    - Rejection of non-compliant gas as per specification, either returned for re-processing or flared by supplier
- Access to clean-up equipment telemetry data and physical sampling of biomethane and biogas

Contracts for Biomethane (RNG) Supply

<u>Union Gas Limited:</u>
A program participant would require a UGL Gas Purchase Agreement to access funding by providing RNG into the regulated utility distribution system. Some participants may also use an M13 Transportation, Producer Balancing and Name Change Service Contract(s) if they are located in a delivery area that is reliant on third party transportation services such as Union North.

Gas Purchase Agreement

- Union's standard Gas Purchase Agreement modified to reflect specific RNG pricing and related provisions
- Purchase of biomethane by the Company for the RNG program
- Contract also governs the injection of pipeline quality gas into Union's distribution system
    - Charges for transportation and balancing of produced gas (fixed unit rate)

    - Charges for producer station administration costs (monthly fixed rate based on Union's M13 rate schedule, as approved by the OEB)
- All Environmental Attributes included
- Ontario Energy Board (OEB) oversight through Gas Supply QRAM and Cap and Trade Filings

M13 Transportation, Producer Balancing and Name Change Service

- This regulated service is overseen by the Ontario Energy Board and allows producers to inject gas into Union's distribution system and transport it to Dawn
- Includes balancing service to handle daily differences between amounts sold and amounts produced
- In order to maintain Union's system reliability, producers may be required to use the M13 to balance production in areas where third party or transactional storage and/or transportation services are required
    - Union would then purchase the supply under a separate agreement at the market point

<u>Enbridge Gas Distribution Inc.:</u>
A program participant would require the injection service contract and either a utility biomethane (RNG) supply contract or a utility biogas upgrading contract to access the funding by providing RNG into a regulated utility distribution system.

Injection Service

- Injection Service Contract
- Fully rate regulated service overseen by the Ontario Energy Board
- Rate determined by cost of service methodology
- Take or pay rate as determined by the specified daily volume
- Measurement of volume and quality of gas
    - Biomethane (RNG) must meet published quality specifications
    - Component testing, on-line testing, or customer equipment if pre-approved and tested
- Mandatory access to any and all upstream telemetry, processing or other data
- Optional Compression Service
    - Take or pay for capital, operating expenses unitized to volume
- In the event an entity wishes NOT to be part of the biomethane (RNG) program, then they can use this service to inject their biomethane (RNG) for their own use or disposition via contracts to third parties, as illustrated by the third party biomethane graphic below.

Biomethane (RNG) Contract

- Purchase of biomethane by the Company for the RNG program
- Pipeline quality gas ready for injection
- Environmental Attributes included
- OEB oversight through Gas Supply QRAM and Cap and Trade Filings

Optional Utility Biogas Cleanup (Upgrading) Service

This optional upgrading service for biomethane contract holders without the technical ability to upgrade raw biogas into biomethane ready for pipeline injection

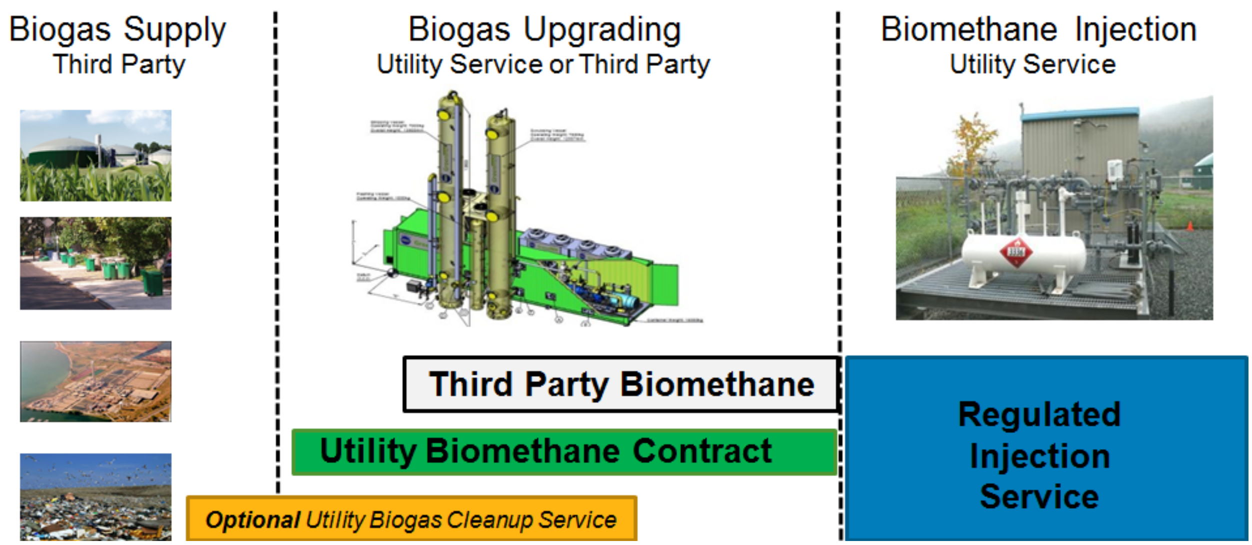
- Technology selection choice by Utility
- Take or pay contract
- Ensure capital recovery of assets, and fixed operating expenses
    - Net Book Value (NBV) plus compensation for cancelled contracts
    - Negotiated provision of services to plant - Water, electricity, land lease
    - Access to all pre-treatment telemetry data

Cost Components

The price paid under a biomethane contract injected into a distribution system would have two cost considerations:

A: Biomethane Producer Costs

B: Regulated Injection Service (EGD) or GPA/M13 Costs (Union)



OEB Regulation of RNG Program Contracts

The Ontario Energy Board is the transparent and independent regulator that is mandated to ensure customers get value from energy suppliers and that their actions are in the public interest. They set rates, regulate utility investments, provide customer information, evaluate consumer complaints and develop regulatory policy for the long term needs of the energy sector. The OEB's authority to regulate of gas distributors is from *Ontario Energy Board Act, 1998*, and provincial statutes including: the *Energy Consumer Protection Act, 2010*, the *Municipal Franchises Act*, the *Oil, Gas and Salt Resources Act*, and the *Assessment Act*.

The OEB states: "It means we make rules that energy companies must live by. It means we can take action if they break our rules or the laws that we enforce, like applying penalties. It means we monitor how they perform and how they treat you to be sure it's legal. It means we listen if you make a complaint about them and act upon what we hear, if an issue needs to be resolved. And lastly, it means that we think about the long-term needs of our energy sector and develop regulatory policy to meet those needs and emerging challenges." - https://www.oeb.ca/about-us/mission-and-mandate

OEB Value for Money Oversight

Regulated Gas Utilities in Ontario must provide applications and keep detailed records. The primary means of OEB oversight will be:

1. Quarterly Rate Adjustment Mechanism (QRAM)
2. Annual Cap and Trade Compliance Plans
3. EBO 188 – OEB Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, specifically
    a. Leave to construct applications for facilities required to connect RNG projects as required
    b. Leave to construct applications for Biogas Upgrading (Cleanup) projects as required
4. Annual Regulatory Filings
5. The rules, codes and requirements for utilities as published by the OEB (https://www.oeb.ca/industry/rules-codes-and-requirements)
6. Filing Guidelines for the Pre-Approval of Natural Gas Supply and / or Upstream Transportation Contracts from the EB-2008-0280 proceeding

The initial funding for the RNG program will be included in a segregated account help for the buy down of RNG supply contract costs. The funds flow will be as follows:

1. The Utility will pay the RNG supplier as per their contract for the cost of each unit of energy (GJ) delivered into the distribution system as measured by the volume/energy delivered into the utility's distribution system.

Less

2. The current cost of gas as determined by a forecast price of natural gas for the term of the agreement at the time the contract is initiated

Less

3. The current cost of carbon abatement as determined by the most recent OEB Long Term Carbon Price Forecast for the term of the agreement at the time the contract is initiated

Equals

4. The result will be the forecast amount to be drawn against the segregated RNG program contract funding.

The total volume procured would service as an input to the reduction of the amount of allowance required to be obtained by the utilities on behalf of customers.

Summary

Total Annual RNG Volumetric Payments

Less

Long Term Forecast Cost of Gas

Less

Carbon Abatement Costs

Equals

Amounts Paid from the RNG Program Fund

Reporting

All volumes of RNG procured will be reported in the standard gas supply procurement processes and documentation.

Cap and Trade compliance plans, forecasts and procurements are provided to the OEB on a periodic basis.

RNG Supply Disposition

The precise allocation and disposition of the procured RNG volumes will require further discussions amongst various stakeholder groups to ensure that the detailed disposition processes are fair and equitable while meeting the mandate of wide accessibility. There is fortunately time before the first RNG from the program flows, but as an initial allocation the use of annual volumes of natural gas delivered to utility customers serves as a reasonable and fair, yet simple and transparent allocation mechanism.

The objective of a final allocation plan will be to provide a formulaic allocation that is equitable and fair to all:

- Utility System Gas Customers - Utility distribution customers who buy their gas molecules from the utility
- Direct Purchase Customers - Utility distribution customers who buy their gas molecules from another party
- Other Gas Users (OGU)
    - Large Emitters
    - Customers of Natural Gas Marketers
    - Other Gas Utilities

The OGU will require new or modified mechanisms to be created to enable fair and reasonable allocations. They will require different or new service offerings and have new administrative and billing processes to functionalize. Additionally, a process must be developed to account and re-allocate supply and demand imbalances caused by various users across the various entities with allocations of RNG.

Within the OGU are:

Larger Emitters – facilities that have GHG emissions over 0.025 $MtCO_2e$ that are mandatory participants in cap and trade program and facilities that emit between 0.010 and 0.025,000 $MtCO_2e$ who have chosen to opt-in to cap and trade and acquire their own allowances. This group is currently not integral to Utility cap and trade compliance plans.

Gas Marketers -- Gas Marketers and specifically those who either currently offer or may offer a voluntary program for the provision of RNG to their customers.

OEB Regulated and Non-Regulated Gas Distributors – Epcor Natural Gas LP is OEB regulated and as such has a cap and trade compliance plan. Kitchener Utilities, Utilities Kingston and Six Nations Natural Gas Limited are not regulated by the OEB.

Administration Costs

It is anticipated that the costs to administer the program would be included in the utility rates as part of the cost of service. Fees would be charged to non-utility participants to ensure fairness and cost recovery for services funded by utility ratepayer. It is anticipated that the costs would be for one but not more than two additional FTEs each year per utility and would be approved as a variance to rates in as a Z –factor for rate making in an incentive regime. The value thereof would be approximately $200,000 - 300,000 each year.

Co-Benefits for Government

By the provision of weights in the selection matrix for projects criteria can be adjusted to favour projects which contribute to the following:

1. Circular Economy
2. Organics Ban
3. Soil Health
4. GHG Reductions
5. Cap and Trade Compliance (see OEB Regulation and Program workings above)

Data on the following would likely be accessible as measures:

1. Total volume delivered by contracted segment
2. Carbon Attributes – GHG compliance
3. Biomethane composition data, and depending on sources / contracts biogas
4. Rejection rate of biomethane, and possibly reasons

Program participants will have information derived from compliance requirement for various ministries, and operational data from the RNG program could be accessed and would act as a supplement to this to all for deeper understanding of processes and the impacts on the production of RNG.

STAFF INTERROGATORY #6

INTERROGATORY

Ref: Exhibit C / Tab 5 / Schedule 2 / p. 7, #19-21
Exhibit C / Tab 5 / Schedule 2 / pp. 10-11
Exhibit C / Tab 5 / Schedule 2 / p. 9, #26

Preamble:
Enbridge Gas states that for its procurement model, the carbon abated cost of natural gas will be determined by "summing the forecast cost of traditional gas supplies over the term of the RNG procurement contract with the Board's LTCPF mid-range forecast carbon cost applicable for each respective year of the same time period."

The OEB has committed to updating its LTCPF every year.

In its illustration of the Renewable Natural Gas Procurement Funding Model, Enbridge Gas shows the cost of RNG in $/GJ:

		Year 1 2018	Year 2 2019	Year 3 2020	Year 4 2021	Year 5 2022	Year 6 2023	Year 7 2024	Year 9 2025	Year 9 2026	Year 10 2027
(a)	Forecast Cost of Traditional Gas Supplies ($/GJ)[1]	$ 3.69	$ 3.45	$ 3.42	$ 3.43	$ 3.46	$ 3.59	$ 3.65	$ 3.73	$ 3.82	$ 3.86
(b)	Forecast Cost of Carbon: Mid-Range LTCPF ($/GJ)[2]	$ 0.85	$ 0.90	$ 0.90	$ 0.95	$ 1.00	$ 1.05	$ 1.56	$ 1.81	$ 2.16	$ 2.51
(c)	Required Provincial Subsidy ($/GJ)[3] (c) = (d) - (a) - (b)	$ 11.46	$ 11.65	$ 11.68	$ 11.61	$ 11.53	$ 11.35	$ 10.79	$ 10.46	$ 10.02	$ 9.63
(d)	Assumed Cost of RNG ($ / GJ)	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00

Questions:

a) Please provide the costs in the table in $ per tonne of CO_2e.

b) Please explain why Enbridge Gas assumed $16/GJ as an illustrative cost of RNG and provide supporting documentation and analysis that shows how Enbridge Gas developed the $16/GJ as a likely price for RNG.

c) Did Enbridge Gas consider any other pricing options, such as variable pricing, over the term of the contract? Please explain.

d) Please explain if, and if so how, the annual updates to the LTCPF could impact ratepayers, provincial funding, and potential RNG suppliers.

Witnesses: A. Chagani
S. McGill

RESPONSE

a) The following table shows the costs in Table 2 in $/tCO_2e$.

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 9	Year 9	Year 10
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
a)	Forecast Cost of Traditional Gas Supplies ($ / tCO2e)[1]	$ 75.55	$ 70.63	$ 70.03	$ 70.30	$ 70.95	$ 73.60	$ 74.79	$ 76.44	$ 78.22	$ 79.02
b)	Forecast Cost of Carbon: Mid-Range LTCPF ($ / tCO2e)[2]	$ 17.00	$ 18.00	$ 18.00	$ 19.00	$ 20.00	$ 21.00	$ 31.00	$ 36.00	$ 43.00	$ 50.00
c)	Required GGRA Subsidy ($ / tCO2e) = (d - a - b)[3]	$ 235.30	$ 239.22	$ 239.83	$ 238.55	$ 236.90	$ 233.25	$ 222.06	$ 215.41	$ 206.63	$ 198.84
d)	Assumed Cost of RNG ($ / tCO2e)	$ 327.85	$ 327.85	$ 327.85	$ 327.85	$ 327.85	$ 327.85	$ 327.85	$ 327.85	$ 327.85	$ 327.85

Notes:
1) Long term natural gas price forecast; Enbridge CDA.
2) Assumed Cost of Carbon = OEB Mid-Range LTCPF.
3) Required GGRA Subsidy must be secured by contract based on life of RNG procurement contracts.
4) Assumed heat rate 0.03842 GJ/m^3
5) Assumed GHG emission factor 0.001875 tCO_2e/m^3

b) Enbridge believes that $16/GJ represents a reasonable proxy of what supplies of RNG will cost. The actual cost of RNG will be determined through an RFP process.

c) Enbridge is of the view that fixed price, fixed term RNG procurement agreements will be required in order to provide RNG producers with a reasonable assurance that their investments in RNG production facilities will be recovered over the useful life of these assets. Further, fixed price, fixed term contracts are required in order to ensure that ratepayers will not be at risk with respect to changes in RNG cost.

d) Once the level of provincial government funding is determined, the cost of RNG and annual RNG procurement volumes will be established through the proposed RFP and contracting process. Thereafter, annual updates to the LTCPF will not impose an incremental impact on the cost of carbon borne by ratepayers associated with the contracted RNG supply. Future RNG procurements under the proposed model would use the most up to date LTCPF. Please see the response to CCC Interrogatory #10 at Exhibit I.C.EGDI.CCC.10 for a discussion about the impact of variances between the applicable LTCPF and actual carbon allowance prices.

Witnesses: A. Chagani
S. McGill

STAFF INTERROGATORY #7

INTERROGATORY

Ref: Exhibit A / Tab 2 / Schedule 1 / p. 6

Preamble:
Enbridge Gas has asked for approval of the Renewable Natural Gas mechanism "as early as possible, and no later than the end of January 2018."

Questions:

a) Please explain the implications if OEB approval of the RNG procurement model is not granted by January 31, 2018.

b) If OEB approval is given for the RNG funding model, please explain Enbridge Gas' expected timelines for:
   i. Negotiations with the province for funding
   ii. Negotiations of agreements with 3rd party RNG suppliers
   iii. Actual injection into its pipelines

RESPONSE

a) The Company has been advised by the Ministry of Environment and Climate Change that it seeks to implement its RNG program initiative in early 2018. The Ministry has also indicated that it seeks to have a clear understanding as to how the gas utilities will conduct their RNG procurement programs prior to committing funding to the initiative. The Company asserts that any delay in commencing procurement of RNG puts into risk the provincial government funding as well as the ability to secure local supply.

b) Enbridge is currently in the midst of discussing RNG funding with the province. Enbridge expects that the province's decision on the matter will be concluded in late January 2018. From that point forward it is expected that approximately 16 weeks will be required to complete the RFP and contracting process. RNG injections from new Ontario production facilities should begin to occur approximately 18 to 24 months after the procurement contracts are executed.

Witnesses: A. Chagani
S. McGill

STAFF INTERROGATORY #8

INTERROGATORY

Ref: Exhibit C / Tab 5 / Schedule 2 / p. 8, #22
Exhibit C / Tab 5 / Schedule 2 / p. 11

Preamble:
Enbridge Gas states that some potential producers of renewable gas supplies are at the early stage of project development in anticipation of market opportunities developing in Ontario while others are closer to fruition, and as a result, Enbridge Gas' 2018 Compliance Plan does not anticipate the introduction of significant RNG volumes into its 2018 gas supply portfolio. Enbridge Gas indicates that it "believes that renewable content will play an increasing role in future compliance plans as RNG production facilities are developed and brought into commercial operation."

Enbridge Gas also states that based on the expected level of Provincial funding, the initial round of the RNG RFP process is likely to capture less than 0.1% of the Company's annual gas volume requirement.

Questions

a) Please explain, and provide supporting documentation, including assumptions and analysis, of the estimated annual amount of RNG (in m^3) and associated GHG reductions (in tonnes of CO_2e) that Enbridge Gas expects to procure going forward.

RESPONSE

The actual volume of RNG that Enbridge can procure will be based on the amount of the Provincial subsidy and the costs that are determined through the RFP process. Once the amount of the subsidy from the government has been finalized and the RFP process completed, Enbridge will be able to determine the volume that can be contracted. In order to provide a response to this interrogatory, Enbridge has made the following assumptions:

1. Enbridge receives half of the government subsidy for RNG, which is expected to be between \$60 to \$100 million, as is discussed in response to the APPrO Interrogatory #3a filed at Exhibit I.C.EGDI.APPrO.3.

Witnesses: A. Chagani
S. McGill
J. Murphy

2. The costs for RNG and carbon are as shown in the illustrative example in Table 2 in Exhibit C, Tab 5, Schedule 2.
3. A heat rate conversion factor of 0.03842 GJ/m^3
4. A GHG emission factor of 0.001875 tCO_2e/m^3

Based on these assumptions, Enbridge's estimates of the aggregate amount of RNG in PJ and m^3 and the associated GHG reductions that will be delivered over the next 10 years are shown in the table below.

	Assumed Subsidy Amount	**Volume of RNG (PJ)**	**Volume of RNG (m^3)**	**GHG Reductions (tCO_2e)**
Minimum	$ 30,000,000	2.72	70,869,787	132,881
Maximum	$ 50,000,000	4.54	118,116,311	221,468

*Note – all amounts in the table are 10 year totals.

Witnesses: A. Chagani
S. McGill
J. Murphy

STAFF INTERROGATORY #9

INTERROGATORY

Ref: Exhibit C / Tab 5 / Schedule 2 / pp. 9-10, #25

Preamble:
Enbridge Gas states that biogas producers require longer term contracts to support capital investments in RNG production, and that for this reason Enbridge Gas is considering entering into RNG procurement contracts with terms of up to 10 years in duration.

Questions:

a) Please explain how Enbrige Gas determined that 10 years is an appropriate length of time for an RNG contract.

b) Please explain whether a 10 year contract for RNG procurement is an industry standard. Please provide examples of RNG contract lengths from other jurisdictions, including Quebec (Gaz Metro) and California.

c) Please provide Enbrige Gas' understanding of the typical useful life of an RNG asset. Please provide any documentation that Enbrige Gas has that support this number or range.

d) Has Enbrige Gas considered matching the contract duration with the estimated useful life of the RNG assets? Please explain.

e) Please provide the estimated price per GJ and per tonne of CO_2e if the contract duration was extended to 15 years and 20 years. Please discuss whether Enbrige Gas expects the price per GJ would be lower with a longer contract duration.

RESPONSE

a) Enbridge has determined that 10 years is an appropriate length of time for an RNG contract based on several factors. Firstly, the Company understands that the operational life of RNG production facilities is in the order of 15 to 20 years, and a 10-year contract represents the mid-point in the life of the equipment. Secondly, Enbridge believes that a 10-year contract term will be sufficient to provide RNG project proponents with reasonable assurance that a significant portion of the cost of these facilities can be recovered in that time. Thirdly, the Company believes that this is a reasonable time frame in which the market may achieve a desired level of maturity and therefore not require additional support. Lastly the 10-year time frame is consistent with the Board's 10-year Long Term Carbon Price Forecast.

b) Enbridge is not aware of an industry standard as this is a nascent market and contracts are usually held in confidence. Enbridge does not have any examples of contracts in other jurisdictions.

c) As discussed in response to a) above, Enbridge's understanding is that the typical useful life of RNG assets is in the order of 15 to 20 years. Please refer to the Electrigaz study filed at EB-2011-0242, Exhibit B, Tab 1, Appendix 4.

d) Please refer to the response to a) above.

e) While the price per GJ could be lower with longer contract duration, Enbridge believes the RFP process will result in competitive prices for RNG for a 10-year term.

Witnesses: A. Chagani
S. McGill

STAFF INTERROGATORY #10

INTERROGATORY

Ref: Exhibit C / Tab 5 / Schedule 2 / p. 5, #13

Preamble:
Enbridge Gas states that over the past year it has given consideration to RNG from three main perspectives; 1) the procurement of RNG supplies for the purpose of reducing the Company's requirement to acquire carbon allowances or carbon offsets; 2) the advancement of RNG production in Ontario; and 3) supporting customer activities related to RNG and RNG production."

Questions:

a) Please explain what Enbridge Gas believes its role is in advancing the adoption of RNG production in Ontario.

b) Please explain what Enbridge Gas believes its role is in supporting customer activities related to RNG and RNG production.

c) Please explain whether Enbridge Gas expects to develop a new business that would involve supplying, producing, and/or developing RNG in the future.
   i. If so, please explain what type of new business Enbridge Gas expects to undertake, and within what timeframe.
   ii. Please explain whether this would be handled by an affiliate or whether this would be a regulated activity.

RESPONSE

a) The Company's objectives with respect to its proposed RNG procurement program are explained in the response to ED Interrogatory #9 filed at Exhibit I.C.EGDI.ED.9.

   Both the province's Climate Change Action Plan and 2017 Long Term Energy Plan ("LTEP") reference RNG as an important part of the province's energy future. The LTEP expresses the provincial government's desire to leverage existing infrastructure, including gas appliances currently used by consumers, while at the same time reducing GHG emissions. The RNG market in Ontario is nascent, and could be enhanced through the active participation of the province's natural gas distribution utilities. This is particularly important given the expectation that a "clean fuel standard" will be imposed/required by either of both of the Provincial and Federal Governments. A "clean fuel standard" will impose a renewable content requirement on all fossil fuels, including natural gas. Enbridge's planned RFP and contracting for RNG will provide important pricing information that will inform future expectations, policy and regulation as the "clean fuel standard" is developed and implemented. It will also encourage the development of RNG supply needed to satisfy any "clean fuel standard".

Enbridge recognizes that the Province is moving to a low carbon economy, and believes it has a role in supporting this objective. The Provincial Government is required to reinvest the proceeds of the Cap and Trade program into carbon abating initiatives. Enbridge believes that it is appropriate to advocate on behalf of its ratepayers, to ensure that ratepayers receive the benefits offered. The RNG procurement proposal returns some of the carbon costs incurred by Enbridge customers to them while helping them to reduce their carbon emissions. At the same time, it helps Enbridge diversify its portfolio of instruments and activities used to meet its compliance obligations

Additionally, please refer to the response to CCC Interrogatory #4 filed at Exhibit I.C.EGDI.CCC.4.

b) Enbridge believes it has a role in supporting RNG production activities by providing biogas conditioning and the injection into the natural gas distribution system. Enbridge has applied to the Board to for an RNG Enabling Program, which includes providing upgrading and injection services (filed at EB-2017-0319).

c) Enbridge has applied to the Board to for an RNG Enabling Program, which includes providing upgrading and injection services. These two new services are being undertaken to support RNG producers who would like to outsource this activity. Please refer to the evidence filed at EB-2017-0319.

   i. The details of the RNG Enabling Program can be found in EB-2017-0319.

   ii. In its EB-2017-0319 Application, the Company has proposed that both RNG upgrading and injection facilities would be owned and operated as part of the Company's OEB rate regulated activities.

Enbridge Gas Distribution has no other regulated RNG business plans in connection with the 2018 Cap and Trade Compliance plan. If Enbridge Gas Distribution develops such plans, they will be filed with the Board as required and appropriate.

Enbridge entities may partner with other entities in Ontario to develop RNG producing facilities which may bid into utility RFPs. This would be subject to compliance with the Affiliate Relationships Code, and would include appropriate protections to ensure equal treatment of all RFP respondents.

Witnesses: A. Chagani
S. McGill

STAFF INTERROGATORY #11

INTERROGATORY

Ref: Exhibit C / Tab 5 / Schedule 2 / p. 5, #12

Preamble:
Enbridge Gas states that the source of RNG has a significant impact on its carbon abatement potential and carbon offset value.

Questions:

a) Please explain why and how the source of RNG has an impact on its carbon abatement potential. Please provide analysis and supporting documentation.

a) Please explain whether, and if so how, the source of RNG could impact:
   i. The market price of RNG
   ii. The price of RNG Enbridge Gas expects to pay in any contract with an RNG supplier
   iii. The RNG funding that will be supplied by the provincial government
   iv. The ratepayers

RESPONSE

a) As discussed in Exhibit C, Tab 5, Schedule 2, when biogas is captured from sources such as landfills and digesters and upgraded into RNG, there are two environmental benefits: emission reduction and fuel substitution. The amount of methane that is generated from a project is dependent on the source of the RNG, and on project specific factors for example the size of a digester, or feed rate. The emission reduction potential (which is related to volume of methane captured in the production of RNG) is therefore variable. The fuel substitution potential with each cubic meter of RNG is the same, regardless of its source, displacing one cubic meter of fossil natural gas and therefore providing an emissions savings of 0.001875 tCO_2e.

a)
   i. The market price of RNG will be determined through the RFP process. It is anticipated that there will be variation in the price based, amongst other factors, on the source of the RNG. As an example, production costs will vary

Witnesses: A. Chagani
S. McGill
J. Murphy

based on location, proximity to distribution network, source material, and potential for offset credit creation.

ii. These prices are unknown at this time, and will be determined through the RFP process.

iii. The source of RNG supplies is not expected to impact the level of funding that will be supplied by the provincial government.

iv. The source of RNG supplies will not impact the ratepayers.

Witnesses: A. Chagani
S. McGill
J. Murphy

APPrO INTERROGATORY #1

INTERROGATORY

Location and Nature of RNG Supplies

Reference: i) EB-2017-0224 Exhibit C Tab 5 Schedule 2:

Preamble: Enbridge is seeking approval to develop a renewable natural gas (RNG) program, whereby Enbridge would enter into long term contracts to acquire RNG. APPrO would like to better understand the nature of the supplies.

Questions:

a) Table 2 provides Enbridge's procurement model from a pricing perspective and includes Enbridge's 10-year price forecast for traditional supplies for the Enbridge CDA:
   i. Is this 10-year forecast, Enbridge's current official 10-year forecast for traditional gas supplies?
   ii. Does this price forecast include the upstream costs of firm transportation to deliver gas to the CDA?
   iii. Please discuss the RNG producer's performance obligations over the term of the contract.
   iv. If the RNG supplier's performance is not firm over the duration of the contract, should the reference price for traditional supply reflect a non-firm supply?

b) Table 2 illustrates the required subsidy on a unit of energy basis. Please discuss how the required subsidy will be recovered. In particular, please discuss how the subsidy will be determined in the event that the actual volume differs from the forecasted volume.

c) Please indicate if there are any limitations as to the pipeline systems that would be used to transport RNG.

RESPONSE

a)
   i. Please see response to Energy Probe Interrogatory #11(a) filed at Exhibit I.C.EGDI.EP.11.

Witnesses: A. Chagani
S. McGill

ii. Yes.

iii. The performance obligations will be set out in the contract. Among other things, specified volumes will have to be delivered and the RNG producer will be required to produce RNG to meet the pipeline specification.

iv. RNG supplies are intended to be firm. The day to day variances in delivery volumes will be administered in a manner comparable to the current treatment for gas deliveries by direct purchase customers.

b) As set out in response to APPrO Interrogatory #3(f) filed at Exhibit I.C.EGDI.APPrO.3, the RNG producers will be responsible to deliver contracted supplies. If volumes are not delivered, then the producer will not be paid (and there is no need for subsidies in respect of such volumes).

c) As explained in response to APPrO Interrogatory #2filed at Exhibit I.C.EGDI.APPrO.2, RNG being injected into Enbridge's system will be at pipeline quality equivalent to conventional natural gas. As such, the limitations from Enbridge's pipeline systems from injecting RNG are no different from the limitations associated with injection of any other natural gas source.

APPrO INTERROGATORY #2

INTERROGATORY

Gas Quality Standards

Reference: i) EB-2017-0224 Exhibit C Tab 5 Schedule 2 paragraph 12, Enbridge states:

RNG has similar physical properties to conventional natural gas. Once upgraded to pipeline quality RNG can be comingled with traditional gas supplies in the pipeline system, thereby displacing traditional fossil based gas supplies.

i) EB-2017-0224 Exhibit C Tab 5 Schedule 2 paragraph 24, Enbridge states:

As there is no established RNG market in Ontario, in order to ensure the lowest cost for RNG, Enbridge will utilize a tendering process for RNG supplies. Terms of the tendering process will be subject to pre-defined criteria. These criteria will include the volume of RNG to be purchased, the term of the procurement contracts, quality standards, identification of receipt points, etc.

Preamble: Enbridge discusses the need to upgrade the quality of RNG, but is vague about the specific quality standards that are being proposed for RNG. Since some potential components of RNG are not found in traditional natural gas supplies and are known to cause damage to customers' equipment and potentially impact customers' health, it is important that a rigorous RNG quality standard be met and maintained to minimize the risk to customers. APPrO would like to understand the detailed quality standards that are being proposed for RNG.

Questions:

a) Has Enbridge developed a comprehensive set of RNG gas quality specifications such as the specifications currently used in the Province of Quebec: BNQ 3672-100 - Quality Specifications for Injection into Natural Gas Distribution and Transmission Systems? If so, please provide a copy of the proposed RNG gas quality specifications.

Witnesses: A. Chagani
S. McGill

b) Is Enbridge seeking approval of the quality specifications for RNG at this time? If not, please explain.
c) Please compare Enbridge's proposed RNG quality specifications (or its current traditional natural gas quality specifications if no RNG quality specifications are currently available) to the BNQ 3672-100 specification.
d) Are there other quality standards for RNG from organizations such as the CSA or ISO? If so, please indicate how Enbridge's RNG quality standards compare with these other standards.
e) Please confirm that the term 'pipeline quality' does not explicitly address potential RNG components such as:
    i. Heavy Metals,
    ii. Siloxanes,
    iii. Volatile and Semi-Volatile Organic Compounds,
    iv. Halocarbons and Organochlorinated Compounds,
    v. Microbiological organisms, including bacteria and viruses, and
    vi. Other biological, chemical, corrosive or other potential hazards.
f) Please indicate how Enbridge will be addressing potential contaminants in the raw RNG that could be detrimental or hazardous to either customers' equipment or customers' health from such things as:
    i. Heavy Metals,
    ii. Siloxanes,
    iii. Volatile and Semi-Volatile Organic Compounds,
    iv. Halocarbons and Organochlorinated Compounds,
    v. Microbiological organisms, including bacteria and viruses, and
    vi. Other biological, chemical, corrosive or other potential hazards.
g) Please indicate how Enbridge will assure that the ongoing quality of RNG will be comparable with traditional natural gas supplies and free from potentially hazardous compounds. Please include a description of how the RNG process facilities will be designed, inspected, and how testing and other quality assurance protocols that will be used to ensure that the RNG gas quality meet the minimum quality specifications at all times, including:
    i. During the initial startup period (i.e. from the first day of delivery until the volume of RNG and the quality of RNG has stabilized and meets the contractual requirements), and
    ii. On a long-term basis after the startup period.

h) The gas industry has relied on Natural Gas Interchangeability Indices (NGII) to ensure the ability to substitute one gaseous fuel for another in a combustion application without materially changing operational safety, efficiency, performance or emissions. Please provide Enbridge's proposed NGII specifications for RNG and the basis for such specifications and indicate how these specifications compare to the current specifications for traditional natural gas. As a minimum, please include the following:
    i. Minimum and Maximum Wobbe Indices,
    ii. AGA Yellow Tipping Index, and
    iii. Weaver Incomplete Combustion Index
i) How will Enbridge address the situation where RNG is tendered for sale by the producer but does not meet all the required gas quality specifications.

RESPONSE

a) Yes, Enbridge has developed gas quality specifications. Please refer to Appendix A to this Exhibit.

b) No, Enbridge is not seeking approval of the quality specifications for RNG. Enbridge will include this requirement in its contracts, and believes that this is sufficient assurance as to the quality specifications of RNG to be injected.

c) The following table compares Enbridge's RNG specification to the BNQ 3672-100 specification (note that Enbridge's RNG specification also includes an overall requirement that RNG must not contain any contaminants, particles, or other impurities at a concentration that are known as a threat to the integrity of the system, human health, or the environment):

	UNITS	Enbridge	(BNQ 3672)
Heating Value	MJ/m^3	36 - 41.3	36 - 41.34
Wobbe Index	MJ/m^3	47.2 - 51.1	47.23 - 51.16
Carbon Dioxide	% vol	2	2.0
Oxygen	% vol	0.4	0.4
Total Inerts	% vol	4	4
Water Content	mg/m^3	35	35
Hydrogen	% vol	0.1	0.1%
Hydrogen Sulfide	mg/m^3	6	7
Total Sulphur	mg/m^3	23	115
Ammonia	mg/m^3	3	3
Siloxanes	mg/m^3	1	1 ppmv
Halocarbons and organochlorinated compounds	mg/m3	10	10
Volatile organic compound (aromatics, oxygenates, alkanes, halocarbons)	- NA-	Site specific	3.7 ppmv
Bacteria	- NA-	Free of	Free of
Particulates, dust, etc.	- NA-	Free of	Free of
Volatile metals (e.g. mercury, arsenic)			Hg 0.05 Ar30 Cu30

Witnesses: A. Chagani
S. McGill

d) Enbridge is not aware of any official specifications for RNG from CSA or ISO.

e) Enbridge’s RNG specification addresses all of the listed potential components.

f) Enbridge will not accept RNG that contains contaminants that could be detrimental or hazardous to either customers’ equipment or customers’ health.

g) Enbridge will develop a sampling and testing protocol to ensure that the ongoing quality of RNG meets the Company’s minimum quality standards.

h) Enbridge uses minimum and maximum Wobbe Indices to define interchangeability of RNG with traditional NG, which can be found in the attached specification.

i) Enbridge will reject RNG that falls outside of the Company’s minimum quality standards.

Witnesses: A. Chagani
S. McGill

Renewable Natural Gas (RNG) Pipeline Gas Quality Specifications

Purpose

This document outlines gas quality specifications for the composition of renewable natural gas (RNG) for injection into the Enbridge gas distribution system. These specifications ensure that RNG to be injected into the system is within expected operating parameters and interchangeable with natural gas.

This document is intended to be used as a guide for evaluating RNG business opportunities or contracting new RNG supply.

Scope

This document covers the pipeline gas quality specifications for RNG for injection into the Enbridge gas distribution system, without respect to biogas sources.

It does not include procedures or standards for designing, constructing or operating biogas or biomethane facilities.

Specifications

RNG composition must meet the specifications outlined in Table 1. The values shown in Table 1 represent maximum levels, unless a range of values is indicated. Minimum and maximum pressures will be set for each RNG facility on a case-by-case basis.

In summary, in order to be injected into the Enbridge gas distribution system, RNG must:

- Not contain any contaminants, particles, or other impurities at a concentration that are known as a threat to the integrity of the system, human health, or the environment.
- Have an energy content no lower than 36.0 MJ/m^3 and no higher than 41.3 MJ/m^3.
- Have a Wobbe Index during normal operation no lower than 47.2 MJ/m^3 and no higher than 51.1 MJ/m^3.
- Not contain more than 2% by volume of carbon dioxide.
- Not contain more than 0.4% by volume of oxygen.
- Not contain more than 4% by volume of total inerts.
- Not contain more than 35 mg/m^3 of water content.
- Not contain more than 0.1% by volume of hydrogen.
- Not contain more than 6 mg/m^3 of hydrogen sulphide.
- Not contain more than 23 mg/m^3 of total sulphur.
- Not contain more than 3 mg/m^3 of ammonia.
- Not contain more than 1 mg/m^3 of total siloxanes.
- Not contain more than 10 mg/m^3 of halocarbons and organochlorinated compounds.
- Be technically free of volatile organic compound, bacteria, particles, and dust.
- Not form liquid hydrocarbons at temperatures of −10°C or higher at the delivery pressure.
- Be delivered at a maximum temperature of 30°C.

Table 1: Renewable Natural Gas – Pipeline Gas Quality Specifications

		Value	Unit	Monitoring Frequency*	Recommended Test
Heating Value	HV	36.0 to 41.3	MJ/m^3	Continuous	D1945 / D7164
Wobbe Index	WN	47.2 to 51.1	MJ/m^3	Continuous	D1945 / D7164
Carbon Dioxide	CO_2	2	% vol	Continuous	D1945
Oxygen	O_2	0.4	% vol	Continuous	D1945
Total Inerts		4	% vol	Continuous	D1945
Water Content	H_2O	35	mg/m^3	Continuous	D1142 / D5454 / D3588
Hydrogen	H_2	0.1	% vol	Periodic	D1945
Hydrogen Sulfide	H_2S	6	mg/m^3	Continuous	D4084 / D6228 / D4468 / D5504 / D7166
Total Sulphur	S	23	mg/m^3	Periodic	D4084 / D6228 / D4468 / D5504 / D7166
Ammonia	NH_3	3	mg/m^3	Periodic	D1945
Siloxanes	Si	1	mg/m^3	Periodic	E.g., Gas Chromatography (ELCD, AED, MS)
Halocarbons and organochlorinated compounds		10	mg/m^3	Periodic	E.g., Gas Chromatography / Electrolytic Conductivity Detector
Volatile organic compound	VOCs	Site-specific		Periodic	E.g., Gas Chromatography / Mass Spectrometry (GC/MS)
Bacteria		Technically free of		Periodic	E.g., Most Probable Number Determination of Total Live Bacteria (MPN), others
Particles, dust, etc.		Technically free of		Continuous	E.g., Environmental recommendations 0.1μm filters
Hydrocarbon Dew Point		−10	°C	Continuous	D5504 / D1142
Delivery Temperature (plastic pipe)		< 30	°C	Continuous	

** In this document, continuous monitoring means real-time or near-real time. Periodic monitoring could be seasonal, semi-annually, or annually. Final monitoring frequency will be defined for each RNG facility.*

Control and Maintenance

For document control and maintenance purposes, the following table captures important information related to this document.

Owned by	Engineering.
Review	Annually or as needed.
Distribution	Enbridge Gas Distribution employees.
Regulations	N/A
Related Documents	N/A

History of Changes

Changes made to this document are tracked in the following table.

REVISION DATE	SUMMARY	PREPARED BY	APPROVERS
2017-Apr-26	V1.0	Johana Gomez, Sr. Engineering Project Manager	Roddi Bassermann, Manager, Stns Telemetry & Controls Gonzalo Juarez, Manager, Engineering Construction and Maintenance Michael Wagle, Chief Engineer

APPrO INTERROGATORY #3

INTERROGATORY

RNG Risk Assessment

Reference: i) EB-2017-0224 Exhibit C Tab 5 Schedule 2:

Preamble: Enbridge is seeking approval to develop a renewable natural gas (RNG) program, whereby Enbridge would enter into long term contracts to acquire RNG. APPrO would like to better understand the cost and long-term risks to customers associated with these new supplies. It is understood that Enbridge is seeking provincial funding to make up the difference between the cost to acquire the RNG and the sum of the cost of conventional gas supply and the avoided cost of carbon.

Questions:

a) Please indicate if the provincial funding that is being sought is a one-time up-front payment or if the funding will be obtained annually, and how the funding will be applied to the revenue requirement.
b) Please provide the specific economic test that will be used to address the long-term cost to develop and operate the incremental facilities to attach RNG. Please include an illustrative example including the incremental capital and operating costs for new facilities.
c) At paragraphs 39-40, Enbridge indicates that it will use the principles in EBO 188, which could result in a deficiency in the early years and a sufficiency in the later years. Could Enbridge shape the timing of the provincial subsidy to eliminate these financial distortions?
d) Please discuss how the volume of available RNG will be forecasted over the life of a RNG project, for various types of RNG sources.
e) Please confirm that some sources of RNG, such as bio-methane from landfill sources, can decline over time, and discuss the implications.
f) Please discuss who will bear the volumetric risk associated with RNG sources.
g) Please identify and discuss all the financial risks that existing ratepayers will bear for projects associated with attaching RNG supplies. Please also discuss which customer rate classes are expected to bear these financial risks.

Witnesses: A. Chagani
S. McGill

h) Please identify all and any other risks that existing ratepayers will bear for projects associated with attaching RNG supplies. Please also discuss which customer rate classes are expected to bear these other risks.

RESPONSE

a) The Government of Ontario's Climate Change Action Plan (Section 6.1 - Promote low-carbon energy supply and products) stated it will use the Greenhouse Gas Reduction Account to provide support to encourage the use of cleaner, renewable natural gas ("RNG") for between $60 and $100 million. This is the expected total for the RNG market in Ontario, which includes Enbridge. For the purpose of answering interrogatories in this proceeding, Enbridge has assumed that it would be allocated half of this funding. However, this has yet to be determined. As discussed in the response to Board Staff Interrogatory #7 filed at I.C.EGDI.STAFF.7, the contract with the provincial government for subsidy funding has not yet been finalized. The Company expects that the initial funding will support and be allocated to the full 10 years of the RNG supply anticipated in the Company's proposal.

b) Please refer to the application for the RNG Enabling program EB-2017-0319.

c) The reference to EBO 188 principles applies to the determination of fees or charges for the RNG enabling program (upgrading and injection facilities for RNG producers). The provincial subsidy is not applicable to the RNG Enabling Program. The provincial subsidy will be applied to reduce the cost of RNG purchased by the Company.

d) Enbridge will not be forecasting the output from any given RNG project. Enbridge will rely on RNG producers' estimates and will set its contracts based on those estimates.

e) Yes some landfill biogas production may decrease over time, after full closure of the site. The changes in volume are expected to be managed by the RNG producer.

f) The RNG producer will be obligated to deliver the contracted supplies.

g) Please refer to the response to CCC Interrogatory #10 filed at Exhibit I.C.CCC.EGDI.10.

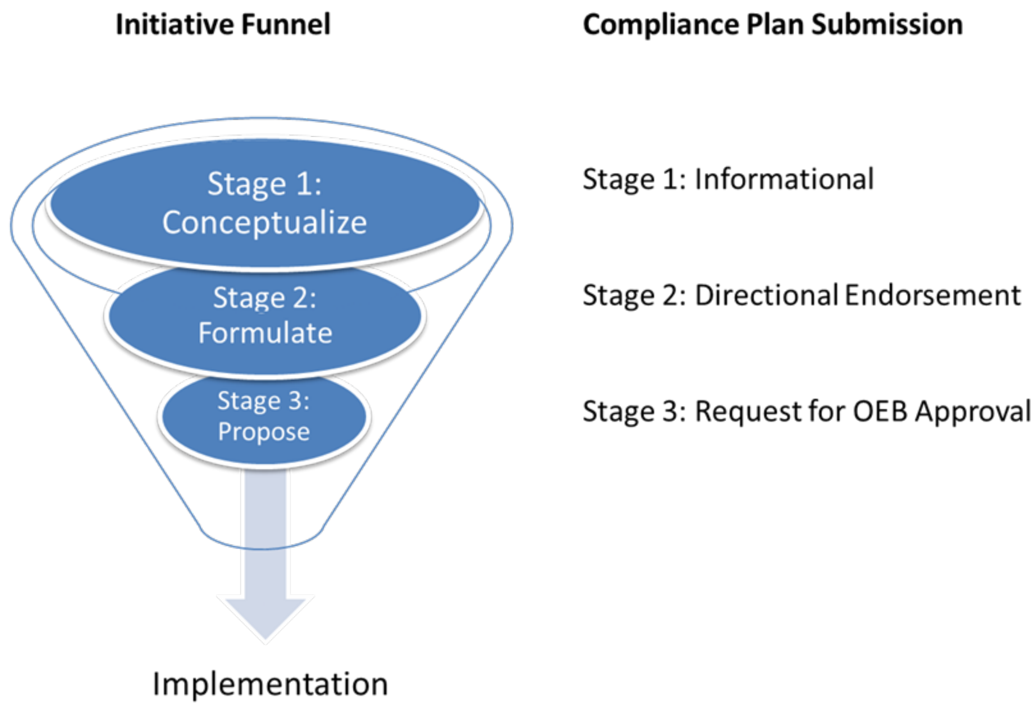
h) Please see response above to part (b).

Witnesses: A. Chagani
S. McGill

<u>BOMA INTERROGATORY #1</u>

<u>INTERROGATORY</u>

Ref: EB-2017-0224, Exhibit C Tab 5 Schedule 1 Page 1 of 15



With respect to this initiative funnel, at what stage does Enbridge do a business case analysis? What are the criteria used to evaluate the initiatives? Will initiatives be ranked? How did RNG become the first initiative to be proposed? Will there be exit strategies developed if the initiative doesn't achieve its results.

<u>RESPONSE</u>

Enbridge believes that a summary of how the initiative funnel was conceived and how it is being implemented is helpful context to this interrogatory response.

The newly introduced initiative funnel provides a high level structure to the various stages that a new technology or idea will generally follow in its development from idea to project. Enbridge determined that there was no perfect way to start applying the initiative funnel so made best efforts to understand and place known technologies and ideas in the various stages on a best fit basis. As with any new process, Enbridge will continue to evaluate and refine the process to meet the changing environment. Further, Enbridge submits that the decision points and timeframe for a particular technology or idea may vary and/or be iterative versus linear.

For the purposes of responding specifically to this Interrogatory, Enbridge's response is broken out into 5 sub sections in line with the above question.

i) Business cases are typically developed at stage 2 or 3 (dependent upon the scale of the initiative and the maturity of the initiative).

ii) Factors that are considered when evaluating initiatives include:

a. Potential to result in carbon reduction
b. Cost to customer and other initiatives
c. Safety
d. Increase early adoption/awareness of lower carbon technology/process
e. Time to market
f. Alignment with key government objectives – e.g., low carbon future, Net Zero
g. Resource availability
h. Sensitivity to timing of development

These factors may evolve or be refined over time.

iii) While not necessarily ranked, initiatives will be assessed and prioritized on an ongoing basis.

iv) RNG procurement was one of the first initiatives proposed as it is strongly in line with criteria provided above.

v) As standard business practice, all initiatives will be monitored and exit strategies developed as needed.

BOMA INTERROGATORY #2

INTERROGATORY

Ref: EB-2017-0224, Exhibit C Tab 5, Schedule 2, Page 1 of 29

> *RNG is a potential Ontario natural gas supply source that offers environmental, economic and waste management benefits. RNG (also known as biomethane) is ungraded gas produced from organic waste, such as that found on farms, at waste water treatment plants, food processing facilities and in landfills. RNG has been identified as a significant GHG abatement opportunity in the Fuels Technical Report1 prepared by Navigant Consulting Inc. on behalf of the Ontario Ministry of Energy and Climate Change (the "MOECC"), the Board's Marginal Abatement Cost Curve ("MACC"), and now the province's Long Term Energy Plan: Delivering Fairness and Choice (the "LTEP")2.*

Currently these products are being used directly in the generation of electricity either through the Fit Program or in cogeneration. What are the typical comparative project economics between direct use and introduction of RNG into the natural gas distribution system? Will the significant subsidization in the near-term result in stranded assets with respect to generation?

RESPONSE

Enbridge has previously included analysis of the economics between electricity generation under the FIT program and RNG generation in EB-2011-0242, filed in response to Vulnerable Energy Consumers Coalition Interrogatory #10 (Exhibit I-15-10). However, because the FIT program is no longer available to new projects, the Company has not updated this analysis.

The Company expects that those parties currently engaged in the production of electricity under the FIT Program will honour their contractual commitments and as such it is not expected that the implementation of the Company's RNG procurement plan will result in FIT contract termination, resulting in stranded assets.

Witnesses: A. Chagani
S. McGill

BOMA INTERROGATORY #3

INTERROGATORY

Ref: EB-2017-0224, Exhibit C, Tab 5. Schedule 2, Page 6 of 29

> *Many jurisdictions are ahead of Ontario in moving to RNG, and several models exist for delivering it to customers. European markets are actively developing renewable pipeline fuels through both RNG and Power-to-Gas ("P2G") developments. In North America, California, British Columbia and Québec have all moved forward with the early development and procurement of RNG to complement the renewable energy options that have traditionally been focused on the electricity grid.*

In September 2009, an Order in Council added initiatives such as RNG to the undertakings of the natural gas utilities. What is the reason for the almost ten year delay in moving forward on these initiatives.

RESPONSE

Enbridge's RNG procurement proposal is prompted by recent developments, particularly the Cap and Trade Program and associated price on carbon as well as the Ontario Government's stated intention and promised funding to encourage the adoption of RNG. Enbridge's RNG procurement proposal does not rely on the changes to Enbridge's Undertakings. The Company is not proposing that it will own assets or enter into new business activities through this proposal.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #1

INTERROGATORY

Re: Ex. C/T5/S2/p. 6

The evidence refers to EGD's EB-2017-0337 submission to the Board to be made later this year. Please indicate what submission the evidence is referring to. How does this relate to EB-2017-0319 (referred to at Ex. C/T1/S1/p. 4)?

RESPONSE

The reference to the docket number EB-2017-0337 was made in error. The Company's EB-2017-0319 application dealing with Enbridge's RNG Enabling Program and Geothermal Energy Service Program was submitted to the Board on January 17, 2018.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #2

INTERROGATORY

Re: Ex. C/T5/S2/p. 6
The evidence states that the ICF study identified a range of carbon abatement costs associated with RNG in the range of $77 to $1,990 per t$CO_2$e. The study also noted a number of limitations and caveats related to its analysis of RNG potential and costs. In the absence of a more comprehensive analysis, why does EGD believe it is prudent to pursue RNG procurement in 2018? If there is no established market in Ontario why is it appropriate to contract for RNG supplies at this time? Why is EGD prepared to commit to 10-year contracts?

RESPONSE

In the absence of a more comprehensive RNG costing analysis, the Company believes it is prudent to embark upon an RFP process to solicit actual pricing from the market to establish the cost of RNG supplies. Please see the response to CCC Interrogatory #12 filed at Exhibit I.C.EGDI.CCC.12.

The Company has discussed the appropriateness of 10-year contracts in the response to Board Staff Interrogatory #9 filed at Exhibit I.C.EGDI.STAFF.9.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #3

INTERROGATORY

Re: Ex. C/T5/S2/p. 8

Please provide a list of all current RNG producers in Ontario and their potential annual production amounts.

RESPONSE

As far as the Company is aware, the only operational RNG production facility in Ontario is located at the City of Hamilton's Woodward Avenue Wastewater Treatment Plant. A biogas upgrading unit was installed to create RNG as part of a Green Infrastructure Fund grant in 2010. The published capacity of the upgrading unit is 750 Nm^3/hr. Annual production will depend on the operating schedule.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #4

INTERROGATORY

Re: Ex. C/T5/S2/p. 9
Is it EGD's view that regardless of the economics associated with RNG production, and the absence of a real market, it has a role in terms of developing an Ontario RNG market? Why should EGD take on that risk?

RESPONSE

The RNG market in Ontario is nascent, and could be enhanced through the active participation of the province's natural gas distribution utilities.

Minister Thibeault's December 10, 2016 letter to the Chair of the OEB, concludes with the following statement.

> In light of the developments noted earlier in this letter, I encourage the OEB to move forward in a timely manner to include RNG as a potential fuel that could help reduce GHG emissions as a part of the gas utilities' supply portfolios.

And, from the province's 2017 Long Term Energy Plan;

> Ontario is looking at using renewable natural gas to lower the carbon intensity of the natural gas that people burn. RNG is a low-carbon fuel produced by the decomposition of organic materials found in landfills, forestry and agricultural residue, green bin and food and beverage waste, as well as in waste from sewage and wastewater treatment plants. Because it comes from organic sources, the use of RNG does not release any additional carbon into the atmosphere. As an added benefit, it can use the existing natural gas distribution system and replace the use of conventional natural gas in today's stoves and furnaces.
>
> The government will continue to work with industry partners and the Ontario Energy Board (OEB) to introduce a requirement that natural gas contain some renewable content, fulfilling a commitment of the Climate Change Action Plan.
>
> The government is also investing proceeds from the auctions in the carbon market to help introduce RNG in the province. The investment will help consumers with the cost of shifting to RNG, as it currently costs more than conventional natural gas. (Ontario's Long –Term Energy Plan 2017; Delivering Fairness and Choice, page 114)

Witnesses: A. Chagani
S. McGill

Based on the above, it is clear that the Province of Ontario sees the development of an Ontario RNG market as a component of its low carbon energy and GHG reduction plans and expects the OEB to work with Ontario's natural gas distribution utilities to integrate RNG into systems to facilitate the development of this market.

With respect to the question on risk and for discussion of the expected "clean fuel standard", please refer to the response to CCC Interrogatory #10 filed at Exhibit I.C.EGDI.CCC.10.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #5

INTERROGATORY

Re: Ex. C/T5/S2/pp. 8-9
EGD is proposing an RNG procurement and funding model:

a) Please describe, in detail, the RFP process that EGD will be undertaking;
b) Has EGD and or Union determined the contractual arrangements that will be made between EGD, Union and the Province? If so, please provide those details. If not, when are the contractual arrangements expected to be finalized?
c) Please explain how a tendering process would involve the Province of Ontario.

RESPONSE

a) Please refer to the response to Board Staff interrogatory #5a filed at Exhibit I.C.EGDI.STAFF.5, Attachment 6.

b) Please refer to the response to Board Staff Interrogatory #5a filed at Exhibit I.C.EGDI.STAFF.5. Details about expected timing are set out in response to Board Staff Interrogatory #7b filed at Exhibit I.C.EGDI.STAFF.7.

c) As part of the discussions about the contractual arrangements between Enbridge and the Province, the Province may provide input into elements of the RFP process.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #6

INTERROGATORY

Re: Ex. C/T5/S2/pp. 9-10

The evidence states that Biogas producers require longer term contracts in order to support capital investments in RNG production facilities and EGD is considering entering into RNG procurement contracts with terms of up to ten years in duration. Will all of the contracts be for 10 years or does EGD expect to have different contract terms with different RNG providers? Please explain EGD's intention with respect to RNG contract terms.

RESPONSE

Enbridge is of the view that RNG procurement agreements with up to ten year terms are required to secure Ontario produced RNG supplies. Please refer to the response to Board Staff Interrogatory #9 filed at Exhibit I.C.EGDI.STAFF.9 for further discussion about RNG procurement contract term (duration).

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #7

INTERROGATORY

Re: Ex. C/T5/S2/pp. 9-10
Please provide all correspondence, meeting materials, reports and presentations related to EGD's collaboration with the Province regarding RNG.

RESPONSE

Please refer to the response to Board Staff Interrogatory #5a filed at Exhibit I.C.EGDI.STAFF.5 for a list of meetings with applicable meeting materials, reports and presentations.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #8

INTERROGATORY

Re: Ex. C/T5/S2/p. 9
The evidence states that the Province will agree to compensate ratepayers for the difference between the cost of the RNG purchased and the carbon abated cost of natural gas. Will this be on a forecast or actual basis? Will there be a true-up mechanism to ensure ratepayers are not responsible for any of the differences? How and when will payments be made?

RESPONSE

The Company's RNG procurement proposal is designed such that the customers will not pay the cost differential between the carbon-abated cost of natural gas and RNG. For a full response please refer to CCC Interrogatory #10 file at Exhibit I.C.EGDI.CCC.10.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #9

INTERROGATORY

Re: Ex. C/T5/S2/p. 11
The evidence states that based on the expected level of Provincial funding, the initial round of the RNG RFP process is likely to capture less than .1% of the Company's annual gas volume requirement. What is the expected level of Provincial funding on an annual basis?

RESPONSE

Please see the Company's response to APPrO Interrogatory #3(a) filed at Exhibit I.C.EGDI.APPrO.3.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #10

INTERROGATORY

Re: Ex. C/T5/S2
Please identify all of the potential risks for EGD's customers regarding its RNG procurement. How will those risks be mitigated? Please explain what is meant by the statement, "Subject to receiving approval for the use of the forecast commodity and carbon cost methodology in this proceeding and the successful negotiation of contact terms and funding, the cost implications related to RNG procurement will be incorporated in future proceedings relying upon existing rate setting mechanisms."

RESPONSE

Contingent on provincial funding available, the Company intends to procure a portion of its natural gas supply through RNG using a competitive RFP process and enter into contracts with RNG producers for up to 10 years. RNG will replace conventional natural gas supplies and carbon allowances that the Company would otherwise have to procure.

For the purposes of the RNG contracting, the Company is seeking approval to use long-term gas forecasts (as discussed in Exhibit C, Tab 5, Schedule 2, p. 9). This will establish the benchmark gas cost and may be used as one of the gas cost inputs into determining the PGVA reference price on an ongoing basis. The Company is also seeking to use the OEB's Long Term Carbon Price Forecast (also discussed in Exhibit C, Tab 5, Schedule 2, p. 9). These forecasted prices will determine the costs that ratepayers will pay. The remaining component making up the RNG price will be funded from the anticipated government subsidy. Put another way, RNG is not expected to cost ratepayers any incremental amounts as government funding will cover the premium between the all-in cost of natural gas (conventional natural gas costs plus the associated carbon cost at the LTCPF rate), and the actual cost of the RNG procurement.

The existing QRAM and annual deferral account clearing processes will capture the differences between actual gas commodity and carbon allowance prices and the benchmark prices used at the time that RNG contracts are negotiated. Given the current low natural gas prices, Enbridge does not see a high risk that future gas costs

Witnesses: A. Chagani
S. McGill

will be substantially lower than forecast (and where future gas costs are higher than forecast, ratepayers will benefit). Enbridge also does not see a high risk that carbon pricing will cease to exist. And should Cap and Trade continue, the downside of the carbon price is bound by a predetermined and regulated floor.

Enbridge's RNG procurement will make up a very small portion of Enbridge's gas supply and Cap and Trade Compliance Plans. Therefore, the impact associated with price variances for gas and/or carbon allowances is expected to be small.

The table set out below shows the impact of actual gas commodity prices and carbon allowance prices being 25% different from what is being forecast. As can be seen, the impacts are very modest – amounting to an annual impact of around 26¢ for a system gas customer.

- Line #1 of the table shows the annual volume of RNG that will be procured based on an illustrative cost of $16/GJ for RNG (the same cost as used in Table 2 in Exhibit C, Tab 5, Schedule 2, and in response to Board Staff Interrogatory #8 at Exhibit I.C.EGDI.STAFF.8).

- Line #2 shows the average assumed cost that customers will pay for the RNG (the average assumed cost of gas plus the average mid-range cost of carbon allowances under the LTCPF multiplied by the assumed volume).

- Line #3 shows the total estimated average cost to be paid. The gas cost will be paid by all system gas customers, and the carbon allowance cost will be paid by all customers except for large final emitters (LFEs) and those who have voluntarily opted to manage their own carbon compliance obligations.

- The next lines show the impacts of a difference of 25% in the forecast cost of gas and the forecast cost of carbon allowances.

- Line #5 (in the "Gas" column) shows that where the cost of the gas commodity is 25% different from the forecast, then the total annual impact will be around $400,000. The way that this amount will be reflected is as follows. Variances from the assumed gas costs in the RNG procurement model versus actual gas costs at the relevant time will be reflected in the PGVA. As seen in the example in the chart, because the RNG volumes are relatively modest compared to the number of system gas customers, the impacts of variances in the gas cost will be small. Where the gas cost is 25% higher than forecast, each system gas customer would pay 19¢ more each year.

- Line #5 (in the "Carbon" column) shows that where the cost of carbon allowances is 25% different from the forecast, then the total annual impact will be around $155,000. The way that this amount will be reflected is as follows. The amounts that Enbridge spends each year to meet its compliance obligations (including through the purchase of carbon allowances) will be recorded in the GHG-Customer Variance Account, with variances from forecast to be cleared to all customers except LFEs and those who have voluntarily opted to manage their own carbon compliance obligations. Where the cost of carbon allowances is different from the LTCPF at the time of the RNG RFP, then the amounts recorded in the GHG-Customer Variance Account will be higher or lower than expected. Again, however, because the RNG volumes are relatively modest compared to the number of customers, the impacts of variances in the carbon allowance cost will be small. Where carbon allowance gas cost is 25% higher than forecast, each system gas customer would pay 7¢ more each year.

		Total	Gas	Carbon
1	**Annual RNG Purchase Volume (GJ)[1]**	453,803	453,803	453,803
2	**10 Year Abated Cost of RNG from Table 2 ($/GJ)**	$4.98	$ 3.61	$1.37
3	**Estimated annual cost**	$2,260,185	$1,637,835	$622,350
4	**Variance % +/-**	25%	25%	25%
5	**Annual Variance +/-**	$565,046	$409,459	$155,588
6	**Customers**		2,100,000	2,200,000
7	**Annual Variance +/- ($/Customer)**		**$0.19**	**$0.07**

Input Assumed Cost of Gas ($/GJ)[2] – $ 3.61

Input Assumed Cost of Carbon ($/GJ)[2] – $ 1.37

Note 1: Average estimated annual volume from Board Staff Interrogatory 8, I.C.EGDI.STAFF.8
Note 2: Ten-year average cost from Exhibit C, Tab 5, Schedule 2, Table 2.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #11

INTERROGATORY

Re: Ex. C/T5/S2
What are the implications for the RNG procurement model if the Ontario Cap and Trade Program is either eliminated or replaced with a carbon tax regime?

RESPONSE

In the event that the current Cap and Trade Program is either eliminated or replaced with a carbon tax regime, there would be no implications for the Company's RNG procurement program provided that provincial government funding for this program is secured for the full term of the RNG contracts before such change is implemented.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #12

INTERROGATORY

Re: Ex. C/T5/S2/p. 11
The evidence states that the RNG procurement model will provide for the acquisition of competitively priced RNG supplies. Please explain how EGD will acquire competitively priced RNG supplies if there is no established RNG market in Ontario (p. 8).

RESPONSE

Enbridge will conduct a competitive RFP process to acquire RNG. By soliciting responses from a variety of potential suppliers, the Company expects to receive competitive offers for the supply of RNG.

Witnesses: A. Chagani
S. McGill

CCC INTERROGATORY #13

INTERROGATORY

Re: Ex. C/T5/S2

In 2018 will EGD and Union be competing for RNG supplies? If the Union and EGD merger is approved and effective January 1, 2019, how will this impact the RNG procurement model? Why would it not be appropriate to await that approval before entering into long term contracts for RNG supply?

RESPONSE

Yes, a possibility exists that Enbridge and Union Gas will have RFPs for supplies of RNG in the market at the same time during 2018. The Company's expectation is that if the amalgamation of Enbridge and Union Gas proceeds as contemplated in the EB-2017-0306 MAADS application now before the Board, then each of the two companies' RNG procurement programs are likely to become integrated on a go-forward basis after January 1, 2019. With respect to the timing of the implementation of the Company's RNG procurement program, please see the Company's response to Board Staff Interrogatory 7 filed at Exhibit I.C.EGDI.STAFF.7(a).

Witnesses: A. Chagani
S. McGill

CME INTERROGATORY #1

INTERROGATORY

Ref: Exhibit C, Tab 5, page 9 of 29

At Exhibit C, Tab 5, page 9, EGD states that "Biogas producers require longer term contracts in order to support capital investments in RNG production facilities. Enbridge is considering entering into RNG procurement contracts with terms of up to 10 years in duration."

(a) CME wishes to better understand the decision to enter into longer-term fixed contracts. Did EGD compare or solicit any third parties to compare the various types and lengths of contracts? If so, please provide the comparisons, or any work done that was used to determine the optimal nature and maximum duration of the contract.

(b) Why was the upper limit of 10 years decided upon?

(c) With long-term fixed contracts, there is a risk to ratepayers if the price of gas and/or carbon is significantly lower than what was forecast at the time of entering into the contract. Does EGD plan to hedge those risks in any way, whether in the contract terms or otherwise?

RESPONSE

a) The Company's assessment that a 10-year term for RNG procurement contracts is reasonable has been informed by discussions between the Company and RNG equipment manufacturers and potential RNG producers. For further information, please refer to the response to Board Staff Interrogatory #9 filed at Exhibit I.C.EGDI.STAFF.9, part a.

b) Please refer to the response to Board Staff Interrogatory #9 filed at Exhibit I.C.EGDI.STAFF.9, part a.

c) For a discussion of risk, please refer to the response to CCC Interrogatory #10 filed at Exhibit I.C.EGDI.CCC.10. Enbridge has no plans to hedge.

Witnesses: A. Chagani
S. McGill

CME INTERROGATORY #2

INTERROGATORY

Ref: Exhibit C, Tab 5, Schedule 2, Page 8 of 29

At Exhibit C, Tab 5, Schedule 2, page 8, Enbridge states "Some potential producers of renewable gas supplies are at the early stage of project development in anticipation of market opportunities developing in Ontario while others are closer to fruition."

(a) Will the individual RNG projects' stage of development (how close they are to fruition) be the primary driver behind the length of the contract term? Why or why not?

(b) If the stage of development drives the contract term, does EGD expect that the length of the contracts will generally decline over time as RNG projects in Ontario become more numerous and further developed?

RESPONSE

a) No, the stage of development will not be the primary driver behind the length of the contract term. Please refer to response to Board Staff Interrogatory #9 filed at Exhibit I.C.EGDI.STAFF.9 for further discussion on contract term (duration).

b) Enbridge does not expect the stage of development to drive contract term. The length of future contracts may be influenced by RNG market maturity, policy, supply requirements and other factors.

Witnesses: A. Chagani
S. McGill

CME INTERROGATORY #3

INTERROGATORY

Ref: Exhibit C, Tab 5, page 9 of 29

At Exhibit C, Tab 5, page 9, EGD states that it will “Negotiate and enter into a contractual arrangement between the Company and the Province whereby the Province agrees to compensate ratepayers for the difference between the cost of the RNG purchased and the carbon abated cost of natural gas. The latter will be determined by summing the forecast cost of traditional gas supplies over the term of the RNG procurement contract with the Board’s LTCPF mid-range forecast carbon cost applicable for each respective year of the same time period.”

CME wishes to better understand the implications of the cost allocation between the various parties to the RNG funding proposal.

(a) Please confirm if the notional cost of carbon that is being factored into the ratepayer cost of RNG is only being used to determine the appropriate allocation of costs between ratepayers and the Ontario Government.

(b) If EGD is granted the funding proposal that they are seeking in this application, and begins using RNG, please confirm if this will decrease the total cap and trade compliance costs that EGD will incur.

(c) If the answer to b) is yes, will the reduction in compliance costs be captured in the Greenhouse Gas Emissions Compliance Obligation – Customer Related Variance Account, or another account?

(d) If the answer to c) is yes, if EGD secures provincial funding, and begins to source RNG, does it plan to begin forecasting the reductions in GHG emissions reductions into their future compliance plans, or will it be left to the variance account to true-up the impact of RNG on the total cap and trade compliance costs?

Witnesses: A. Langstaff
J. Murphy

RESPONSE

(a) Ratepayers will incur the cost of carbon abated natural gas. The Ontario Government will fund the difference between the RFP price of RNG and the carbon abated cost of natural gas paid by ratepayers. Please refer to the response to CCC Interrogatory #10 filed at Exhibit I.C.EGDI.CCC.10.

(b) The RNG funding proposal decreases the Company's Cap and Trade obligation, but keeps the costs unchanged from what they would have been without RNG procurement. Please refer to the response to CCC Interrogatory #10 filed at Exhibit I.C.EGDI.CCC.10.

(c) Not applicable.

(d) Although the response is not yes to (c), the RNG anticipated to be procured in future years will be incorporated into emissions forecasts in future compliance plans.

Witnesses: A. Langstaff
J. Murphy

ENVIRONMENTAL DEFENCE INTERROGATORY #1

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

Should the OEB use the Total Resource Cost (TRC) Test to evaluate the cost-effectiveness of Enbridge's proposed Renewable Natural Gas Procurement Program? If no, please fully explain why not.

RESPONSE

Enbridge's RNG procurement program keeps customers indifferent to including RNG in the Company's gas supply when compared to the forecasted cost of conventional natural gas including the applicable forecasted carbon costs. Therefore, Enbridge does not believe a TRC test to be meaningful since its RNG procurement proposal does not impose any incremental cost upon the Company's ratepayers.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #2

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

Please provide Enbridge's forecast of the TRC Test net benefits and benefit/cost ratios of its proposed Renewable Natural Gas Procurement Program for each of the next ten years. Please state your assumptions and show your calculations. Please use best efforts to develop a response to this interrogatory and make assumptions as needed.

RESPONSE

Please refer to the response to Environmental Defence Interrogatory #1 filed at Exhibit I.C.EGDI.ED.1.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #3

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

Please provide Enbridge's forecast of the annual bill impact of its proposed Renewable Natural Gas Procurement Program for a typical residential customer for each of the next ten years. Please state your assumptions and show your calculations.

RESPONSE

On a forecast basis, over the 10-year period the incremental bill impact of the RNG procurement program will be 0, as the premium paid for RNG will be supported by Provincial subsidy.

Please refer to the response to CCC Interrogatory #10 filed at Exhibit I.C.EGDI.CCC.10 for further discussion on the funding model proposed for RNG procurement and related ratepayer impacts.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #4

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

How much RNG does Enbridge wish to contract for under the proposed procurement program in 2018? Please provide the response in a table showing the expected RNG to be provided in each year covered by the expected 2018 contracts and a grand total for the entire period. If there is uncertainty about the amount, please provide a best efforts response, including an explanation of the response, and a range of potential amounts (if necessary). Please provide the information in both m^3 and GJ and indicate the appropriate conversion factor

RESPONSE

Please refer to the response to Board Staff Interrogatory #8 filed at Exhibit I.C.EGDI.STAFF.8.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #5

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

Please estimate the cost per tonne of the greenhouse gas (GHG) emissions reductions (co2e) that the proposed procurement program is expected to achieve via the contracts to be entered into in 2018. Please provide the estimate based on the costs and emission reductions for the lifetime of the contracts (or if that is not possible, please use an illustrative contract year that would be representative of the average costs).

GHG emissions reductions may arise from (a) the displacement of conventional natural gas and (b) the capture of methane that would have been vented to the atmosphere as fugitive emissions. If the $/tonne estimate includes GHG emissions reductions arising from avoided fugitive methane emissions, please (a) provide the underlying calculations and (b) also provide an estimate that does not include the GHG emissions reductions from avoided fugitive methane emissions.

Presumably the cost per tonne would roughly equal the amount of the proposed subsidy divided by the tonnes of carbon emissions avoided by the RNG in question – if Enbridge uses a different calculation, please explain why, and indicate the magnitude of difference between the two calculation methods.

RESPONSE

The GHG reductions are not known until the volume of RNG that can be procured is established, please refer to Board Staff Interrogatory #8 filed at Exhibit I.C.EGDI.STAFF.8 for an illustrative example of the RNG volumes that may be procured. An illustration of $/tonne abated based on the fuel substitution of the RNG purchases assumed in Board Staff Interrogatory #8 can be found in the materials provided in Board Staff Interrogatory #6 filed at Exhibit I.C.EGDI.STAFF.6.

Witnesses: A. Chagani
S. McGill
J. Murphy

ENVIRONMENTAL DEFENCE INTERROGATORY #6

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

Please provide a forecast of the total gross cost of the provincial subsidy that will be needed for the contracts that Enbridge wishes to enter into in 2018. Please provide this as a table showing the forecast total cost for each year covered by the relevant contracts and a grand total for the entire period. Please make assumptions as needed and state them in the response. Please include caveats as needed.

RESPONSE

Please see the response to APPrO Interrogatory #3(a) filed at Exhibit I.C.EGDI.APPrO.3.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #7

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

(a) How many customers does Enbridge have?
(b) How many residential customers does Enbridge have?
(c) Please calculate the cost of the proposed subsidy on a per customer basis (i.e. the grand total calculated in the previous interrogatory divided by the number of customers).

RESPONSE

a) Enbridge has approximately 2.2 million customers.

b) Enbridge has approximately 1.9 million residential customers.

c) The available subsidy is $13.64 to $22.73 on a per customer basis, assuming that Enbridge is able to access half of the proposed provincial funding for RNG. Please see responses to APPrO Interrogatory #3a filed at Exhibit I.C.EGDI.APPrO.3 and Board Staff Interrogatory #8 filed at Exhibit I.C.EGDI.STAFF.8.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #8

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, page 11

Enbridge's evidence refers to "the expected level of provincial funding" at Ex. C-5-2 p. 11.

(a) What is the expected level of provincial funding?
(b) Is that level for all utilities or just Enbridge? If the former, what is the level for all utilities?
(c) How much RNG does Enbridge expect to be able to contract for with the expected level of funding?

RESPONSE

(a) Please refer to the response to APPrO Interrogatory #3a filed at Exhibit I.C.EGDI.APPrO.3.

(b) Please refer to the response to APPrO Interrogatory #3a filed at Exhibit I.C.EGDI.APPrO.3.

(c) Please refer to the response to Board Staff Interrogatory #8 filed at Exhibit I.C.EGDI.STAFF.8.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #9

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

(a) Is the RNG procurement program predicated on an expectation that it will spur market change and result in lowering of the price of RNG and improved cost effectiveness over time? Please explain in detail.
(b) If Enbridge's proposed program is approved and implemented as planned, what will the forecast impact be on the price and cost-effectiveness of RNG going forward? Please provide a qualitative and narrative response. Please also provide a best efforts quantitative response, including the impact on price and cost-effectiveness going forward to 2030, noting necessary uncertainties and caveats.
(c) Please provide an estimate of the investments that would be needed to make RNG cost effective by 2030, noting any uncertainties and caveats.
(d) Please estimate the time and investments required to make RNG cost effective.

RESPONSE

a) Consistent with Enbridge's abatement strategy, the Company's objectives with respect to its proposed RNG procurement program are to:

   a. support the Ontario government's Climate Change Action Plan's objective to reduce emissions from fossil-fuel use in buildings,
   b. develop RNG as an energy source as a low carbon fuel that leverages existing energy infrastructure,
   c. initiate a competitive market for the supply of RNG in Ontario, and
   d. procure RNG supplies as an abatement initiative as part of reducing the Company's Cap-and-Trade compliance obligations, under a model where the purchase of RNG imposes no material incremental cost on customers.

   Please see also the response to Board Staff Interrogatory #10a filed at Exhibit I.C.EGDI.STAFF.10.

Witnesses: A. Chagani
S. McGill

b) The proposed RNG program is expected to support a number of RNG producers making necessary investments and entering the market. This is expected to support growth of RNG supply opportunities. All things being equal, this will help move towards a competitive market for RNG in the future.

c) The investments required to grow RNG supply in Ontario will primarily be made by RNG producers (note that Enbridge is planning to make certain investments in processing and injection facilities where requested by producers). The RNG producers' investments will be supported by the long term contracts that Enbridge proposes to enter into with the RNG producers (underpinned by the government subsidies). RNG suppliers would have more information than Enbridge about what amount of investment is required to grow the RNG market to any particular level.

d) Please refer to responses b and c.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #10

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

Is Enbridge amendable to provide annual reporting to the Board on the effectiveness of its RNG program in achieving its objective of achieving market change and improving cost effectiveness, including the tracking of cost-effectiveness metrics such as the differential between the cost of RNG versus the combined price of gas and carbon?

RESPONSE

Please refer to the response to Energy Probe Interrogatory #8e filed at Exhibit I.C.EGDI.EP.8.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #11

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

(a) Please provide a concise list of the high-level objectives of the RNG program.
(b) Is Enbridge amendable to providing annual reporting, with concrete metrics, on the success of the proposed procurement project in meeting those objectives?

RESPONSE

(a) Please refer to the response to Environmental Defence Interrogatory 9a filed at Exhibit I.C.EGDI.ED.9.

(b) Please refer to the response to Energy Probe Interrogatory #8e filed at Exhibit I.C.EGDI.EP.8.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #12

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

Please provide Enbridge's best efforts estimate of the RNG potential available for development in Ontario in the medium term (in m^3/yr). Please also provide a copy of any reports or studies that include an estimate the available RNG potential, including any reports or studies completed by ICF.

RESPONSE

The most recent study of the RNG potential in Ontario was completed by ICF, and included in the Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities (EB-2016-0359) report. Table 17 provided on page 47 of the MACC report shows the RNG potential in Canada and Ontario. For reference, this Table has been copied below.

Table 17 RNG Resource Potential in 2028 for Canada and Ontario

Feedstock for RNG	Canada Resource Potential Estimate (million m^3/y)	Ontario Resource Potential Estimate (million m^3/y)
LFG	290	113
WWT gas	180	71
Animal manure	874	191
SSO (Residential and Commercial)	300	110
Agricultural residue	774	142
Total	**2,418**	**627**

The Fuels Technical Report (at page 31 of 190) also includes an assessment of RNG potential supplies for Ontario (see attachment to Energy Probe Interrogatory #5(a) filed at Exhibit I.C.EGDI.EP.5).

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #13

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

(a) Please list all facilities (and organizations) that Enbridge has identified as potentially being in a position to enter into an RNG supply contract with Enbridge.
(b) Of those, please provide a list of those which are currently venting methane to the atmosphere without capture or flaring.
(c) Of those, please provide a list of those which would be required by government regulations to capture and/or flare their methane emissions within the next five years regardless of whether they enter into an RNG supply contract.
(d) Please provide an estimate of the percent of the RNG supplies (i.e. % of m^3/yr) that could be contracted for over the next 10 years that will result in the capture of methane emissions that would otherwise be released to the atmosphere without flaring. If a single estimate is not possible, please provide a range of potential, including any caveats and a discussion.

RESPONSE

(a) Enbridge has conducted a market scan to determine the number of potential RNG projects in Ontario over the next 10 years. Please refer to the response to Board Staff Interrogatory #5a, Attachment 4, slide 8 filed at Exhibit I.C.EGDI.STAFF.5. Enbridge will determine the suppliers that are in a position to enter into an RNG supply contract through its RFP process.

(b) As discussed above in response to (a), Enbridge will determine the potential suppliers through the RFP process. Until the suppliers have been determined, Enbridge is unable to provide the list requested.

(c) and (d) Enbridge is unable to respond to this question, as the Company has not yet determined which suppliers it will contract with.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #14

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

Is Enbridge seeking approval to enter into these procurement contracts going forward, or only for 2018? In other words, if approval is granted, would Enbridge need to seek approval again in 2019 or 2020 to enter into this kind of procurement contract?

RESPONSE

The Company is seeking the Board's endorsement of this RNG procurement model. Provided that the subsidy funding from the province is expanded beyond 2018, Enbridge would use the same model going forward and only seek approval for changes or modifications to the model.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #15

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

How much RNG does Enbridge estimate that it will contract for under the proposed program in 2018 to 2020 (inclusive)? Please provide the response in a table showing the expected RNG to be provided in each year covered by the contracts that would be entered into in those years and a grand total for the entire period. If there is uncertainty about the amount, please provide a best efforts response, including an explanation of the response, and a range of potential amounts if necessary. Please provide the information in both m^3 and GJ and indicate the appropriate conversion factor.

RESPONSE

Please refer to the response to Board Staff Interrogatory #8 filed at Exhibit I.C.EGDI.STAFF.8.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #16

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

Please estimate the cost per tonne of the greenhouse gas (GHG) emissions reductions (co2e) that the proposed procurement program is expected to achieve via the contracts Enbridge would anticipate entering into in 2018 to 2020 (inclusive). Please provide the estimate based on the costs and emission reductions for the lifetime of the contracts (or if that is not possible, please use an illustrative contract year that would be representative of the average costs).

GHG emissions reductions may arise from (a) the displacement of conventional natural gas and (b) the capture of methane that would have been vented to the atmosphere as fugitive emissions. If the $/tonne estimate includes GHG emissions reductions arising from avoided fugitive methane emissions, please (a) provide the underlying calculations and (b) also provide an estimate that does not include the GHG emissions reductions from avoided fugitive methane emissions.

Presumably the cost per tonne would roughly equal the amount of the proposed subsidy divided by the tonnes of carbon emissions avoided by the RNG in question – if Enbridge uses a different calculation, please explain why, and indicate the magnitude of difference between the two calculation methods.

RESPONSE

This is a duplicate interrogatory to Environmental Defence #5. Please refer to response filed at Exhibit I.C.EGDI.ED.5.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #17

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

Please provide a forecast of the total gross cost of the provincial subsidy that will be needed for the contracts that Enbridge wishes to enter into in 2018 to 2020 (inclusive). Please provide this as a table showing the forecast total cost for each year covered by the relevant contracts and a grand total for the entire period. Please make assumptions as needed and state them in the response. Please include caveats as needed.

RESPONSE

Discussions between the Company and the province have not yet concluded, therefore the total amount of the provincial subsidy has not been finalized. Please refer to the response to APPrO Interrogatory #3a filed at Exhibit I.C.EGDI.APPrO.3.

As explained in the response to Board Staff #8 filed at Exhibit I.C.EGDI.STAFF.8, the RNG volumes to be procured will be based on the amount of the provincial subsidy.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #18

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

(a) Under the proposed model, would the cost allocation between the provincial government and ratepayers be recalculated each year (or another period of time) based on updated forecasts of the carbon price and gas price?
(b) Why does Enbridge propose to use forecasts of carbon and gas prices for calculating the cost allocation between the provincial government and ratepayers instead of the actual current carbon and gas prices (e.g. for each quarter of delivery)?
(c) Is any mechanism being proposed to true up deviations between forecasts used to calculate the allocation of costs between the provincial government and ratepayers and the actual amounts?

RESPONSE

Please refer to the response to CCC Interrogatory #10 filed at Exhibit I.C.EGDI.CCC.10.

Witnesses: A. Chagani
S. McGill

ENVIRONMENTAL DEFENCE INTERROGATORY #19

INTERROGATORY

Reference: Ex. C, Tab 5, Sch. 2, pages 4 – 14

Please compare the proposed RNG procurement program with the RNG procurement program in place in California, including an itemized list of the differences and an explanation for why those differences are being proposed.

RESPONSE

The proposed RNG procurement program is distinct from the systems employed in California. California seeks to reduce the carbon intensity of various transportation fuels through standardized instruments and policies such as low carbon fuel standards. The proposed RNG procurement program is intended to proactively assist Ontario natural gas customers to reduce their GHG emissions by including RNG in their gas supply while making use of available Government subsidies.

Witnesses: A. Chagani
S. McGill

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

Reference: General

Preamble: Enbridge and Union have Merged and Amalco has applied for a Rate Setting Mechanism for 2019 and beyond.

a) Please explain why Amalco has not prepared a combined Compliance Plan, including specifically a single RNG Program for approval starting in 2018.
b) Please provide detailed response addressing matters such as regulatory efficiency, consistency, transparency, duplication and costs.

RESPONSE

a) and b) The amalgamation proposal between Enbridge and Union Gas was filed with the OEB on November 2, 2017, and this application is still in process. Until a decision has been rendered, Enbridge and Union Gas are not a single entity and therefore a combined Compliance Plan has not been prepared.

Please see also the response to LPMA Interrogatory #1 filed at Exhibit I.C.EGDI.LPMA.1.

Witnesses: A. Chagani
S. McGill
F. Oliver-Glasford

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

Reference: Exhibit C, Tab 4, Schedule 1, Appendix A, page 5

Has Ontario updated any protocols other than the Landfill Gas Offset Protocol? If so, please provide a list and any changes these protocols are expected to have on Enbridge's application.

RESPONSE

On December 28, 2017, the "Ontario Offset Credits Regulation", Ontario Regulation 539/17, along with the "Offset Initiative Protocols for Ontario's Cap and Trade Program" were posted to the Environmental Registry. This first release of the offset protocols only included the landfill gas offset protocol. Enbridge understands that 12 additional offset protocols, including two protocols that may include renewable natural gas projects (anaerobic digestion of organic waste and manure, and organic waste management) are being developed for use in Ontario. To date, drafts of these protocols have not been made publicly available. These additional two protocols should not have an impact on this application.

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

Reference, Exhibit C, Tab 4, Schedule 1, Appendix A; Exhibit C Tab 6 Schedule 1 Page 24

Preamble: On October 4, 2017, the MOECC posted an updated version of the proposed Ontario Offset Credits regulation and the one incorporated protocol – Landfill Gas (LFG).

a) Please clarify Under O. Reg. 144/16 for each type of RNG procurement whether EGD will be acting as an *Offset Initiative Operator'* and/or an '*Offset Initiative Sponsor'*.
b) Please discuss the risks and benefits of the planned approach(es).
   - Primary offset sourcing – purchasing directly from project owners or developers, at various stages of project development.
   - Secondary offset purchasing – purchasing from the secondary market
   - Hybrid options including carbon fund participation.
c) Specifically indicate who pays for the costs of reversals and how will these be dealt with in rates.

RESPONSE

a) to b) In the event that Enbridge acts as an Offset Initiative Operator' and/or an 'Offset Initiative Sponsor' under O. Reg. 144/16, the details will be provided as part of Enbridge's confidential submissions in applicable Compliance Plan filings. Please refer to the response to Board Staff Interrogatory #3 filed at Exhibit I.C.EGDI.STAFF.3.

c) Enbridge's understanding of the Ontario Offset Credits Regulation is that risks associated with the reversal of Ontario originated offsets would not be borne by ratepayers.

Witnesses: A. Langstaff
J. Murphy

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 1, page 9

Within the GGEIDA, does Enbridge have a target percentage of administrative costs in relation to total costs?

RESPONSE

Enbridge's estimate of administrative costs is based on a ground-up evaluation of the resources required to properly plan for and implement Cap and Trade. Enbridge's 2018 forecast administrative costs represent less than 1.4% of the program's forecast total implementation and sustainment costs. Enbridge confirms that its percentage administration costs are within the range of spending percentages by California utilities as documented in the Board's Discussion Paper from May 25, 2016 (up to 2.7% of compliance costs).

Note that the above quoted percentage does not include any costs associated with OEB procedural matters, as an estimate was not available at the time of filing.

For additional information, refer to Exhibit D, Tab 1, Schedule 1.

Witnesses: A. Langstaff
F. Oliver-Glasford

ENERGY PROBE INTERROGATORY #5

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 2, Pages 4-6

Preamble: Energy Probe wishes to understand better the Government Policy background to the company's RNG Procurement Proposal.

a) Please provide/file a copy of the referenced Navigant Report
b) Provide references to any other reports/documents that EGD has relied upon to prepare its proposal.
c) Please provide/file a copy of the referenced Minister Thibeault's Letter of December 10, 2016
d) Please provide a copy/extract of the relevant parts from the OEB "Gas Supply Framework."
e) Please provide a summary schedule/list of meetings with MOECC and OEB Staff on RNG Procurement. Include main topics discussed and specific documents provided by the parties.

RESPONSE

a) A copy of the Navigant Fuels Technical Report is included as Attachment 1 to this Exhibit.

b) Please refer to the response to Board Staff Interrogatory #2 filed at Exhibit I.C.EGDI.STAFF.2.

c) Minister Thibeault's Letter of December 10, 2016 is included as Attachment 2 to this Exhibit.

d) The Board initiated a working group to develop a Gas Supply Framework in 2017; however, this document has not been released.

e) Please refer to the response to Board Staff Interrogatory #5a filed at Exhibit I.C.EGDI.STAFF.5.

Witnesses: A. Chagani
S. McGill

Fuels Technical Report

Prepared for:

The Ministry of Energy

September 2016

Submitted by:
Navigant Consulting, Inc.
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Suite 1250
Toronto, ON M5H 2R2

navigant.com

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DISCLAIMER

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FOREWORD

The following report is in response to the request of the Ontario Minister of Energy to complete a technical report that examines the fuels sector in Ontario to support development of the Long-Term Energy Plan (LTEP).

The Fuels Technical Report (FTR) establishes a comprehensive view of the current state of the fuels sector in Ontario, including a review of fuels consumption and a set of outlooks for the 2016 through 2035 period. The FTR is meant to be complementary to the Independent Electricity System Operator's (IESO) technical report on the electricity system, the Ontario Planning Outlook (OPO). The reports share a set of common assumptions, economic activity and demographic data, as well as the uptake of electric equipment and transportation options.

Ontario's fuels sector is multifaceted and dynamic. Fuels are an important component of the province's economy, critical for households, businesses and industry. Fuels are necessary for two main uses, as a source of energy and as feedstock in the manufacture of consumer products. Within the province, an array of fuels is used by Ontario consumers for various energy and non-energy purposes, ranging from space and water heating and cooking, to transportation, industrial processes and electricity generation.

Ontario's fuels and electricity sectors are closely linked. Both electricity and fuels can be a source of energy for space heating equipment in homes and businesses. In the future it is likely that a growing number of transportation options will offer electric alternatives to fuel-based options. Choices made around these products and services will influence the demand for both electricity and fuel energy in parallel.

Ontario's fuels sector has experienced considerable change over the past several years. Change has been driven by evolving fuels supply resources and pathways, new fuel-using technologies and the introduction and uptake of new and low-carbon alternative fuels.

The sector has proven to be flexible and responsive to shifts in both the supply landscape and demand profile. Ontarians currently have a wide variety of affordable fuels and fuel-using technologies to choose from. This adaptability will be important as the province moves forward with implementing its climate change policies, including Ontario's cap and trade program and Climate Change Action Plan (CCAP), and participating in other, broader pan-Canadian climate change initiatives as set out in the Vancouver Declaration.

Addressing climate change will have an impact on the demand for and supply of fuel. Fuels sector participants in Ontario will need to be key players in this transformative change. Ontario's fuels system is well-positioned to meet changing demand and supply characteristics for fuels because of the diversity and robustness within the supply chain that exists today. This supply system is adaptable, providing the opportunity to be leveraged well into the future and actively participate in achievement of the province's greenhouse gas (GHG) emissions reduction targets.

This report begins with an overview of the current state of Ontario's fuels sector, including a summary of the fuel types and demand profile across each sector of the economy and a discussion of the end uses for the various fuels. The FTR also examines the outlook for demand under a set of scenarios and explores the effects on the systems which produce and deliver those fuels over the next two decades.

1. THE STATE OF THE SYSTEM: 10-YEAR REVIEW

1.1 Overview

In 2015, Ontario consumed approximately 2,500 PJ of fuel for energy purposes. This is a decline from approximately 2,900 PJ in 2005, reflecting the phase out of coal use for electricity generation, improving efficiency and conservation efforts and changes in economic activity. The majority of the energy consumed in Ontario continues to be derived from the fuels discussed in this technical report. Since 2010, approximately 500 PJ of electric energy have been consumed annually, approximately one-fifth of the provincial fuels energy use.

Since 2005, sectoral shares of total energy have changed. The most significant, and visible, change is the amount of fuels energy used for electricity generation, which has declined by three-quarters relative to 2005. The residential and transportation sectors have both experienced modest growth in fuels use in this period, and the commercial and industrial sectors have experienced a small decline in fuels use.

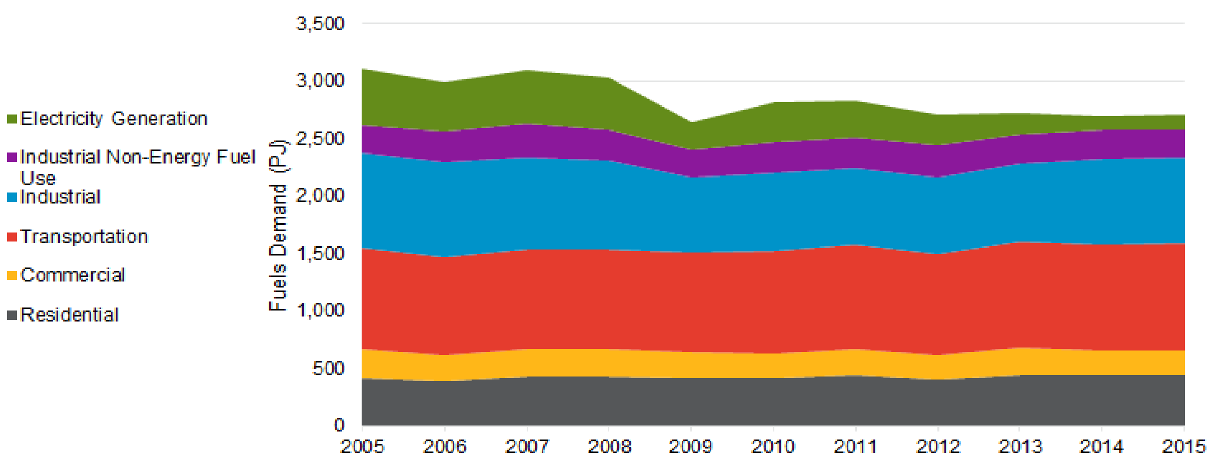
Notes to this Report

Units of Measure:
To compare fuels on an equivalent basis, all energy is reported as units of energy content in gigajoules (GJ) and petajoules (PJ). These measures can be characterized as follows:

- A PJ is a million GJ
- A house uses about 100 GJ of energy in a year.
- 100 litres of gasoline provides about 3.5 GJ
- A kilowatt-hour is 0.0036 GJ
- A terawatt-hour is 3.6 PJ
- Burning 50,000 tonnes of wood produces 1 PJ

Historic Data:
Historical modeled data are derived primarily from data published by Natural Resources Canada and Statistics Canada. Actual data is typically reported one to three years later than real time. Values presented for 2014 and 2015 may therefore represent modeled projections or estimates, rather than actual values.

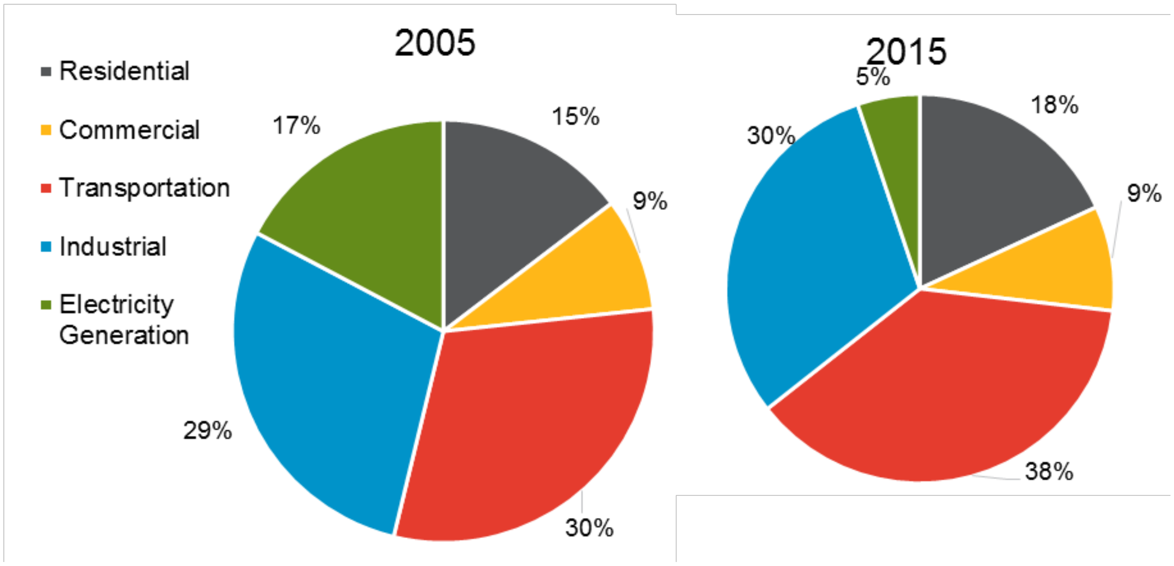
Figure 1: Total Ontario Fuels Energy Demand[1]



Source: CanESS, 2016

[1] Values for 2014 and 2015 are, in some cases, projections or estimates rather than actuals.

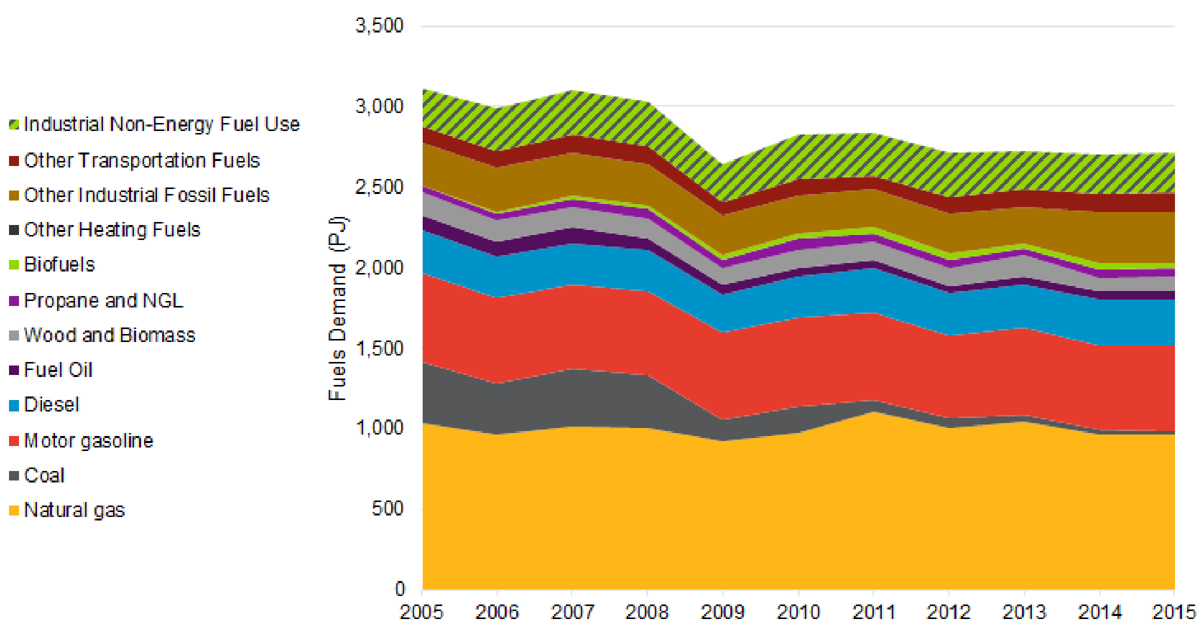
Figure 2: Fuels Energy Demand by Sector 2005 and 2015



Source: CanESS, 2016

The Ontario fuels sector is comprised of numerous different fuel types with a variety of diverse applications. Although a small number of fuels (i.e., natural gas, gasoline and diesel) account for the majority of fuels energy use in the province, many, many more fuels also exist to service quasi-niche needs. Propane, wood and biomass, kerosene, aviation fuel, biofuels, petroleum coke and others all serve a variety of end-uses in the residential, commercial, industrial and transportation sectors.

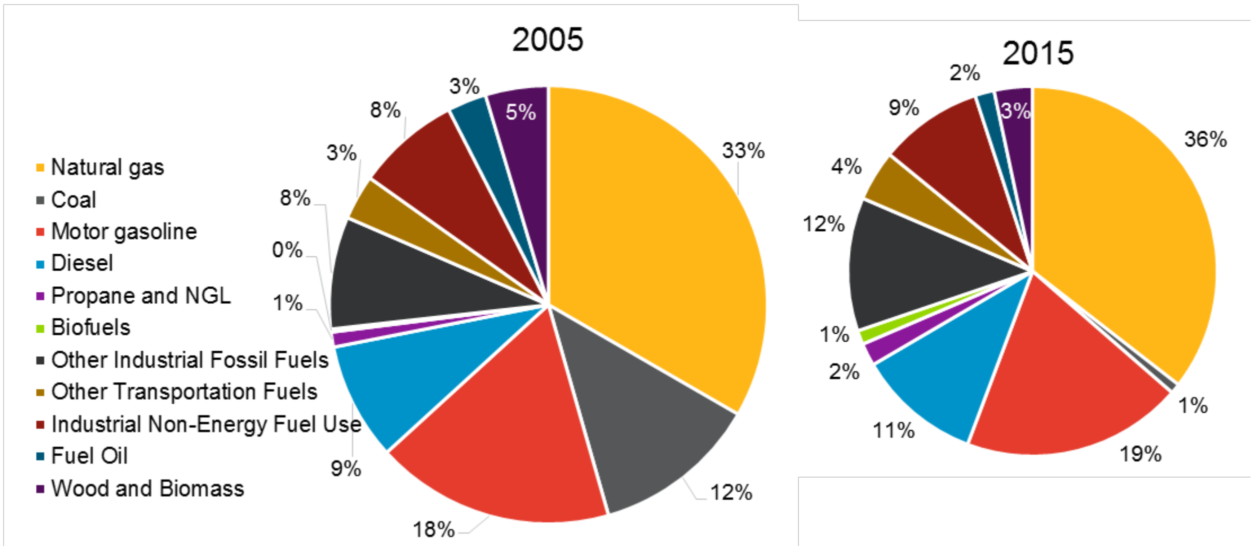
Figure 3: Fuels Energy Demand by Fuel Type



Source: CanESS, 2016

Since 2005, the most substantial shift in fuel consumption has been the reduction in coal use, from 12% of fuels energy to less than 1%, used nearly exclusively by the industrial sector. This is principally due to the retirement of the provincial coal-fired electricity generation fleet. The other most significant change in the distribution of fuels use in Ontario is the growth in the use of biofuels, principally ethanol, over the period. Since 2005, ethanol use (mostly for blending with gasoline) has nearly tripled in Ontario.

Figure 4: Fuels Demand by Fuel Type 2005 and 2015



Source: CanESS, 2016

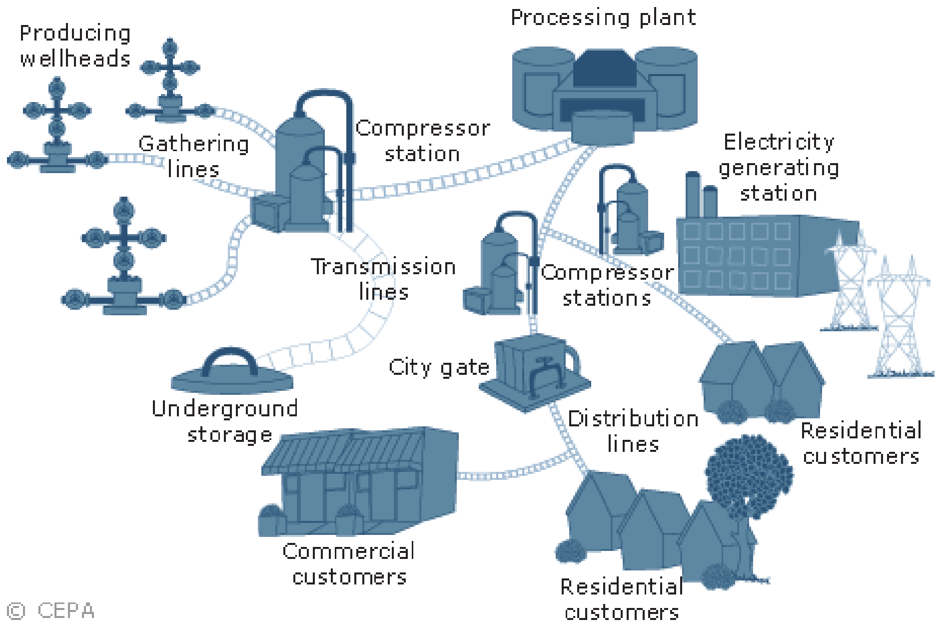
1.2 Natural Gas

Natural gas is found deep beneath the earth's surface. Natural gas consists mainly of methane, although other liquid hydrocarbons (called natural gas liquids or NGLs) can be entrained in natural gas supply.

In Ontario, natural gas is commonly used as a fuel for space and water heating in the residential and commercial sectors. It also has important applications in industry, as a fuel source for energy-intensive operations (e.g., process heat) and non-energy uses (i.e., to make materials and chemicals). In 2015, natural gas generation accounted for about 10% of Ontario's electricity production and 25% of the province's installed electricity generating capacity.

Natural gas is delivered to Ontario via a complex system of high volume transmission pipelines. Historically, much of Ontario's natural gas supply was sourced from Western Canada. However, U.S. gas production has increased in recent years - especially in areas proximate to Ontario (such as Pennsylvania) - resulting in Ontario meeting more of its requirements from U.S. production. Ontario produces minimal quantities of natural gas within its borders (i.e., less than 1% of demand).

Figure 5: Natural Gas Delivery

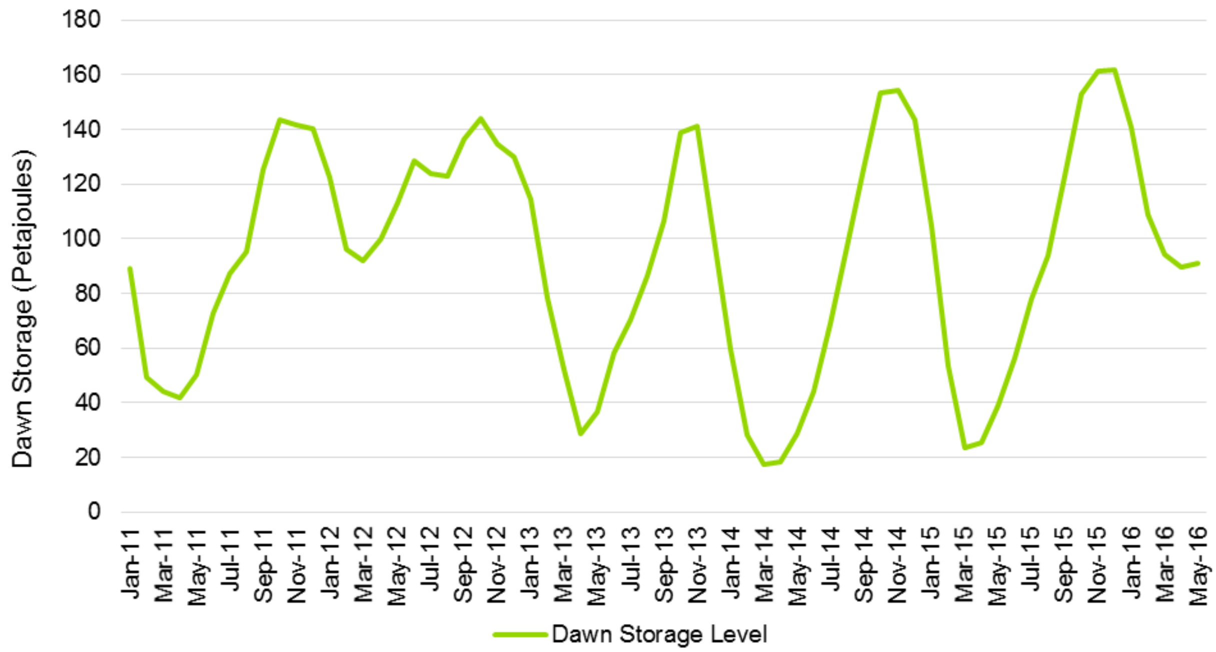


Source: Canadian Energy Pipeline Association (CEPA), 2016.[2]

Ontario uses storage infrastructure in southwestern Ontario (near Sarnia) called the Dawn Hub to help manage seasonal demand, by storing gas during the summer and providing it during the winter. Figure 6 below illustrates the seasonal demand at Dawn. The Dawn Hub is one the largest storage facilities in North America and is used to manage natural gas demand by end-users in Ontario, Quebec and the eastern U.S.

[2] Canadian Energy Pipeline Association, *the Natural Gas Delivery Network*. Accessed June, 2016. http://www.cepa.com/about-pipelines/types-of-pipelines/natural-gas-pipelines

Figure 6: Dawn Storage



Source: Velocity Suite, 2016. SNL Natural Gas Prices, 2016.

Within Ontario, natural gas is delivered to end-users by a network of transmission and distribution pipelines. These pipeline systems are operated by local distribution companies (LDCs). In Ontario, delivery charges by LDCs are rate regulated by the Ontario Energy Board (OEB) through a public and transparent review process. The OEB regulates rates to protect ratepayers while ensuring that the LDCs cover their delivery costs and earn a fair return.

Ontario gas customers have a choice of buying the natural gas commodity from the LDCs or through independent marketers. The commodity component supplied by the LDCs is regulated on a “pass through” basis and its price fluctuates quarterly as gas market conditions change. The LDC earns no return on the sale of the gas commodity. The gas commodity provided by independent marketers is not regulated. Independent marketers may offer fixed price contracts or attributes such as renewable natural gas. The LDCs and marketers acquire the natural gas supply in an unregulated, integrated North American market. To attract supply to the province, Ontario gas users must pay the market price (i.e., Ontario is a price taker).

1.3 Propane

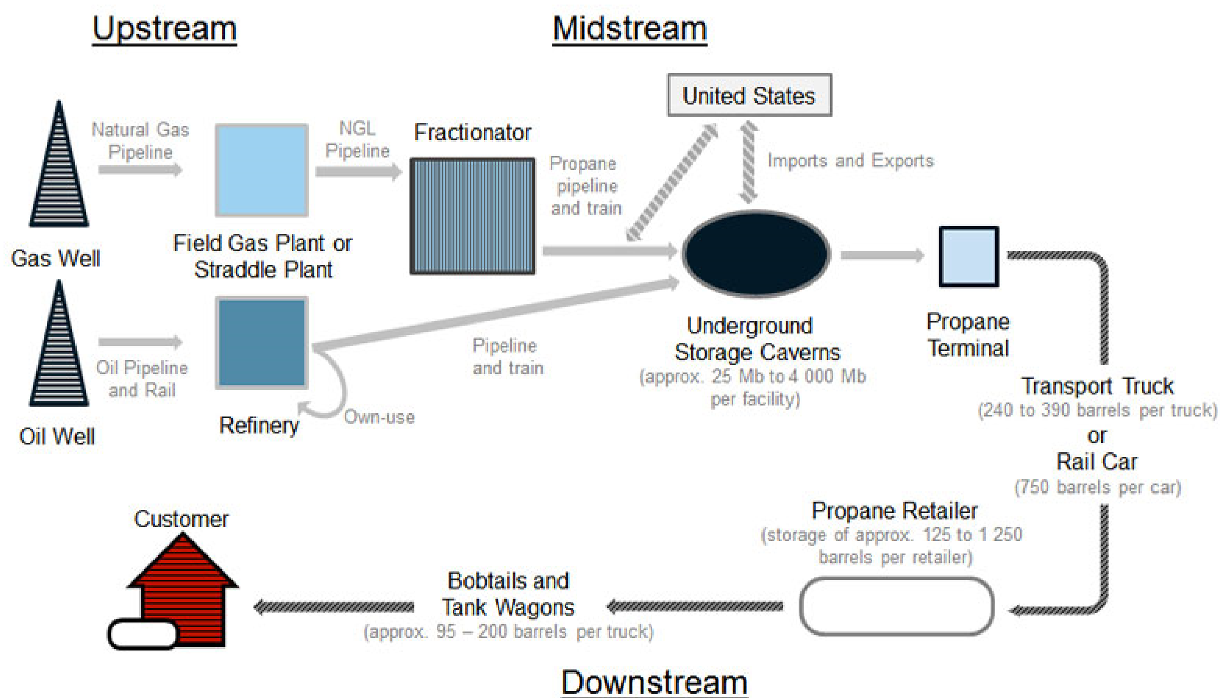
Propane is a natural gas liquid (NGL) that is extracted at natural gas processing facilities. Propane is also a by-product of the petroleum refining process.

In Ontario, propane is commonly used as a home heating fuel, predominantly in rural areas and communities without access to natural gas. Other propane uses include: water heating, barbeques, portable heating, agricultural (e.g., crop drying, greenhouse and livestock facility heating), transportation (i.e., propane vehicles) and non-energy uses (e.g., feedstock to make plastics).

Since propane is extracted from natural gas, significant quantities are imported into Ontario from Western Canada and other continental sources by rail. However, unlike natural gas, Ontario does have domestic propane production sources. Ontario's four petroleum refineries produce propane and an industrial facility in Sarnia-Lambton (called a "fractionator") processes a pipeline delivered NGL-mix into on-specification products (i.e., propane, butane and ethane) for the Ontario and regional market.

Within Ontario, propane is delivered to end users by truck. About 140 large propane distribution facilities are located in Ontario. These facilities may be supplied by truck or (for larger facilities) by rail and have above-ground propane storage tanks.

Figure 7: The Canadian Propane Industry Supply Chain



Source:NRCan[3]

Propane can also be stored underground in salt caverns and depleted production wells. Typically, propane is injected into storage in summer months and withdrawn from storage in winter months. Ontario uses storage infrastructure in the Sarnia-area to manage seasonal demand. The Sarnia area is a key storage propane hub in eastern North America and is used to manage propane demand by end-users in Ontario, Quebec and the eastern U.S.

Wholesale propane commodity prices are determined in an unregulated, integrated North American market. In Ontario, propane distributors compete to supply end-users and end-user prices are not regulated.

[3] National Energy Board, *Propane Market Review: 2016 Update – Energy Briefing Note,* May 2016 https://www.neb-one.gc.ca/nrg/sttstc/ntrlgslqds/rprt/2016/2016prpn-eng.html#s10

1.4 Oil Products

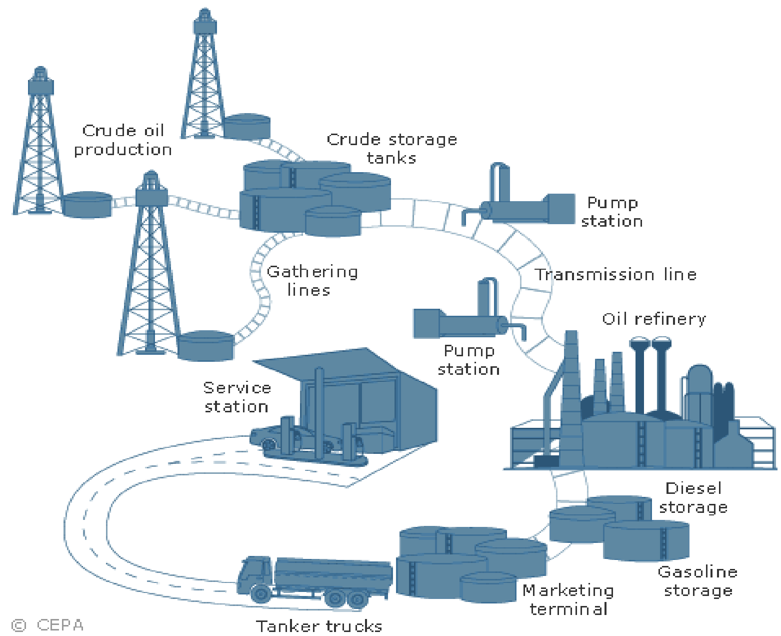
Oil products are produced at petroleum refineries. Petroleum refineries are industrial facilities that process crude oil into finished fuels like gasoline, diesel, jet fuel and fuel oil; and non-energy products like petrochemical feedstocks and asphalt. Crude oil is a fossil fuel, and it exists as a mixture of hydrocarbons in liquid form in underground pools or reservoirs, in tiny spaces within sedimentary rocks, and near the surface in oil sands.

In Ontario, oil products are predominantly used in the transportation sector to fuel cars, trucks, buses and planes. Fuel oil (or heating oil) is also used to provide space heating in rural areas and remote communities without access to natural gas. Diesel can also be used to generate electricity in remote communities or as backup generation. Important industrial uses of oil products include use as feedstock for the chemical sector. Another significant non-energy use of oil products is asphalt for road construction.

Four fuel refineries are located in Ontario, in Sarnia and Nanticoke. These facilities, which have a crude oil processing capacity of 393,000 barrels per day, supply a significant portion of Ontario's oil product demand. Ontario also imports oil products by pipeline (via the Trans Northern pipeline from Quebec, which supplies Eastern Ontario and the Toronto area), rail and marine (during the Great Lakes / Seaway shipping season). As with natural gas, Ontario has minimal crude oil production within its borders and relies on oil pipelines to deliver crude oil to the fuel refineries located in the province.

Within Ontario, oil products are delivered to distribution terminals by pipeline, rail, marine and truck. Southern Ontario terminals are typically supplied by pipeline while more remote terminals are supplied by other modes. Ultimately, most oil products used in transportation and in the residential and commercial sectors are delivered to their final point of distribution (or use) by truck.

Figure 8: Crude Oil Delivery



Source: Canadian Energy Pipeline Association (CEPA), 2016.[4]

Oil products are typically stored at refineries and distribution terminals. Oil product storage is typically used to manage day-to-day or week-to-week fluctuations in demand. As oil product demand is less seasonal than for natural gas or propane, there is less long-term storage infrastructure for oil products than for some other fuels.

Both crude oil and petroleum product prices are determined in an unregulated, integrated North American market. Consequently, to attract supply to the province, Ontario crude oil and oil product users must pay the market price (i.e., Ontario is a price taker).

1.5 Wood and Biomass

Biomass and wood are renewable resources (e.g., forest or agricultural materials) that are used in a variety of fuel applications.

Biomass and wood resources are used as energy sources in industry, especially in the forestry sector. Biomass is used as the fuel for electricity generation at converted coal stations (e.g., Atikokan Generating Station) as well as at combined heat and power facilities. For space heating, wood stoves are a common secondary heat source in rural and remote communities and are the primary heat source in some areas. Wood pellets can be used to provide space heating in larger businesses (commercial businesses, hospitals, schools, etc.) - although this usage is not yet widespread in Ontario.

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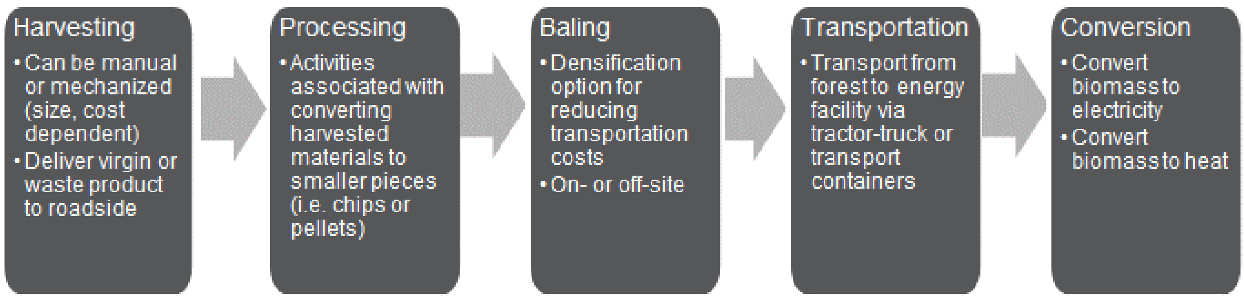
[4] Canadian Energy Pipeline Association, *the Crude Oil Delivery Network*. Accessed June, 2016. http://www.cepa.com/about-pipelines/types-of-pipelines/liquids-pipelines

As illustrated in Figure 9, the biomass supply chain consists of harvesting, processing, baling, transportation and conversion. Harvesting of biomass can be performed using manual or mechanized techniques, depending on size and cost. Processing biomass involves converting the harvested timber into smaller pieces. Wood chip and pellet baling compact the wood for ease of transport. Biomass relies on transportation and distribution by truck.

Figure 9: Biomass Delivery



Ontario has substantial forestry resources and biomass more generally. Ontario's forest management guides and standards are regularly updated - this ensures that new uses of Crown forest resources, like bioenergy, occur in a sustainable way.

Current pricing of biomass is largely based on costs of acquisition and distribution.

1.6 Alternative Fuels

Alternative fuels currently available in Ontario consist of three distinct fuels: ethanol, biodiesel / renewable diesel and renewable natural gas.

Ethanol

Ethanol is a renewable fuel. It is a clear, colorless alcohol made from the sugars found in grains, such as corn, sorghum, and barley, as well as potato skins, rice, sugar cane, sugar beets and yard clippings..

In Ontario, ethanol is primarily used to fuel automobiles. Since 2007, Ontario regulations have required that fuel suppliers' sales of gasoline contain at least 5% ethanol content (calculated on an annual average basis). Some ethanol produced in Ontario is used in the beverage sector and in industrial applications (e.g., paints/solvents, base chemicals, disinfectants, etc.).

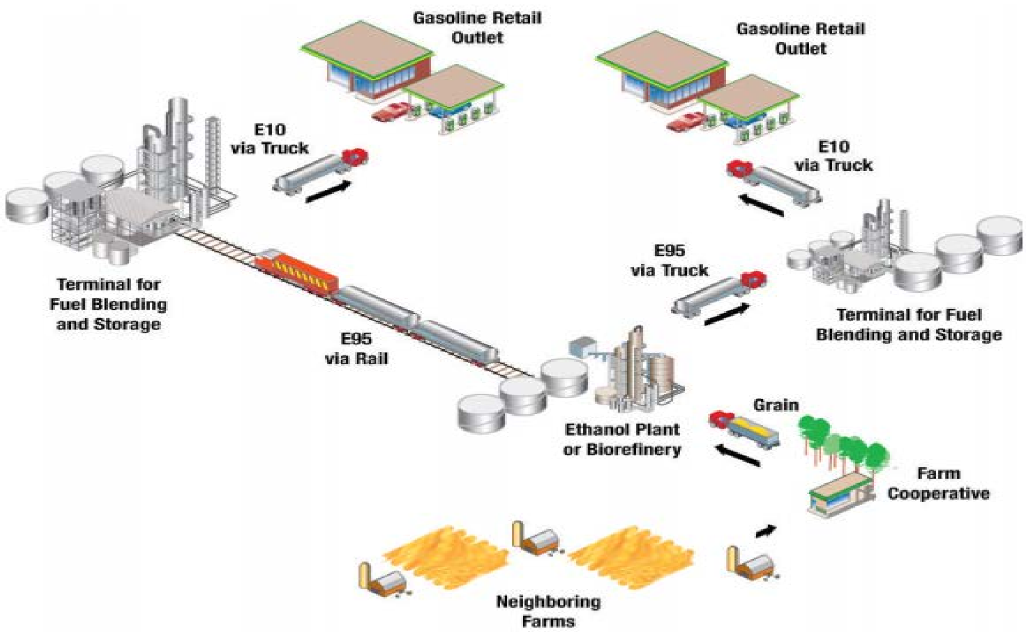
Ontario has six manufacturing facilities in the province. All of the Ontario facilities use corn as the feedstock to produce ethanol. Corn is delivered to ethanol facilities by truck; corn used at Ontario ethanol facilities is mostly domestically produced although there are some imports. Ontario also imports ethanol by truck and rail.

Ethanol is delivered to petroleum distribution terminals by truck and rail, where it is blended with a gasoline-blendstock to produce an on-specification finished fuel.

Similar to oil products, there is limited on-site storage for ethanol at production facilities and distribution terminals.

The ethanol delivery network is illustrated in Figure 10 below.

Figure 10: Ethanol Delivery Network



Source: National Bioenergy Center, National Renewable Energy Laboratory[5]

Wholesale ethanol commodity prices are determined in an unregulated, integrated North American market.

Biodiesel / Renewable Diesel

Biodiesel is a renewable fuel that can be used instead of diesel fuel made from petroleum. Biodiesel can be made from vegetable oils (e.g., soybean oil) and animal fats. Renewable diesel can be made from the same feedstocks as biodiesel; however, it is processed in a way that the product is chemically similar to petroleum diesel.

Biodiesel and renewable diesel are used as petroleum diesel replacements and additives in the transportation sector. Since 2014, Ontario has required fuel suppliers to have bio-based content in their diesel supplies. By 2017, the blending requirement will be 4%.

[5] *As cited in:* United States Department of Agriculture, Agricultural Marketing Services (USDA-AMS), “Ethanol transportation backgrounder: expansion of U.S. corn-based ethanol from the agricultural transportation perspective,” September 2007. http://naldc.nal.usda.gov/naldc/download.xhtml?id=46310&content=PDF

Ontario has five biodiesel manufacturing facilities. Some biodiesel is used in Ontario; however, some production is exported to capture lucrative U.S. incentives. Biodiesel is typically transported by rail and truck. Renewable diesel is only produced at a few facilities globally - none in Ontario.

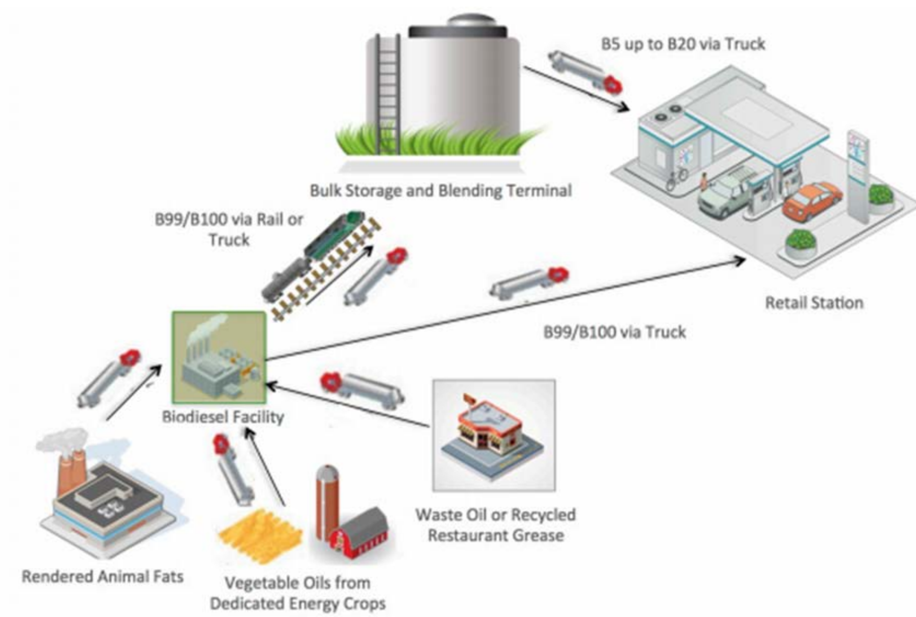
Biodiesel distribution within Ontario is primarily by truck and rail. As with ethanol, biodiesel is blended with diesel at petroleum distribution terminals (**Note:** One biodiesel producer in Ontario is located adjacent to a petroleum distribution terminal and connects to that terminal by pipeline).

Similar to ethanol and petroleum products, there is limited on-site storage for biodiesel.

Wholesale biodiesel commodity prices are determined in an unregulated, integrated North American market.

The biodiesel delivery network is illustrated in Figure 11 below.

Figure 11: Biodiesel Delivery Network



Source: Stillwater Associates LLC[6]

Renewable Natural Gas

Renewable natural gas (RNG) is the methane component of biogas, which is produced from the decomposition of organic matter. Biogas can be derived from landfills, livestock operations, farms, wastewater treatment plants or waste from industrial facilities (e.g., food processors). Once processed to remove impurities, the resulting RNG can be injected into the natural gas pipeline system and is fully interchangeable with conventional natural gas.

[6] Stillwater Associates LLC, "Petroleum and Renewable Fuels Supply Chain," February 2016. http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/files/Stillwater_Fuels_Supply_Chain.pdf

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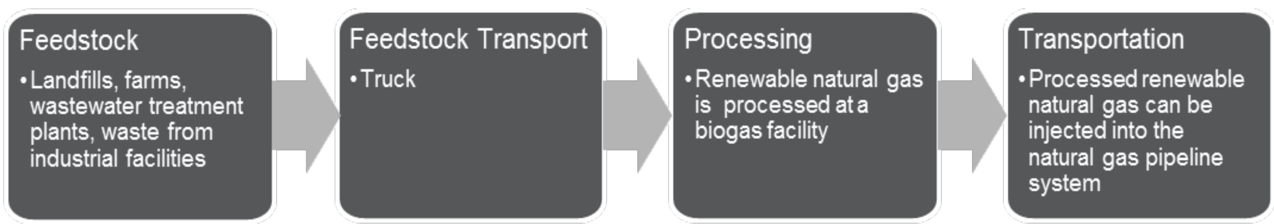
In 2013, there were 37 operating biogas facilities in Ontario. However, production volumes from these facilities were quite small, relative to the size of the province's natural gas system. RNG production requires connections to the province's natural gas system as well as equipment to process the RNG to ensure quality standards are met.

RNG can use existing storage resources of the natural gas system. Currently, RNG is procured on a site-by-site basis, typically under long-term contracts.

Figure 12 below illustrates the renewable natural gas production process.

Figure 12: Renewable Natural Gas Production Process



1.7 Demand

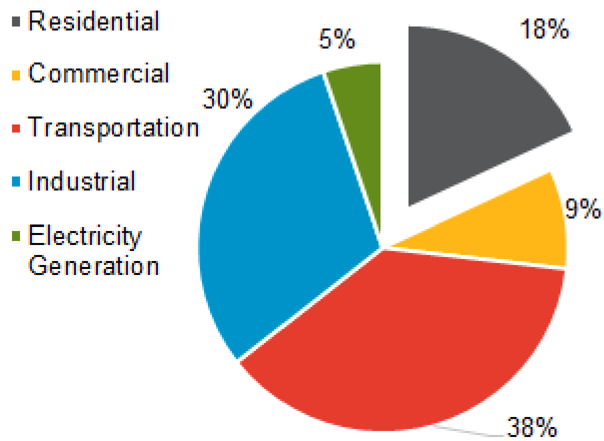
This section of Chapter 1 provides additional detail regarding the fuels energy by four sectors: residential, commercial, industrial, and transportation. Readers interested in the electricity generation sector may refer to the Independent System Operator (IESO) Ontario Planning Outlook (OPO) report.[7]

[7] Independent Electricity System Operator, *Ontario Planning Outlook*, September 2016 http://www.ieso.ca/Pages/Ontario's-Power-System/Ontario-Planning-Outlook/default.aspx

1.7.1 Residential

The residential sector consumes approximately 18% of Ontario's fuels energy.

Figure 13: Ontario Residential Fuels Demand - 2015



Source: CanESS, 2016

Natural gas is the main fuel used in the residential sector, used for space and water-heating. Natural gas supplied over 80% of the total fuel energy used in the sector in 2015. Fuel demand in the residential sector is dominated by space heating. In Ontario, approximately 75% of total fuels energy demand in the home is used for space heating.[8] Fuels are also used for water heating, and, to a lesser degree for cooking and other appliance end-uses.

The demand for space heating results in year to year changes in residential fuel demand, reflecting milder and colder heating seasons. Figure 14 illustrates this year over year variability.

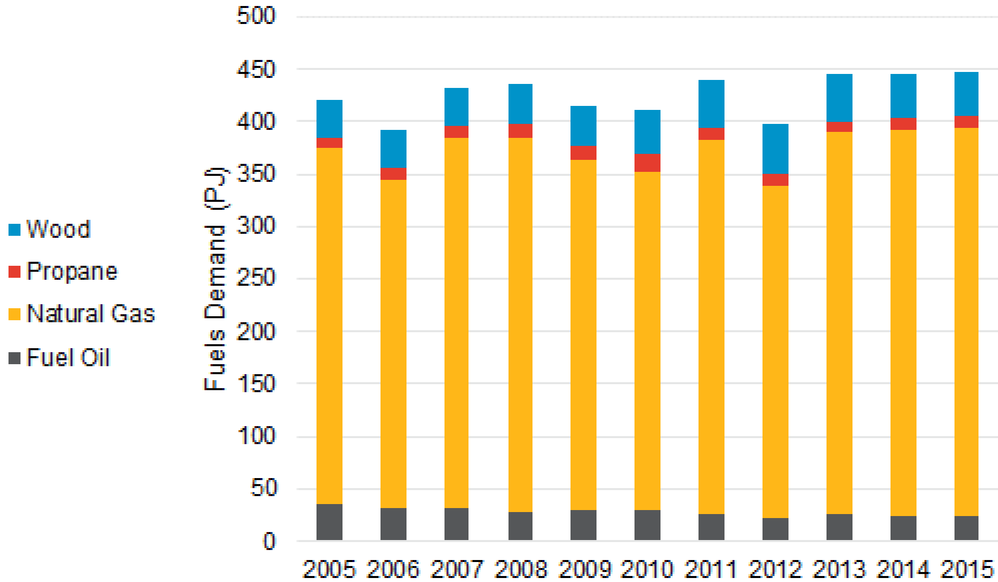
[8] In 2013, the combined fuels energy use for residential space-heating was approximately 320 PJ. The total fuel use by the residential sector in the same year was approximately 428 PJ.

Natural Resources Canada, *Comprehensive Energy Use Database: Residential Sector*, Accessed July 2016

http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_res_on.cfm

Table 1 and Table 5

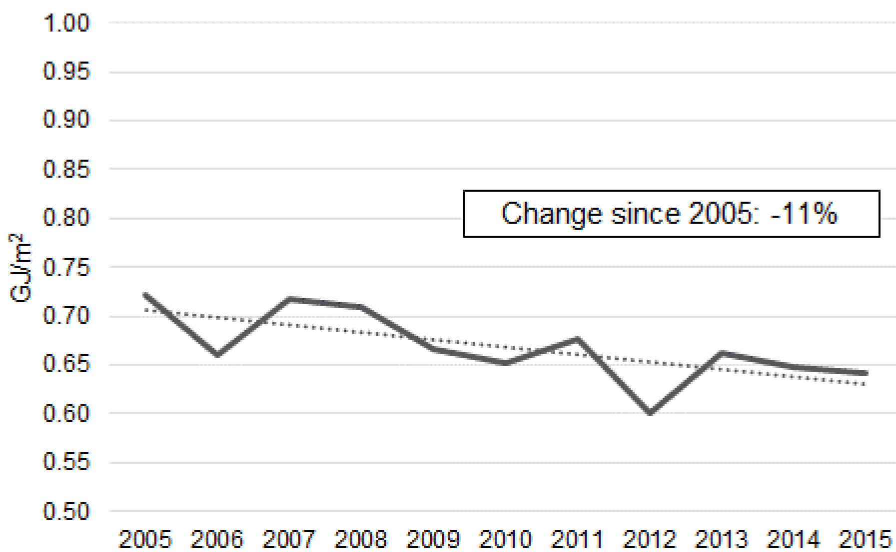
Figure 14: Residential Demand by Fuel Type: 2005-2015



Source: CanESS, 2016

From 2005 to 2015, overall fuels energy use per square metre in the residential sector decreased by 11%. This reflects total efficiency gains in the sector. Over the period, improved energy efficiency in heating equipment, conservation efforts, more stringent building codes, tighter building envelopes for new construction and increasing urbanization and housing density have contributed to a reduction in energy use of 0.08 GJ per square metre as shown in Figure 15, below.

Figure 15: Residential Fuels Energy Use Per Square Metre of Floor-Space

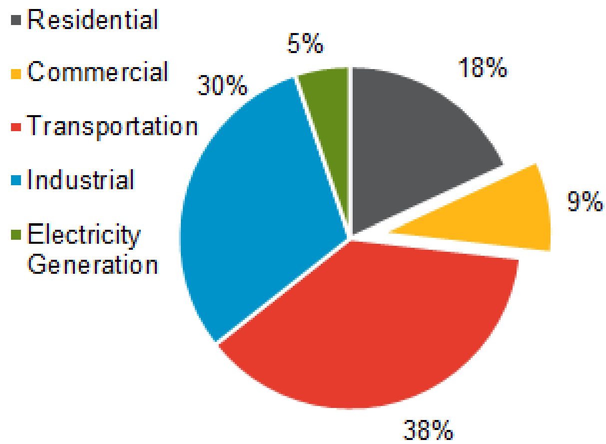


Source: CanESS, 2016

1.7.2 Commercial

The commercial sector consumes approximately 9% of Ontario's fuels energy.

Figure 16: Commercial Fuel Demand - 2015



Source: CanESS, 2016

Natural gas is the main fuel used in the commercial sector, used principally for space and water-heating. Natural gas supplied more than 90% of the total fuel energy used in the sector in 2015. Fuel demand in the commercial sector is dominated by space heating. In Ontario, approximately 85% of total fuels energy demand in commercial buildings is used for space heating.[9] Fuels are also used for water heating, and, to a lesser degree for cooking and other appliance end-uses.

Although the commercial sector's fuels use is quite sensitive to annual weather trends, it is more sensitive than the residential sector to changes in the economy.

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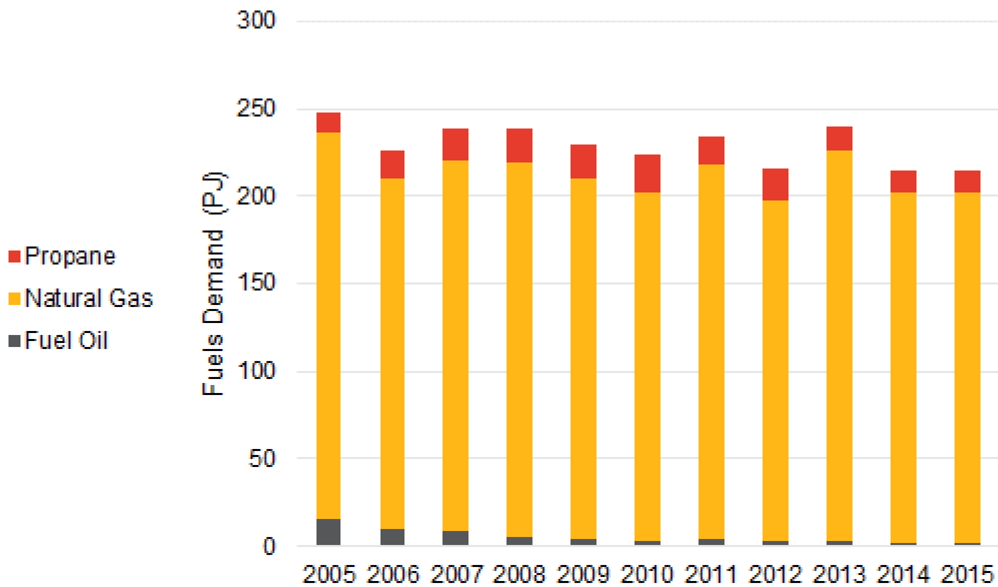
[9] In 2013, the combined fuels energy use for commercial space-heating was approximately 202 PJ. The total fuel use by the commercial sector in the same year was approximately 235 PJ.

Natural Resources Canada, *Comprehensive Energy Use Database: Commercial Sector*, Accessed July 2016

http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_res_on.cfm

Table 1 and Table 24

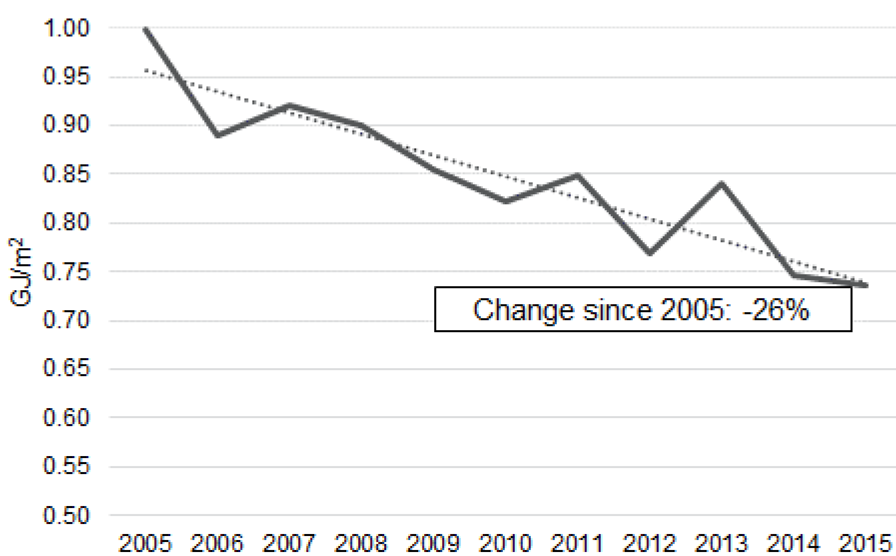
Figure 17: Commercial Demand by Fuel Type: 2005-2015



Source: CanESS, 2016

From 2005 to 2015, overall fuels energy use per square metre in the commercial sector decreased by 26%. This reflects total efficiency gains in the sector. Over the time period, improved energy efficiency in heating equipment, conservation efforts, more stringent building codes, tighter building envelopes for new construction and trends in commercial activities have contributed to a reduction in energy use of 0.26 GJ per square metre as shown in Figure 18, below.

Figure 18: Commercial Fuels Energy Use Per Square Metre of Floor-Space

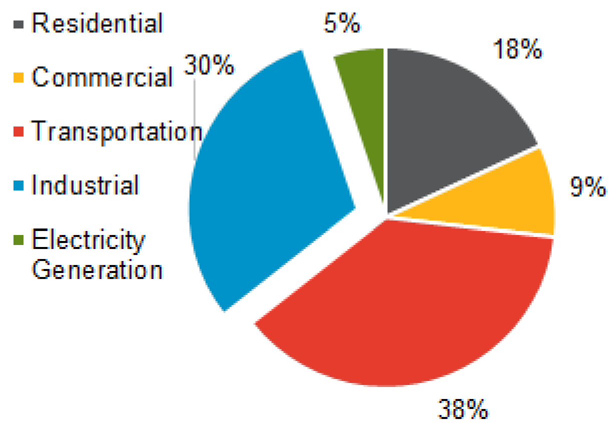


Source: CanESS, 2016

1.7.3 Industrial

The industrial sector consumes approximately 30% of Ontario's fuels energy. In addition to this fuel used for energy (approximately 750 PJ in 2015), the industrial sector used an additional approximately 250 PJ of fuels in 2015 for non-energy purposes (e.g., as feedstock for down-stream products).

Figure 19: Industrial Fuel Demand - 2015

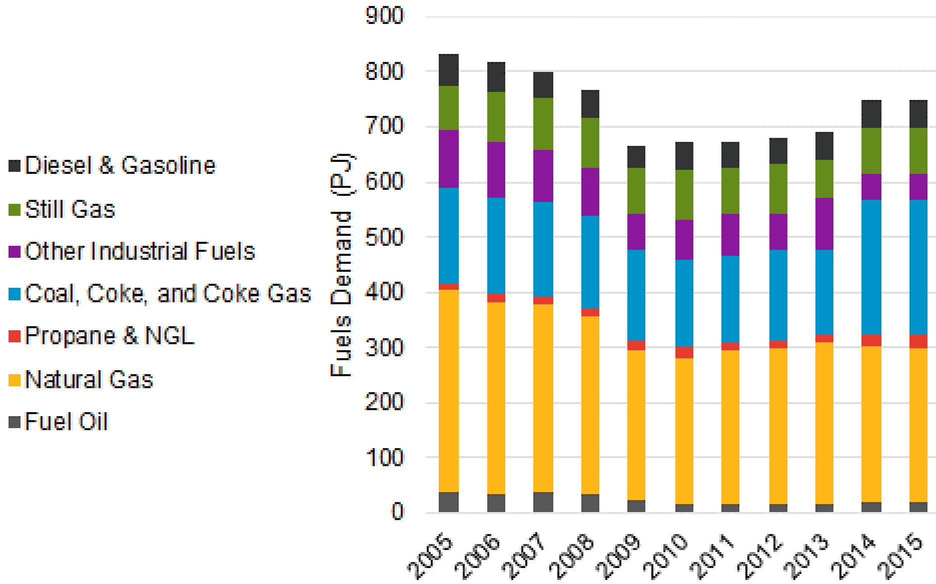


Source: CanESS, 2016

In contrast to the residential and commercial sectors, the industrial sector makes use of a wide variety of fuels for energy use. Like in the residential and commercial sectors, natural gas is the most common fuel used, however it represents less than 40% of total fuel energy use. Coal, coke and coke gas represent approximately a third of all industrial energy use, with other fuels such as kerosene, propane (and other natural gas liquids) and biomass serving important industrial niches.

Macroeconomic fluctuations and other drivers of industrial production are the principal drivers of fuels consumption variability, rather than weather.

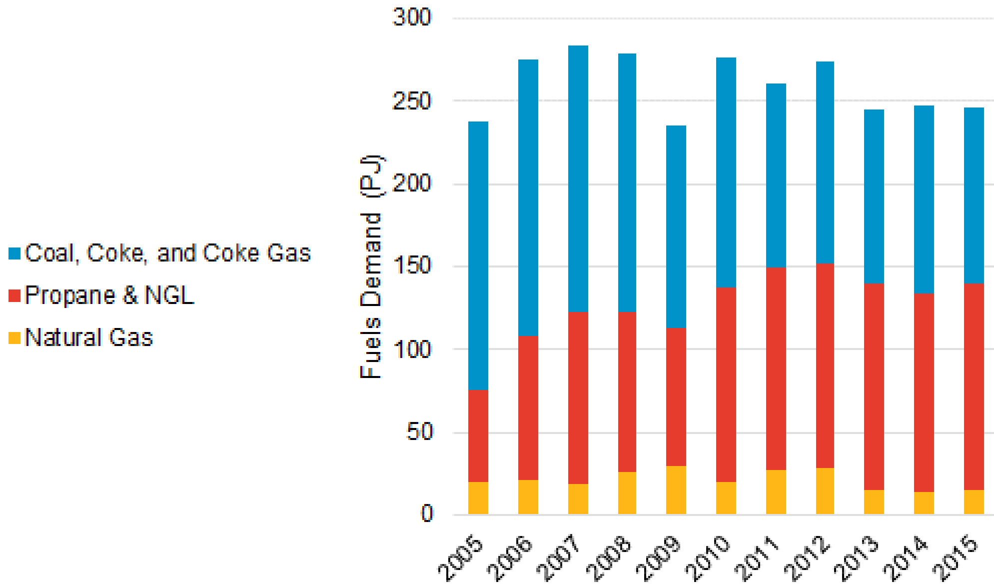
Figure 20: Industrial Energy Demand by Fuel Type: 2005-2015



Source: CanESS, 2016

In addition to energy and combustion-related demand, a substantial amount of fuels product is used in non-energy processes as a raw material feedstock. For example, natural gas is used as an input to produce hydrogen, petroleum products are used in the production of asphalt, pesticides and plastics and a number of fuels products can be used to develop lubricants and greases. Non-energy related fuels consumption is illustrated in Figure 21 below. **Note:** The "Coal, Coke and Coke Gas" category shown below includes petroleum coke.

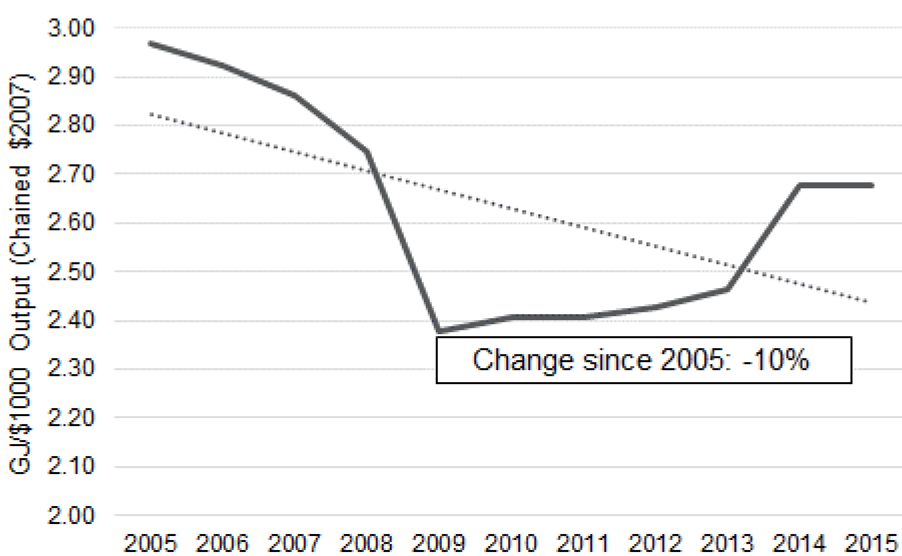
Figure 21: Non-Energy Industrial Demand by Type: 2005-2015



Source: CanESS, 2016

From 2005 to 2015, overall fuels energy use per $1,000 of economic output decreased by 10%. This reflects efficiency gains in the sector, and may also reflect production utilization. Over the time period, improved energy efficiency in industrial processes, conservation efforts, the impact of macroeconomic trends on industrial output, and other trends in activity towards less energy intensive industries, have contributed to a reduction in energy use of 0.29 GJ per $1,000 of output as shown in Figure 22, below.

Figure 22: Industrial Fuels Energy Use Per $1,000 of Economic Output

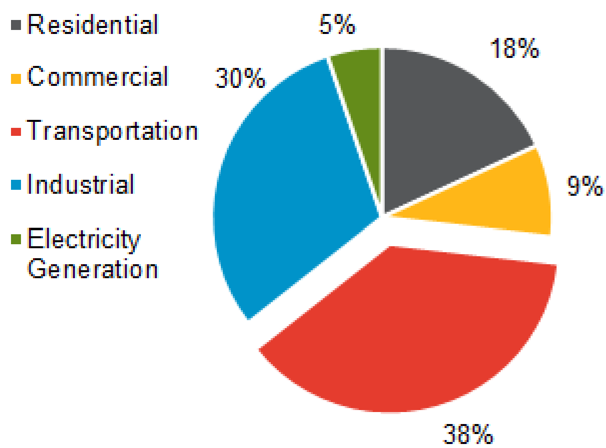


Source: CanESS, 2016

1.7.4 Transportation

The transportation sector consumes approximately 38% of Ontario's fuels energy.

Figure 23: Transportation Energy Fuel Demand - 2015

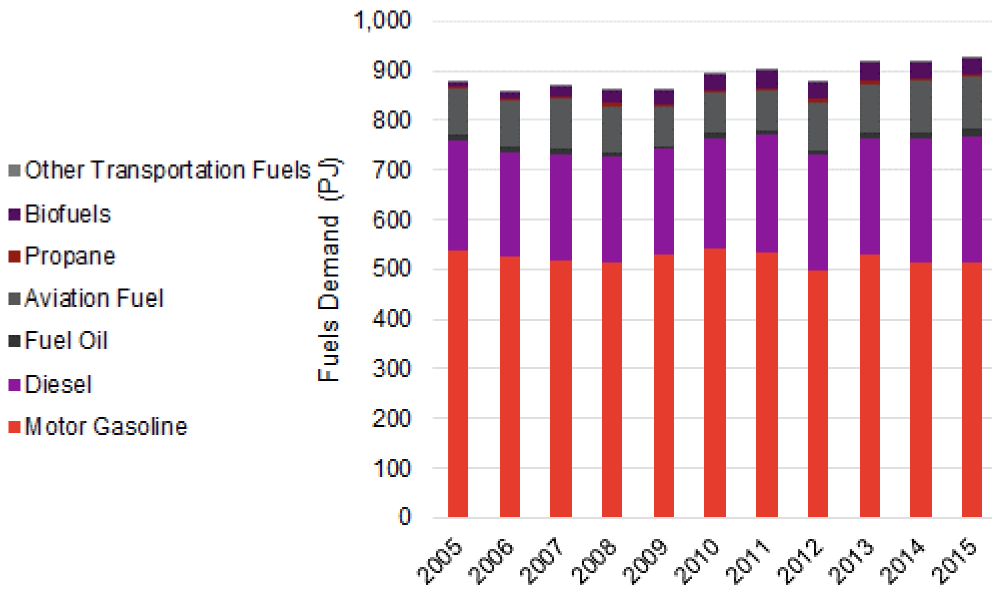


Source: CanESS, 2016

Gasoline and diesel dominate transportation fuels use, representing nearly 85% of total transportation fuels use in 2015. Most gasoline and diesel fuel is used by road transportation. Biofuels (ethanol and bio-based diesels) have grown substantially in relative importance, from less than 1% of transportation fuels energy use in 2005 to nearly 3% in 2015. Biofuels are typically blended with their corresponding conventional fossil fuel in order to meet existing green fuel mandates. Other fuels include fuel oil (typically in marine applications), aviation fuel, and other, more niche fuels, including propane and compressed natural gas.

Propane is typically used for high-usage short-range vehicles (taxis and delivery vans), and compressed natural gas is typically used in more heavy-duty applications, notably for urban transit buses. Transportation fuels use is less variable than fuels use in any of the other sectors considered in this report.

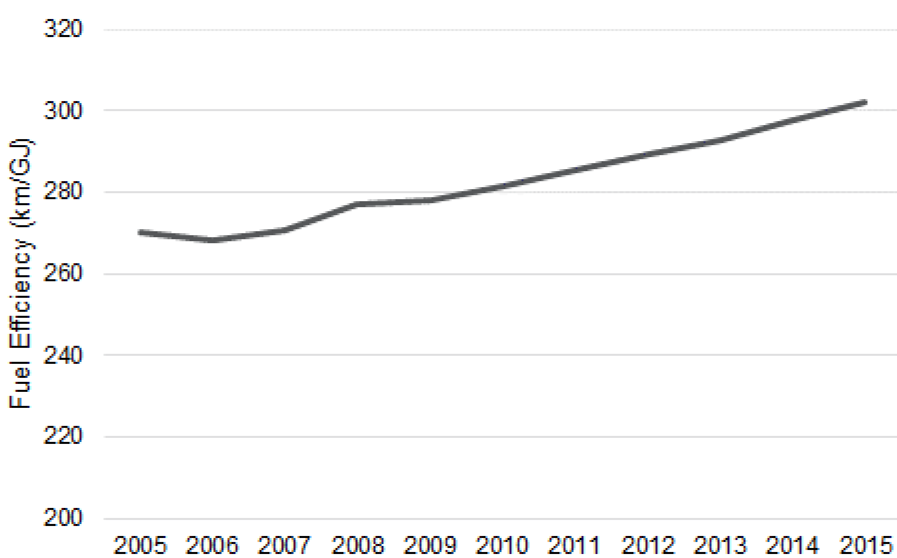
Figure 24: Transportation Demand by Fuel Type: 2005-2015



Source: CanESS, 2016

Improving efficiency standards and market pressures have substantially improved the efficiency of many vehicles since 2005. An intuitive example of this is the clear improvement in fuel efficiency of light duty road vehicles (cars and light trucks used for personal and commercial purposes). The efficiency of these vehicles has on average improved from 270 km/GJ (9.2 km/litre or 21.7 miles per gallon) in 2005 to 302 km/GJ (10.3 km/litre or 24.3 miles per gallon) in 2015.

Figure 25: Light Duty Vehicle Efficiency Improvements – 2005 to 2015



Source: CanESS, 2016

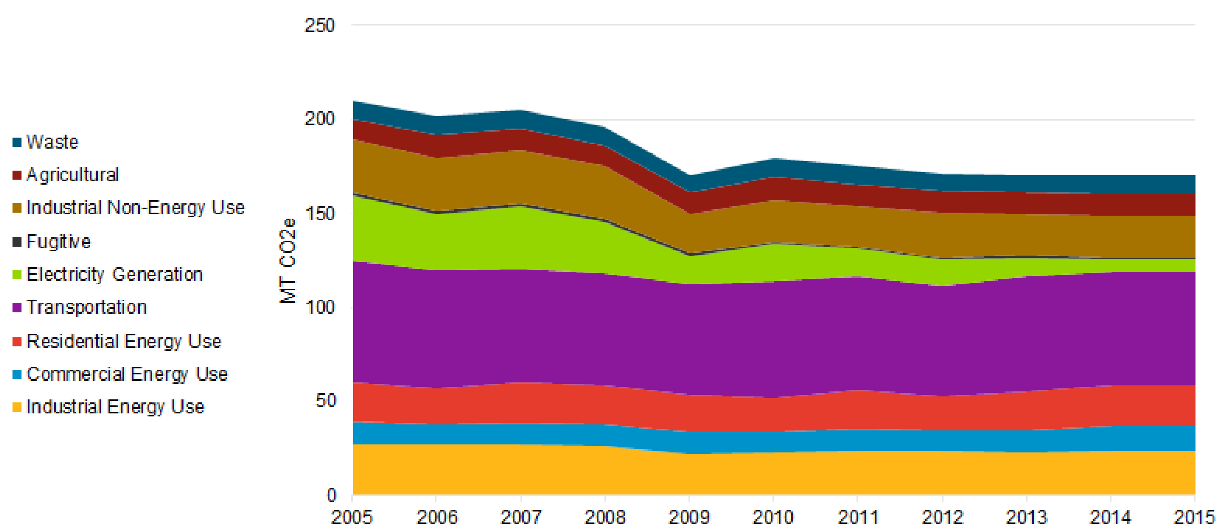
1.8 Historical GHG Emissions

Ontario's greenhouse gas (GHG) emissions have declined significantly over the past 10 years from 211 megatonnes (MT) of carbon dioxide equivalent (CO_2e) in 2005 to approximately 170 MT in 2015[10].

Approximately two-thirds of this reduction is attributable to the electricity generation sector's phase out of coal as a fuel source. The remainder is primarily attributable to changes in industrial non-energy use, transportation efficiency improvements and total industrial energy requirements.

Historical GHG emissions are illustrated in Figure 26 below. Both combustion and non-combustion emissions are illustrated in this figure. Fuel use for electricity generation is also shown to provide the overall trend in energy-related GHG emissions. This chart is provided to demonstrate the proportion of total GHGs relevant to the Fuels Technical Report: Residential, Commercial, Industrial and Transportation energy use (the bottom four areas of the graph). As of 2015, these comprise approximately 70% of provincial GHG emissions.

Figure 26: Historical Ontario GHG Emissions



Source: Environment Canada

[10] Environment Canada, *Environment Canada Data Catalogue, National and Provincial/Territorial Greenhouse Gas Emission Tables*, Accessed July 2016

Table A11-12

http://donnees.ec.gc.ca/data/substances/monitor/national-and-provincial-territorial-greenhouse-gas-emission-tables/C-Tables-IPCC-Sector-Provinces-Territories/?lang=en

2. FUELS SYSTEM 20-YEAR OUTLOOK

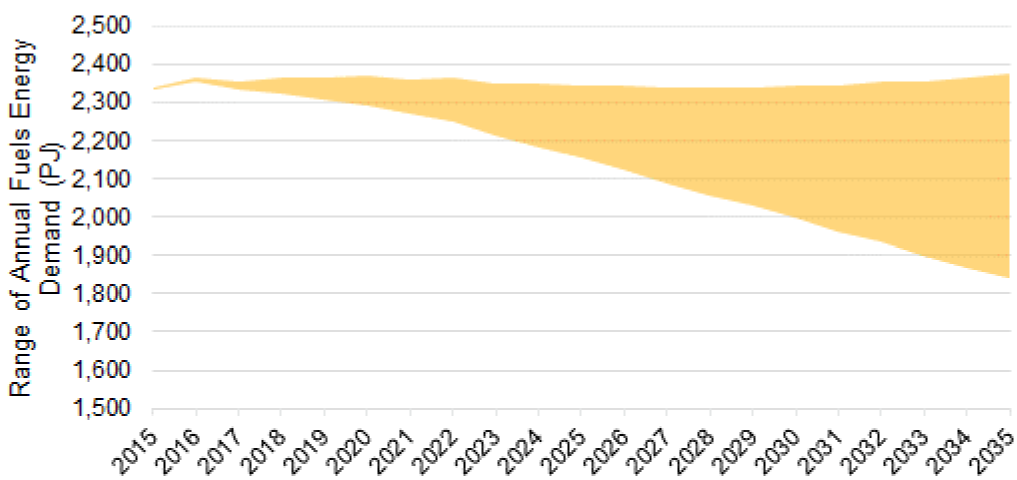
2.1 Demand Outlook

The demand for fuels is the starting point used in assessing the outlook for fuels in Ontario. There is considerable uncertainty with all demand outlooks, as future demand for fuels will depend on global macroeconomic and fuels market trends and technology development, as well as more local provincial economic, demographic and policy trends.

In preparing this report and the associated analysis, Navigant has considered a range of possible fuels sector characterizations and outlooks for demand, ranging from 1,800 PJ to 2,400 PJ in 2035[11], compared to 2,300 PJ in 2015 (see Figure 27, below). This range is reflected in five outlooks that provide context for the long-term policy discussions that will inform Ontario's Long Term Energy Plan (LTEP).

The outlooks all reflect actions identified in the government's recently announced Climate Change Action Plan. The outlooks are all consistent with the outlooks presented by IESO in its OPO, and were developed based on a common set of assumptions and data regarding economic activity, demographics, fuel shares, electrification, pricing, weather, etc.

Figure 27: Demand Uncertainty



Source: CanESS, 2016

The outlooks considered for Ontario's energy fuels demand are:

- Outlook B, which reflects all of the assumptions adopted by IESO for the OPO Outlook B, and further assumes that natural gas demand-side management (DSM) programs supporting efficiency and conservation improvements will continue at present levels of funding and that transportation fuels standards will proceed as planned.

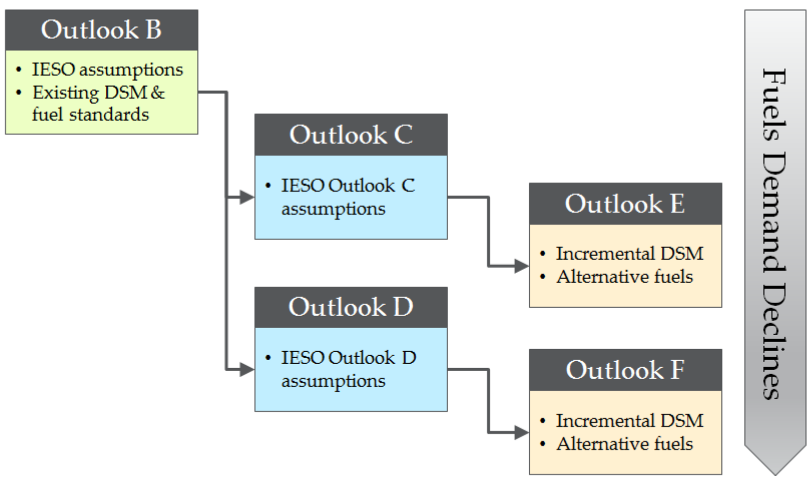
[11] This range includes only fuels used to provide energy. Non-energy fuel use by the industrial sector is not considered in the outlooks.

- Outlooks C and D, which reflect all of the assumptions adopted by IESO for the OPO Outlooks C and D, and further assume that natural gas DSM will continue at present levels of funding and that transportation fuels standards will proceed as planned.
- Outlooks E and F, which reflect all of the assumptions adopted by IESO for the OPO Outlooks C and D (respectively), but also explore different levels of additional natural gas DSM, and the displacement of some conventional fuels with less carbon-intense alternatives.

Outlook A was developed by IESO to explore the implications of lower electricity demand. Applying the assumptions of Outlook A to the fuels sector would result in lower fuels demand than Outlook B. Lower fuels demand is already explored in the FTR by Outlooks C, D, E and F. Given the fact that lower fuels demand scenarios were already being explored by four alternative outlooks, it was determined that modeling Outlook A would provide incremental information of only limited value. Outlook A has therefore not been modeled as part of the FTR.

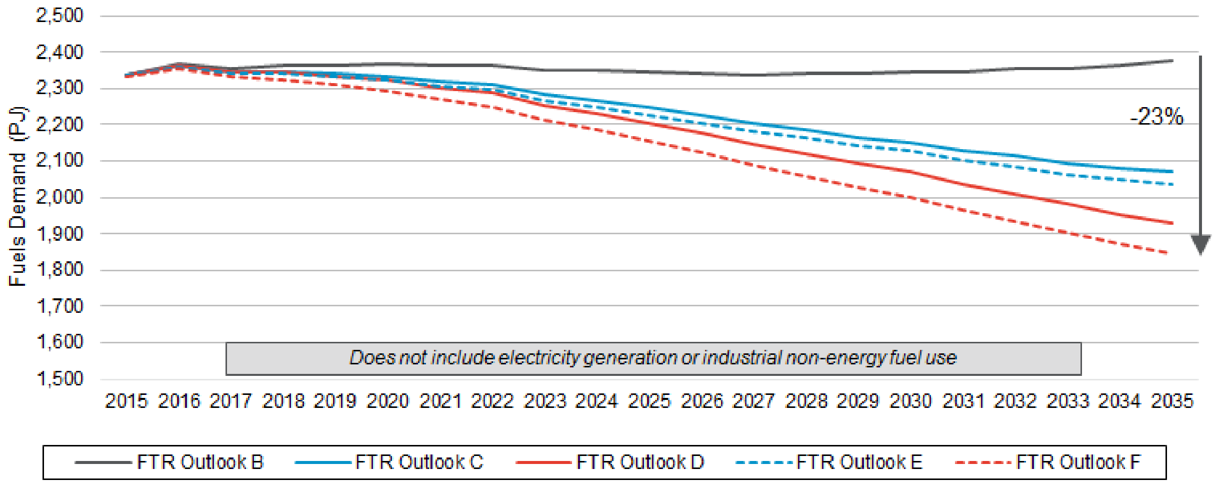
The incremental relationships between these outlooks, and their relative position in the range of fuels energy demand highlighted in Figure 27, above, is illustrated in Figure 28, below.

Figure 28: Illustration of Outlook Relationships



The total energy-related fuels demand of each outlook is illustrated in Figure 29, below. As may be seen, in the final year of the outlook horizon, Outlook F yields a total Ontario energy-related fuels demand that is 23% lower than that projected by Outlook B.

Figure 29: Five Fuels Energy Demand Outlooks

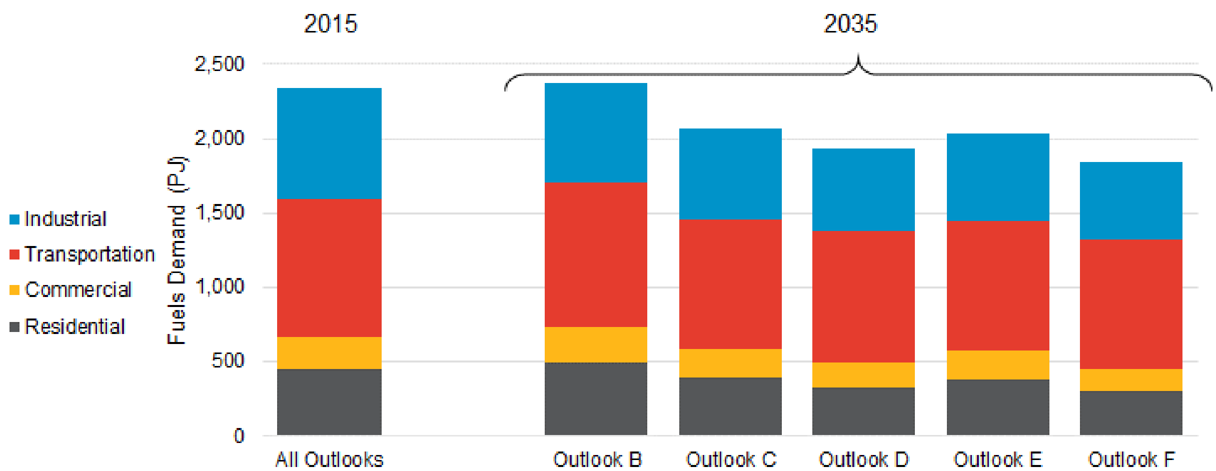


Source: CanESS & Navigant Analysis, 2016

The fuels energy demand in 2035 (as well as the initial 2015 levels) by sector across the five outlooks is illustrated in

Figure 30, below. The majority of fuels energy in all outlooks is consumed by the industrial and transportation sectors, which together account for approximately three-quarters of total fuels energy demand.[12]

Figure 30: Sectoral Breakdown of Energy Demand by Outlook, 2015 vs 2035



Source: CanESS & Navigant Analysis, 2016

[12] Figures do not include industrial non-energy use fuels demand.

Assumptions across the demand outlooks are summarized in Table 1, on the next page. The following acronyms appear in this table:

- EV: electric vehicles
- DSM: demand-side management (natural gas focused conservation)
- OEB: Ontario Energy Board
- APS: Achievable Potential Study, the OEB's Natural Gas Conservation Potential Study[13]
- RNG: Renewable natural gas
- CNG: Compressed natural gas
- LNG: Liquefied natural gas

[13] ICF International, submitted to the Ontario Energy Board, *Final Report: Natural Gas Conservation Potential Study*, June 30, 2016, updated July 7, 2016

http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Natural+Gas+Conservation+Potential+Study

Table 1: Assumptions Across Demand Outlooks

Sector	Outlook B	Outlook C	Outlook D	Outlook E	Outlook F
Residential	498 PJ in 2035	Oil and propane heating switches to heat pumps, electric and water heating gain 25% of gas market share. (388 PJ in 2035)	Oil and propane heating switches to heat pumps, electric and water heating gain 50% of gas market share.[14] (322 PJ in 2035)	Assumptions as per Outlook C, plus: • Incremental DSM consistent with OEB APS "semi-constrained" potential. • 35 PJ of RNG used by 2035 (381 PJ in 2035)	Assumptions as per Outlook D, plus: • Incremental DSM consistent with OEB APS "unconstrained" potential. • 66 PJ of RNG used by 2035 (302 PJ in 2035)
Commercial	233 PJ in 2035	Oil and propane heating switches to heat pumps, electric and water heating gain 25% of gas market share. (192 PJ in 2035)	Oil and propane heating switches to heat pumps, electric and water heating gain 50% of gas market share. (177 PJ in 2035)	Assumptions as per Outlook C, plus: • Incremental DSM consistent with OEB APS "semi-constrained" potential. • 20 PJ of RNG used by 2035 (187 PJ in 2035)	Assumptions as per Outlook D, plus: • Incremental DSM consistent with OEB APS "unconstrained" potential. • 42 PJ of RNG used by 2035 (147 PJ in 2035)
Industrial	671 PJ in 2035	5% of 2012 fossil energy switches to electric equivalent (607 PJ in 2035)	10% of 2012 fossil energy switches to electric equivalent (550 PJ in 2035)	Assumptions as per Outlook C, plus: • Incremental DSM consistent with OEB APS "semi-constrained" potential. • 23 PJ of RNG used by 2035 (591 PJ in 2035)	Assumptions as per Outlook D, plus: • Incremental DSM consistent with OEB APS "unconstrained" potential. • 48 PJ of RNG used by 2035 (519 PJ in 2035)
Transportation	967 PJ in 2035	• 2.4 million EVs by 2035. • Planned electrified transit projects 2017-2035 (883 PJ in 2035)	• 2.4 million EVs by 2035. • Planned electrified transit projects 2017-2035 (883 PJ in 2035)	Assumptions as per Outlook C, plus: • Incremental non-electrified transit. • Substitute transportation natural gas, propane, hydrogen, ethanol, and bio-based diesels for conventional fuels (878 PJ in 2035)	Assumptions as per Outlook C, plus: • Incremental non-electrified transit. • Substitute more transportation natural gas, propane, hydrogen, ethanol, and bio-based diesels for conventional fuels than in Outlook E (874 PJ in 2035)
Total	2,377 PJ in 2035	2,070 PJ in 2035	1,931 PJ in 2035	2,037 PJ in 2035	1,842 PJ in 2035

[14] By 2035, of the number of natural gas-fueled space and water heating equipment being sold in Outlook B (due to existing equipment reaching end of life and new additions driven by growth in the residential and commercial sectors), 25 percent of this stock in Outlook C and 50 percent in Outlook D is replaced with air-source heat pumps.

Each of the following sub-sections illustrate changes in fuel demand over time for each sector (residential, commercial, industrial, transportation). Each chart shows a single sector, and compares fuels use in 2025 and in 2035 to fuels use in 2015 by fuel for three outlooks: B, D and F.

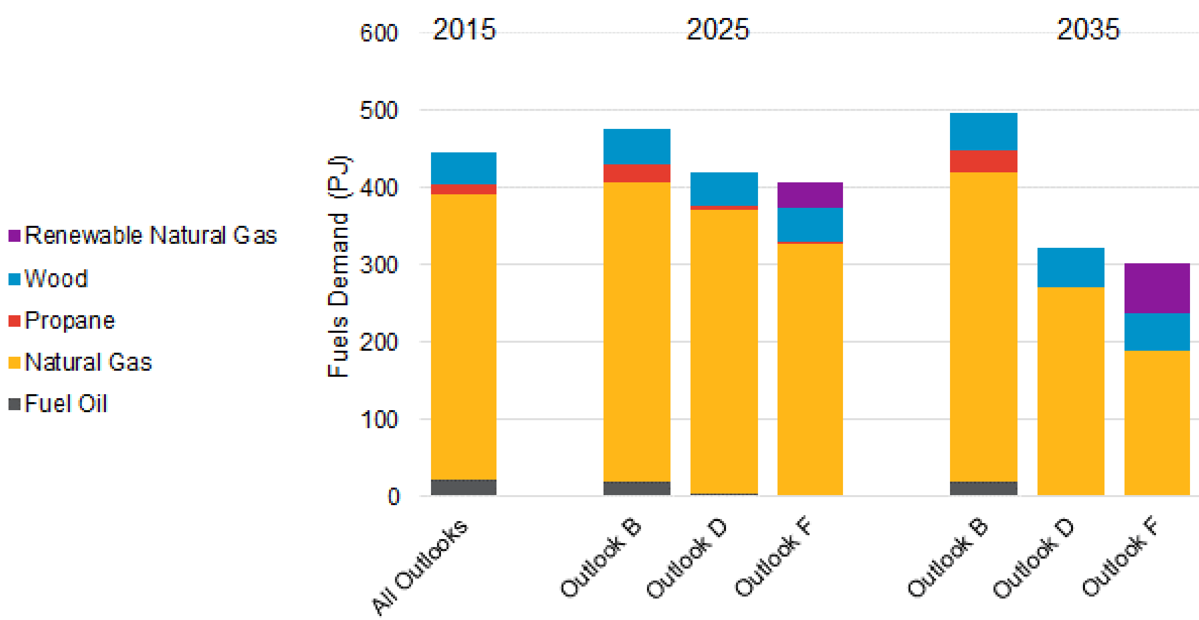
The purpose of this sectoral breakdown is to contrast IESO outlooks (C and D) with those that assume incremental natural gas DSM and additional use of alternative fuels (E and F). Since C and D (and E and F) differ from each other only in degree, only the most extreme outlooks from the two groups (i.e., D and F) are shown.

2.1.1 Residential

Outlook D results in a substantial reduction in residential fuels demand (relative to Outlook B) as a result of IESO assumptions regarding the electrification of space and water heating. Total residential fuel demand in 2035 is 35% lower in Outlook D than it is in Outlook B. Total residential energy use in 2035 in Outlook F is four percentage points lower than in Outlook D (or 39% less than in Outlook B) as a result of incremental natural gas DSM. In addition to this, however, a substantial volume of conventional natural gas (66 PJ) has been replaced by renewable natural gas (RNG).

Residential fuels energy demand for Outlooks B, D and F in 2025 and 2035 are illustrated in Figure 31 below.

Figure 31: Residential Outlook

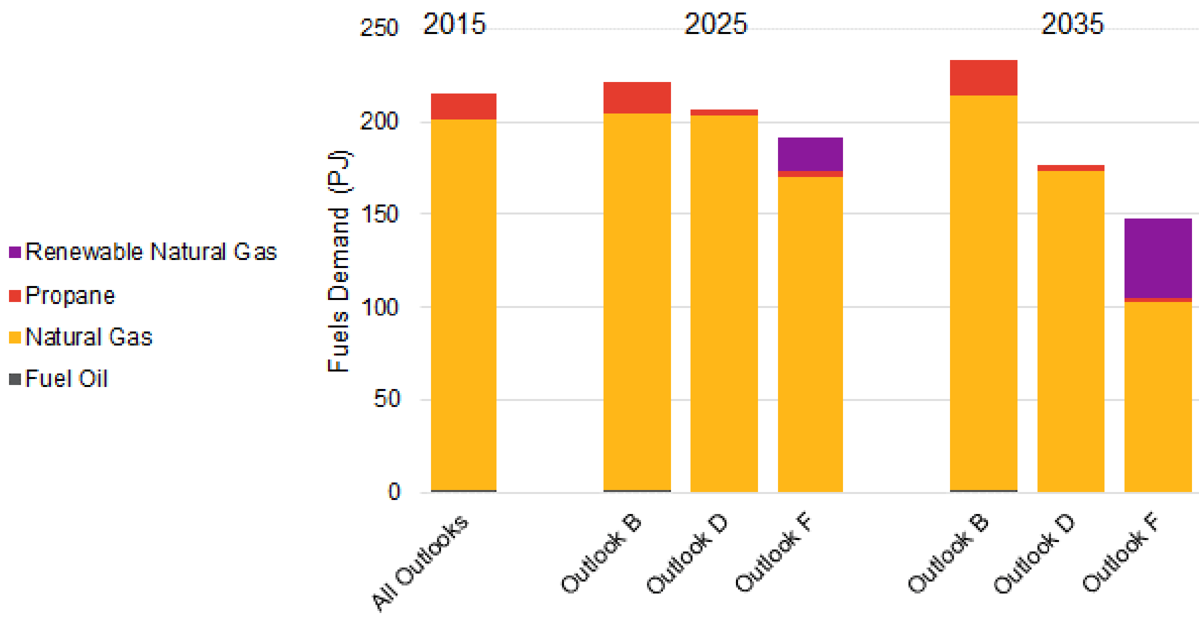


2.1.2 Commercial

Outlook D results in a substantial reduction in commercial fuels demand (relative to Outlook B) as a result of IESO assumptions regarding the electrification of space and water heating. Total commercial fuel demand in 2035 is 24% lower in Outlook D than it is in Outlook B. Total commercial energy use in 2035 in Outlook F is thirteen percentage points lower than in Outlook D (or 37% less than in Outlook B) as a result of incremental natural gas DSM. In addition to this, however, a substantial volume of conventional natural gas (42 PJ) has been replaced by renewable natural gas (RNG).

Commercial fuels energy demand for Outlooks B, D, and F in 2025 and 2035 are illustrated in Figure 32 below.

Figure 32: Commercial Outlook



Source: CanESS & Navigant Analysis, 2016

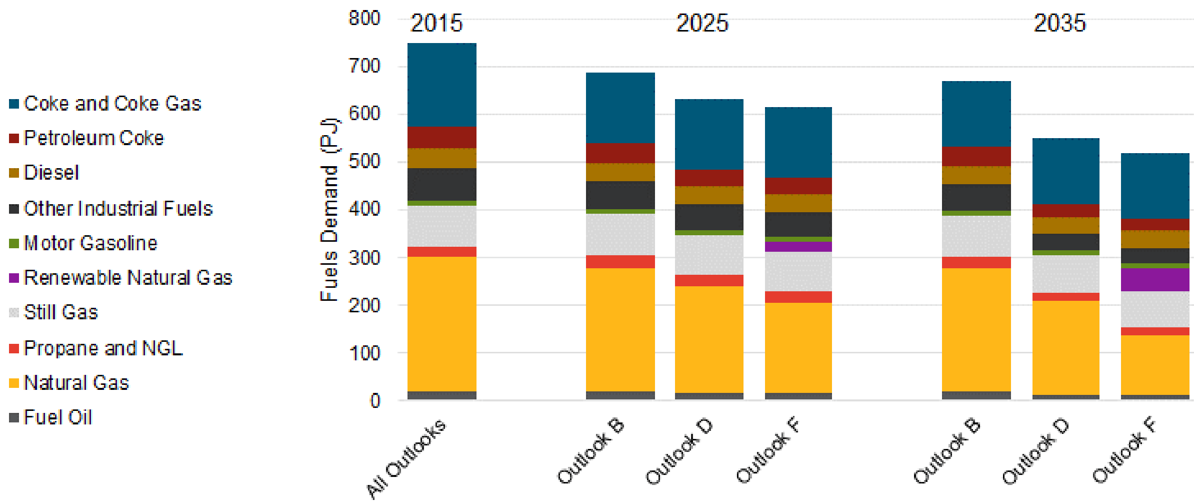
2.1.3 Industrial

Outlook D results in a substantial reduction in industrial fuels demand (relative to Outlook B) as a result of IESO assumptions regarding the electrification of industrial processes. Total industrial fuel demand (for energy use) in 2035 is 18% lower in Outlook D than it is in Outlook B. Although smaller, as a proportion of total sectoral fuels energy use, than the reduction observed in the residential and commercial sector, the total energy reduction in the industrial sector in Outlook D (compared to Outlook B) by 2035 is more than twice the commercial energy reduction.

Total industrial energy use in 2035 in Outlook F (excluding non-energy fuels use) is approximately five percentage points lower than in Outlook D (or 23% less than in Outlook B) as a result of incremental natural gas DSM. In addition to this, however, a substantial volume of conventional natural gas (48 PJ) has been replaced by renewable natural gas (RNG).

Industrial fuels energy demand for Outlooks B, D and F in 2025 and 2035 are illustrated in Figure 33 below.

Figure 33: Industrial Outlook



Source: CanESS & Navigant Analysis, 2016

2.1.4 Transportation

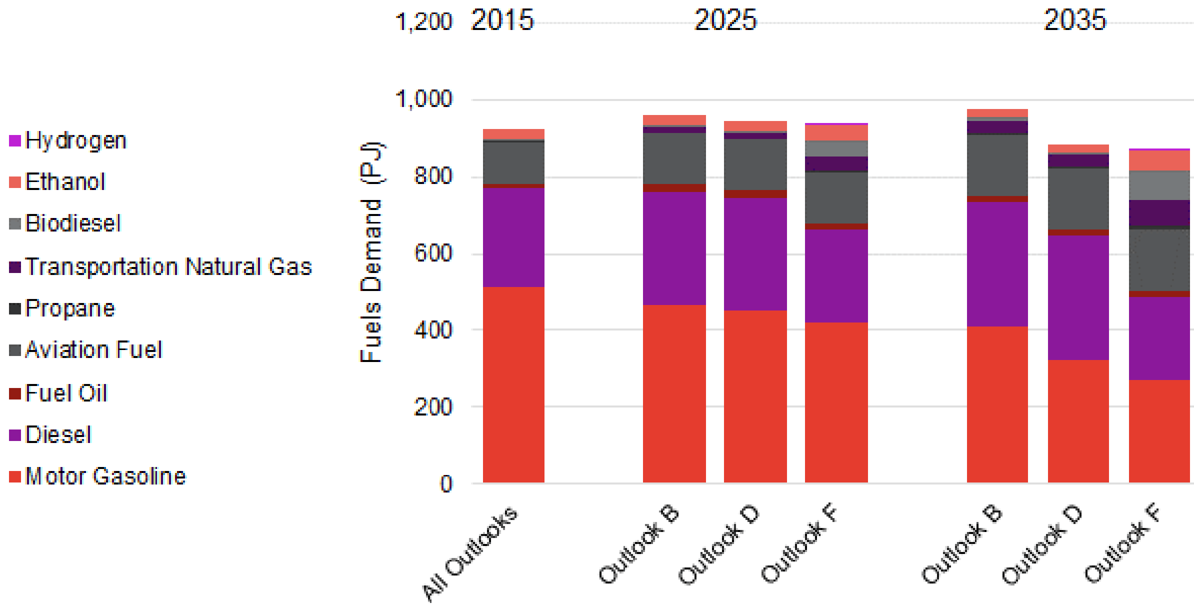
Outlook D results in a moderate reduction in transportation fuels demand (relative to Outlook B) as a result of IESO assumptions regarding the adoption of EVs. Total transportation fuel demand in 2035 is 9.5% lower in Outlook D than it is in Outlook B. As in the case of the industrial sector, this reduction, although small in proportion to total transportation fuels use, is substantial in absolute terms – 92 PJ, compared to Outlook B, nearly twice the energy reduction observed in the commercial sector in Outlook D relative to Outlook B.

Total energy use in 2035 in Outlook F is less than one percentage point lower than in Outlook D (or 10.4% less than in Outlook B). This is due to the fact that the transportation sector assumptions for Outlook F (incremental to Outlook D) are all related to fuel switching. Some modest energy reductions are observed due to improved efficiencies associated with some technologies and fuels, but since incremental Outlook F assumptions are based on a movement toward fuels with lower GHG emissions, little change is seen in total energy consumption.

The most substantial fuel switching impacts observed in Outlook F are those associated with ethanol (for light duty vehicles), bio-based diesels and natural gas (for heavy duty vehicles). Outlook F also considers the impact of increased use of hydrogen fuel cell vehicles (HFCV) and propane-fueled vehicles, but the impact of these changes is more modest.

Transportation fuels energy demand for Outlooks B, D and F in 2025 and 2035 are illustrated in Figure 34 below.

Figure 34: Transportation Outlook



Source: CanESS & Navigant Analysis, 2016

2.2 Conservation Outlook

Conservation potential is a key component of IESO's outlooks for the Ontario electricity system, and is embedded in all of the outlooks modeled in the OPO. This conservation is achieved through the deployment of conservation programs targeting different end-uses across different sectors, as well as municipal, provincial and federal codes and standards.

For most of the fuels sector, no corresponding portfolio of conservation programs exists, with the exception of natural gas DSM programs from the regulated natural gas utilities. Other specific conservation initiatives in the fuels sector include codes and standards relating to new equipment and construction, and vehicle fuel economy standards.

Outlooks B, C and D all reflect the assumption that natural gas DSM programs will continue at current (i.e., 2017 – 2020) levels of funding. The natural gas DSM in each of these outlooks approximately corresponds to the "constrained achievable" potential mapped out in the Ontario Energy Board's Conservation Potential study.[15] Outlooks E and F also apply incremental DSM. Outlook E reflects the incremental natural gas DSM potential estimated for the "semi-constrained" achievable potential scenario in the OEB study. Outlook F reflects the incremental natural gas DSM potential estimated for the "unconstrained" achievable potential scenario in the OEB study. Potential reductions of natural gas use

[15] ICF International, submitted to the Ontario Energy Board, *Final Report: Natural Gas Conservation Potential Study*, June 30, 2016, updated July 7, 2016

http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Natural+Gas+Conservation+Potential+Study are affected by the fuel-switching assumed by IESO for Outlooks C and D. Outlooks C and D both assume a significant amount of fuel switching from natural gas to electricity for space, water and process heat. This in turn reduces the incremental DSM potential available in these outlooks.[16]

Codes and standards affecting natural gas consumption are not included in the OEB study and are not explicitly modeled in CanESS in the same way that vehicle fuel economy standards are. The effects of building codes and other types of standards affecting residential, commercial and industrial natural gas use are captured through the extension forward of declining trends in energy intensity in those sectors.

All of the FTR outlooks also reflect fuels standards regulation currently in force, and the more stringent fuel economy standards scheduled to come into effect in the future. These standards include both U.S. Environmental Protection Agency (EPA)[17] fuel economy standards for light-duty, medium duty and heavy duty vehicles, specifically:

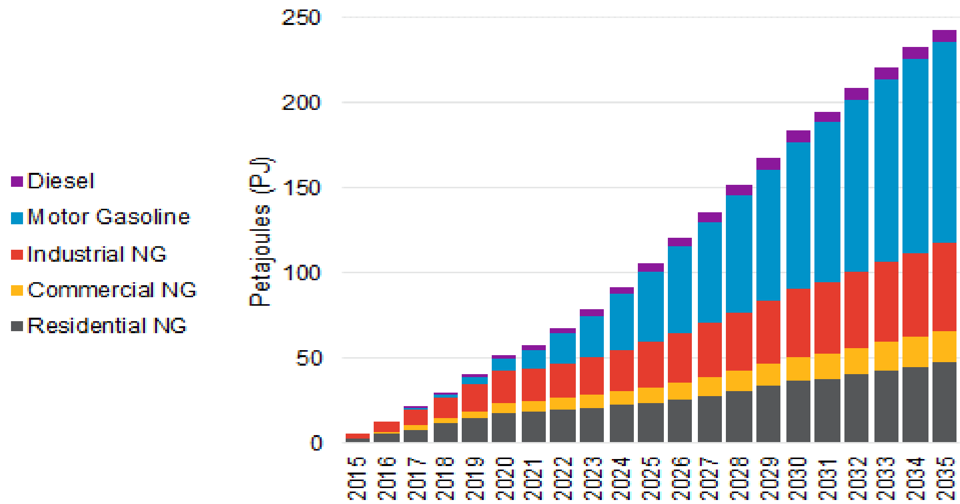
- The Corporate Average Fuel Economy (CAFE) standard. This applies to cars and light trucks.
- The Fuel Efficiency and GHG Emission Program for Medium- and Heavy-Duty Trucks. This applies to medium and heavy-duty trucks.

The conservation impact of vehicle codes and standards natural gas DSM is illustrated in Figure 35 below. A more detailed breakdown of the composition of natural gas DSM potential through to 2030 (e.g., by end-use, sector, etc.) may be found in the OEB report cited above.

[16] Navigant has worked closely with detailed sectoral and end-use data from the achievable potential study provided by the OEB to calibrate its DSM assumptions, and although the DSM assumed for the FTR is nearly identical at the aggregate level for Outlook B, it varies slightly at the sectoral level. Most, but not all, of this variation at the sectoral level is accounted for by differing sectoral definitions: the OEB report defines multi-family residential as part of the commercial sector, whereas in the FTR this segment falls in the “residential” sector. Likewise, the OEB study includes electricity generation (“utilities”) in the “industrial” sector whereas the FTR does not. Once sectoral definitions are adjusted appropriately some small sectoral differences in total estimated consumption remain, but are extremely low at the aggregate provincial level, for Outlook B.

[17] Canadian fuel economy standards are harmonized with U.S. standards.

Figure 35: Conservation Achievement and Outlook to 2035 (Outlook B)



Source: CanESS & Navigant Analysis, 2016

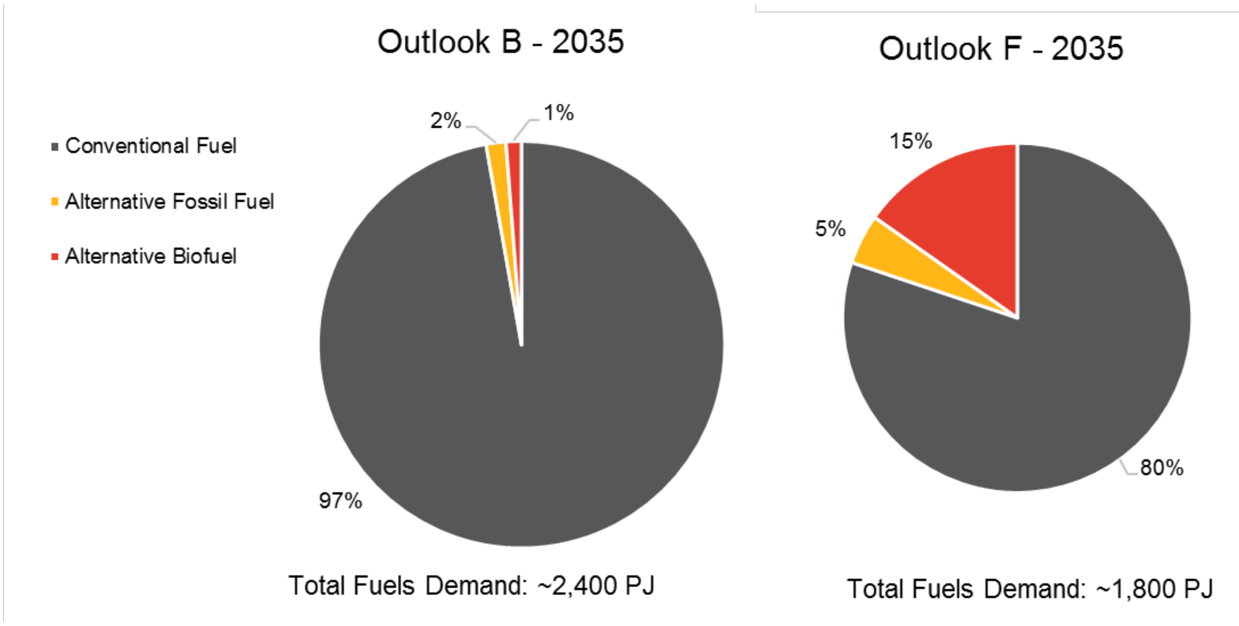
2.3 Supply Outlook

As discussed, fuels are supplied by a series of robust commodity markets where the demand for product is essential in establishing supply, infrastructure and processing needs. Fuels markets are flexible, responsive to demand shifts and price changes. Supply infrastructure is also typically responsive to changes in demand, which provides a strong signal for investment needs. In all scenarios, the supply outlook is expected to provide sufficient quantities of product to meet Ontario's demands for conventional fossil fuels. Current and planned infrastructure could be capable of meeting the demands in Outlook B, which is based on a relatively flat demand for fossil fuels, as well as all other Outlooks where fossil fuel demand is contracting. Assuming the appropriate contribution of reinvestments and proper maintenance to processing, storage, transmission and distribution facilities, no issues in supply are projected.

Where outlooks see demand growth for alternative fuels, new investment in infrastructure and greater expectations for imports of alternative fuels will be required. New ethanol processing facilities and biodiesel refineries may be needed in outlooks with higher demands for alternative fuels, along with the associated investment in storage, distribution networks and terminal asset.

Figure 36 below, illustrates the range of demands that supply systems could need to meet by 2035 as conditions in the market change. Existing infrastructure for conventional fossil fuels is likely to be sufficient, while the substantial change across outlooks in alternatives will require new investments in processing and delivery infrastructure.

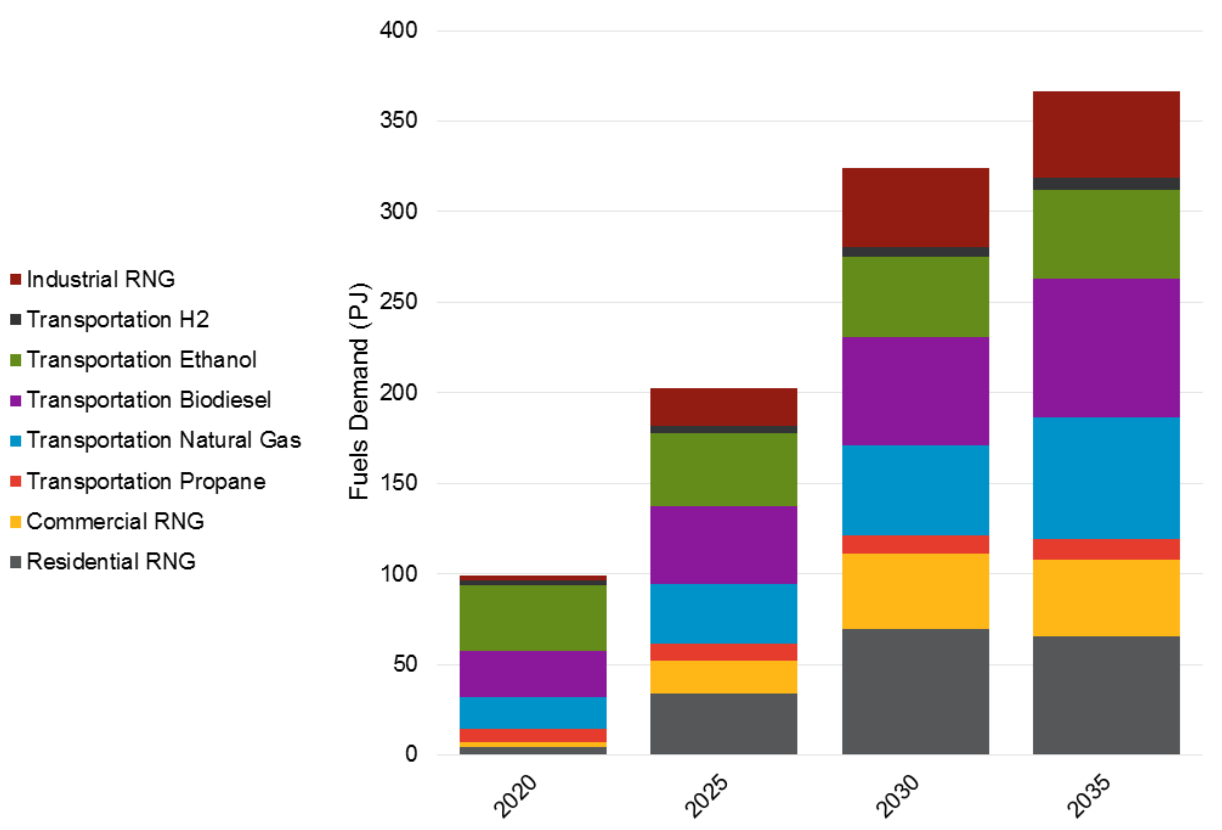
Figure 36: Alternative Fuels in 2035 – Outlook B and F



Source: CanESS & Navigant Analysis, 2016

A more detailed breakdown of the composition of alternative fuels in Outlook F, and how that changes over time, is shown in Figure 37, below.

Figure 37: Outlook F Alternative Fuel Breakdown



Source: CanESS & Navigant Analysis, 2016

At present, limited renewable natural gas facilities exist in Ontario, and production capacity at these facilities would be insufficient to satisfy the requirements of either Outlook E or Outlook F. Likewise, bio-based diesel refineries in Ontario have a total production capacity of approximately 300 million litres per year[18], or 10.2 PJ per year. The Outlook F requirement for bio-based diesels by 2035 is nearly 80 PJ per year. Ontario's current ethanol production capacity is approximately one billion litres a year[19], or just over 20 PJ. The Outlook F requirement for ethanol by 2035 is approximately 50 PJ per year.

Development of domestic biofuel production capacity, or the sourcing of substantial volumes of imports would be required to meet the biofuels demands of Outlook F.

2.3.1 Supply Resources

Ontario's non-electric energy needs have historically been satisfied by a wide variety of fuels. The diverse nature of the fuels sector is a function of both free-market dynamics, and the diverse requirements and niche needs of Ontario's fuel users. No single fuel is suitable for all applications.

[18] Renewable Industries Canada, *Industry Map*. Accessed June, 2016. http://ricanada.org/industry/industry-map/

[19] Renewable Industries Canada, *Industry Map*. Accessed June, 2016. http://ricanada.org/industry/industry-map/

The characteristics of the major groups of fuels considered in this report are discussed below.

2.3.1.1 Conservation

Conservation is not in itself a fuel, but can be used as way of reducing fuel consumption. As noted in the Conservation Outlook, aside from natural gas, program-driven energy conservation does not generally exist in the fuels sector. The potential for natural gas DSM (conservation), based on the findings of the OEB's Conservation Potential Study, have been accounted for in all five outlooks, as have fuel economy standards.

2.3.1.2 Natural gas

Natural gas is the most common heating fuel in Ontario, by share. However, natural gas is not accessible to all Ontario consumers because the distribution network is not available to all regions. Generally, rural or remote parts of the province are not served by natural gas piping networks. Delivery of liquified natural gas and compressed natural gas by truck or rail is a possible alternative. Adoption of this fuel has been encouraged by the gradual expansion of the distribution network, and historically low prices in relation to other space- and water-heating fuel options. Most of Ontario's natural gas is currently transported to the province via pipeline from Western Canada[20], with an increasing trend to supplies from the U.S. northeast, and substantial quantities of natural gas are stored in south-western Ontario to cover winter heating capacity requirements.

2.3.1.3 Renewable natural gas

Renewable natural gas (RNG) is a biogas product of the decomposition of organic matter. Biogas can be derived from landfills, livestock operations, wastewater treatment, or waste from industrial, institutional, and commercial entities. As outlined in a 2014 CanBio Report entitled *Status on Bioenergy in Canada*,[21] Ontario has become the leader in Canada for in-farm biogas facilities, although no large-scale RNG production facilities currently exist in Ontario, Enbridge and Union Gas have forecast the capability to deliver 155 PJ (nearly 4.3 million cubic meters) of renewable gas per year by 2030.[22]

2.3.1.4 Propane

Propane is a stable, economically transportable alternative to natural gas and is used for space-heating in remote areas without access to natural gas, for transportation and in industrial applications. Propane's stability and storage longevity contribute to its adoption by remote communities and industry. Historically

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[20] Navigant, *North America Natural Gas Market Outlook*, Spring 2016

[21] Renewable Energies, 2014 Canbio Report on the Status of Bioenergy in Canada. December, 2014. http://www.fpac.ca/wp-content/uploads/2014_CanBio_Report.pdf

[22] ICF International on behalf of Enbridge Gas Distribution and Union Gas, *Results from Aligned Cap & Trade Natural Gas Initiatives Analysis*, November 2015

Filed with the Ontario Energy Board: 2016-04-22

EB-2016-0004, Exhibit S3.EGDI.OGA.3

propane was produced using oil by-products (liquefied petroleum gas), but currently the majority of Ontario's propane supply is derived from natural gas (natural gas liquid) produced in Alberta.[23]

2.3.1.5 Oil products

Refined oil products are used principally as a transportation fuel (gasoline, diesel, aviation fuel). Fuel oil is also used for industrial process heating and home heating, although home heating use of fuel oil has been in decline for some time, due partly to the high cost of the product and to the insurance premiums required of homeowners that use oil. Although a very modest amount of crude oil is produced in Ontario, the majority of Ontario's oil products are refined in Ontario using crude oil transported from Alberta.[24]

2.3.1.6 Ethanol

Despite Ontario producing more bioethanol than any other province in Ontario, the province imports approximately 20% of its current requirements.[25] The existing provincial mandate for green fuels requires that at least 5% of the volume of all gasoline sold in the province is made up of ethanol. Ethanol is more corrosive than standard gasoline, and many car warranties only cover the use of up to 10% ethanol blends.[26] Ontario ethanol refineries have a nominal production capacity of over a billion litres per year, equivalent to 23 PJ. [27]

2.3.1.7 Biodiesel

There are two types of bio-based diesel: "biodiesel", and "renewable" diesel. The key difference between the two is that biodiesel congeals at higher temperatures than petro-diesel, limiting the blend rate for this fuel in colder months. Renewable diesel does not have this limitation and may be blended (or used without blending) in all conditions suitable to petro-diesel. Ontario biodiesel refineries (including one not yet operational) have a nominal production capacity of nearly 300 million litres a year, equivalent to approximately 10 PJ. [28]

2.3.1.8 Hydrogen

Hydrogen is considered in this report only as a fuel for hydrogen fuel cell vehicles (HFCVs). Currently, most hydrogen is produced from methane or coal gasification, although some is also produced via the gasification of biomass or water electrolysis. Hydrogen may be produced without carbon emissions by using electrolysis with electricity from non-emitting sources. There are currently two hydrogen production

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[23] National Energy Board and Competition Bureau, *Propane Market Review – Final Report*, April 2014

http://www.nrcan.gc.ca/energy/crude-petroleum/15927

[24] Statistics Canada, Table 134-0001: Refinery Supply of Crude Oil and Equivalent, Annual

http://www5.statcan.gc.ca/cansim/a26?lang=eng&id=1340001

[25] Ethanol production data provided by the Ministry of the Environment and Climate Change

[26] International Council on Clean Transportation, *Technical Barriers to the Consumption of Higher Blends of Ethanol*, February 2014

http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/files/ICCT_Ethanol.pdf

[27] Renewable Industries Canada, *Industry Map*. Accessed June, 2016. http://ricanada.org/industry/industry-map/

[28] Renewable Industries Canada, *Industry Map*. Accessed June, 2016. http://ricanada.org/industry/industry-map/

facilities in Ontario, both in Sarnia, with a total production capacity of 230,000 kg per day, equivalent to approximately 10 PJ per year. [29]

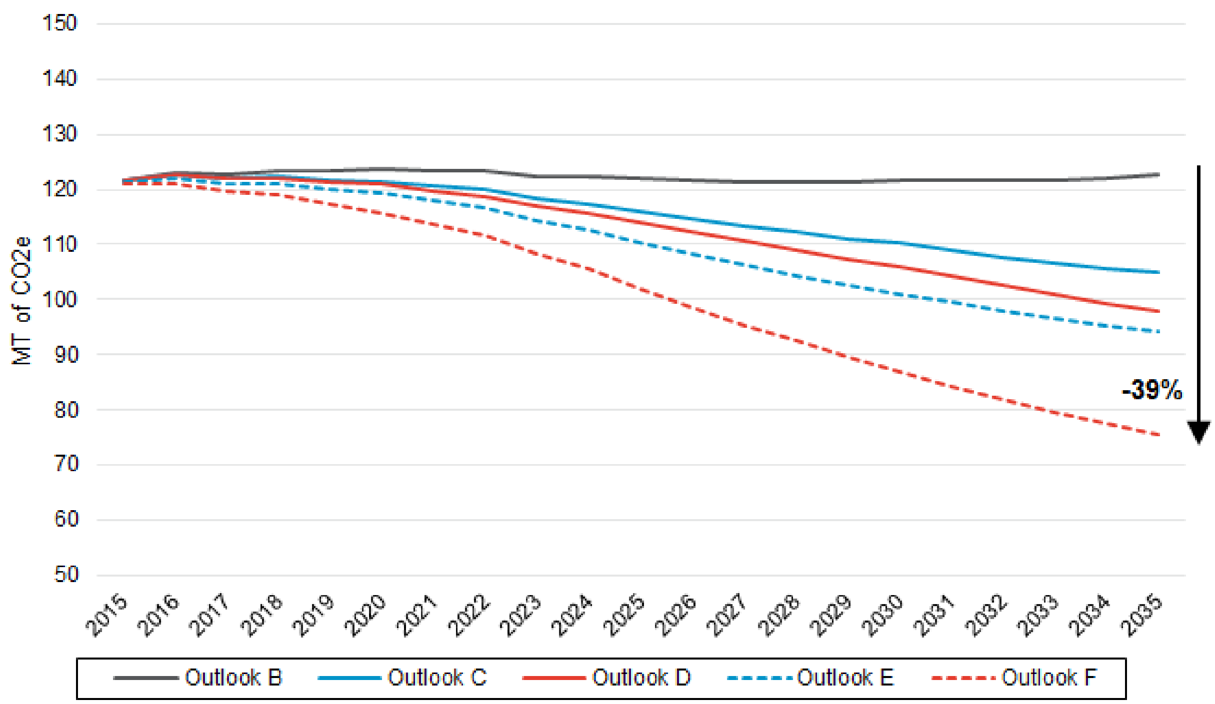
2.4 Emissions Outlook

Carbon emissions from Ontario's fuels sector are projected to decline significantly under Outlooks C, D, E and F. Emissions reductions observed in Outlooks C and D are driven mainly by the electrification assumed to take place across all sectors. Further emissions reductions identified through Outlooks E and F are the result of incremental natural gas DSM and to the increased use of alternative, less carbon-emitting fuels.

Outlook F delivers the most substantial emissions reductions, relative to 2014, with 46 MT of annual reductions by 2035.

GHG emissions that result from energy related fuels use across the outlooks are illustrated in Figure 38 below. This includes only combustion-related fuels emissions and does not include emissions from electricity generation fuels use, which are addressed within the OPO. Outlook F (combining both electrification initiatives and fuels-directed initiatives) yields substantial decarbonisation potential, reducing emissions of CO_2e by nearly 40% in 2035 compared to Outlook B.

Figure 38: Fuels Combustion GHG Emissions Outlook

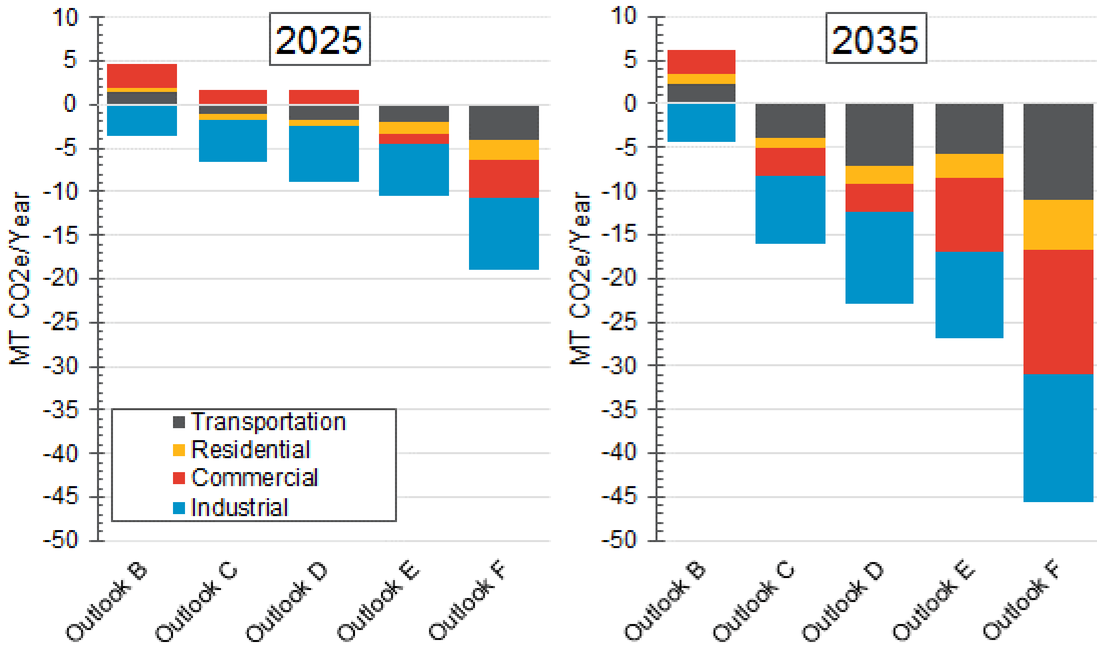


[29] Hydrogen Analysis Resource Center, *Merchant Hydrogen Plant Capacities in North America*, accessed September 2016 http://hydrogen.pnl.gov/hydrogen-data/merchant-hydrogen-plant-capacities-north-america

Source: CanESS & Navigant Analysis, 2016

The majority of emissions reductions in Outlooks C through F are realized in the industrial and transportation sectors. Although energy reductions in these sectors across the outlooks are less than those observed for the residential sector, emissions potential is greater due to more carbon-intensive nature of the fuels used for energy in those sectors. The difference, by sector and outlook between emissions in 2014[30] and emissions in 2025 and 2035 is illustrated in Figure 39. **Note:** In this figure reductions are represented by negative values.

Figure 39: Emissions Relative to 2014 Levels



Source: CanESS & Navigant Analysis, 2016

2.5 Fuels System Cost Outlook

The total cost of fuels service over the planning outlooks will be determined by global fuel prices, the mix of fuels demanded (or mandated) in Ontario, the carbon costs of cap and trade, and the costs of maintaining existing regulated natural gas delivery infrastructure. The growth in these costs across the planning horizon is shown in Figure 40, below.

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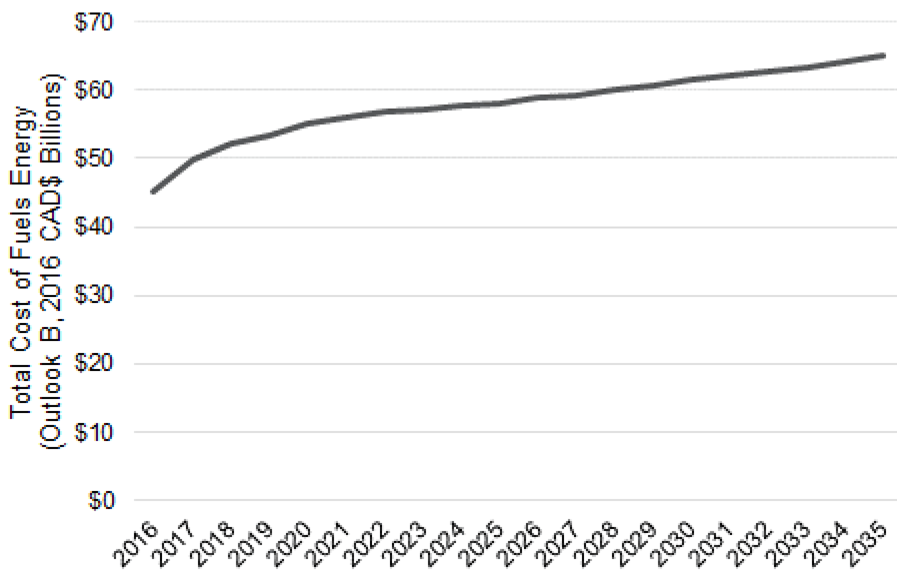
[30] The anchor year of 2014 (rather than 2015 or 2016) is used for the emissions comparison to allow for comparisons with values included in the 2014 Ontario Climate Change Update, as well as the values reported by Environment Canada (last actuals reported are for 2014)

Government of Ontario, Ministry of the Environment and Climate Change, *Ontario's Climate Change Update 2014*, 2014 https://dr6j45jk9xcmk.cloudfront.net/documents/3618/climate-change-report-2014.pdf

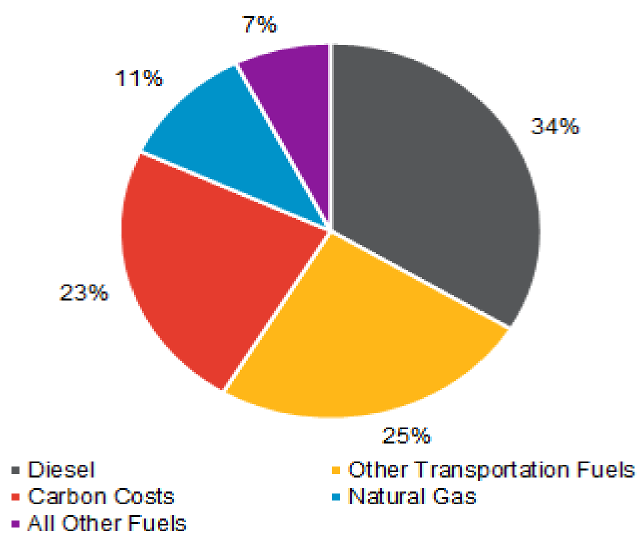
Figure 40: Total Cost of Fuels for Energy in Outlook B



In Outlook B, the total cost of fuels for energy use would increase by approximately 40%, or about twenty billion dollars between 2016 and 2035. The principal driving factors for this increase in total fuels costs are increasing fossil fuel prices – particularly transportation fuel prices – and the carbon cost of fossil fuel emissions (i.e., the cap and trade carbon price).

The distribution of the increase in system costs for Outlook B is shown in Figure 41 below.

Figure 41: Drivers of System Cost Increases 2016 to 2035



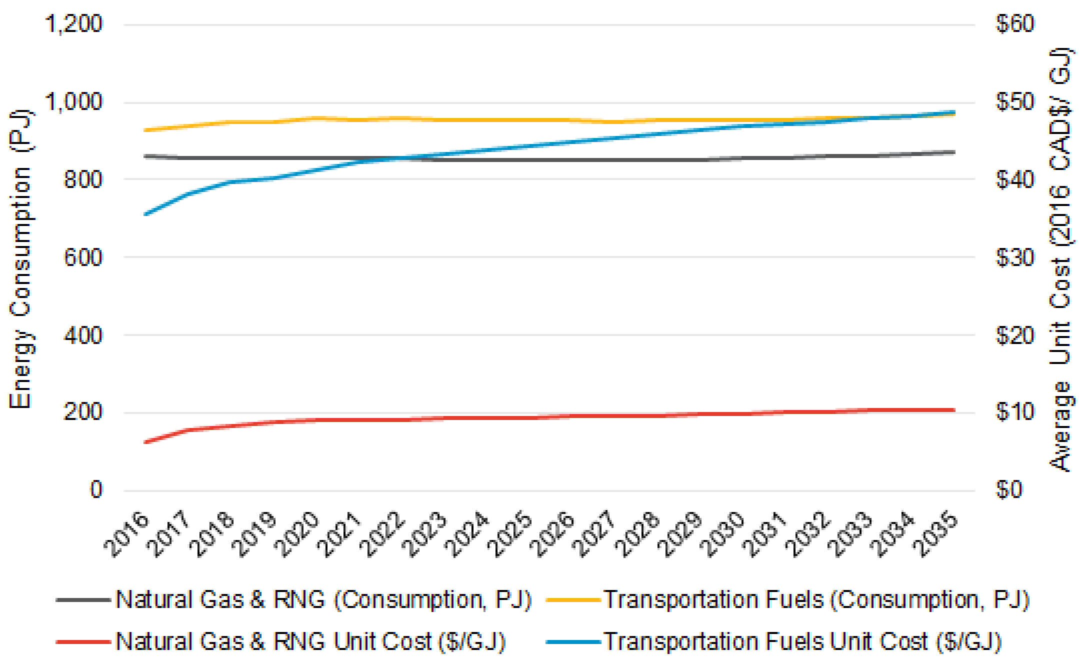
Source: CanESS & Navigant Analysis, 2016

Approximately one third of the total cost increase is due to the increased use of diesel fuel (up 20% in 2035 from 2016), combined with the increased price of that fuel (up 30% in real terms in 2035 from 2016) under conditions of the outlook. Increasing use of aviation fuel (up 47% from 2016) and the cost of aviation fuel (twice the cost in 2035 as in 2016) is the driver of the increased costs observed for "Other Transportation Fuels".

Increases in the system cost of natural gas are due almost entirely to changes in the total delivered cost of gas (up 36% from 2016 to 2035) to procure gas supplies and maintain the supply network. Growth in gas consumption is expected to be very modest in Outlook B (up approximately 1% in 2035 from 2016). Although motor gasoline's unit cost rises by approximately the same ratio as diesel, the impact of this price change on total cost is almost entirely offset by the substantial increase in the use of EVs assumed for this Outlook.

The average unit cost of both natural gas and transportation fuels (inclusive of carbon prices) increases at a decreasing rate for the first few years of the Outlook and then, by 2021, stabilizes at an annual increase of approximately 1% per year. The increase in unit costs are due entirely the forecast increase in the delivered price of these products and the cost of carbon flowing from Ontario's cap and trade regime.

Figure 42: Average Unit Cost of Natural Gas[31] and Transportation Fuels in Outlook B



Source: CanESS & Navigant Analysis, 2016

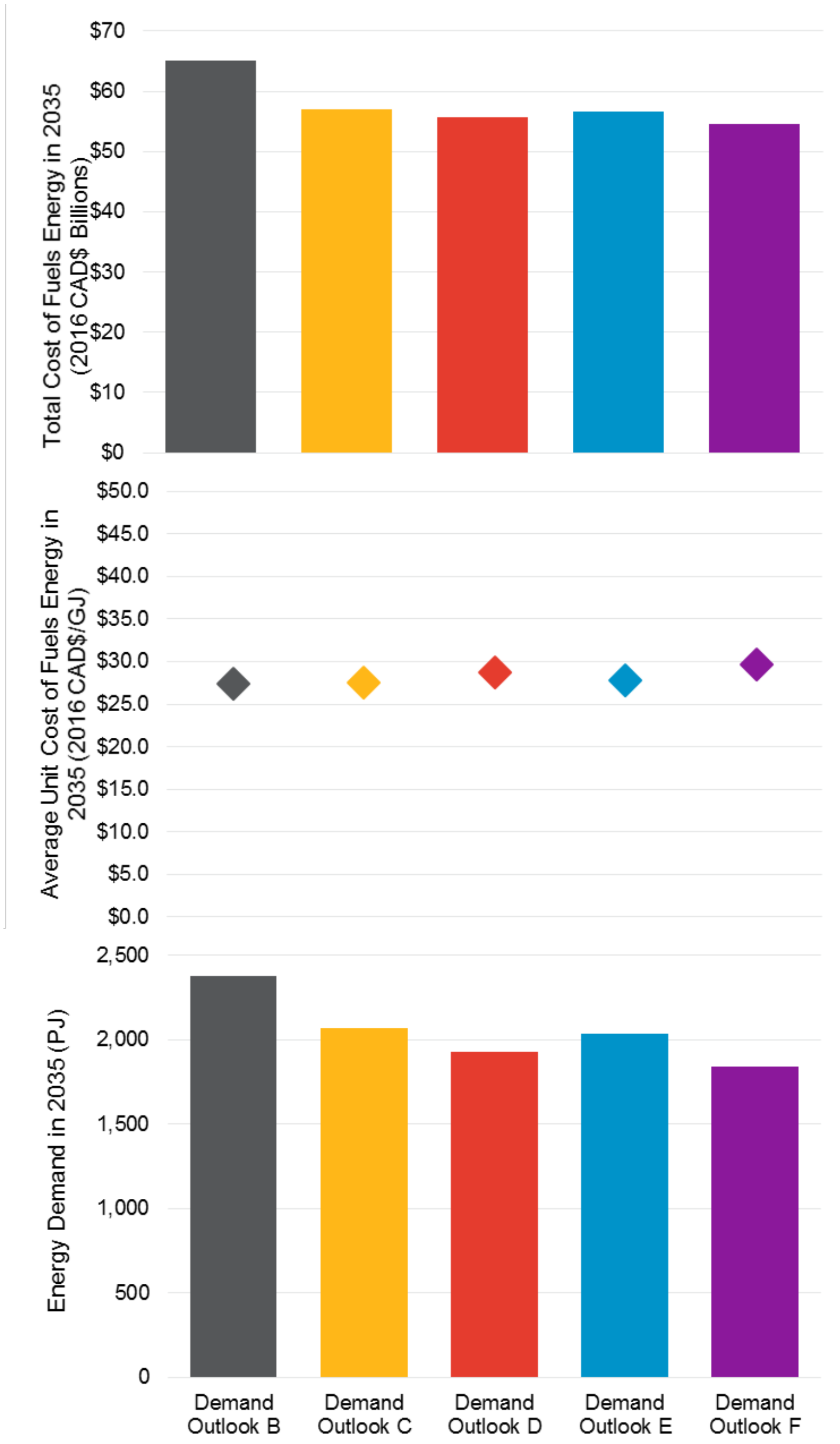
Total fuels energy costs fall substantially in the alternative outlooks, C through F, as may be seen in Figure 43. This is due to a number of factors, principally the reduction in fuel use as a result of electrification of space-heating, industrial processes and light-duty transportation (Outlook C and D). It is

[31] Does not include industrial non-energy use natural gas.

these electrification Outlooks that result in the biggest impact to total fuels energy costs. Outlook E and F deliver very modest additional reductions in total fuel cost as a result of incremental natural gas DSM, and the shifting of fuel consumption to less carbon-intensive fuels with commensurately lower carbon costs (Outlook E and F).

Despite total costs falling substantially as a result of electrification, average unit costs *increase* very modestly across the five outlooks. This is principally the result of the distribution component of natural gas costs, which (different from all other fuels) are assumed to be fixed, regardless of reductions in volume consumed.

Figure 43: Cost of Fuels Energy Across Demand Outlooks



Source: CanESS & Navigant Analysis, 2016

3. CONCLUSION

Ontario's fuels sector is made up of rich diversity of fuels which are produced and delivered through a variety of means and markets. Fuels serve Ontario consumers in many applications ranging from space and water heating and cooking, to transportation, electricity generation and non-energy related industrial processes. This mix of fuels is supplied in a dynamic marketplace that has a long record of success in meeting the fuel energy needs of the province.

Looking forward, a key priority of the Government of Ontario is decarbonisation of the economy, including the fuels sector, in order to meet its climate change objectives. It is expected that reducing greenhouse gas (GHG) emissions will also continue to be a focus of other provinces and regions that supply fuel products to Ontario.

From an Ontario perspective, with GHG-emitting fuel use in the electricity sector being substantially reduced over the past decade, the largest contributors of fuels-related GHG emissions are the transportation, industrial combustion and residential sectors in the province. Therefore, it is in these sectors that Ontario can take action to see significant GHG reductions, by introducing new low-carbon alternative fuels, promoting fuel-switching to cleaner energy sources and increasing energy conservation.

Ontario's Climate Change Action Plan (CCAP) outlines the government's intent to target these sectors with a variety of initiatives, programs and projects that will help to move Ontario to a low-carbon economy future. Ontario's economy-wide cap and trade program will also concurrently provide a market-based mechanism that incents business to reduce their GHG emissions. Finally, Ontario will also stand to benefit for the efforts of its neighboring jurisdictions to decarbonize the fuels supplies they ultimately deliver to Ontarians.

Ontario's transition to a low carbon economy will have significant implications for its fuels sector, creating new opportunities as well as future risks that require consideration from government policy makers. This report illustrates the potential impacts associated with the transition from conventional fuels to lower carbon alternatives in the various demand outlooks examined. Outlooks examined in this report are meant to provide insight into future possibilities, rather than to be deterministic.
A number of insights arise from the analysis conducted for this report which highlight key considerations for the fuels sector and its stakeholders. These include:

- There will be value in maintaining flexibility in Ontario's fuels sector. The wide range of fuels in use today reflects the diverse energy needs of the Ontario economy as well as how the sector has successfully adapted and evolved as those needs have changed over time. Options for the future will similarly need to serve that diverse range of needs. Maintaining flexibility will allow options for responding to the considerable uncertainty associated with the outlooks of future demand and supply markets and particularly with regard to technology development and innovation in fuels, vehicles and infrastructure. New options and approaches are likely to materialize in the future. Preserving and developing a mix of alternatives can preserve the ability to adopt the most promising solutions in the future.

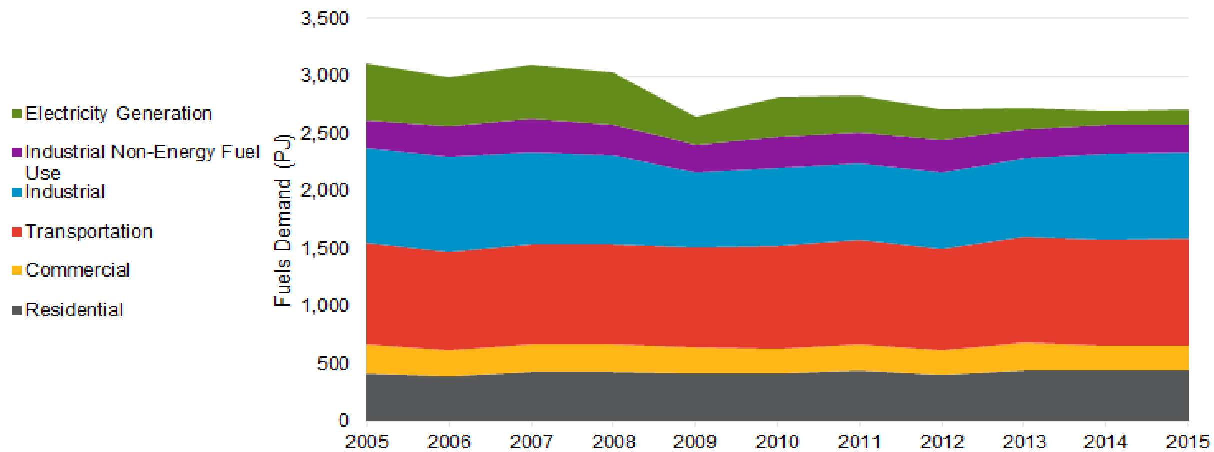
- Many alternative fuel technologies are technically feasible today. This report illustrates the range of fuels and technologies available in Ontario's fuels sector, as well as regulatory and policy levers that can support adoption.

- Choices should be considered in the context of the broader integrated energy system. As demonstrated through this report and the OPO, changes in one sector can have material implications for other sectors, particularly when converting from one energy resource to another. Understanding those implications will be important in deciding on an integrated energy future.

In summary, Ontario has a range of options available in the fuels sector to meet societal goals for GHG reductions and economic objectives. To support LTEP consultations, this report has laid out the context of how Ontario meets energy demands through the fuels sector today, and examines some of the implications of different options for the future.

APPENDIX A. DATA TABLES

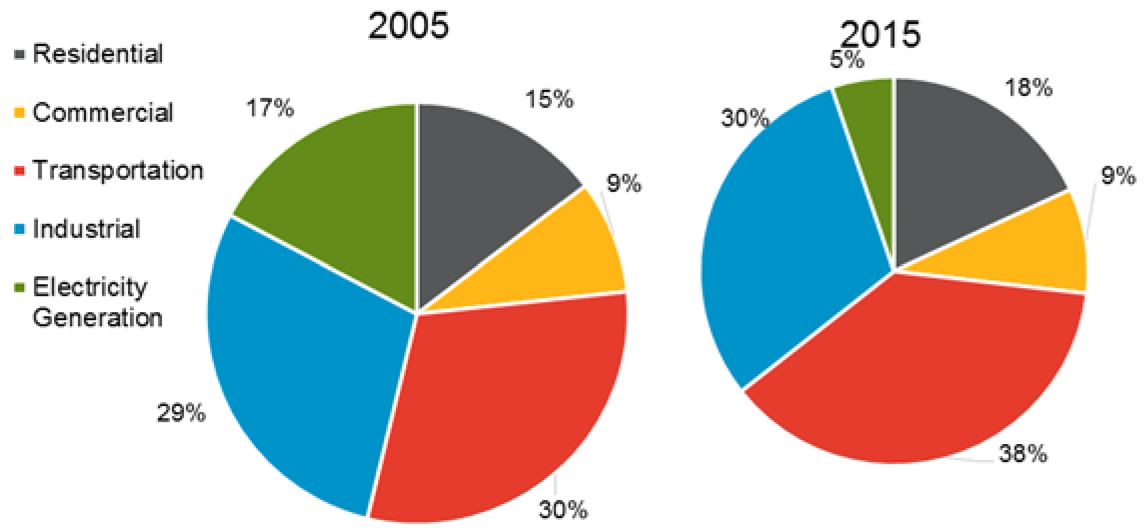
Figure 1: Total Ontario Fuels Energy Demand



Data for Figure 1: Total Ontario Fuels Energy Demand

Fuels Demand (PJ)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	421	393	433	436	415	412	439	398	445	445	447
Commercial	249	226	239	239	230	224	234	215	239	215	215
Transportation	876	855	870	862	859	892	900	878	915	918	927
Industrial	831	818	801	769	666	673	674	680	690	749	750
Industrial Non-Energy Fuel Use	238	275	283	279	235	276	260	274	245	247	246
Electricity Generation	497	427	479	444	237	345	326	264	194	129	128

Figure 2: Fuels Energy Demand by Sector 2005 and 2015



Data for Figure 2: Fuels Energy Demand by Sector 2005 and 2015

Fuels Demand (PJ)	2005	2015
Residential	421	447
Commercial	249	215
Transportation	876	927
Industrial	831	750
Electricity Generation	497	128

Figure 3: Fuels Energy Demand by Fuel Type

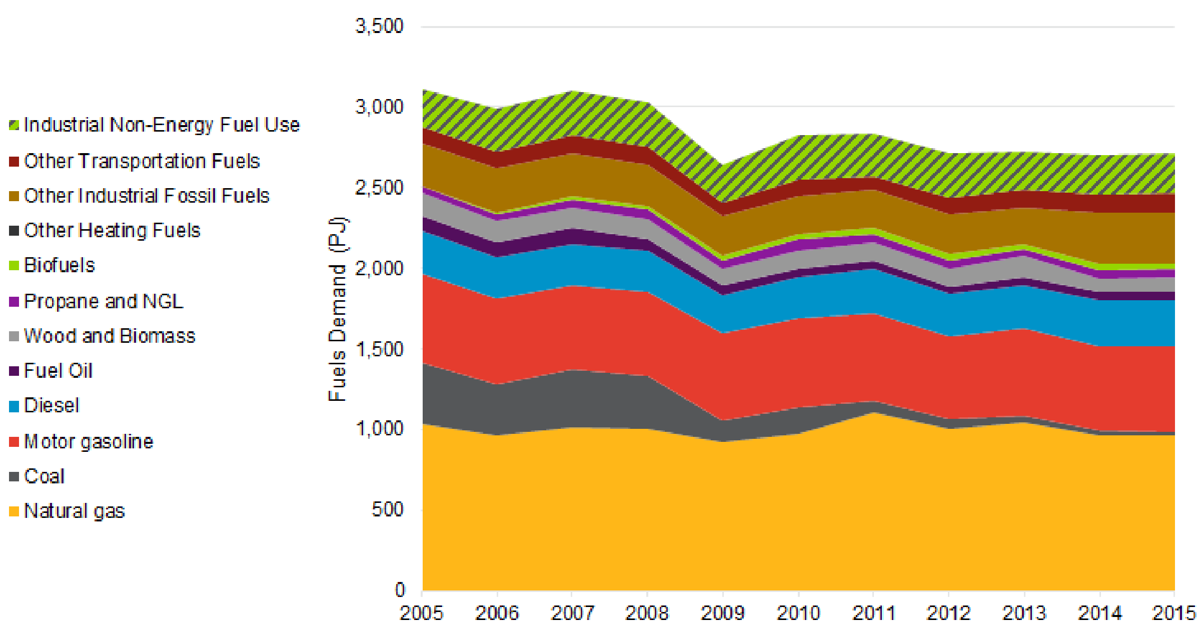
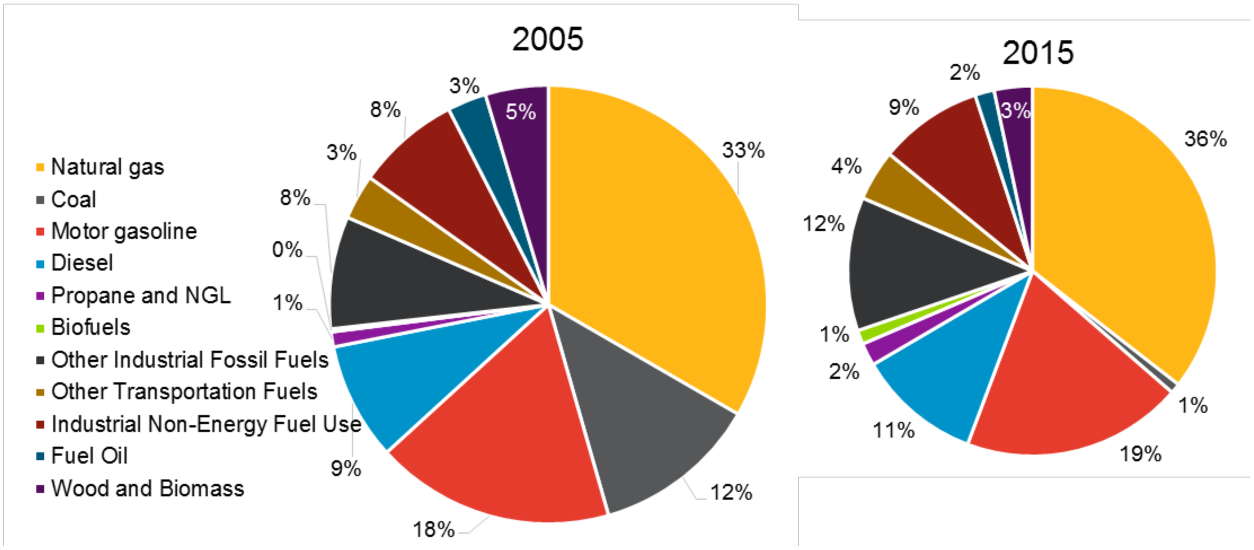


Figure 4: Fuels Demand by Fuel Type 2005 and 2015

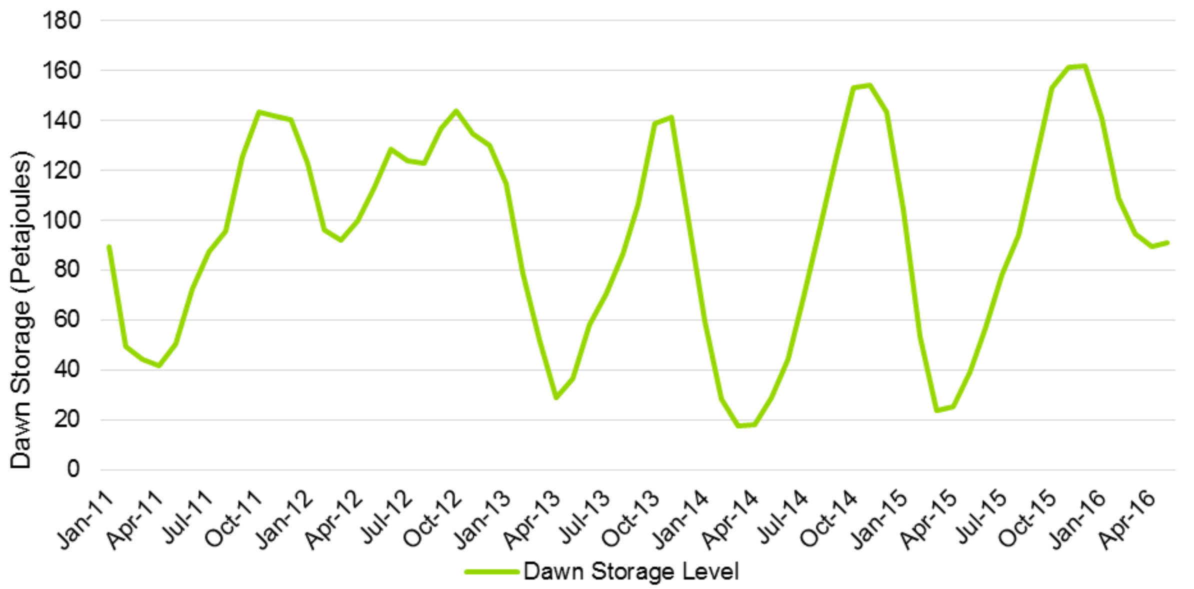


Data for Figure 3 and Figure 4

Fuels Demand (PJ)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Natural gas	1,037	964	1,012	1,009	927	973	1,111	1,008	1,041	966	963
Coal	381	314	359	326	128	160	67	58	43	24	24
Motor gasoline	549	538	527	521	541	555	545	508	541	525	524
Diesel	270	254	255	256	242	260	273	269	272	289	294
Fuel Oil	90	86	96	72	57	52	55	46	46	47	46
Wood and Biomass	144	136	122	122	102	113	113	111	134	89	91
Propane and NGL	34	46	51	54	55	65	50	54	43	52	54
Biofuels	7	12	22	26	27	31	34	35	35	33	33
Other Heating Fuels	0	0	1	0	0	0	0	0	0	0	0
Other Industrial Fossil Fuels	258	267	267	258	243	243	237	242	216	315	317
Other Transportation Fuels	103	103	110	104	86	93	89	105	113	116	120
Industrial Non-Energy Fuel Use	238	275	283	279	235	276	260	274	245	247	246

No quantitative data inform the graphic presented in Figure 5.

Figure 6: Dawn Storage

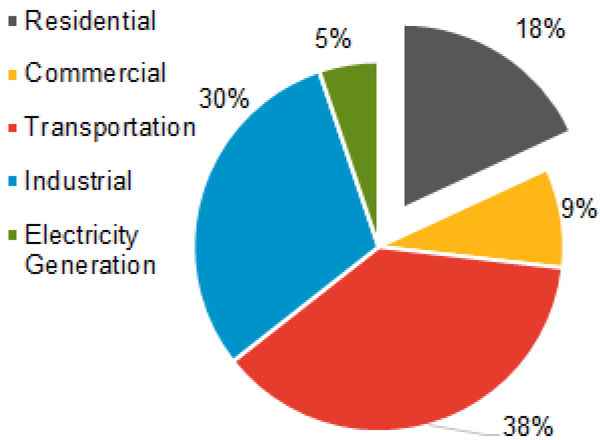


Data for Figure 6: Dawn Storage

Month	PJ	Month	PJ	Month	PJ
Jan-11	89	Jan-13	114	Jan-15	104
Feb-11	49	Feb-13	78	Feb-15	54
Mar-11	44	Mar-13	52	Mar-15	24
Apr-11	42	Apr-13	29	Apr-15	26
May-11	50	May-13	37	May-15	39
Jun-11	73	Jun-13	58	Jun-15	56
Jul-11	87	Jul-13	71	Jul-15	78
Aug-11	95	Aug-13	86	Aug-15	94
Sep-11	125	Sep-13	106	Sep-15	123
Oct-11	143	Oct-13	139	Oct-15	153
Nov-11	142	Nov-13	141	Nov-15	162
Dec-11	140	Dec-13	101	Dec-15	162
Jan-12	123	Jan-14	60	Jan-16	141
Feb-12	96	Feb-14	28	Feb-16	109
Mar-12	92	Mar-14	18	Mar-16	95
Apr-12	100	Apr-14	18	Apr-16	90
May-12	113	May-14	29		
Jun-12	128	Jun-14	44		
Jul-12	124	Jul-14	69		
Aug-12	123	Aug-14	97		
Sep-12	137	Sep-14	126		
Oct-12	144	Oct-14	153		
Nov-12	135	Nov-14	154		
Dec-12	130	Dec-14	143		

No quantitative data inform the graphics presented in Figure 7, Figure 8, Figure 9, Figure 10, Figure 11, Figure 12.

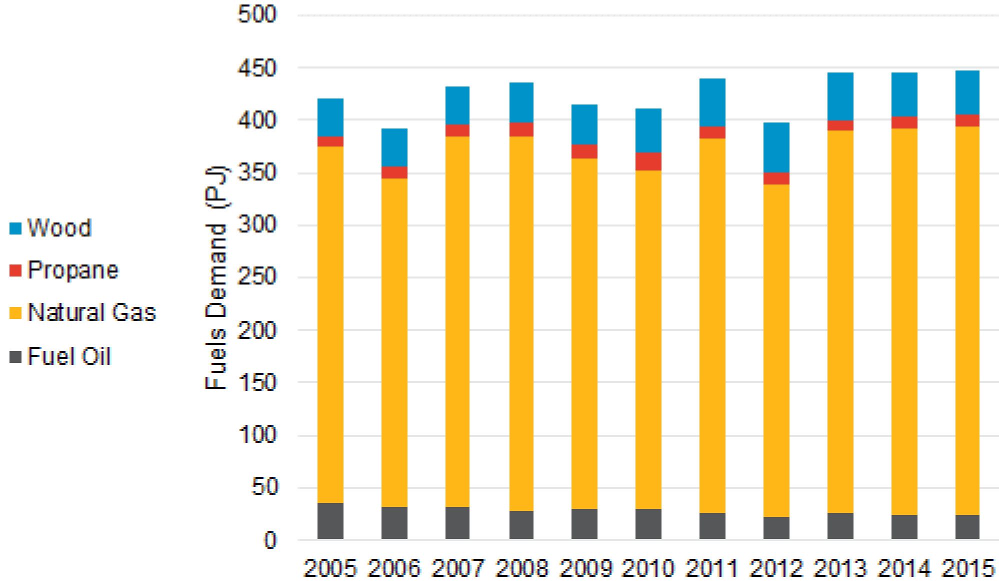
Figure 13: Ontario Residential Fuels Demand - 2015



Data for
Figure 13: Ontario Residential Fuels Demand - 2015

Fuels Demand (PJ)	2015
Residential	447
Commercial	215
Transportation	927
Industrial	750
Electricity Generation	128

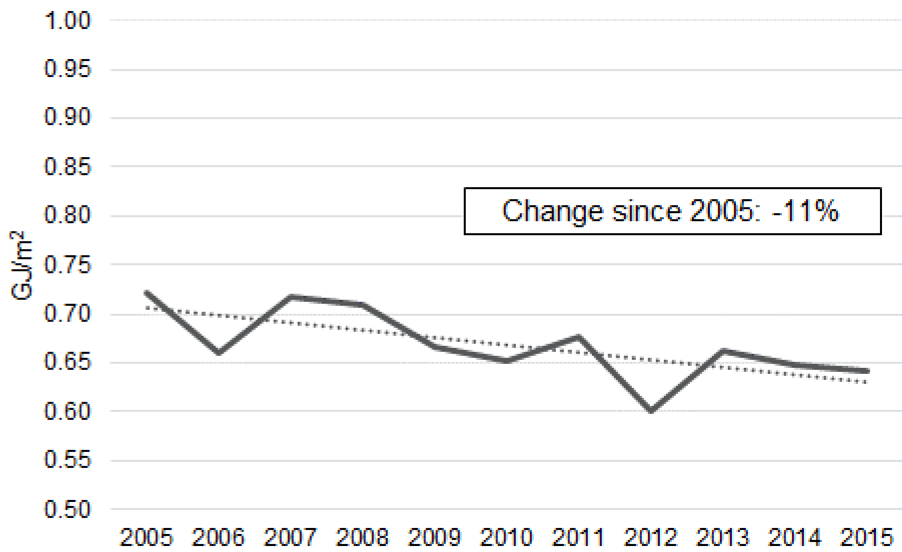
Figure 14: Residential Demand by Fuel Type: 2005-2015



Data for Figure 14: Residential Demand by Fuel Type: 2005-2015

Fuel Type	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Fuel Oil	35	31	33	28	29	30	26	23	25	25	24
Natural Gas	341	313	351	356	334	322	356	315	364	367	369
Propane	8	11	12	13	14	16	12	13	10	11	13
Wood	38	36	36	38	38	43	45	47	46	42	41

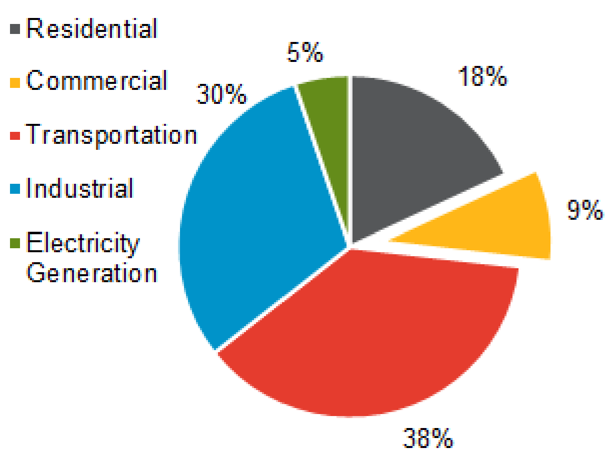
Figure 15: Residential Fuels Energy Use Per Square Metre of Floor-Space



Data for Figure 15: Residential Fuels Energy Use Per Square Metre of Floor-Space

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential Energy Intensity (GJ/m2)	0.72	0.66	0.72	0.71	0.67	0.65	0.68	0.60	0.66	0.65	0.64

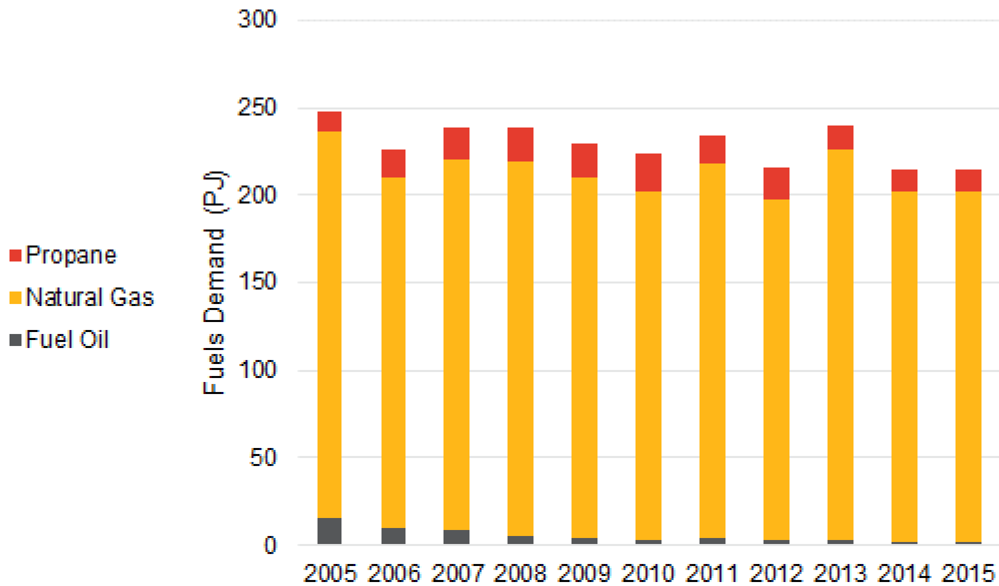
Figure 16: Commercial Fuel Demand - 2015



Data for Figure 16: Commercial Fuel Demand - 2015

Fuels Demand (PJ)	2015
Residential	447
Commercial	215
Transportation	927
Industrial	750
Electricity Generation	128

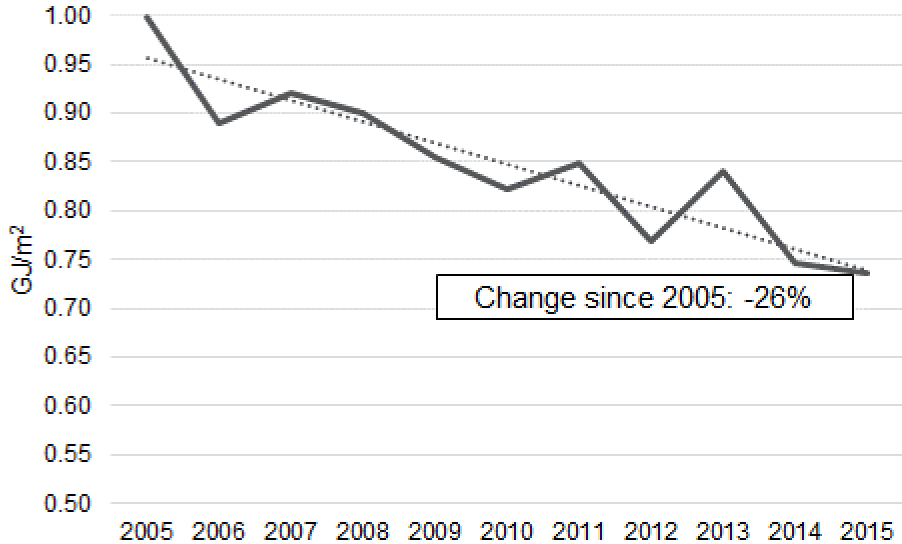
Figure 17: Commercial Demand by Fuel Type: 2005-2015



Data for Figure 17: Commercial Demand by Fuel Type: 2005-2015

Fuel Type	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Fuel Oil	15	10	8	5	4	3	4	3	3	2	2
Natural Gas	221	199	212	214	207	198	214	195	222	200	200
Propane	12	16	18	19	19	22	17	18	14	13	13
Renewable Natural Gas	0	0	0	0	0	0	0	0	0	0	0

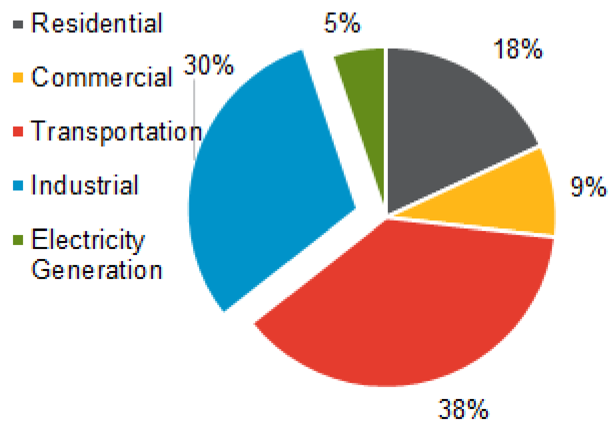
Figure 18: Commercial Fuels Energy Use Per Square Metre of Floor-Space



Data for Figure 18: Commercial Fuels Energy Use Per Square Metre of Floor-Space

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Energy Intensity (GJ/m2)	1.00	0.89	0.92	0.90	0.85	0.82	0.85	0.77	0.84	0.75	0.74

Figure 19: Industrial Fuel Demand - 2015

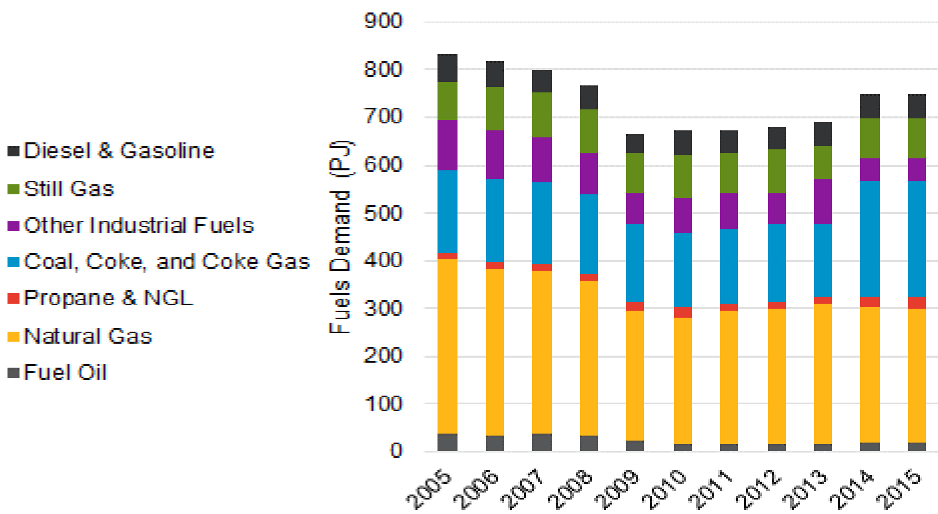


Data for Figure 19: Industrial Fuel Demand - 2015

Fuels Demand (PJ)	2015
Residential	447
Commercial	215

Transportation	927
Industrial	750
Electricity Generation	128

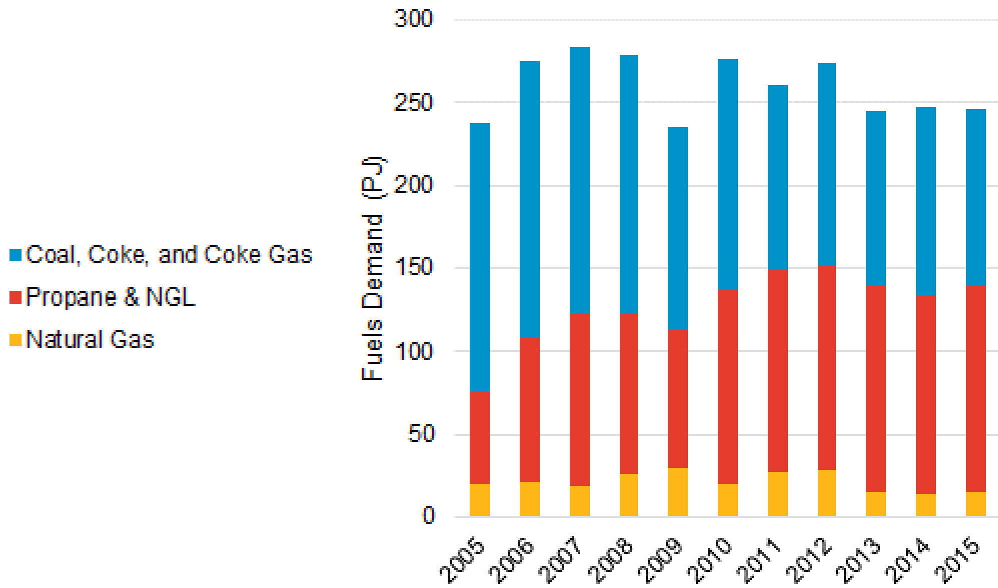
Figure 20: Industrial Energy Demand by Fuel Type: 2005-2015



Data for Figure 20: Industrial Energy Demand by Fuel Type: 2005-2015

Fuel	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Fuel Oil	39	36	39	34	22	15	17	15	16	20	20
Natural Gas	364	348	338	322	274	268	278	284	294	282	281
Propane & NGL	10	14	15	16	16	21	15	15	13	22	23
Coal, Coke, and Coke Gas	177	175	173	165	163	155	157	161	153	243	244
Other Industrial Fuels	102	102	93	88	67	73	73	68	94	47	47
Still Gas	81	89	94	92	83	89	86	90	69	84	85
Diesel & Gasoline	58	56	50	52	41	52	47	47	51	50	51

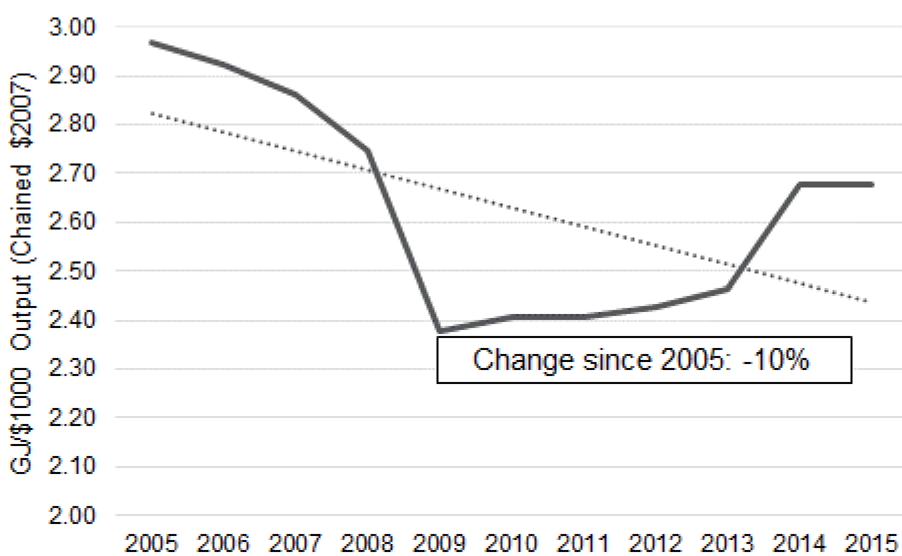
Figure 21: Non-Energy Industrial Demand by Type: 2005-2015



Data for Figure 21: Non-Energy Industrial Demand by Type: 2005-2015

Fuel	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Natural Gas	19	21	19	26	29	20	28	28	15	14	15
Propane & NGL	56	87	104	96	84	118	121	124	124	120	126
Coal, Coke, and Coke Gas	162	167	161	156	121	139	111	122	105	113	106

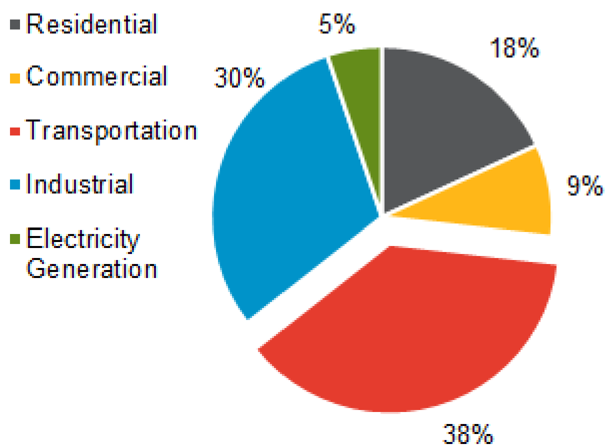
Figure 22: Industrial Fuels Energy Use Per $1,000 of Economic Output



Data for Figure 22: Industrial Fuels Energy Use Per $1,000 of Economic Output

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Industrial Energy Intensity (GJ/$1000)	2.97	2.92	2.86	2.74	2.38	2.40	2.41	2.43	2.46	2.68	2.68

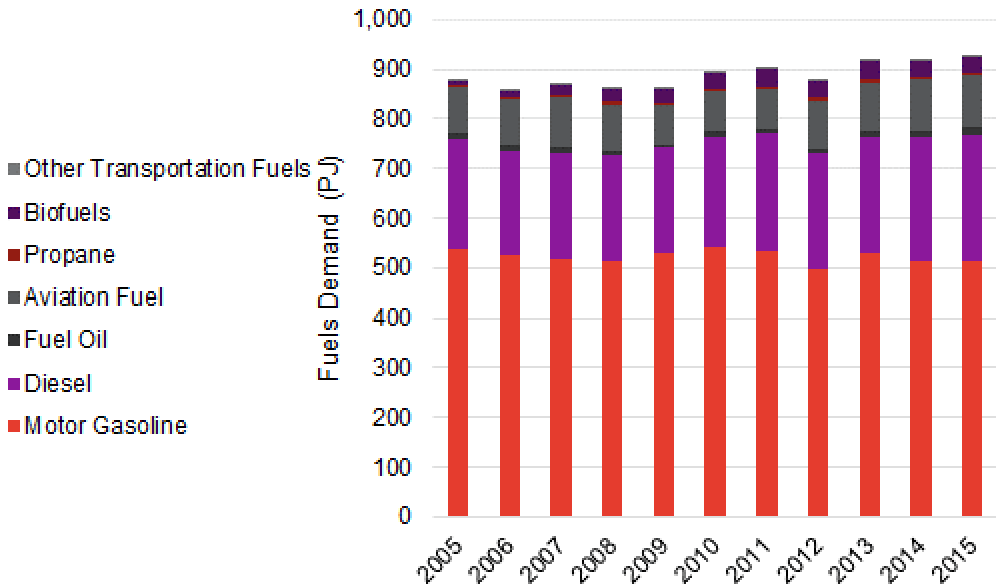
Figure 23: Transportation Energy Fuel Demand - 2015



Data for Figure 23: Transportation Energy Fuel Demand - 2015

Fuels Demand (PJ)	2015
Residential	447
Commercial	215
Transportation	927
Industrial	750
Electricity Generation	128

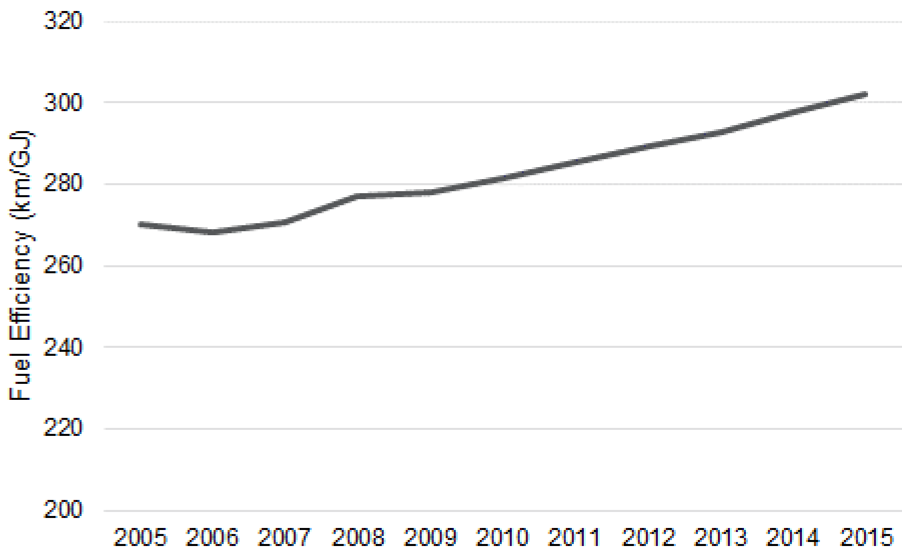
Figure 24: Transportation Demand by Fuel Type: 2005-2015



Data for Figure 24: Transportation Demand by Fuel Type: 2005-2015

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Motor Gasoline	536	524	518	512	532	540	533	498	531	515	514
Diesel	225	211	214	213	210	222	238	232	231	249	254
Fuel Oil	10	10	10	10	7	12	8	10	14	13	14
Aviation Fuel	93	93	101	94	79	81	80	95	99	102	105
Propane	4	5	6	6	5	6	7	8	6	5	5
Biofuels	7	12	22	26	27	31	34	35	35	33	33
Other Transportation Fuels	0	0	0	0	0	0	0	0	0	1	2

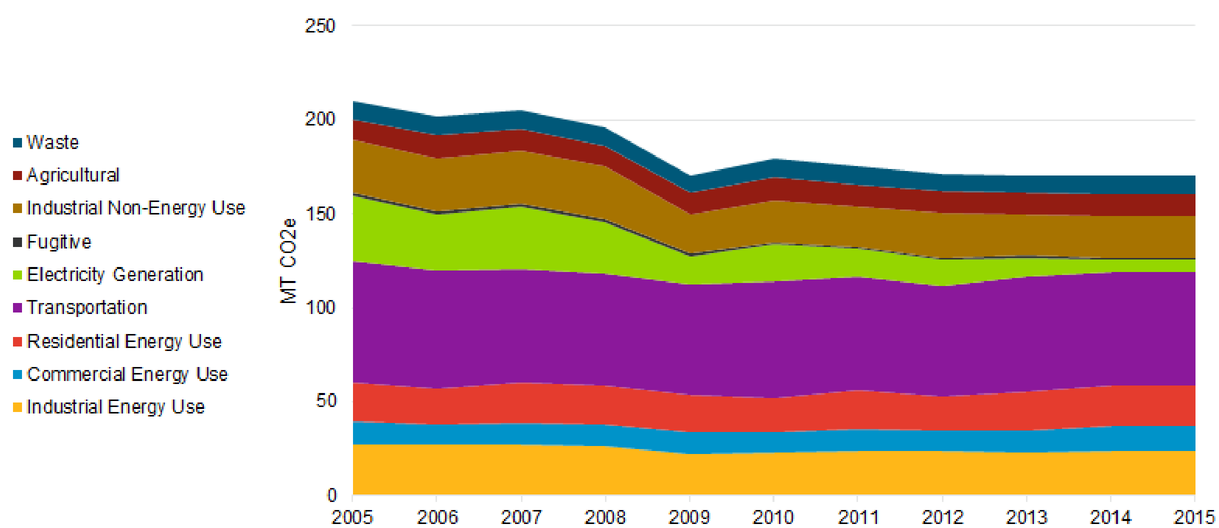
Figure 25: Light Duty Vehicle Efficiency Improvements – 2005 to 2015



Data for Figure 25: Light Duty Vehicle Efficiency Improvements – 2005 to 2015

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Light Duty Vehicle Efficiency (km/GJ)	270	268	271	277	278	281	285	289	293	298	302

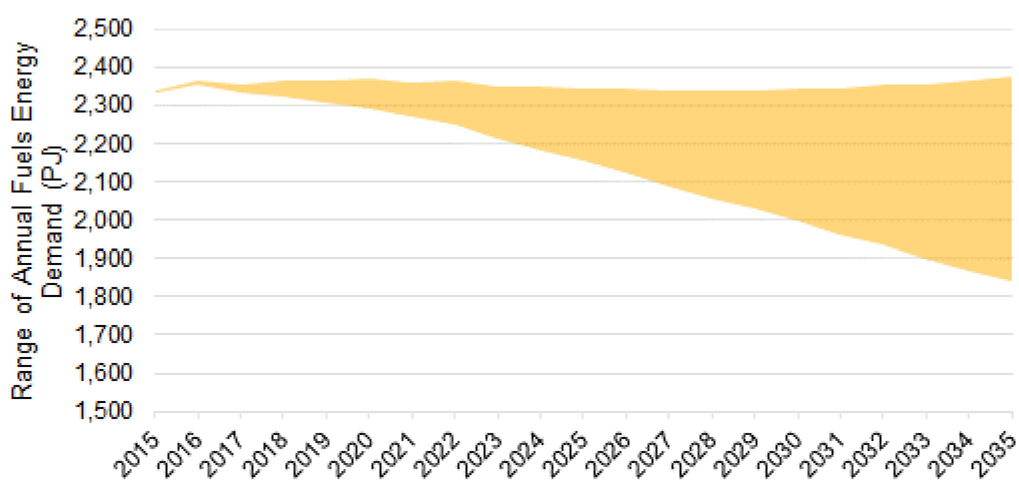
Figure 26: Historical Ontario GHG Emissions



Data for Figure 26: Historical Ontario GHG Emissions

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Industrial Energy Use	27	27	27	26	23	23	24	24	23	24	24
Commercial Energy Use	13	11	12	12	11	11	12	11	12	13	13
Residential Energy Use	21	19	21	21	20	19	21	18	20	22	22
Transportation	65	62	61	59	59	61	61	58	61	60	60
Electricity Generation	35	30	33	27	15	20	14	14	10	6	6
Fugitive	2	2	2	2	2	1	1	1	1	1	1
Industrial Non-Energy Use	28	29	28	28	21	23	21	23	22	22	22
Agricultural	11	12	11	11	11	12	12	12	12	12	12
Waste	10	10	10	10	10	9	10	10	9	9	9

Figure 27: Demand Uncertainty



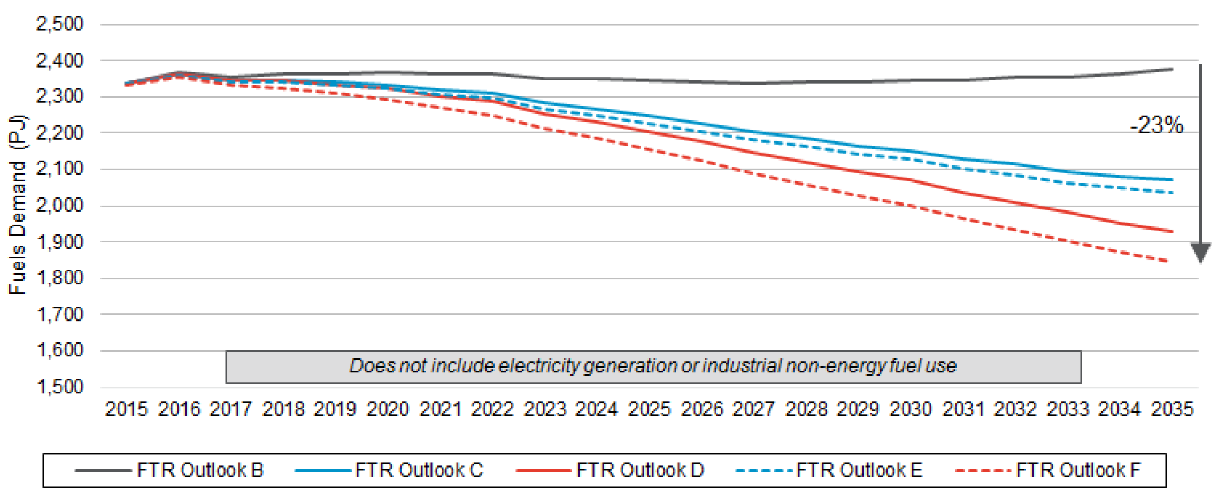
Data for Figure 27: Demand Uncertainty

Year	Lower Bound	Upper Bound
2015	2,334	2,338
2016	2,355	2,368
2017	2,333	2,354
2018	2,325	2,363

Year	Lower Bound	Upper Bound
2019	2,309	2,364
2020	2,293	2,369
2021	2,269	2,363
2022	2,249	2,364
2023	2,211	2,350
2024	2,185	2,351
2025	2,155	2,345
2026	2,122	2,343
2027	2,089	2,338
2028	2,058	2,339
2029	2,029	2,339
2030	2,000	2,347
2031	1,964	2,344
2032	1,935	2,353
2033	1,901	2,355
2034	1,870	2,364
2035	1,843	2,377

No quantitative data inform the graphic presented in Figure 28.

Figure 29: Five Fuels Energy Demand Outlooks

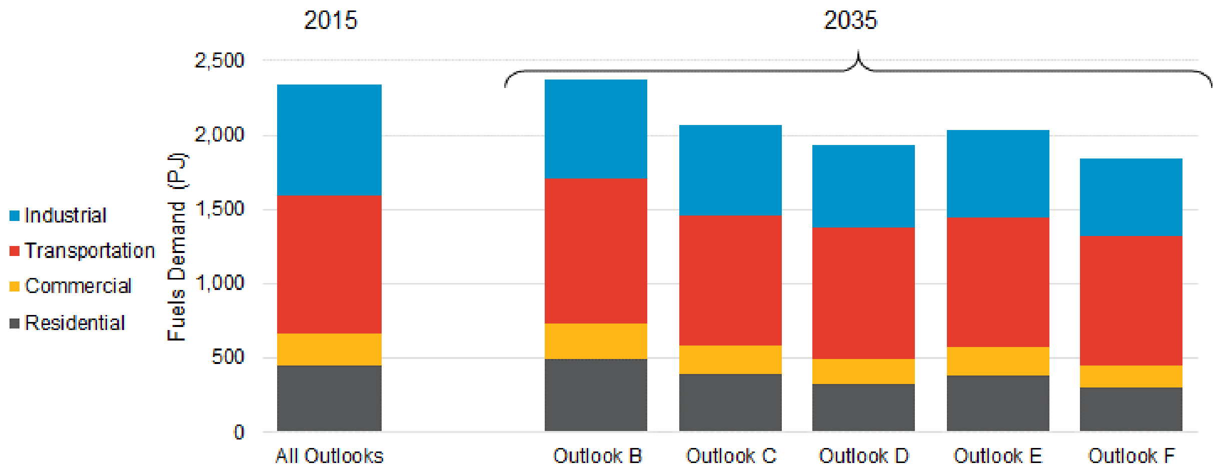


Data for Figure 29: Five Fuels Energy Demand Outlooks

Year	FTR Outlook B	FTR Outlook C	FTR Outlook D	FTR Outlook E	FTR Outlook F
2015	2,338	2,338	2,338	2,336	2,334
2016	2,368	2,363	2,363	2,360	2,355

Year	FTR Outlook B	FTR Outlook C	FTR Outlook D	FTR Outlook E	FTR Outlook F
2017	2,354	2,346	2,346	2,342	2,333
2018	2,363	2,347	2,344	2,341	2,325
2019	2,364	2,341	2,333	2,332	2,309
2020	2,369	2,334	2,322	2,324	2,293
2021	2,363	2,319	2,302	2,307	2,269
2022	2,364	2,310	2,287	2,296	2,249
2023	2,350	2,282	2,254	2,266	2,211
2024	2,351	2,266	2,231	2,249	2,185
2025	2,345	2,246	2,206	2,228	2,155
2026	2,343	2,225	2,177	2,205	2,122
2027	2,338	2,205	2,147	2,183	2,089
2028	2,339	2,185	2,121	2,162	2,058
2029	2,339	2,165	2,095	2,141	2,029
2030	2,347	2,153	2,069	2,127	2,000
2031	2,344	2,129	2,037	2,102	1,964
2032	2,353	2,115	2,011	2,086	1,935
2033	2,355	2,093	1,981	2,064	1,901
2034	2,364	2,080	1,954	2,049	1,870
2035	2,377	2,070	1,931	2,037	1,843

Figure 30: Sectoral Breakdown of Energy Demand by Outlook, 2015 vs 2035

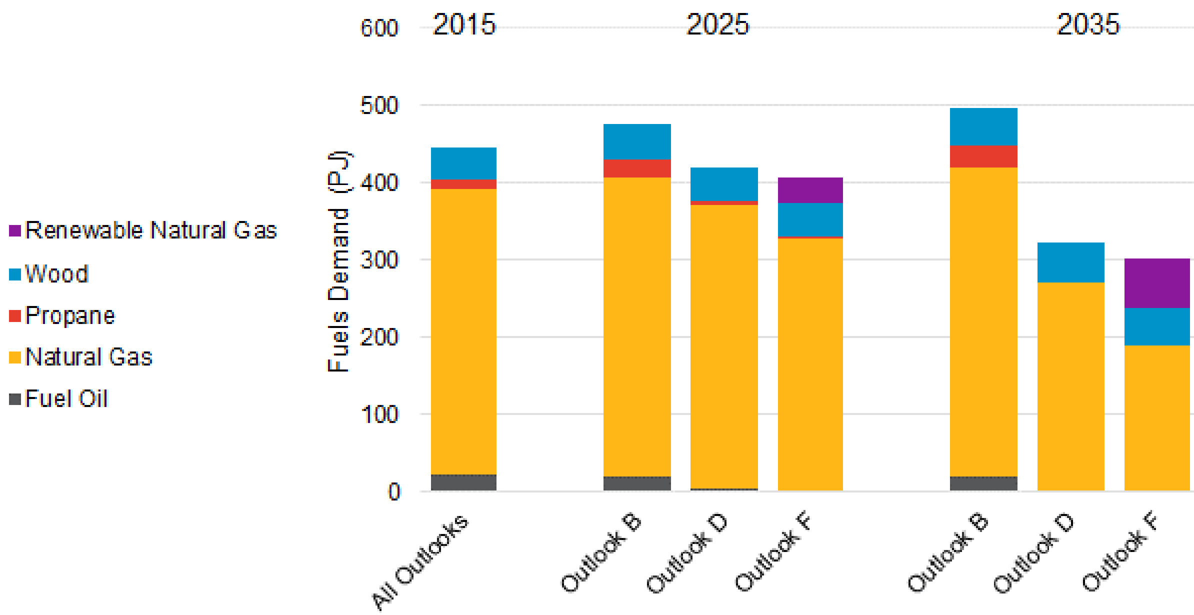


Data for Figure 30: Sectoral Breakdown of Energy Demand by Outlook, 2015 vs 2035

Energy (PJ)	2015	B 2035	C 2035	D 2035	E 2035	F 2035
Residential	447	498	388	322	381	303
Commercial	215	233	192	177	187	147

Transportation	927	975	883	883	878	874
Industrial	750	671	607	550	591	519

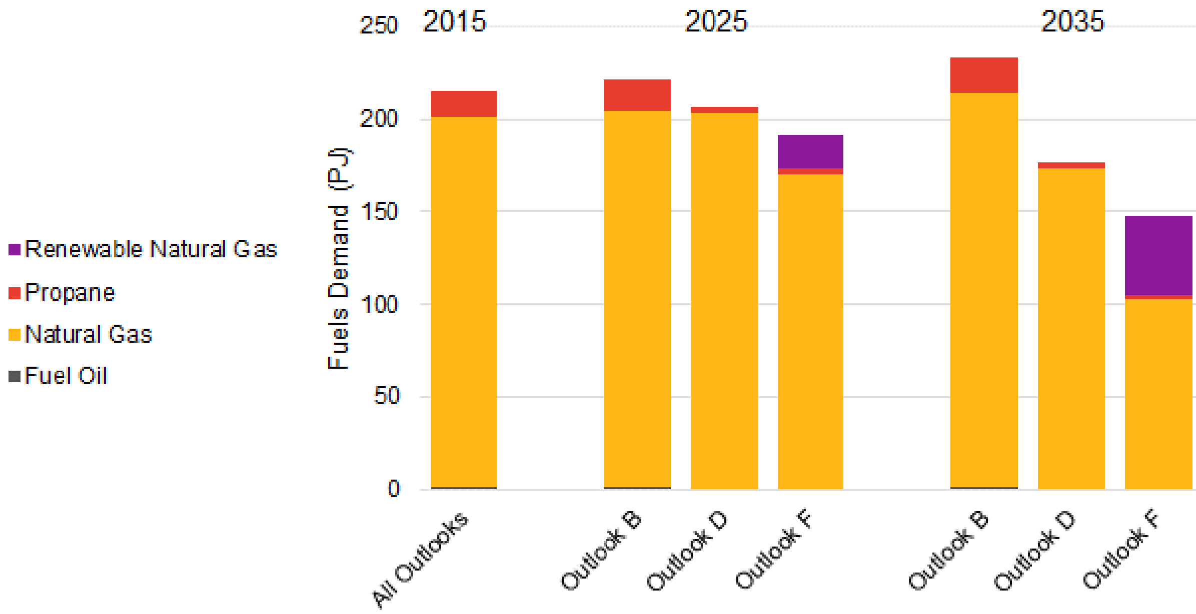
Figure 31: Residential Outlook



Data for Figure 31: Residential Outlook

	2015	2025			2035		
	All Outlooks	Outlook B	Outlook D	Outlook F	Outlook B	Outlook D	Outlook F
Fuel Oil	24	19	4	4	21	1	0
Natural Gas	369	388	368	324	400	270	188
Propane	13	24	4	3	28	0	0
Wood	41	45	45	44	50	50	49
Renewable Natural Gas	0	0	0	34	0	0	66

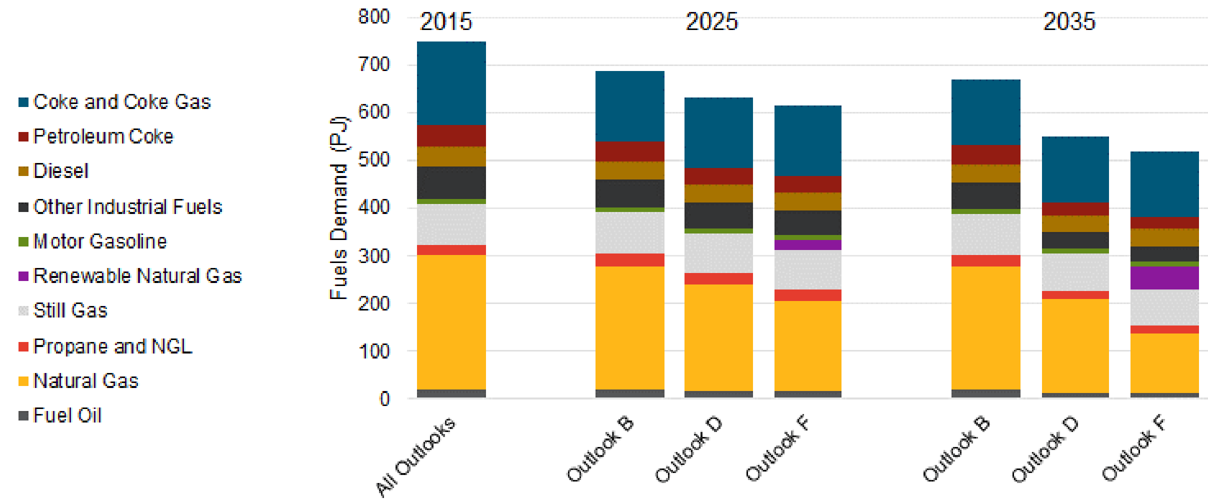
Figure 32: Commercial Outlook



Data for Figure 32: Commercial Outlook

	2015	2025			2035		
	All Outlooks	Outlook B	Outlook D	Outlook F	Outlook B	Outlook D	Outlook F
Fuel Oil	2	1	0	0	1	0	0
Natural Gas	200	203	203	170	213	173	103
Propane	13	16	3	3	19	4	3
Renewable Natural Gas	0	0	0	19	0	0	42

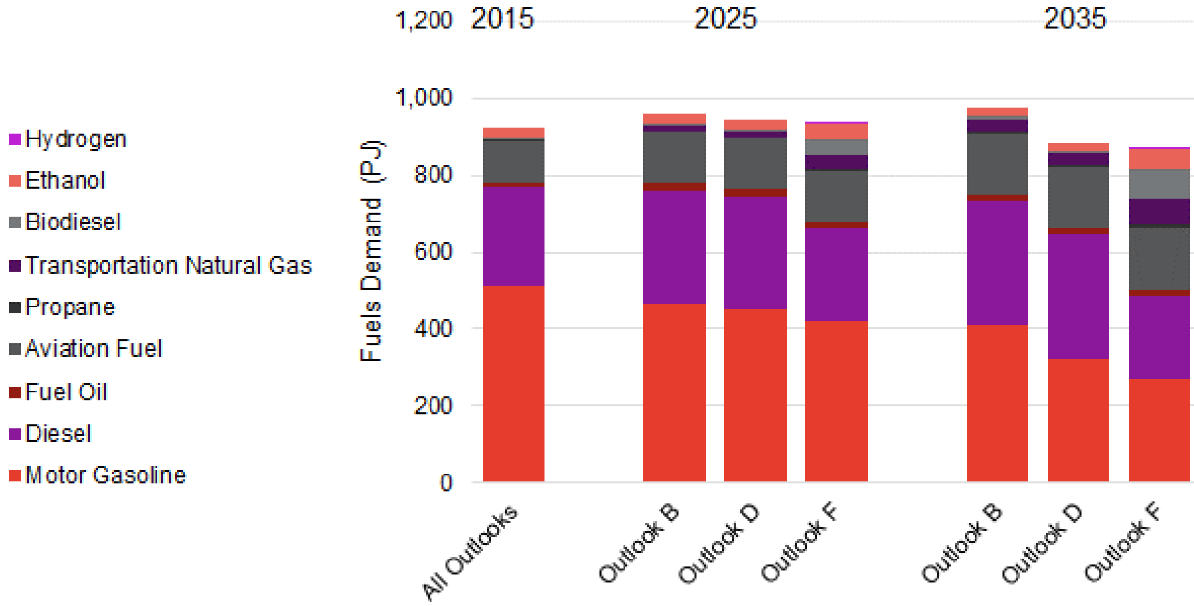
Figure 33: Industrial Outlook



Data for Figure 33: Industrial Outlook

	2015	2025			2035		
	All Outlooks	**B**	**D**	**F**	**B**	**D**	**F**
Fuel Oil	20	19	16	16	19	13	13
Natural Gas	281	260	224	190	260	195	124
Propane and NGL	23	25	24	24	24	19	19
Still Gas	85	85	84	81	85	79	74
Renewable Natural Gas	0	0	0	20	0	0	48
Motor Gasoline	10	10	10	10	10	10	10
Other Industrial Fuels	71	59	53	53	57	33	33
Diesel	40	38	37	37	37	36	36
Petroleum Coke	45	42	38	37	41	27	26
Coke and Coke Gas	175	147	147	147	138	138	138

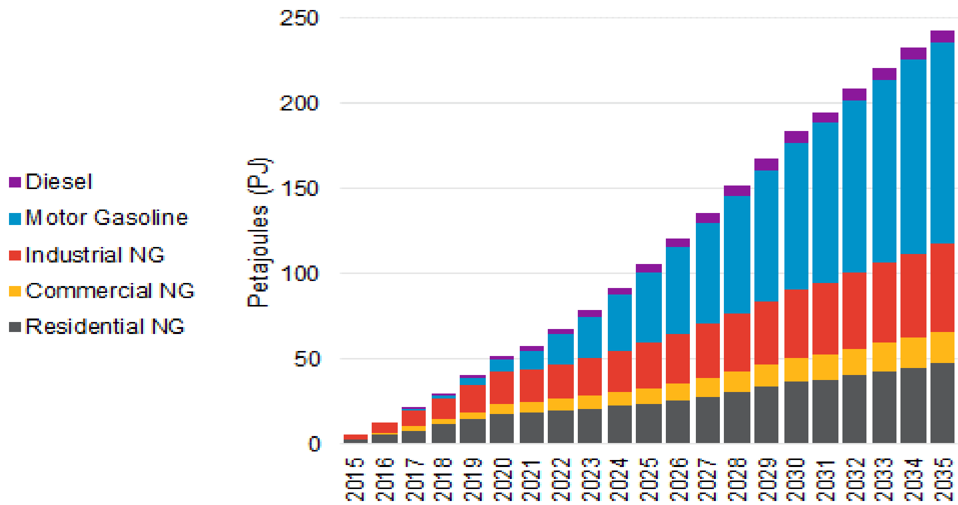
Figure 34: Transportation Outlook



Data for Figure 34: Transportation Outlook

	2015	2025			2035		
	All Outlooks	**B**	**D**	**F**	**B**	**D**	**F**
Motor Gasoline	514	467	451	422	408	323	272
Diesel	254	295	295	238	326	322	217
Fuel Oil	14	16	16	16	16	16	16
Aviation Fuel	105	134	134	134	159	159	159
Propane	5	5	5	9	4	4	11
Transportation Natural Gas	2	13	13	33	33	33	67
Biodiesel	5	6	6	43	7	7	77
Ethanol	28	25	25	40	22	19	49
Hydrogen	0	0	0	4	0	0	7

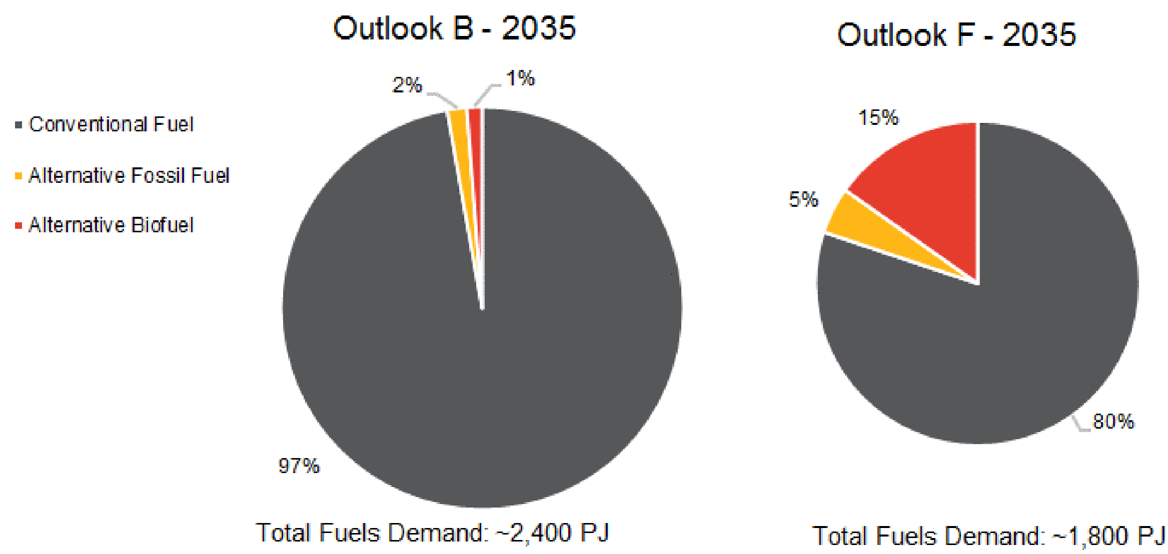
Figure 35: Conservation Achievement and Outlook to 2035 (Outlook B)



Data for Figure 35: Conservation Achievement and Outlook to 2035 (Outlook B)

Year	Residential NG	Commercial NG	Industrial NG	Motor Gasoline	Diesel
2015	3	1	3	0	0
2016	6	2	6	0	0
2017	8	2	9	1	0
2018	12	3	12	2	1
2019	15	5	16	4	2
2020	18	6	19	7	2
2021	19	6	18	11	3
2022	20	7	20	17	3
2023	21	7	22	24	4
2024	23	8	25	32	4
2025	24	9	27	41	5
2026	26	10	29	51	5
2027	28	11	32	59	6
2028	31	12	34	69	6
2029	34	13	37	77	6
2030	37	14	40	86	6
2031	38	15	42	93	7
2032	41	16	45	101	7
2033	43	17	47	107	7
2034	45	17	50	113	7
2035	47	18	52	118	7

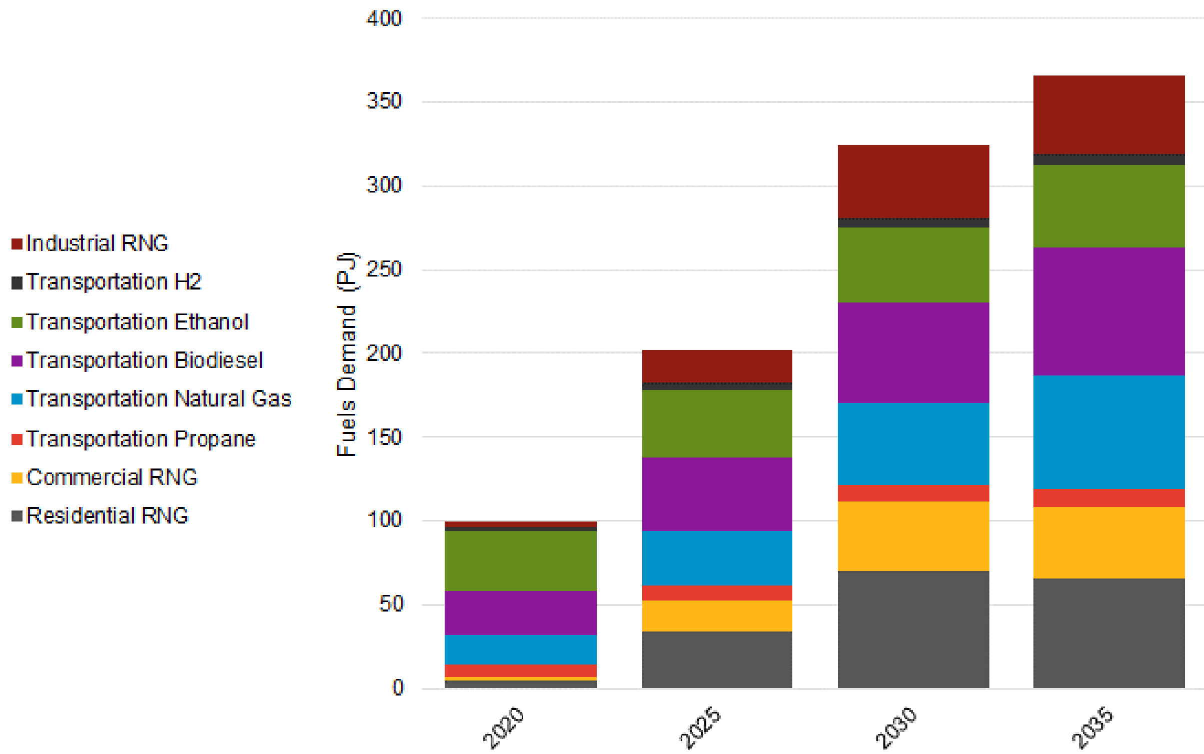
Figure 36: Alternative Fuels in 2035 – Outlook B and F



Data for Figure 36: Alternative Fuels in 2035 – Outlook B and F

Fuel	Outlook B	Outlook F
Conventional Fuel	2,310	1,477
Alternative Fossil Fuel	37	85
Alternative Biofuel	29	281
Total	2,377	1,843

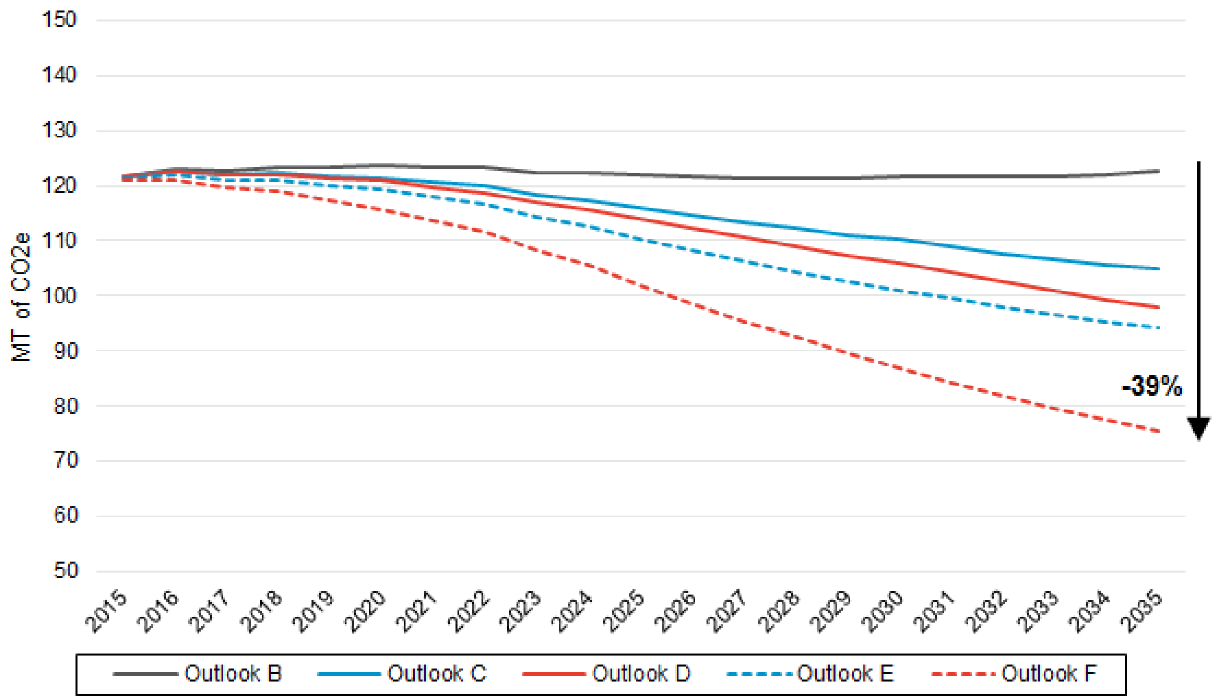
Figure 37: Outlook F Alternative Fuel Breakdown



Data for Figure 37: Outlook F Alternative Fuel Breakdown

Fuel	2020	2025	2030	2035
Residential RNG	4	34	69	66
Commercial RNG	2	19	42	42
Transportation Propane	8	9	10	11
Transportation Natural Gas	17	33	49	67
Transportation Biodiesel	26	43	60	77
Transportation Ethanol	36	40	44	49
Transportation H2	3	4	6	7
Industrial RNG	3	20	44	48

Figure 38: Fuels Combustion GHG Emissions Outlook

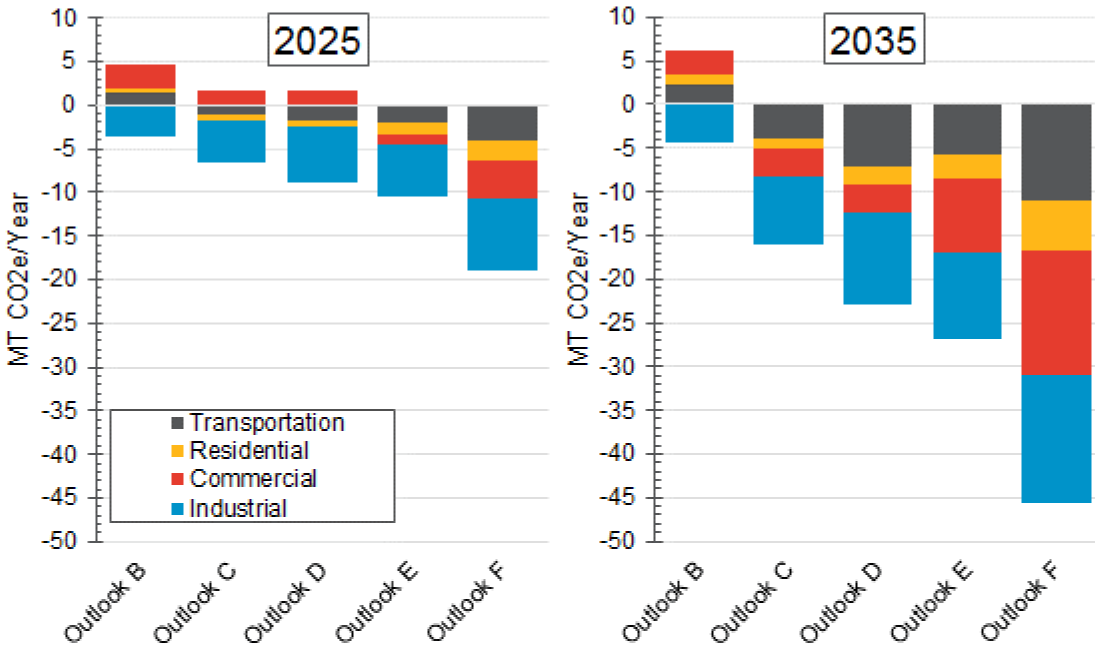


Data for Figure 38: Fuels Combustion GHG Emissions Outlook

MT of CO2e	Outlook B	Outlook C	Outlook D	Outlook E	Outlook F
2015	122	122	122	121	121
2016	123	123	123	122	121
2017	123	122	122	121	120
2018	123	122	122	121	119
2019	123	122	121	120	117
2020	124	122	121	119	116
2021	123	121	120	118	114
2022	123	120	119	117	112
2023	123	118	117	114	108
2024	122	117	116	113	106
2025	122	116	114	110	102
2026	122	115	112	108	99
2027	121	113	111	106	95
2028	121	112	109	104	92
2029	121	111	107	103	90
2030	122	110	106	101	87
2031	122	109	104	99	84

MT of CO2e	Outlook B	Outlook C	Outlook D	Outlook E	Outlook F
2032	122	108	103	98	82
2033	122	106	101	96	80
2034	122	106	99	95	77
2035	123	105	98	94	75

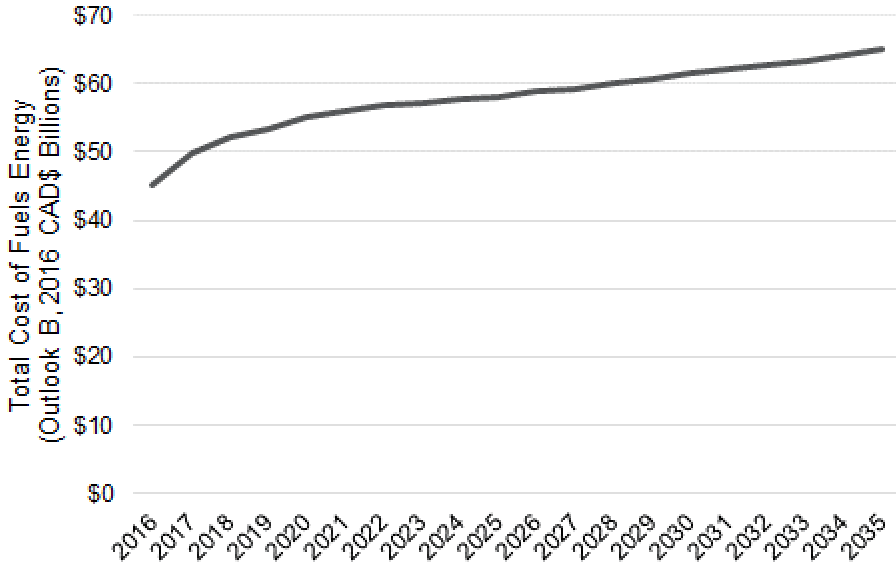
Figure 39: Emissions Relative to 2014 Levels



Data for Figure 39: Emissions Relative to 2014 Levels

	2025					2035				
	B	C	D	E	F	B	C	D	E	F
Transportation	1	-1	-2	-2	-4	2	-4	-7	-6	-11
Residential	0	-1	-1	-1	-2	1	-1	-2	-3	-6
Commercial	3	2	2	-1	-4	3	-3	-3	-9	-14
Industrial	-4	-5	-6	-6	-8	-4	-8	-11	-10	-15

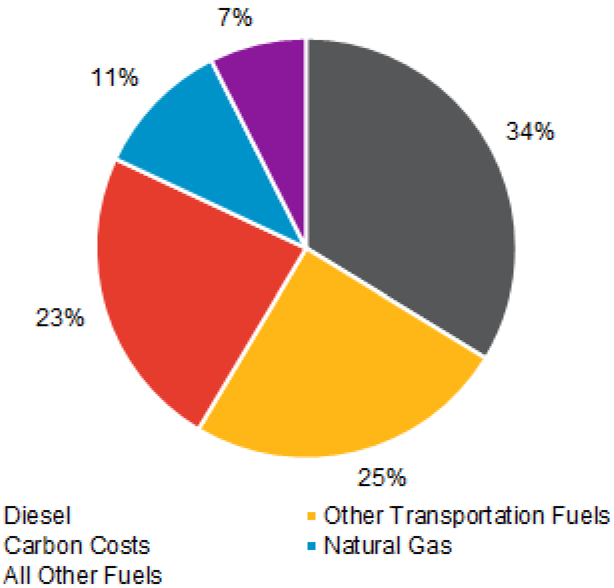
Figure 40: Total Cost of Fuels for Energy in Outlook B



Data for Figure 40: Total Cost of Fuels for Energy in Outlook B

2016 Billion CAD$	Outlook B
2016	$45
2017	$50
2018	$52
2019	$53
2020	$55
2021	$56
2022	$57
2023	$57
2024	$58
2025	$58
2026	$59
2027	$59
2028	$60
2029	$61
2030	$62
2031	$62
2032	$63
2033	$63
2034	$64
2035	$65

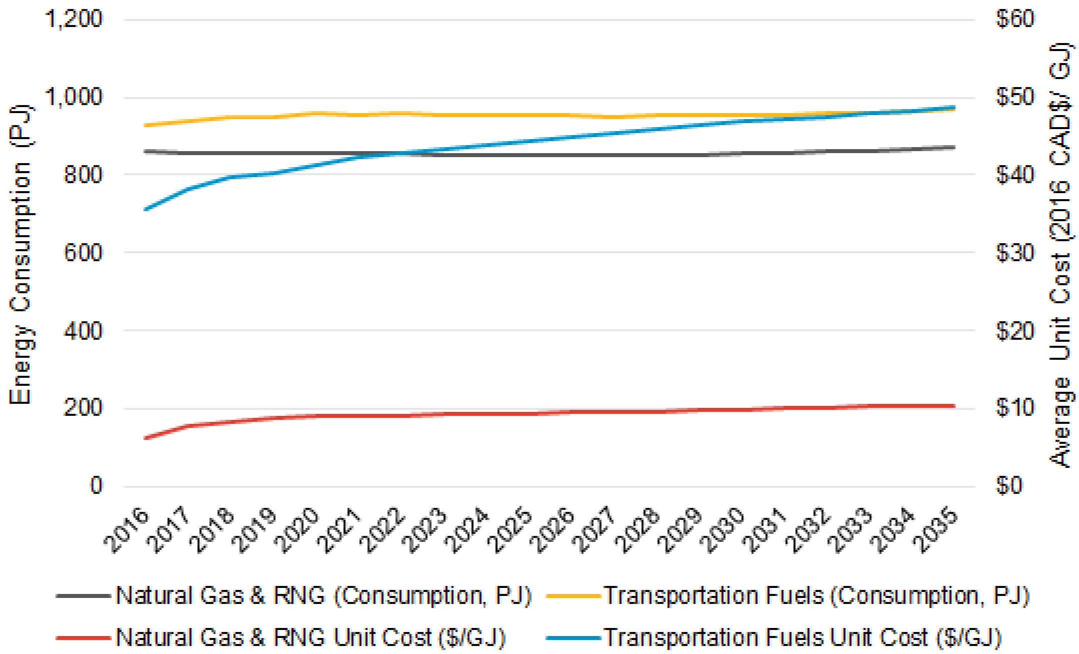
Figure 41: Drivers of System Cost Increases 2016 to 2035



Data for Figure 41: Drivers of System Cost Increases 2016 to 2035

	Total Cost Change (2016 Bill Cad$)			
	2016	**2035**	**Delta**	**%**
All Other Fuels	26	28	1	7%
Carbon Costs	0	5	5	23%
Other Transportation Fuels	3	7	5	25%
Diesel	11	18	7	34%
Natural Gas	5	8	2	11%

Figure 42: Average Unit Cost of Natural Gas and Transportation Fuels in Outlook B

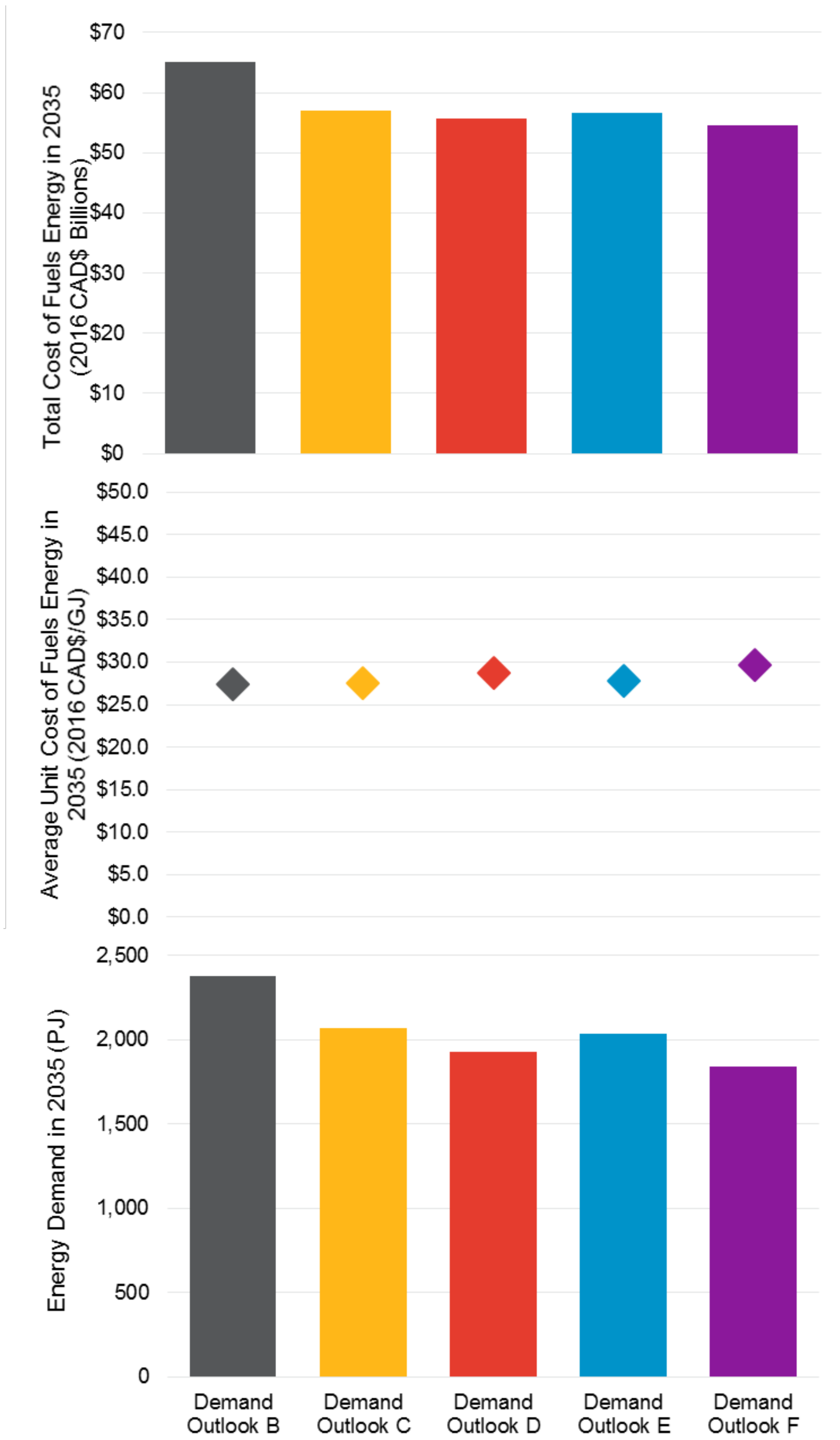


Data for Figure 42: Average Unit Cost of Natural Gas and Transportation Fuels in Outlook B

Year	Natural Gas & RNG (Consumption, PJ)	Transportation Fuels (Consumption, P	Natural Gas & RNG Unit Cost ($/GJ)	Transportation Fuels Unit Cost ($/GJ)
2016	862	938	$6	$36
2017	854	945	$8	$38
2018	857	956	$8	$40
2019	856	960	$9	$41
2020	858	966	$9	$41
2021	855	965	$9	$42
2022	856	967	$9	$43
2023	851	964	$9	$43
2024	853	964	$9	$44
2025	852	961	$9	$44
2026	852	962	$10	$45
2027	850	959	$10	$45
2028	852	961	$10	$46
2029	853	960	$10	$46
2030	857	963	$10	$47
2031	857	963	$10	$47
2032	861	966	$10	$48
2033	863	967	$10	$48

Year	Natural Gas & RNG (Consumption, PJ)	Transportation Fuels (Consumption, P	Natural Gas & RNG Unit Cost ($/GJ)	Transportation Fuels Unit Cost ($/GJ)
2034	866	971	$10	$48
2035	873	975	$10	$49

Figure 43: Cost of Fuels Energy Across Demand Outlooks


Total Cost of Fuels Energy in 2035 (2016 CAD$ Billions)
$70
$60
$50
$40
$30
$20
$10
$0
Average Unit Cost of Fuels Energy in 2035 (2016 CAD$/GJ)
$50.0
$45.0
$40.0
$35.0
$30.0
$25.0
$20.0
$15.0
$10.0
$5.0
$0.0
Energy Demand in 2035 (PJ)
2,500
2,000
1,500
1,000
500
0
Demand Outlook B
Demand Outlook C
Demand Outlook D
Demand Outlook E
Demand Outlook F

Data for Figure 43: Cost of Fuels Energy Across Demand Outlooks

2035	Demand Outlook B	Demand Outlook C	Demand Outlook D	Demand Outlook E	Demand Outlook F
Total Cost (2016 CAD$ Billions)	$65	$57	$56	$57	$55
Unit Cost (2016 CAD/$GJ)	$27.3	$27.5	$28.8	$27.8	$29.6
Energy Demand (PJ)	2,377	2,070	1,931	2,037	1,843

FTR Module 1

Module 1: Additional Information about Fuels Supply

Prepared for:

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September, 2016

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TABLE OF CONTENTS

1. MODULE 1 - ADDITIONAL INFORMATION ABOUT FUELS AND SUPPLY

This module provides additional information about the different fuels discussed in the body of the FTR and their respective supply chains:

- Natural Gas;
- Propane;
- Oil Products;
- Wood and biomass; and
- Alternative fuels.

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Each section of the module contains a discussion of fuel group-specific:

- Supply and production sources;
- Delivery;
- Trends; and
- Capacity sufficiency.

The level of detail and discussion varies for each fuel group, reflecting the variability in the characteristics of the fuels and the supply chains for each of the different fuels.

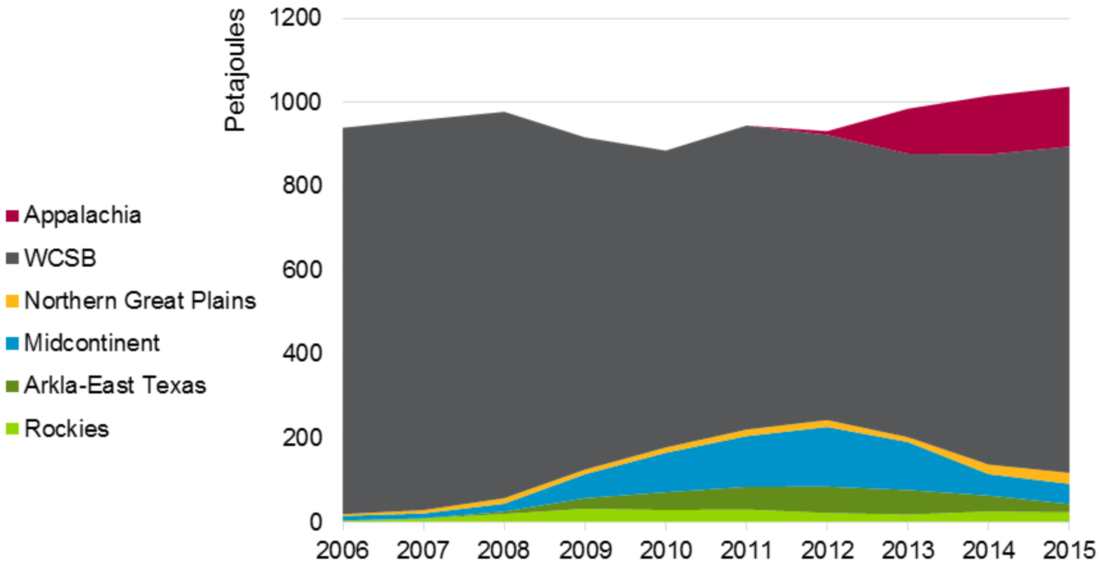
1.1 Natural Gas

1.1.1 Supply Sources

Historically, natural gas supplies to Ontario have been sourced primarily from the Western Canadian Sedimentary Basin (WCSB) located in Alberta, Saskatchewan and British Columbia. Over the last five years however, Ontario has been increasingly supplied by natural gas basins located in the US. Recent developments in shale gas extraction have led to conventional supplies being displaced by natural gas moving north from shale resources in the Appalachian Basin (i.e., extending over the states of New York, Pennsylvania, Maryland, Ohio, West Virginia, Virginia, Kentucky, Tennessee and Alabama) in the US.

Figure 1 below illustrates this shift.

Figure 1: Ontario Natural Gas Supply by Source



Source: Navigant's North America Natural Gas Market Outlook, Spring 2016; RBAC

As discussed further in the delivery section below, Ontario has pipeline connections to multiple North American natural gas supply basins.

Natural gas imports from the Appalachian Basin (which includes the Utica and Marcellus shales) tend to be concentrated at Niagara Falls, which was converted into an import point in November 2012. Interest in accessing Appalachian Basin supplies is driven by economics. Since the Appalachian Basin is closer to Ontario than is Western Canada, supply from the Appalachian Basin can have a lower delivered cost into Ontario than Western Canadian supply, leading to increased viable competition.

Of note, the total natural gas energy supplied to Ontario in 2015 (over 1,000 petajoules) is equivalent to approximately twice the amount of electric energy consumed by the province in that year.

1.1.2 Delivery

Overview

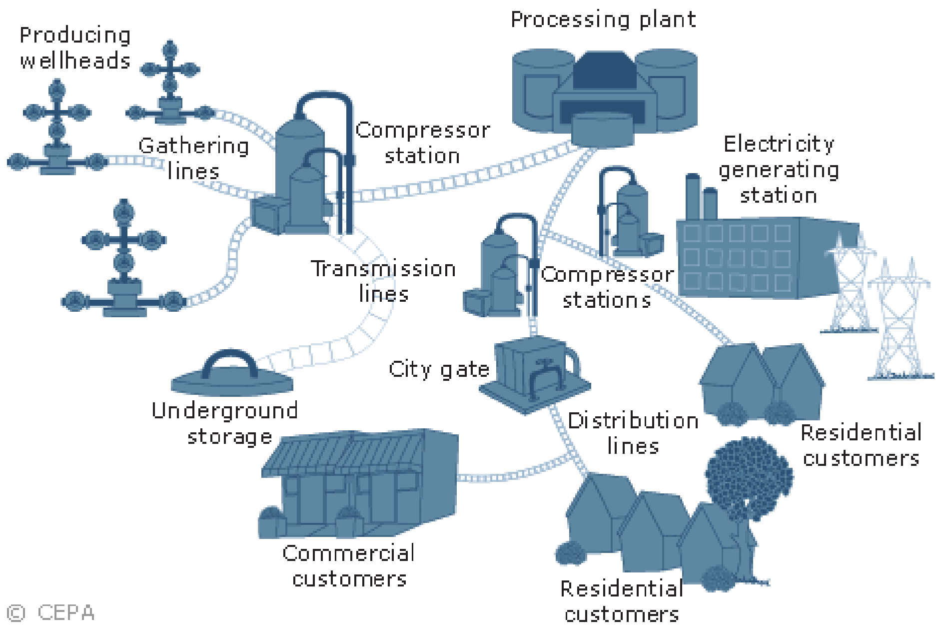
Natural gas is moved across Canada and between Canada and the US along a complex system of pipelines.

Natural gas is transported from its source (producing wellheads) along gathering pipelines to processing facilities. Processing facilities remove impurities from the natural gas to ensure the product meets pipeline specifications; some processing plants also extract natural gas liquids (e.g., ethane, propane, butane) for resale. From here, the processed product may move long distances via transmission pipelines. For Canadian pipelines, the National Energy Board (NEB) regulates companies that own and/or operate interprovincial or international pipelines (both natural gas and liquids pipelines).

Often, natural gas is placed into underground storage so it can be delivered regionally to market during periods of peak demand (e.g., winter heating season).

Once closer to its destination, product is transferred to distribution lines, which are operated by local distribution companies. Ontario local distribution companies are regulated by the Ontario Energy Board (OEB). It is these distribution lines (and feeder lines) that move the gas from the transmission system to the customer burner tip. Compressors, located at stations spaced at regular intervals along the pipeline, are used to regulate the pipeline pressure that transports the natural gas. Figure 2 illustrates the natural gas delivery network.

Figure 2: Natural Gas Delivery



Source: Canadian Energy Pipeline Association (CEPA), 2016.[1]

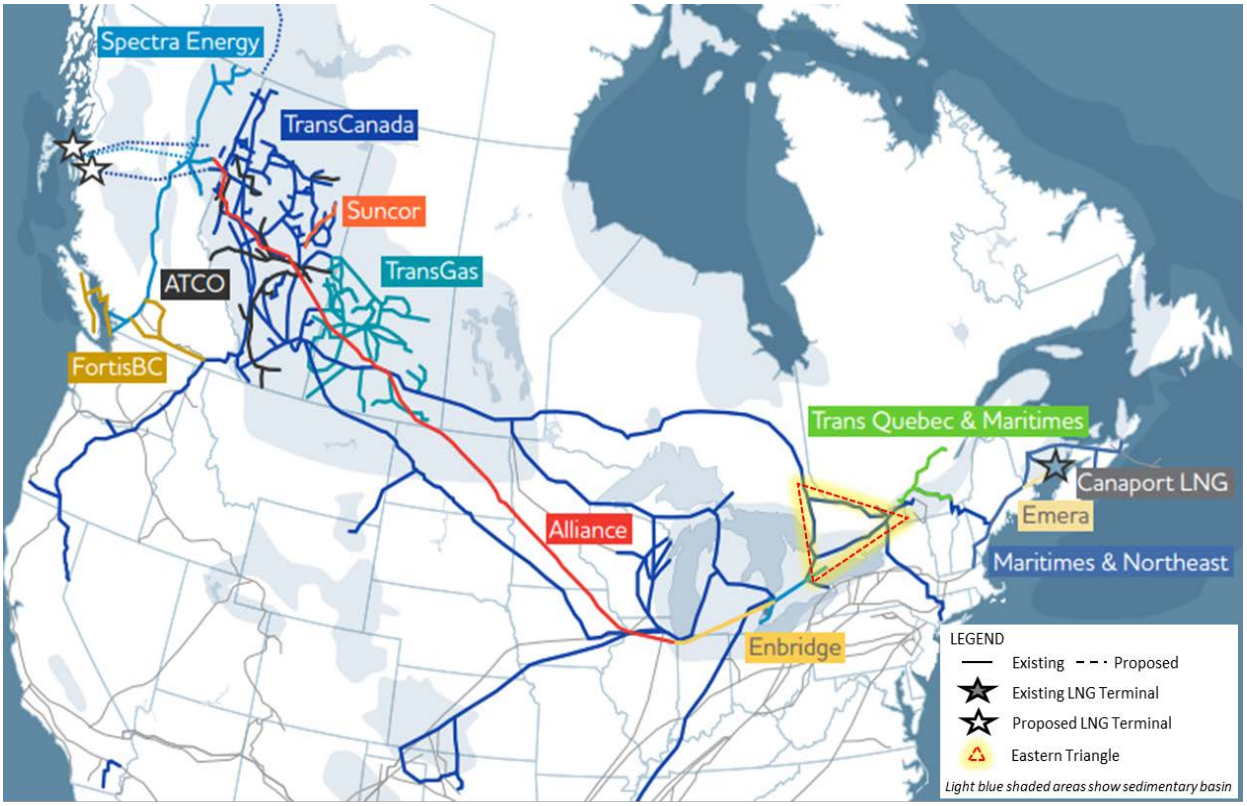
Transmission (Pipelines)

As discussed earlier in the report, Ontario relies on natural gas produced outside of the province to meet its needs.

The longest natural gas pipeline system in Canada is the TransCanada Mainline which extends from the Prairies across Canada, passing north of the Great Lakes and into Southern Ontario. This system transports natural gas from the Alberta/Saskatchewan border and the Ontario/US border to serve eastern Canada and the US. The TransCanada Mainline consists of multiple lines along its route. The “Eastern Triangle” segment of the Mainline extends from North Bay, to the southeast and southwest, supplying the Ontario, Quebec, and export markets. The TransCanada Mainline, the Eastern Triangle, and other major pipelines are illustrated in Figure 3 below. The Ontario “Eastern Triangle” is highlighted in this map with a red dashed line.

[1] Canadian Energy Pipeline Association, *the Natural Gas Delivery Network*. Accessed June, 2016. http://www.cepa.com/about-pipelines/types-of-pipelines/natural-gas-pipelines

Figure 3: Natural Gas Pipelines



Source: Canadian Energy Pipeline Association, 2016.[2]

While TransCanada owns the Eastern Triangle, Union Gas Ltd owns the transmission pipeline between the Dawn Hub (near Sarnia) and Parkway (a delivery point that connects with TransCanada's Eastern Triangle). This pipeline connects the key gas pricing hub and storage at Dawn with the TransCanada pipeline to the northeast, and US markets to the south. This Union Gas transmission pipeline is located entirely within Ontario and is regulated by the Ontario Energy Board.

Distribution

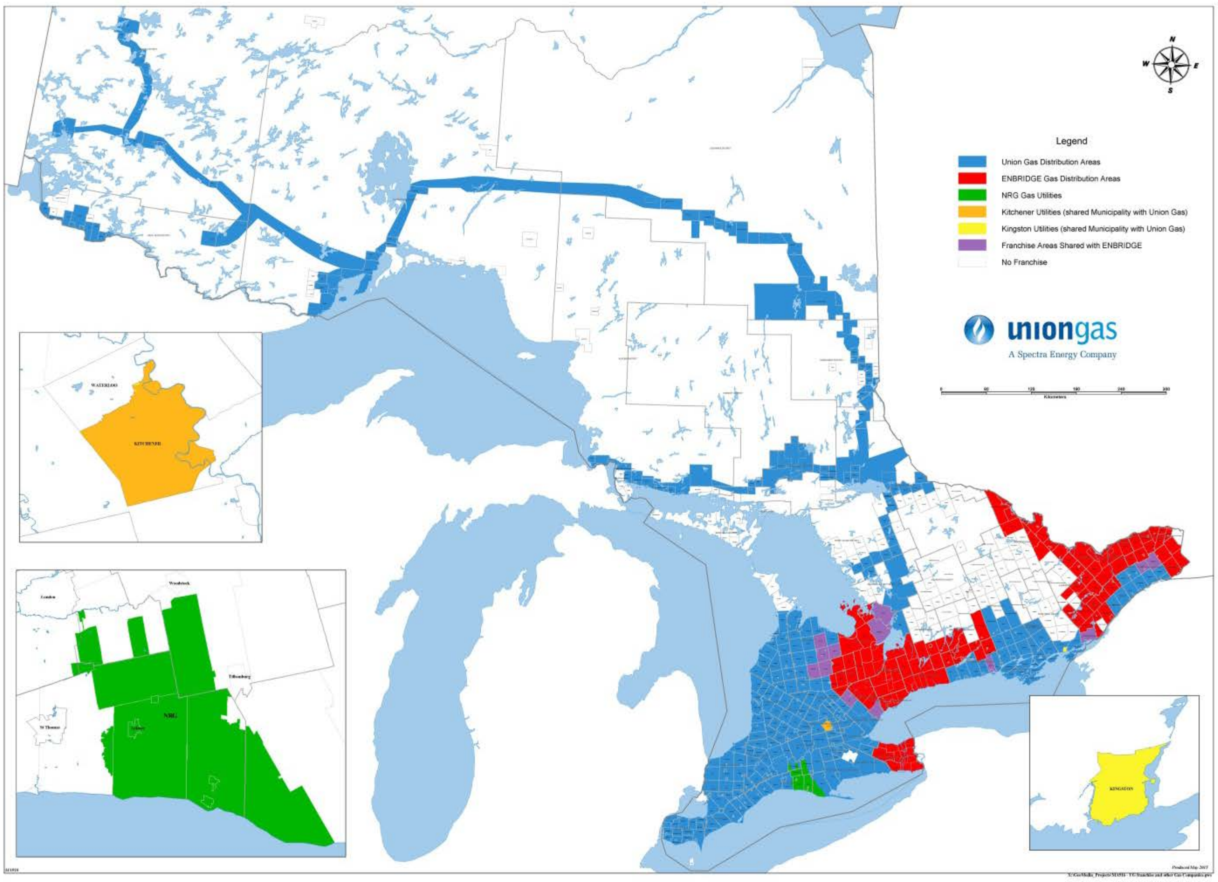
Ontario's regulated local distribution companies have franchise agreements with municipalities across the province. A franchise agreement allows a local distribution company to provide service and must be approved by the OEB. Investor owned local distribution companies are regulated by the OEB in Ontario (**Note**: Two municipalities, Kitchener and Kingston, provide gas service in their own service territory and are not regulated by the OEB).

[2] Canadian Energy Pipeline Association (CEPA), Liquids Pipelines Maps. Accessed June, 2016. http://www.cepa.com/map/pdf/ng-cepa2014.pdf

Municipalities with franchise agreements are generally located adjacent to major natural gas transmission infrastructure. Coverage in southern Ontario, the GTA and eastern Ontario (near Ottawa) is quite good.

Similarly, communities in northern Ontario located near the TransCanada pipeline system also have franchise agreements (**Note:** that not all areas in a municipality with a franchise agreement would necessarily have gas service. For instance, it may not be economically viable for a distribution company to connect to some customers in rural and remote areas).

Figure 4: Ontario Gas Distribution Franchise Areas



Source: Union Gas

Communities without a franchise agreement do not currently have natural gas access. These communities are typically rural or remote communities located some distance from natural gas transmission infrastructure.

The Government of Ontario has publicly announced its intention to support the expansion of natural gas access to more areas of the province[3]. Two programs, led by the Ministry of Infrastructure are in development: a Natural Gas Access Loan of up to $200 million over two years to help communities

[3]Ministry of Energy Mandate Letter, September 2014. https://www.ontario.ca/page/2014-mandate-letter-energy

partner with utilities to extend access to natural gas supplies; and a $30 million Natural Gas Economic Development Grant to accelerate projects with clear economic development potential.

On February 17, 2015, the Minister of Energy wrote the OEB requesting it move forward on a timely basis to examine opportunities to facilitate access to natural gas services to more communities and to ensure the rational expansion of the natural gas transmission and distribution system in Ontario.

Storage

The Dawn Hub is the major trading hub in Ontario, and in Canada, providing direct access to major supply basins in North America. Western Canadian natural gas can access Dawn using the TransCanada system to the Manitoba/US border and then the Great Lakes Gas Transmission line to southwestern Ontario. Dawn is also supplied by the Alliance-Vector pipeline system, which originates in northeastern BC and passes through Chicago. Other, smaller, U.S. pipeline systems also connect to Dawn.

Over 100 companies actively trade at Dawn, and it is located near the largest natural gas storage facilities in Canada. Storage capacity at the Dawn Hub is 272 billion cubic feet (bcf), split between Enbridge (112 bcf[4]) and Union (160 bcf[5]). These storage facilities are used by the Ontario, Quebec and U.S. gas utilities and other gas users manage seasonal demand. The Dawn hub is located near the southern tip of Ontario in Sarnia.

1.1.3 Trends

Starting in 2008, North American natural gas supply prospects changed dramatically, from impending scarcity to an era of growing production and supply abundance. The high prices and volatility of the preceding decade encouraged the development of shale gas resources. Prior to that development, shale gas was known to exist in many areas, but was largely uneconomic to develop. The effectiveness and cost of horizontal drilling and hydraulic fracturing, two previously known technologies that had not yet been employed together, improved to the point where unconventional production could be grown to unprecedented levels.

As discussed earlier, significant increases in shale gas production have occurred in the Marcellus and Utica shale. The development of shale gas has spurred interest in increasing Ontario's access to this resource. As shown below, these resources are located in the Appalachian region proximate to Ontario. At this time, there does not appear to be commercially exploitable shale gas resources in Ontario.

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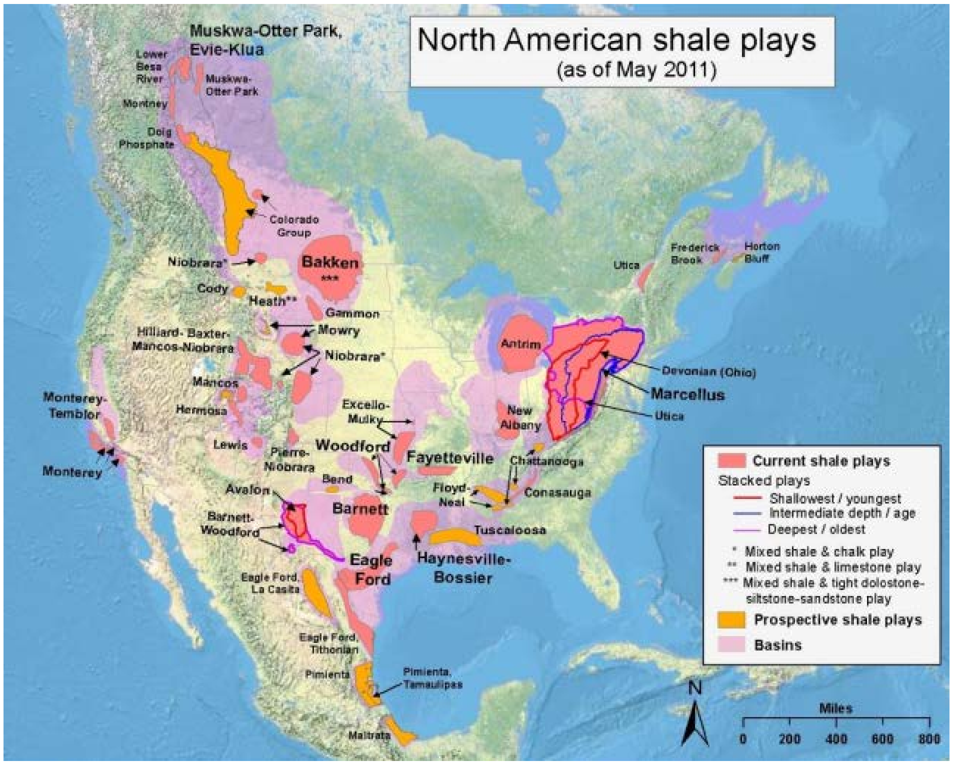
[4] Enbridge Gas Distribution, *Gas Storage and Enbridge Gas Distribution*, accessed September 2016 https://www.enbridgegas.com/about/gas-storage/

[5] Spectra Energy, *Dawn Hub – Union Gas, a business unit of Spectra Energy, offers a growing storage and transportation business to and from the Dawn Hub*, accessed September 2016 http://www.spectraenergy.com/Operations/Canadian-Natural-Gas-Operations/Storage/Dawn-Hub/

Figure 5: North American Shale Gas and Shale Oil Resources



Source: US Energy Information Administration based in data from various published studies. Canada and Mexico plays from ARI.

Another trend in Ontario is interest from rural and remote communities to access natural gas. The OEB recently conducted a Generic Hearing to review the regulatory options to increase access to natural gas.

1.1.4 Capacity Sufficiency

Current natural gas supply and delivery capacity is sufficient to meet peak demand. Substantial amounts of shale gas remain unextracted. The large storage facilities at Dawn increase flexibility and ensure gas is supplied year round and during peak seasons stabilizing prices throughout the year.

1.2 Propane

Although not consumed in the same volume as natural gas or refined petroleum products such as motor gasoline and diesel fuel, propane is a key part of Ontario's combustible fuel mix. Propane consumption is niche-driven, often serving as a stable, economically transportable alternative to natural gas in rural and remote areas.

1.2.1 Supply Sources

Ontario demand for propane and other natural gas liquids was over 50 PJ in 2015.

Since propane is extracted from natural gas, significant quantities are imported into Ontario from Western Canada and other continental sources by rail.

Only 1% of propane used in Canada in 2013 was imported[6], with almost all of the propane used in Ontario produced in Canada. Since most propane produced in Canada (85-90%)[7] is produced by processing natural gas, Canadian propane supply is predominantly from regions that also dominate in terms of natural gas production (i.e., Western Canada).

However, unlike natural gas, Ontario does have domestic propane production sources. Ontario's four petroleum refineries produce propane and an industrial facility in Sarnia-Lambton (called a "fractionator") processes a pipeline delivered NGL-mix into products such as propane, butane and ethane for the Ontario and regional market.

1.2.2 Delivery

Propane reaches end-users by a complex distribution network.

Propane is a natural gas liquid (NGL) that is extracted at natural gas processing facilities. Propane is also a by-product of the petroleum refining process.

Propane produced in Western Canada can be delivered to Ontario distribution terminals by rail.

Alternatively, propane can be produced at Ontario petroleum refineries. This production method uses the infrastructure in the oil products supply chain. Similarly, the fractionator facility in Sarnia that produces propane is supplied with NGLs that are transported using part of the pipeline infrastructure that supplies Ontario's refineries.

Within Ontario, propane is delivered to end users by truck. About 140 large propane distribution facilities are located in Ontario. These facilities may be supplied by truck or (for larger facilities) by rail and have above-ground propane storage tanks.

Propane can also be stored underground in salt caverns and depleted production wells. Typically, propane is injected into storage in summer months and withdrawn from storage in winter months. Ontario uses storage infrastructure in the Sarnia-area to manage seasonal demand. The Sarnia area is a key propane storage hub in eastern North America and is used to manage propane demand by end-users in Ontario, Quebec and the eastern U.S.

The propane delivery network and supply chain is illustrated below:

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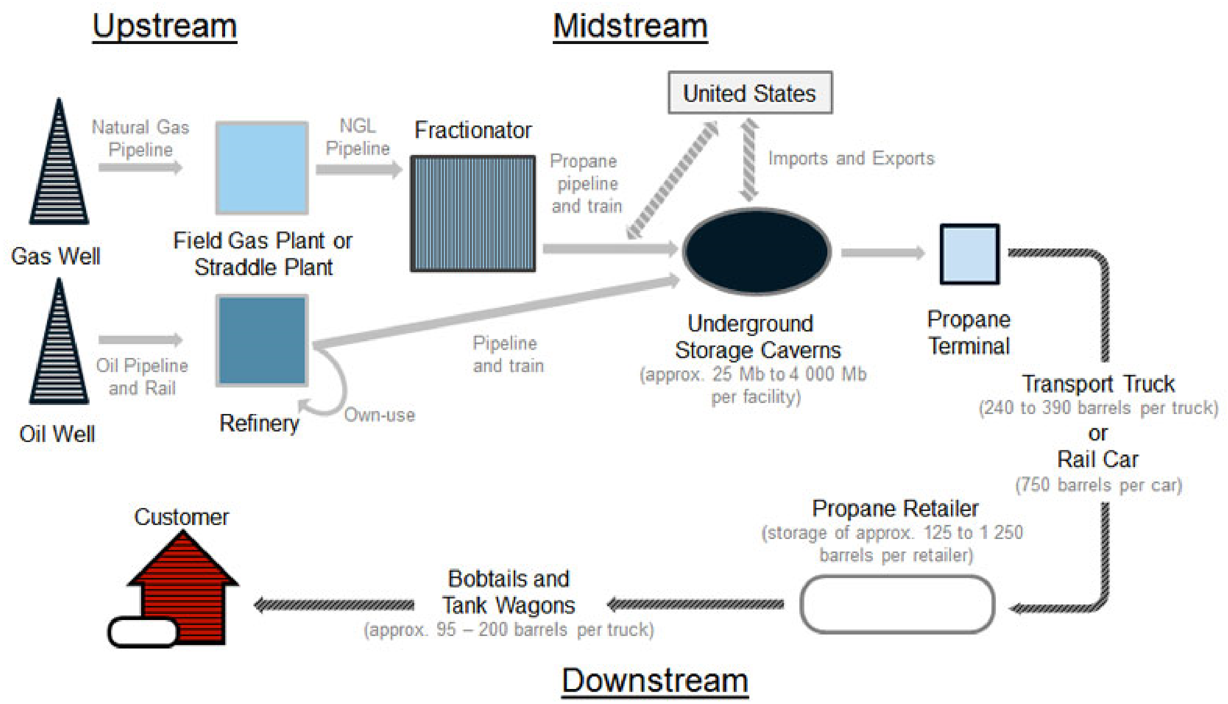
[6] Gas Processing Management Inc. Prepared for the Canadian Propane Association, *Canadian Propane Market Review*, October 2014

[7] National Energy Board and Competition Bureau, *Propane Market Review – Final Report*, April 2014

http://www.nrcan.gc.ca/energy/crude-petroleum/15927

Figure 3.2

Figure 6: Propane Delivery Network



Source: NRCan[8]

1.2.3 Trends

Propane demand in Canada has grown in recent years, partly driven by the growing use of propane for residential heating in Ontario. Ontario consumes more propane for home heating than the rest of Canada combined, and residential propane consumption for heating has grown steadily since 2005.[9]

1.2.4 Capacity Sufficiency

As primarily a by-product of natural gas, propane availability in North America is closely tied to North American natural gas production.

Consequently, U.S. propane supply is expected to grow significantly; while this surplus is expected to mostly flow overseas as exports, the growing U.S. surplus may provide some additional relief in times of very high demand in Canada and the U.S.[10]

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[8] National Energy Board, *Propane Market Review: 2016 Update – Energy Briefing Note,* May 2016 https://www.neb-one.gc.ca/nrg/sttstc/ntrlgslqds/rprt/2016/2016prpn-eng.html#s10

[9] National Energy Board and Competition Bureau, *Propane Market Review – Final Report*, April 2014 http://www.nrcan.gc.ca/energy/crude-petroleum/15927

Figure 3.2

[10] National Energy Board and Competition Bureau, *Propane Market Review – Final Report*, April 2014, http://www.nrcan.gc.ca/energy/crude-petroleum/15927, Conclusions, Section 8.7

1.3 Oil Products

Unlike natural gas, the oil products supply chain contains an additional intermediate step- petroleum refining. Petroleum refineries process crude oil into finished oil products such as gasoline, diesel and jet fuel.

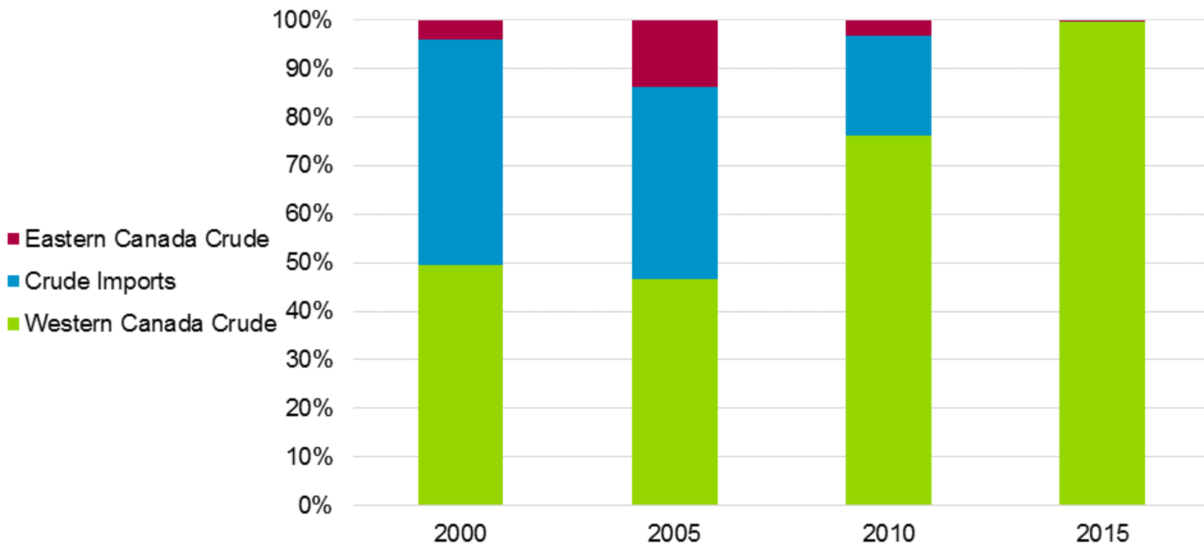
This sub-section discusses supply chain considerations for both crude oil and oil products.

1.3.1 Supply Sources

Crude Oil

Ontario produces only minor amounts of crude oil – less than 0.08% of total Canadian production in 2015.[11] Ontario's crude oil imports, previously evenly split between Canadian and international sources are now drawn almost exclusively from western Canada, as illustrated in Figure 7. Crude oil is delivered to Ontario refineries by pipeline.

Figure 7: Ontario Crude Oil Supply by Source



Source: Statistics Canada[12]

Oil Products

The provincial demand for the primary oil products used as fuels: (i.e., excluding petrochemical feedstocks and asphalt) is illustrated in Figure 8. Similar to natural gas, Ontario's total use of oil products

---

[11] Canadian Association of Petroleum Producers, *Technical Report: Statistical Handbook for Canada's Upstream Petroleum Industry*, May 2016

http://www.capp.ca/publications-and-statistics/publications/275430

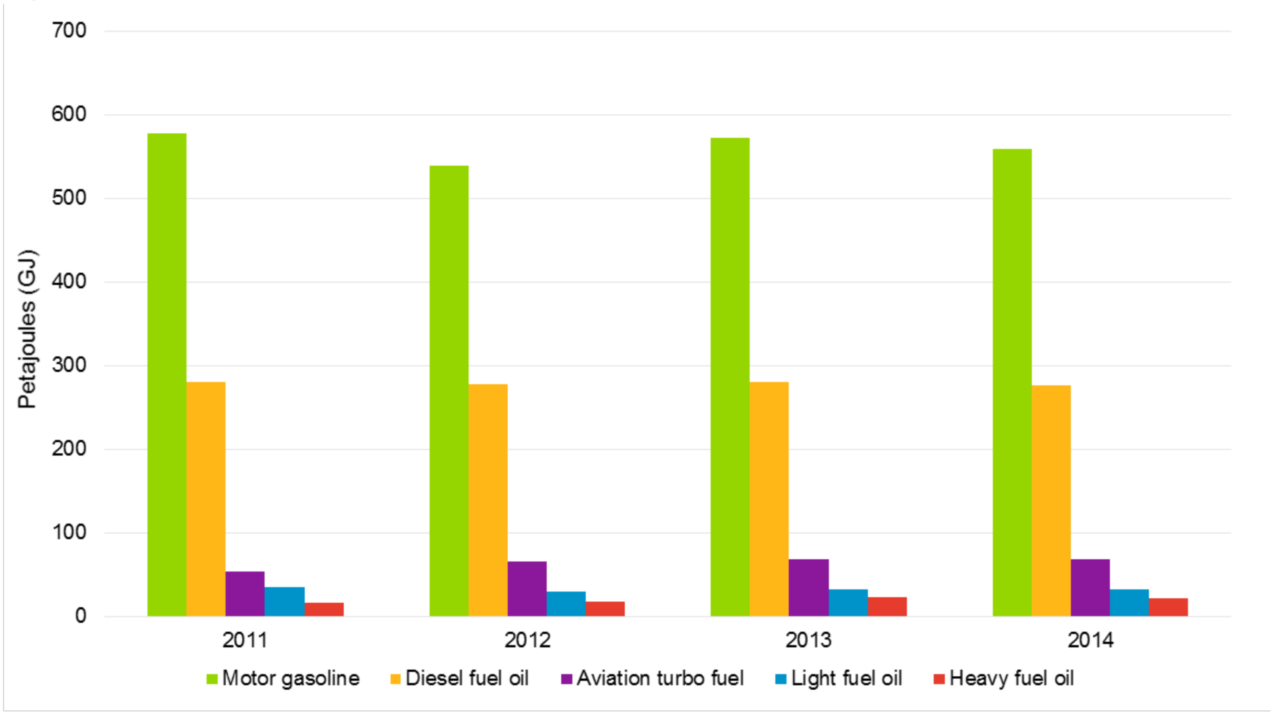
[12] Statistics Canada, Table 134-0001: Refinery Supply of Crude Oil and Equivalent, Annual

http://www5.statcan.gc.ca/cansim/a26?lang=eng&id=1340001

as fuels is close to 1,000 PJ annually. (i.e., roughly equivalent to approximately twice the amount of electric energy consumed by the province in a year).

Gasoline, diesel and jet fuel are common transportation fuels. Light fuel oil incorporates fuels used for home heating as defined by Statistics Canada – this category includes all distillate fuels for power burners, heating oil number 2, heating oil number 3, furnace fuel oil, gas oil and light industrial fuel. Heavy fuel oil would primarily relate to fuels used in industrial processes – as defined by Statistics Canada it includes fuel oils numbers 4/5/6 and residual fuel oil.

Figure 8: Oil Product Provincial Demand, 2011 - 2014[13]



Source: Statistics Canada[14]

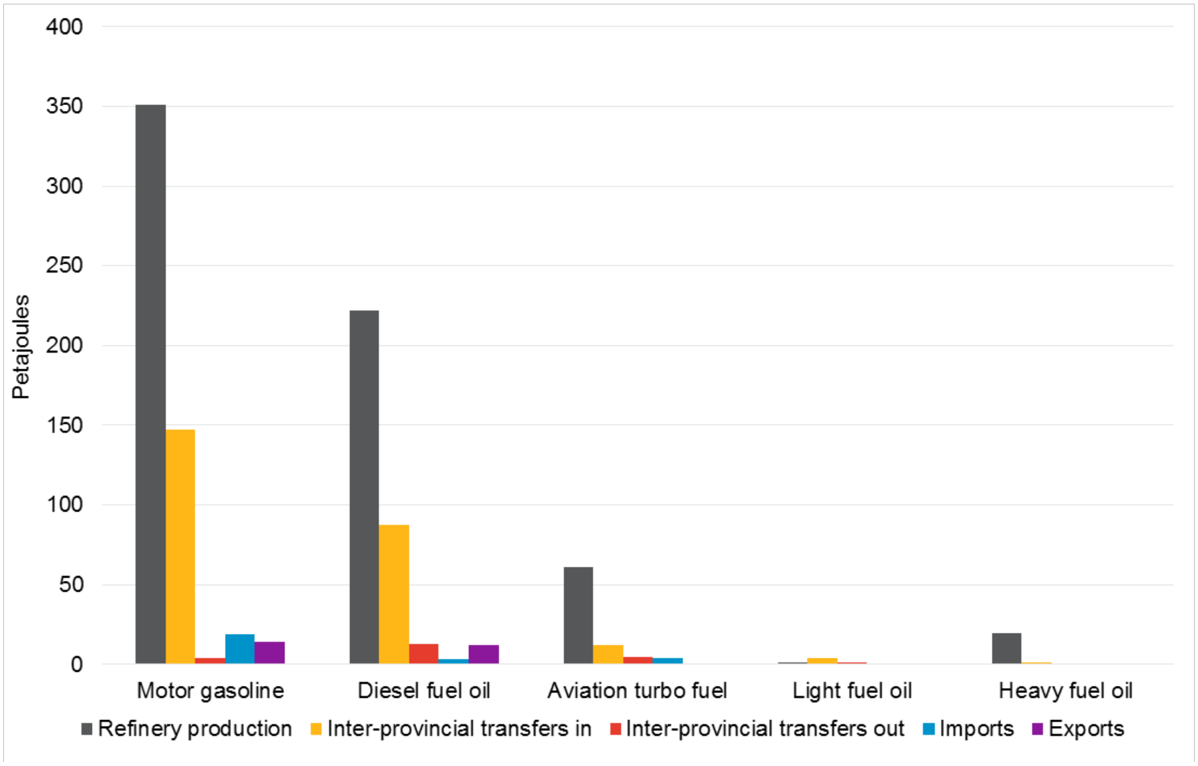
Ontario refiners produce the majority of oil products used in Ontario, but do not produce enough oil products to supply Ontario's total demand. The province relies on out-of-province supply to fully satisfy demand, primarily supplied from Quebec. Given Ontario's reliance on imports, price and supply conditions in the overall North American market are key factors impacting the province.

As illustrated in Figure 9, below, Ontario's domestic production of oil products at refineries is supplemented by transfers-in from other provinces and imports.

[13] Series unavailable for 2015.

[14] Statistics Canada, CANSIM Table 128-0017. Retrieved 2016
http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=1280017&tabMode=dataTable&srchLan=-1&p1=-1&p2=9

Figure 9: Supply and Disposition of Refined Petroleum Products – Ontario 2015[15]



Source: Statistics Canada[16]

Overview

Oil products reach end users by a complex infrastructure network.

Gathering lines move crude oil from the production wells to oil batteries (or storage tanks), and smaller diameter feeder lines transport crude oil from the batteries to nearby refineries or pipeline terminals. Crude oil that is transported to Ontario from across the country travels via long-haul transmission pipelines. For Canadian pipelines, the National Energy Board (NEB) regulates companies that own and/or operate interprovincial or international pipelines (both natural gas and liquids pipelines). Crude oil can also be transported by other modes, such as rail, marine and truck.

Once at a refinery, crude oil is processed into a variety of oil products. Oil products are then transported by pipeline, rail, marine and truck to end-users and distribution terminals. From primary distribution terminals, oil products are typically delivered to the final distribution point (e.g., gas station) by truck.

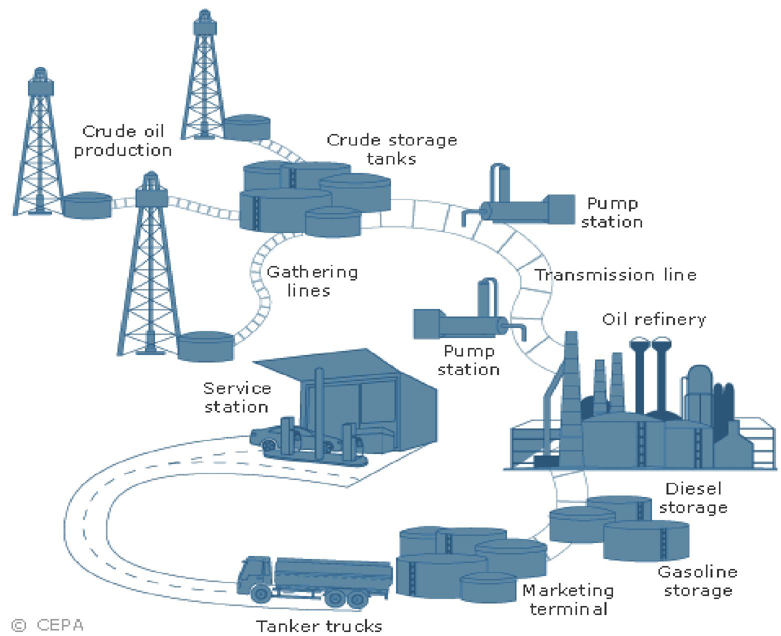
---

[15] Data presented in this table is the average monthly series available from Statistics Canada, converted to an annual value. Several months within this series are suppressed in order to meet the confidentiality requirements of the Statistics Act. For this reason, numbers here should be taken with caution and instead be used a representation of general trends in the supply of these fuels.

[16] Statistics Canada, CANSIM Table 134-0004. Retrieved June, 2016
http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=1340004&tabMode=dataTable&srchLan=-1&p1=-1&p2=9

Figure 10 below illustrates the crude transmission network, as well as downstream refining and distribution.

Figure 10: Crude Oil Delivery



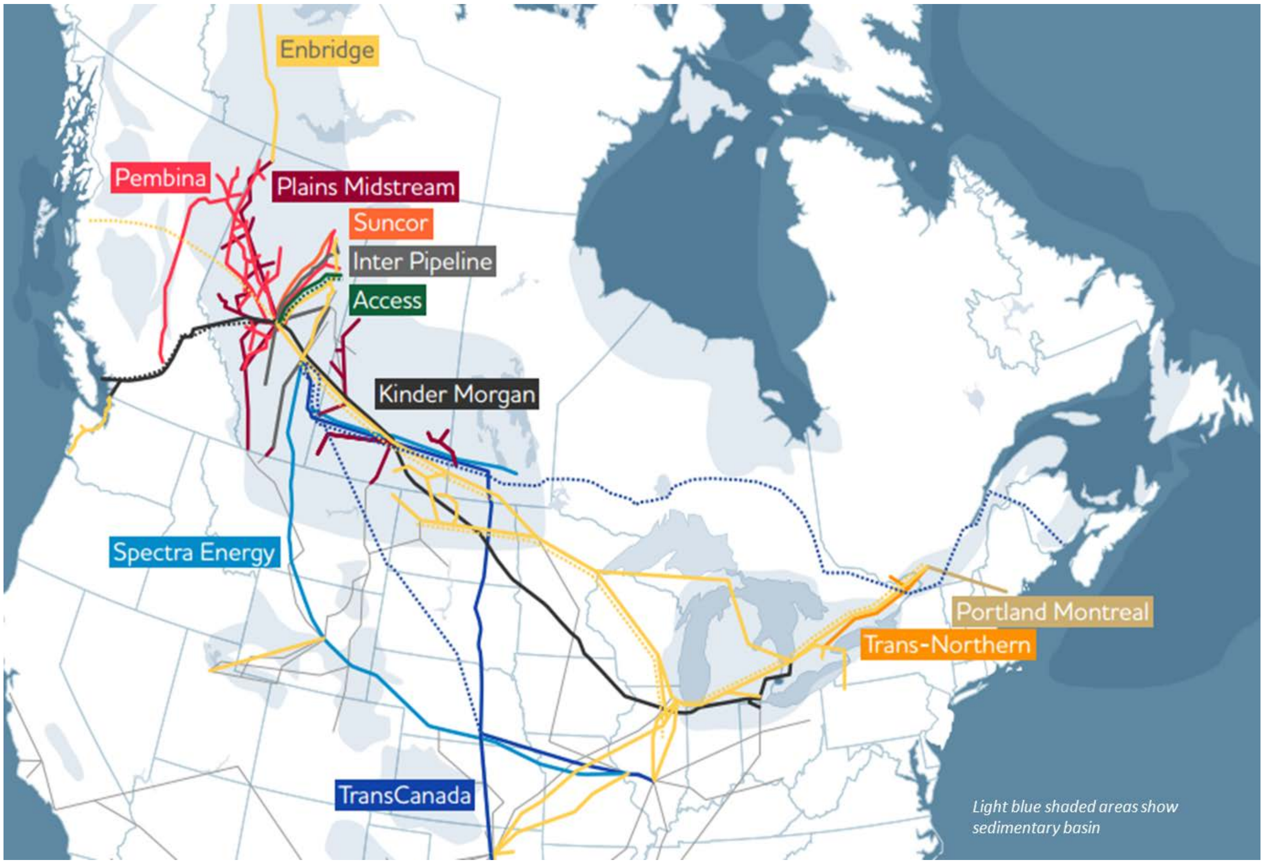
Source: Canadian Energy Pipeline Association (CEPA), 2016.[17]

Transmission (Pipelines)

As noted above, nearly all of Ontario's crude oil imports come from Western Canada. The liquids pipeline network exits Western Canada and connects to terminals and refineries across Canada and into the U.S. Notable pipelines that extend from Western Canada to the East include Spectra Energy's Express and Platte pipeline, Kinder Morgan's Cochin pipeline, TransCanada's Keystone, and the Enbridge Mainline system. Figure 11 illustrates Canada's main liquids pipelines.

[17] Canadian Energy Pipeline Association, t*he Crude Oil Delivery Network*. Accessed June, 2016. http://www.cepa.com/about-pipelines/types-of-pipelines/liquids-pipelines

Figure 11: Liquids Pipelines



Source: Canadian Energy Pipeline Association, 2016.[18]

The most relevant oil transmission pipeline to Ontario is the Enbridge Mainline (the yellow line in Figure 11). The Enbridge Mainline supplies refineries in Sarnia with crude oil via Line 5 (a northern route via Michigan) and Line 6 (southern route via Chicago). Line 5 also supplies natural gas liquids (NGLs) to a fractionator in Sarnia (a fractionator process NGLs into ethane, propane and butane).

Enbridge Line 9 currently delivers crude oil from Sarnia to Montreal, QC. In Ontario, at an Enbridge terminal facility near Hamilton (called Westover)[19], Enbridge Line 9 connects to two additional Enbridge pipelines: Line 10 (which is an export pipeline ultimately supplying a refinery in Warren, PA) and Line 11 (which supplies the Imperial Oil refinery at Nanticoke).

Another key interprovincial pipeline system is the Trans-Northern Pipeline (the orange line in Figure 11). The Trans-Northern Pipeline originates in Montreal and transports refined products (such as gasoline, diesel fuel, etc.) to eastern Ontario and GTA-area distribution terminals. The Trans Northern pipeline also allows the Nanticoke refinery to supply the Hamilton and GTA-area terminals.

[18] Canadian Energy Pipeline Association (CEPA), Liquids Pipelines Maps. Accessed June, 2016. http://www.cepa.com/map/pdf/liquids-cepa2014.pdf

[19] Enbridge Line 7 also connects to Sarnia and Westover terminal.

Additionally, two refiner-owned pipelines connect Sarnia refiners to southern Ontario and GTA primary distribution terminals.

Distribution

Crude oil is converted into petroleum products at refineries. Ontario has four refineries and a combined capacity of 393,000 b/d, as illustrated in Table 1 below.

As discussed earlier, Ontario refiners supply a significant portion of the fuels used in the province.

Table 1: Ontario Crude Oil Refineries

Owner	Location	Capacity (b/d)	Products
Imperial Oil	Sarnia, ON	121,000	Gasoline, aviation fuel, diesel, home heating fuel and marine fuel.
Imperial Oil	Nanticoke, ON	112,000	Gasoline, aviation fuel, diesel, home heating fuel, heavy fuel oil, and asphalt.
Suncor Energy	Sarnia, ON	85,000	Gasoline, kerosene, jet and diesel fuels.
Shell Canada	Sarnia, ON	75,000	Gasoline, distillates, liquid petroleum gas, heavy oils, pure chemicals, solvents.

Source: Companies' Websites, 2016

After crude oil is refined into various petroleum products it is transported to terminals within the province for final distribution to consumers. Terminals receive refined products by pipeline, ship, railway, or truck, and act as a distribution chain for – and temporary storage of – products prior to final distribution.

In southern Ontario, refined products are primarily moved by pipeline from refineries to terminals. Rail can also supplement deliveries into Eastern parts of the province. The Valero terminal in Maitland, Ontario, for example, is understood to be supplied by train from Valero's refinery in Quebec City.

The Thunder Bay terminal is primarily supplied by rail from Western Canadian refiners. The Sault Ste. Marie terminal is supplied by rail from both Ontario and Quebec refiners. In addition to pipelines, Ontario distributors have access to Quebec and Atlantic refineries via the St. Lawrence Seaway and to US refiners via the Great Lakes, during the shipping season.

In 2015, there were 3,208 retail gas stations operating in Ontario.[20] In addition to retail outlets, petroleum products are transported to commercial consumers (e.g., truckers who buy fuel at facilities called cardlocks) and wholesale distributers (e.g., companies that deliver fuel directly to end users).

[20] Kent Marketing Group, *National Retail Petroleum Site Census, 2015*.

1.3.2 Trends

In the past decade both Western Canadian crude oil production and U.S. oil production have increased considerably. This has led to displacement of imported crude oil with continental supply and a desire to expand pipeline infrastructure to economically deliver crude oil to markets (i.e., refiners and export terminals).

Ontario has been impacted by this trend. As outlined earlier, Ontario is now almost fully supplied by Western Canadian crude oil. This shift was facilitated by changing the operation of pipeline infrastructure.

Enbridge Line 9 was built in the 1970s to deliver crude oil from Sarnia to Montreal. In 1998, due to changing market conditions, the pipeline flow was reversed to deliver offshore crude oil into Sarnia. As market conditions changed again, Line 9 became significantly underutilized. In July 2012, the flow of the segment of Enbridge Line 9 between Sarnia and Westover terminal was re-reversed. This enabled the Imperial Oil refinery in Nanticoke, ON, to be fully supplied with continental crude oil (this refinery connects to Westover terminal by pipeline). Similarly, the segment of Enbridge Line 9 between Westover and Montreal was reversed in December 2015, which enables Quebec refineries to access continental crude oil supplies by pipeline. In December 2015, the capacity for the entire Line 9 from Sarnia was also expanded by 60,000 barrels per day to 300,000 barrels per day.

1.3.3 Capacity Sufficiency

Oil products such as gasoline have been an important aspect of the province's energy mix for years. Consequently, the infrastructure for crude oil deliveries, refinery production, oil product imports and oil product distribution is well established.

Overall, the oil products supply chain has functioned well and demonstrated resiliency in meeting peak demand. Unanticipated disruptions in refinery production can result in higher prices and supply disruptions.

1.4 Wood and Biomass

Biomass and wood are renewable resources (e.g., forest or agricultural materials) that are used in a variety of fuel applications.

1.4.1 Supply Sources

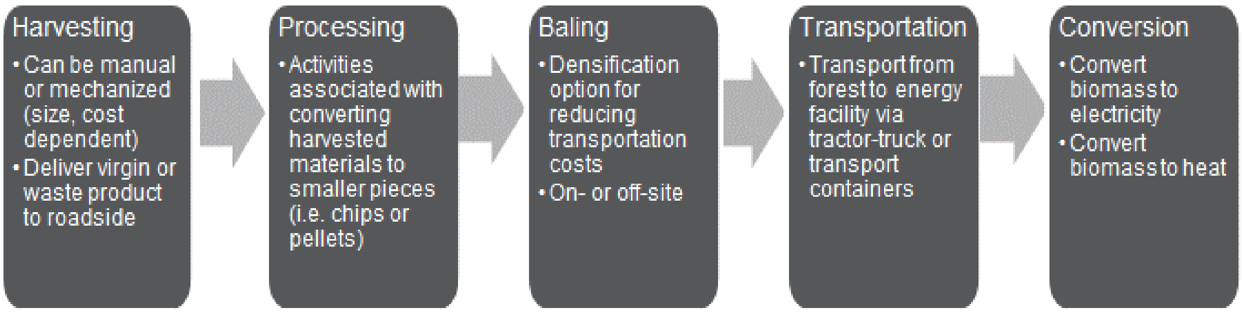
In 2015, Ontario consumed approximately 91 PJ of wood and biomass energy supplied primarily by local sources for residential, commercial and industrial processes.

1.4.2 Delivery

Wood used as a fuel is typically consumed locally, with limited distribution by truck.

As illustrated in Figure 12, the biomass supply chain consists of harvesting, processing, baling, transportation, and conversion. Harvesting of biomass can be performed using manual or mechanized techniques, depending on size and cost. Processing biomass involves converting the harvested timber into smaller pieces. Wood chip and pellet baling compact the wood for ease of transport. Biomass relies on transportation and distribution by truck.

Figure 12: Biomass Delivery



Wood and other biomass resources can be converted into pellets. Producing pellets involves the compression of biomass into a small, compact, consistently sized, dense and low-moisture content fuel that can be easily burned in pellet stoves, central heating furnaces and other heating appliances. Wood pellets are the most common type of pellet fuel and are generally made from compacted sawdust and related wastes from the milling of lumber, manufacture of wood products and furniture, and construction. Pellets - after packaging – can be distributed to end-users by truck, rail and marine.

1.4.3 Trends

Biomass is often used where wood pellet manufacturing exists. This allows for easy access to biomass fuel.

The largest biomass electricity generating plant in Canada is located in Northern Ontario. The Atikokan Generating Station is a 200 megawatt (MW) capacity generating facility that was converted from coal to biomass in 2014.

The Government of Ontario supports the use of underutilized forest resources to develop the bioeconomy - which includes using biomass to produce energy (i.e., heat, electricity and fuels). Biomass energy is prevalent in Northern Ontario, where there are several biomass projects in development and/or operation. For example, the Biomass North Development Centre has developed a Northern Ontario Bioeconomy Strategy (NO-BO) that aims to promote and develop a bioeconomy throughout Northern Ontario. The strategy was developed in partnership by the Union of Ontario Indians and the former Biomass Innovation Centre.

1.4.4 Capacity Sufficiency

Ontario has significant forestry resources and biomass more generally. Ontario's forest management guides and standards are regularly updated – this ensures that new uses of Crown forest resources, like bioenergy, occur in a sustainable way

1.5 Alternative Fuels

This section addresses four renewable fuels: ethanol, biodiesel, renewable diesel, and biogas /renewable natural gas. The renewable fuels industry has grown dramatically over the past few years due to government policies (e.g., blending requirements), as discussed in further detail below.

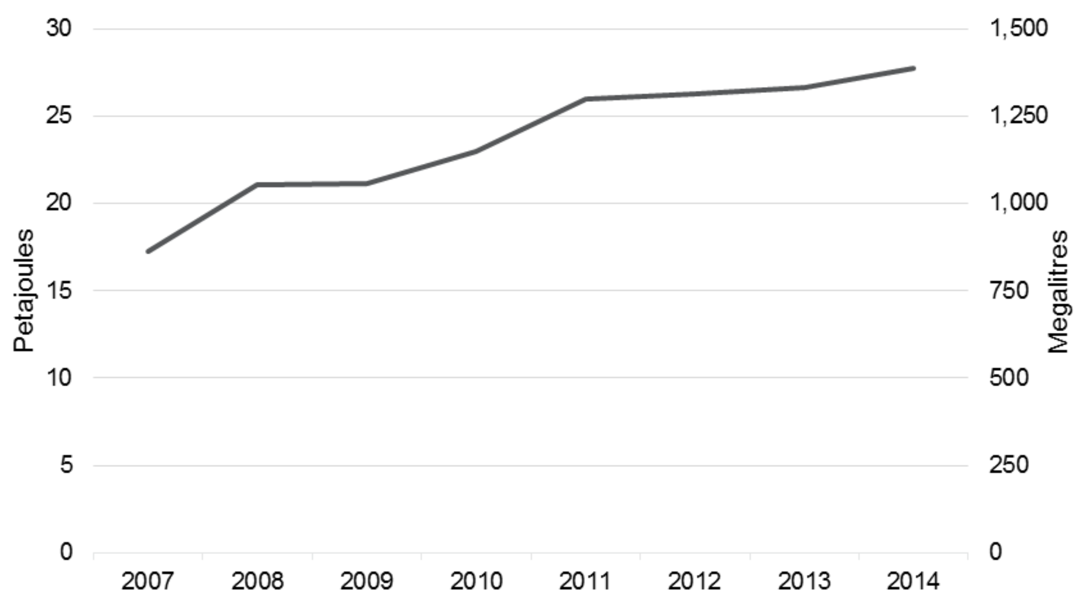
Due to differences between the renewable fuels, each of ethanol, biodiesel/renewable diesel and biogas / RNG are discussed in turn.

1.5.1 Ethanol

1.5.1.1 Supply Sources

Ontario consumption of ethanol has increased steadily since 2007, as illustrated in Figure 13 below.

Figure 13: Ontario Ethanol Consumption, 2007-2014



Source: Ministry of Environment and Climate Change, 2016

This consumption was met with both Ontario production and imports.

Ethanol Production

Ontario currently has six operational ethanol refineries Ethanol Production. These are illustrated below:

Table 2: Ethanol Production Facilities

Company/Plant Name	Location	Capacity (Million Litres/Year)	Feedstock
Greenfield Specialty Alcohols	Chatham	130	Corn
Suncor St. Clair Ethanol Plant	Sarnia	400	Corn
IGPC Ethanol Inc.	Aylmer	162	Corn
Greenfield Specialty Alcohols	Tiverton	27	Corn
Kawartha Ethanol	Havelock	120	Corn
Greenfield Specialty Alcohols	Johnstown	250	Corn
Total Capacity (Million Litres/Year)		**1,089**	
Total Capacity (PJ/Year)		**22.8**	

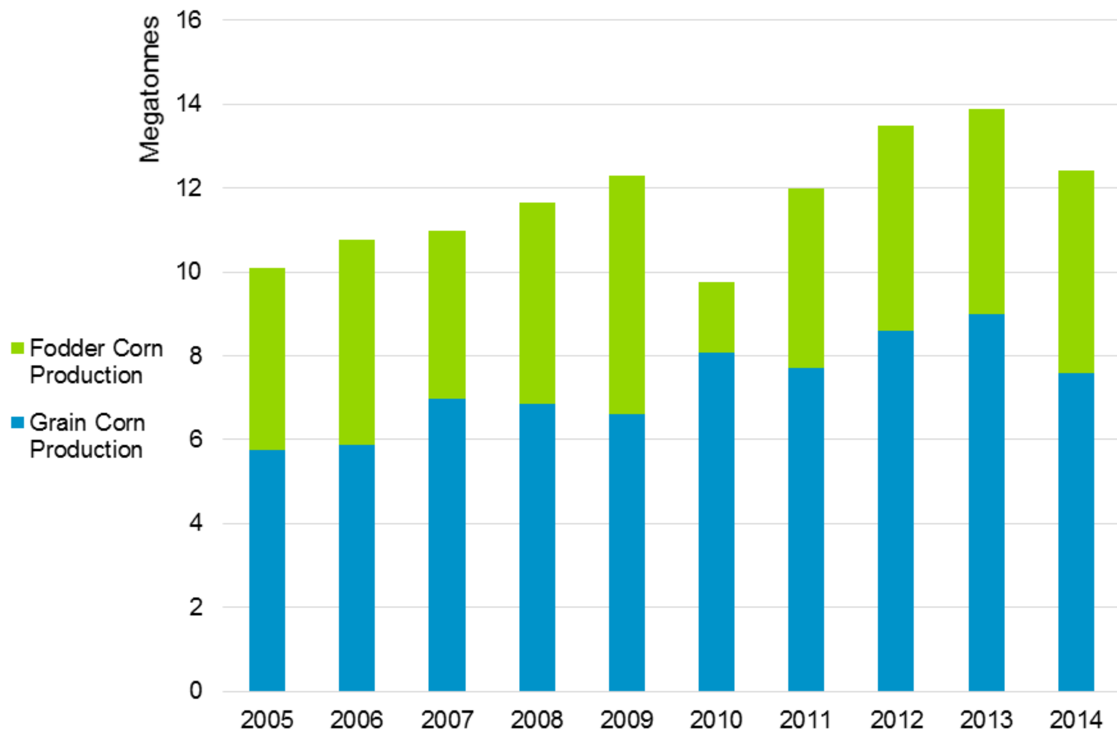
1.5.1.2 Delivery

Feedstock

Corn is the main feedstock for ethanol production in Ontario. Ontario is a significant corn producing province.

Ontario corn production levels are shown below.

Figure 14: Corn Production in Ontario



Source: Ontario Ministry of Agriculture, Food, and Rural Affairs[21]

Distribution

Ethanol's primary fuel use is an additive to gasoline. Consequently, ethanol currently relies significantly on the gasoline distribution infrastructure to reach end-users.

Ethanol and ethanol-blended gasoline are typically not transported by pipeline. This is due to issues with attraction of water. Ethanol is delivered to fuel distribution terminals by rail and truck where it is added to a gasoline-based blendstock to produce an on-specification finished fuel. A typical finished fuel with ethanol added contains 10% ethanol – this fuel is called E10.

In Ontario, most fuel distribution terminals in southern and eastern Ontario are have ethanol blending capability. However, some lower volume terminals in northern Ontario (e.g., Thunder Bay and Sault Ste-Marie) may not blend ethanol. These terminals continue to be supplied with unblended gasoline.

Retail gasoline stations require some modifications and infrastructure upgrades to sell E10 (as opposed to straight gasoline). Specifically, this includes cleaning of on-site storage tanks and ensuring dispensers are rated to handle E10.

[21] Ontario Ministry of Agriculture, Food, and Rural Affairs, *Historical Provincial Estimates by Crop*. Retrieved July, 2016. http://www.omafra.gov.on.ca/english/stats/crops/index.html

E10 is sold as "regular gasoline". Substantially all of the vehicles on the road today can use E10. This has resulted in E10 being widely distributed in southern Ontario and in the U.S.

1.5.1.3 Trends

A key factor in the growth of ethanol is government policies, including mandates and production support.

Ontario is the largest bioethanol producing province in Canada, largely due to its policies around renewable fuels. Under (O. Reg. 535/05) in the *Environmental Protection Act, 1990* (CEPA), gasoline suppliers must include a minimum of at least 5% (annual average) ethanol content in motor gasoline. These entities must submit a compliance report to the government each year and ensure that the ethanol based fuel meets specific standards set out in the regulations.

To assist the province in meeting its ethanol goals the *Ontario Ethanol Growth Fund (OEGF)* was established. The OEGF was launched in 2005 following the announcement of ethanol requirements under the Renewable Fuel Regulations, discussed above. The 12 year, $520 million fund is intended to assist ethanol producers to meet financial challenges, provide support for independent blenders of ethanol and gasoline, and fund research and development.

Additional policy support was provided by federal government initiatives. Starting in 2010, the *Renewable Fuel Regulations* sets national ethanol and biodiesel blend mandate targets. The main requirements for ethanol under the *Renewable Fuel Regulations* requires fuel producers and importers to have an average renewable content of at least 5% based on volume of gasoline produced or imported. Another federal initiative pertaining to biofuels is *ecoENERGY for Biofuels* which provides financial incentives for ethanol and biodiesel production in Canada.

Ontario's Climate Change Action Plan proposes additional measures that would support ethanol use, including: measures to boost renewable content of gasoline and assistance to fuel distributors to offer high-level blends for renewable fuels.

1.5.1.4 Capacity Sufficiency

Ontario's current ethanol requirements are being met by a combination of domestic production and imports.

Today, growing domestic ethanol production capacity is largely constrained, by feedstock availability and not processing capability. Ontario's ethanol producers use primarily domestic corn for their operations[22]. However, Ontario is understood to be a moderate net importer of corn.

Research is ongoing to use a variety of alternative feedstocks - corn stover, wastes, etc through cellulosic production. Cellulosic ethanol production can be incented by policies (e.g., fuel standards that account for life cycle emissions). Biomass that could be used for cellulosic ethanol also faces competing uses.

Additional ethanol use in Ontario can also likely be acommodated by imports. Given robust North American transportation networks, rail and marine can be used to import ethanol from the U.S. Midwest and Brazil.

[22] Ministry of Energy, Ontario, 2016

At the distribution level, ethanol growth is constrained by vehicle and refuelling infrastructure. For example, infrastructure upgrades (i.e., pumps and storage tanks) may be required at fueling stations to sell higher blends of ethanol (e.g., E15). While many newer vehicles can use E15, vehicle manufacturers do not typically recommend the use of E15 in vehicles built prior to 2010-2012.

Similarly, specialized equipment is needed to sell blends of E55 to E85 and only specially equipped vehicles (called "flex-fuel vehicles) can use this level of ethanol blend.

1.5.2 Biodiesel and Renewable Diesel

1.5.2.1 Supply Sources

Statistics on the use of biodiesel and renewable diesel in Ontario are not yet publicly available.

Ontario's recently introduced blending requirements under the Greener Diesel regulation are understood to be met by a combination of domestically produced biodiesel and imported renewable diesel.

1.5.2.2 Delivery

Feedstock

Biodiesel and renewable diesel are derived from organic materials such as plant oils, waste cooking oils, animal fats, and other oils (such as fish). The distinction between diesel fuels classified as biodiesel versus renewable diesel depends on the process used to create them.

Biodiesel and Renewable Diesel Production
There are currently five biodiesel refineries in Ontario. The locations and production capacities of these are summarized in Table 2 below. The total operational production capacity of all five refineries is equivalent to approximately 10.2 PJ per year. No renewable diesel production facilities exist in Canada.

Table 3: Biodiesel Facilities in Ontario[23]

Company/Plant Name	Location	Capacity (Million Litres/Year)	Feedstock
Methes Energies Canada, Inc.	Sombra	50	Multi-feedstock
Noroxel Energy Ltd.	Springfield	5	Yellow grease
Atlantic Biodiesel	Welland	170	Multi-feedstock
Biox Corporation	Hamilton	66	Multi-feedstock
Methes Energies Canada, Inc.	Mississauga	5	Yellow grease
Total Capacity (Million Litres/Year)		**296**	
Total Capacity (PJ/Year)		**10.2**	

Source: Renewable Industries Canada, 2016[24]

1.5.2.3 Distribution

Biodiesel and renewable diesel are used as additives to diesel fuel.

Biodiesel is delivered to fuel distribution terminals by rail and truck where it is added to diesel fuel. Like ethanol, biodiesel and biodiesel blends are not transported by pipeline.

A typical finished fuel with biodiesel contains 5% biodiesel - this fuel is called B5. Blends of up to B5 are typically interchangeable with conventional diesel fuel. However, biodiesel characteristics limit its use in cold weather; which limits the use of biodiesel blends in winter.

Some vehicle manufacturers authorize the use of biodiesel blends of up to B20 in their vehicles.

Renewable diesel poses fewer challenges for fuel suppliers. For instance, since renewable diesel is chemically similar to conventional diesel it can be transported into Ontario via pipeline. (This reduces the requirements for truck distribution and blending infrastructure). Renewable diesel imports are understood to access Ontario via the Trans-Northern Pipeline originating in Montreal.

[23] NB: although referred to as “renewable diesel” refineries in the source document, all of these refineries are in fact biodiesel, not renewable diesel (as defined above), refineries.

[24] Renewable Industries Canada, *Industry Map*. Accessed June, 2016. http://ricanada.org/industry/industry-map/

1.5.2.4 Trends

As with ethanol, biodiesel and renewable diesel use has been boosted by government policy.

Under Ontario Greener Diesel Requirements in (O. Reg. 97/14), fuel suppliers that import, manufacture, or acquire diesel fuel must ensure, by 2017, that the amount of bio-based diesel in the diesel fuel is 4% of total volume. In addition, and also by 2017, the bio-based diesel component of the blend must have 70% lower GHG emissions than standard petroleum diesel. The Greener Diesel regulation was introduced in 2014 with a 2% blending requirement.

At the federal level, the *Renewable Fuel Regulations* sets national ethanol and biodiesel blend mandate targets. The main bio-based diesel requirements under the *Renewable Fuel Regulations* requires fuel producers and importers to have an average renewable content of at least 2% based on the volume of diesel fuel produced or imported.

Another federal initiative pertaining to biofuels is *ecoENERGY for Biofuels* which provides financial incentives for ethanol and biodiesel production in Canada. This initiative provides operating incentives for producers. The program is scheduled to end on March 31st, 2017.

1.5.2.5 Capacity Sufficiency

Ontario's current biodiesel requirements are being met by a combination of domestic production and imports.

Growing domestic biodiesel or renewable diesel production capacity is contrained, to a degree, by feedstock availability.

Biofuel feedstock can include cooking grease, soybean oil, waste vegetable (i.e. canola) oil, hemp oil, etc. While feedstock varies, prices and availability generally drive choice of feedstock for producers.

Additional biodiesel or renewable diesel use in Ontario can likely be acommodated by imports. Given robust North American transportation networks, rail and marine can be used to import biodiesel and renewable diesel from the U.S. and renewable diesel from Europe and Asia.

At the distribution level, biodiesel growth is constrained by inadequate distribution infrastructure. To distributebiodiesel at terminals, investments in storage, loading infrastructure, blending equipment and heating (i.e., to ensure biodiesel blends in colder months) is needed. More distribution terminals in Ontario will need to invest in biodiesel blending if use is to increase materially.

Ontario production of renewable diesel would require a large-scale investment.

1.5.3 Biogas/Renewable Natural Gas and Biomass

1.5.3.1 Supply Sources

In 2013, there were 37 operating biogas facilities in Ontario, with a combined capacity of 27,223 kW.[25] In addition, there were 44 biogas plants that are currently in development or under construction in Ontario as of 2013.

1.5.3.2 Delivery

Renewable natural gas (RNG) is produced from biogas, which is a product of the decomposition of organic matter. In some applications biogas can be used directly as a fuel. For use as RNG the biogas is processed to meet natural gas purity standards, and the resulting RNG is fully interchangeable with conventional natural gas. Biogas can be derived from landfills, livestock operations, wastewater treatment, or waste from industrial, institutional, and commercial entities.

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[25] Renewable Energies, 2014 CanBio Report on the Status of Bioenergy in Canada. December, 2014 (P. 26). http://www.fpac.ca/wp-content/uploads/2014_CanBio_Report.pdf

1.5.3.3 Trends

Ontario's Climate Change Action Plan proposes to establish a low carbon content requirement for natural gas. The Climate Change Action Plan also proposes to fund a pilot program that uses RNG in commercial-scale demonstration projects for transportation.

RNG is also being used in California as a transportation fuel under California's Low Carbon Fuel Standard.

1.5.3.4 Capacity Sufficiency

According to the Canadian Gas Association, Alberta Research Council (2008) suggests that Canada has the potential to produce 1,300 billion cubic feet per year of RNG.[26]

A recent study commissioned by the Ontario gas utilities have forecast Ontario RNG production of 4.3 billion m^3 of RNG per year by 2030, approximately 160 PJ, or equivalent to a little less than half of the natural gas used by the residential sector in Ontario in 2013.

A key consideration in RNG capacity is the availability of biomass resources, which has competing uses.

[26] Canadian Gas Association, *Renewable Natural Gas*. Issue 5 2013. Retrieved July, 2016. http://www.cga.ca/wp-content/uploads/2015/04/CGA_bulletin_RenewableNaturalGas_-EN.pdf

FUELS TECHNICAL REPORT – MODULE 2: DEMAND OUTLOOK

SEPTEMBER 2016

NAVIGANT REFERENCE 187360

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DEMAND OUTLOOKS - GLOSSARY

The following acronyms appear throughout this module:

- APS: Achievable Potential Study, the OEB's 2016 Natural Gas Conservation Potential Study
- CNG: Compressed natural gas
- DSM: demand-side management (natural gas focused conservation)
- EV: electric vehicles
- IESO: Independent Electricity System Operator
- FTR: Fuels Technical Report
- LNG: Liquefied natural gas
- OEB: Ontario Energy Board
- OPO: Ontario Planning Outlook
- PJ: Petajoule
- RNG: Renewable natural gas

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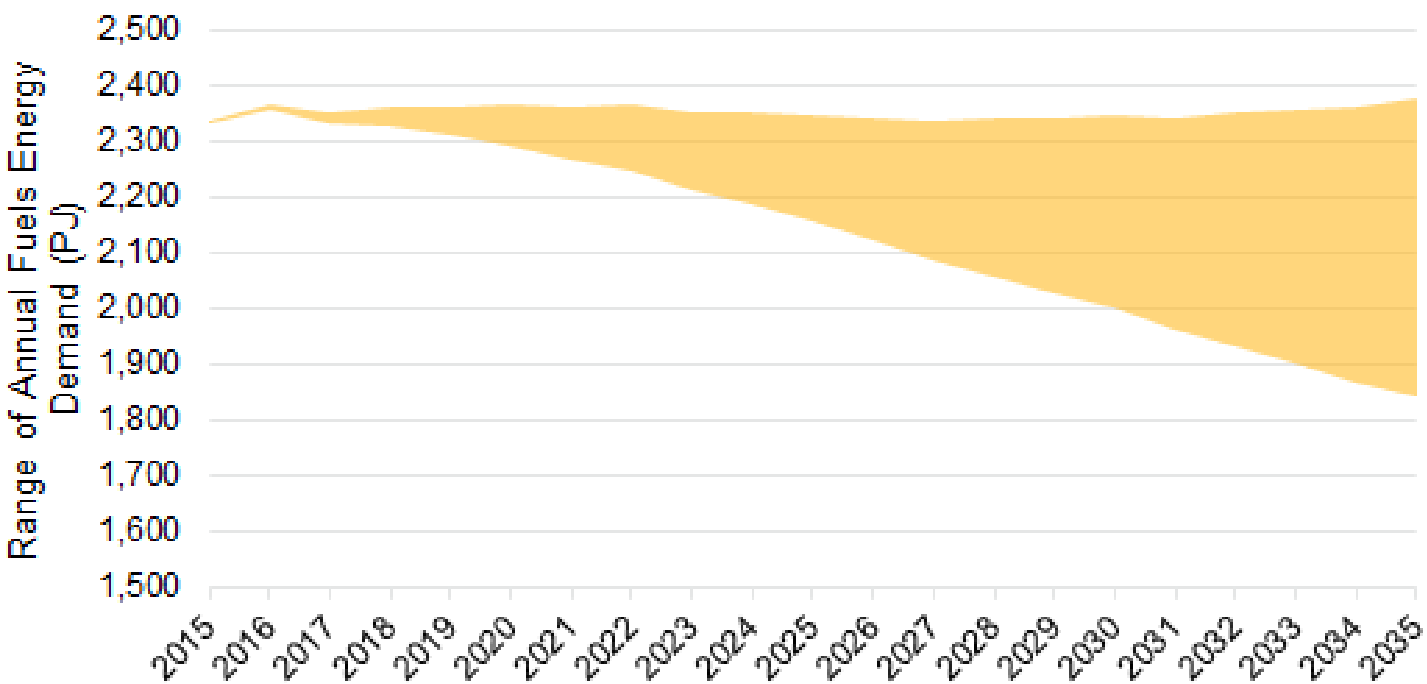
FUELS SYSTEM 20-YEAR OUTLOOK: DEMAND OUTLOOK

- By 2035, the outlook for fuels demand ranges from between approximately 1,800 PJ (Outlook F) and nearly 2,400 PJ (Outlook B).
- The FTR recognizes the uncertainty in future fuels demand by addressing a range of possible futures.



Note: All outlooks are net of demand side management (DSM) and of the fuels savings resulting from fuel economy standards.

DEMAND OUTLOOK (CONT'D)

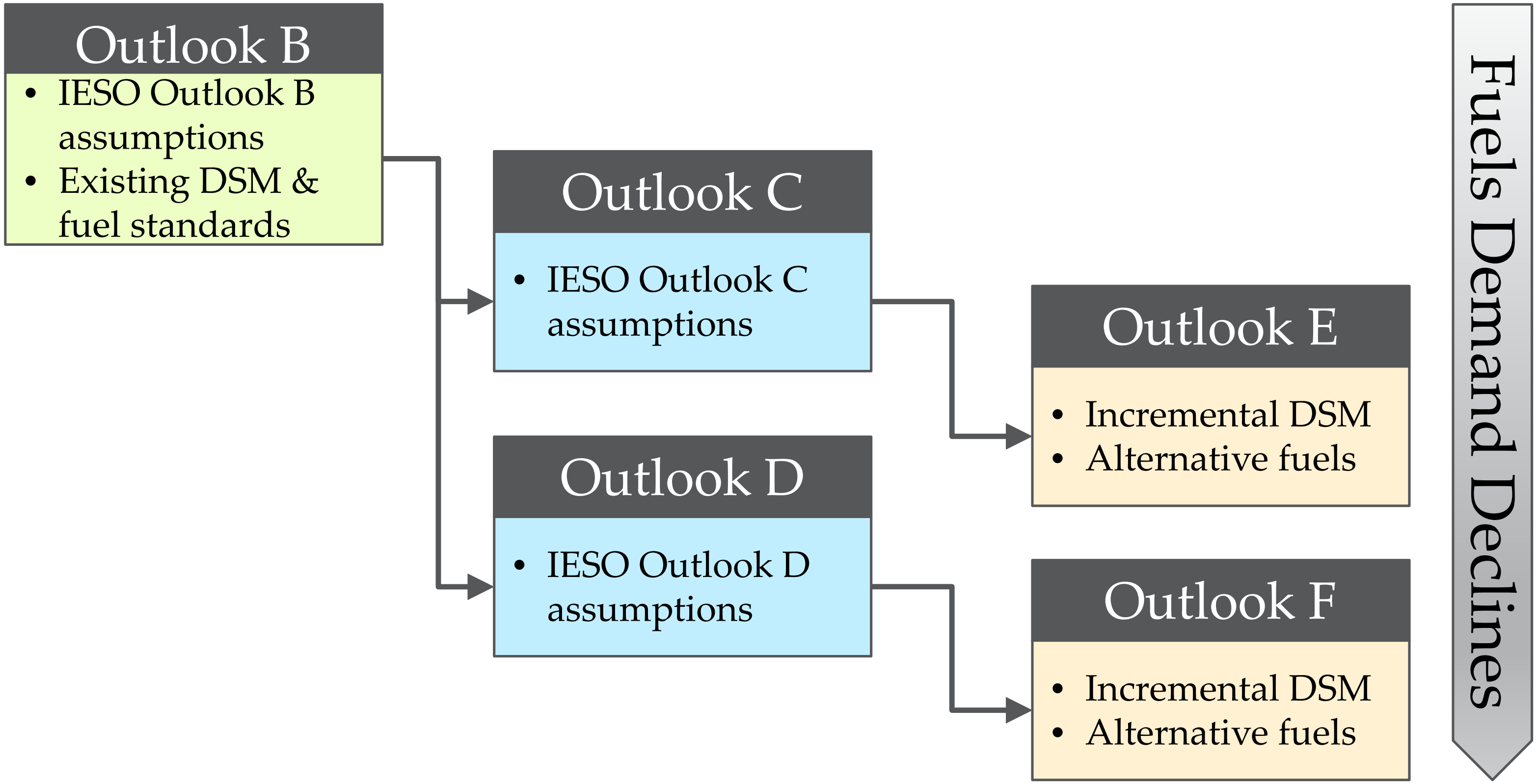
- Five demand outlooks have been developed to provide context for the Long-Term Energy Plan (LTEP) discussion.

- The range of future fuels demand is influenced by a wide variety of factors, including:
  - Global macroeconomic and fuel pricing trends;
  - Ontario-specific demographic and economic trends and technology development; and
  - Trends in policy related to (or that materially affect) fuels use.

- Implementation of the province's climate change policies consistent with the cap and trade program and the Climate Change Action Plan will have an impact on the demand for fuels, primarily through the potential for greater electrification and increased use of alternative fuels which exists in nearly every part of the Ontario fuels energy system.

DEMAND OUTLOOK (CONT'D)

- FTR demand outlooks reflect all of the assumptions adopted by the IESO for the corresponding Ontario Planning Outlook (OPO) demand outlooks.
- **Note:** Outlook A was developed by IESO to explore the implications of lower electricity demand. Applying the assumptions of Outlook A to the fuels sector would result in lower fuels demand than Outlook B. Lower fuels demand is already explored in the FTR by Outlooks C, D, E and F. Outlook A has therefore not been modeled as part of the FTR.



DEFINITION OF OUTLOOKS

Sector	Outlook B	Outlook C	Outlook D	Outlook E	Outlook F
Residential	498 PJ in 2035	Oil and propane heating switches to heat pumps, electric and water heating gain 25% of gas market share.* (388 PJ in 2035)	Oil and propane heating switches to heat pumps, electric and water heating gain 50% of gas market share.* (322 PJ in 2035)	Assumptions as per Outlook C, plus: • Incremental DSM consistent with OEB APS "semi-constrained" potential. • 35 PJ of RNG used by 2035 (381 PJ in 2035)	Assumptions as per Outlook D, plus: • Incremental DSM consistent with OEB APS "unconstrained" potential. • 66 PJ of RNG used by 2035 (302 PJ in 2035)
Commercial	233 PJ in 2035	Oil and propane heating switches to heat pumps, electric and water heating gain 25% of gas market share.* (192 PJ in 2035)	Oil and propane heating switches to heat pumps, electric and water heating gain 50% of gas market share.* (177 PJ in 2035)	Assumptions as per Outlook C, plus: • Incremental DSM consistent with OEB APS "semi-constrained" potential. • 20 PJ of RNG used by 2035 (187 PJ in 2035)	Assumptions as per Outlook D, plus: • Incremental DSM consistent with OEB APS "unconstrained" potential. • 42 PJ of RNG used by 2035 (147 PJ in 2035)
Industrial	671 PJ in 2035	5% of 2012 fossil energy switches to electric equivalent (607 PJ in 2035)	10% of 2012 fossil energy switches to electric equivalent (550 PJ in 2035)	Assumptions as per Outlook C, plus: • Incremental DSM consistent with OEB APS "semi-constrained" potential. • 23 PJ of RNG used by 2035 (591 PJ in 2035)	Assumptions as per Outlook D, plus: • Incremental DSM consistent with OEB APS "unconstrained" potential. • 48 PJ of RNG used by 2035 (519 PJ in 2035)
Transportation	967 PJ in 2035	• 2.4 million EVs by 2035. • Planned electrified transit projects 2017-2035 (883 PJ in 2035)	• 2.4 million EVs by 2035. • Planned electrified transit projects 2017-2035 (883 PJ in 2035)	Assumptions as per Outlook C, plus: • Incremental non-electrified transit. • Substitute CNG, LNG, propane, hydrogen, ethanol, and bio-based diesels for conventional fuels (878 PJ in 2035)	Assumptions as per Outlook C, plus: • Incremental non-electrified transit. • Substitute more CNG, LNG, propane, hydrogen, ethanol, and bio-based diesels for conventional fuels than in Outlook E (874 PJ in 2035)
Total	2,377 PJ in 2035	2,070 PJ in 2035	1,931 PJ in 2035	2,037 PJ in 2035	1,842 PJ in 2035

** "market share" refers to a proportion of annual equipment sales, not of total installed equipment stock.*

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DEFINITION OF OUTLOOKS (CONT'D)

- FTR demand outlooks reflect all of the assumptions adopted by the IESO for the corresponding Ontario Planning Outlook (OPO) demand outlooks.
- Additional fuels-related assumptions are applied in Outlooks E and F, as summarized in the preceding table. Details of these assumptions are provided below.
- All outcomes are assumed to be achieved by 2035 and to be incremental to what would have been achieved under Outlook B.

#	Outlook E	Outlook F
1	200,000 single-family fossil-fuel-heated dwellings have their building envelope sufficiently improved to reduce heating load by 20 GJ/year.	600,000 single-family fossil-fuel-heated dwellings have their building envelope sufficiently improved to reduce heating load by 20 GJ/year.
2	85,000 multi-family fossil-fuel-heated dwellings have their building envelope sufficiently improved to reduce heating load by 9 GJ/year.	255,000 multi-family fossil-fuel-heated dwellings have their building envelope sufficiently improved to reduce heating load by 9 GJ/year.
3	2% reduction in heating load for fossil-fuel heated commercial buildings due to improved building envelope.	6% reduction in heating load for fossil-fuel heated commercial buildings due to improved building envelope.
4	90 million urban trips per year on diesel-fueled buses	180 million urban trips per year on diesel-fueled buses

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DEFINITION OF OUTLOOKS (CONT'D)

#	Outlook E	Outlook F
5	600 diesel-fueled buses replaced by natural gas buses	1,200 diesel-fueled buses replaced by natural gas buses
6	650 million litres of gasoline replaced by ethanol.	1,300 million litres of gasoline replaced by ethanol.
7	500 million litres of petro-diesel replaced by biodiesel.	1,000 million litres of petro-diesel replaced by biodiesel.
8	500 million litres of petro-diesel replaced by renewable diesel.	1,000 million litres of petro-diesel replaced by renewable diesel.
9	70,000 propane light-duty vehicles on the road	175,000 propane light-duty vehicles on the road
10	150,000 hydrogen fuel-cell light-duty vehicles on the road	300,000 hydrogen fuel-cell light-duty vehicles on the road
11	7.5% of heavy duty freight vehicle km traveled powered by natural gas.	15% of heavy duty freight vehicle km traveled powered by natural gas.
11	78 PJ of RNG injected to the system	155 PJ of RNG injected to the system
12	2 PJ of residential natural gas use reduction due to improved efficiency (incremental DSM).	5 PJ of residential natural gas use reduction due to improved efficiency (incremental DSM).
13	2 PJ of commercial natural gas use reduction due to improved efficiency (incremental DSM).	11 PJ of commercial natural gas use reduction due to improved efficiency (incremental DSM).
14	12 PJ of industrial natural gas use reduction due to improved efficiency (incremental DSM).	24 PJ of industrial natural gas use reduction due to improved efficiency (incremental DSM).

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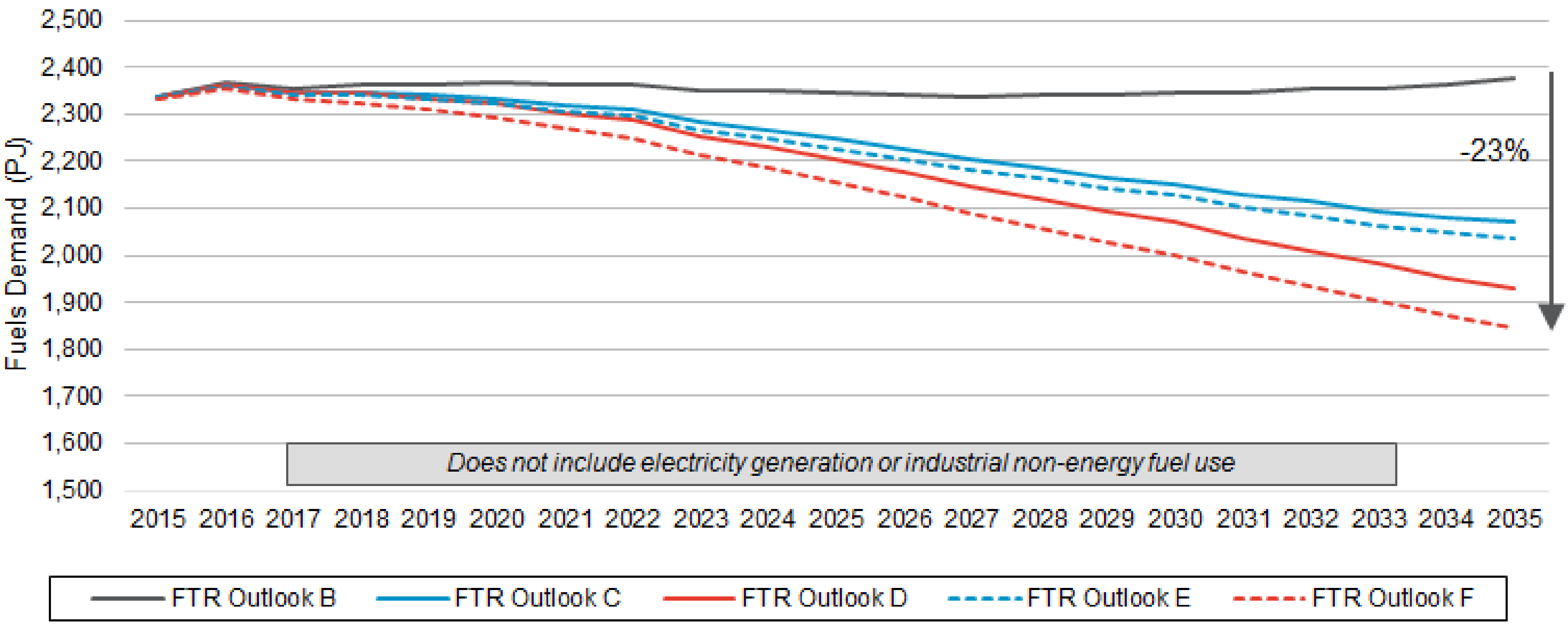
ANNUAL NET FUELS ENERGY DEMAND ACROSS DEMAND OUTLOOKS



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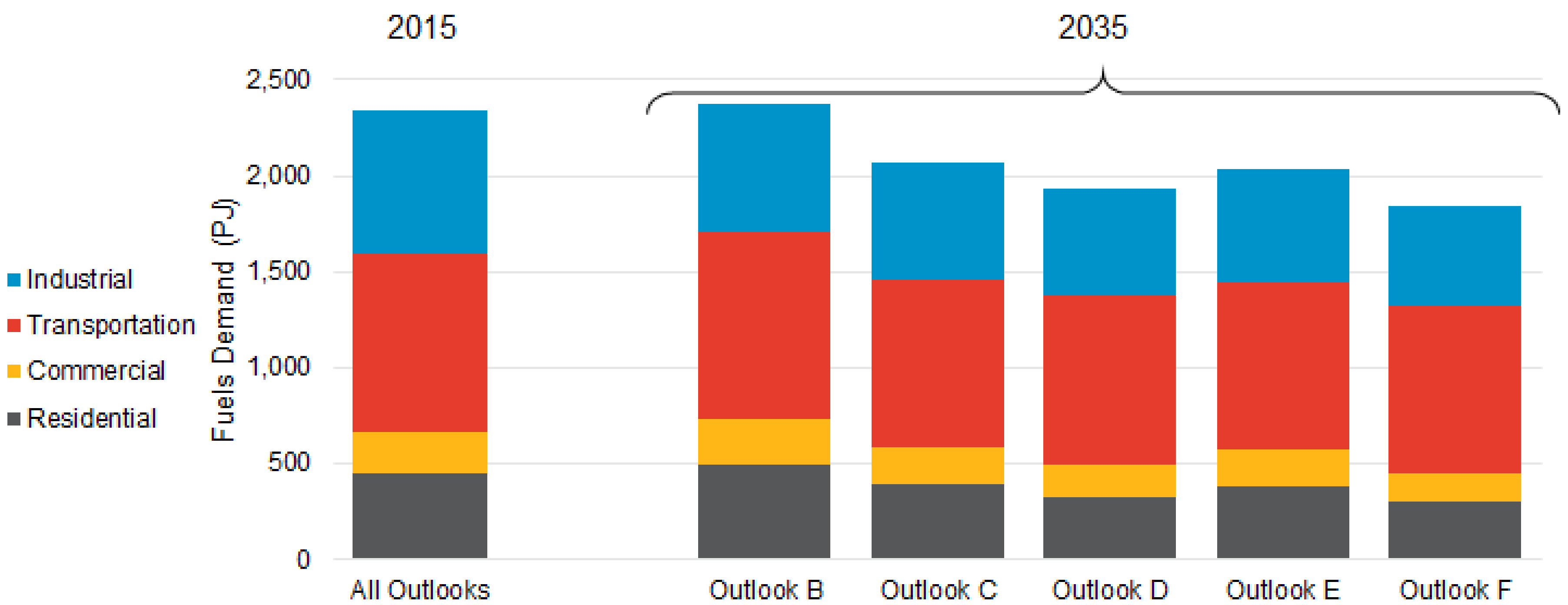
BREAKDOWN OF FUELS ENERGY DEMAND BY SECTOR 2015 AND 2035 (OUTLOOKS B, C, D, E, F)



Energy (PJ)	2015	B 2035	C 2035	D 2035	E 2035	F 2035
Residential	447	498	388	322	381	302
Commercial	215	233	192	177	187	147
Transportation	927	975	883	883	878	874
Industrial	750	671	607	550	591	519

 /

FUELS ENERGY DEMAND BY SECTOR AND OUTLOOK (PJ)

	Residential					Commercial					Transportation					Industrial				
Year	B	C	D	E	F	B	C	D	E	F	B	C	D	E	F	B	C	D	E	F
2015	447	447	447	446	446	215	215	215	215	214	927	926	926	926	926	750	750	750	749	748
2016	451	449	449	449	449	215	213	213	213	210	938	937	937	937	936	763	763	763	761	760
2017	454	450	450	450	448	216	213	213	213	209	945	945	945	944	943	738	738	738	736	733
2018	462	456	455	455	451	217	212	212	211	206	956	955	955	954	952	729	725	722	722	715
2019	464	455	454	453	448	218	212	212	211	206	960	959	959	957	955	722	715	709	711	700
2020	469	456	453	454	446	219	210	210	209	203	966	964	964	962	960	715	704	695	699	685
2021	468	451	447	448	438	218	209	209	207	200	965	961	961	959	957	712	698	685	692	674
2022	472	449	442	446	433	218	209	209	207	199	967	961	961	959	956	708	691	674	684	661
2023	470	442	433	439	423	219	208	208	205	196	964	955	955	952	950	697	677	658	670	643
2024	476	441	429	438	418	220	206	206	204	193	964	952	952	949	947	690	666	644	658	628
2025	476	436	421	431	408	221	206	206	204	192	961	945	945	942	939	686	659	633	650	616
2026	480	432	413	428	400	222	205	205	202	189	962	940	940	937	934	678	648	618	638	600
2027	479	425	402	420	388	223	206	203	203	186	959	932	932	928	925	677	642	610	632	590
2028	482	421	394	416	378	224	204	202	201	183	961	927	927	923	920	672	634	598	623	577
2029	483	415	383	409	367	226	203	203	199	182	960	918	918	915	911	671	629	590	617	568
2030	487	411	374	406	357	227	204	199	200	177	963	913	913	909	906	670	624	583	612	559
2031	488	405	363	399	346	228	202	198	198	174	963	905	905	901	898	665	616	571	603	546
2032	492	402	354	396	336	229	201	194	197	169	966	900	900	896	892	665	612	564	598	538
2033	492	396	342	389	323	231	197	190	193	163	967	892	892	888	884	665	609	558	594	530
2034	494	391	331	384	312	232	196	183	191	155	971	887	887	882	878	667	607	553	592	524
2035	498	388	322	381	302	233	192	177	187	147	975	883	883	878	874	671	607	550	591	519

NAVIGANT

ECONOMIC ASSUMPTIONS UNDERLYING FUELS DEMAND OUTLOOK

- Economic assumptions reflect the assumptions adopted by the IESO for the OPO.

Driver	2005-2015	2015-2025	2025-2035
	Outlooks B,C,D,E,F	Outlooks B,C,D,E,F	Outlooks B,C,D,E,F
Growth in number of residential households	15%	14%	9%
Growth in commercial floor space	20%	15%	11%
Ontario Industrial GDP (annual growth rate)	-2%	1%	1%

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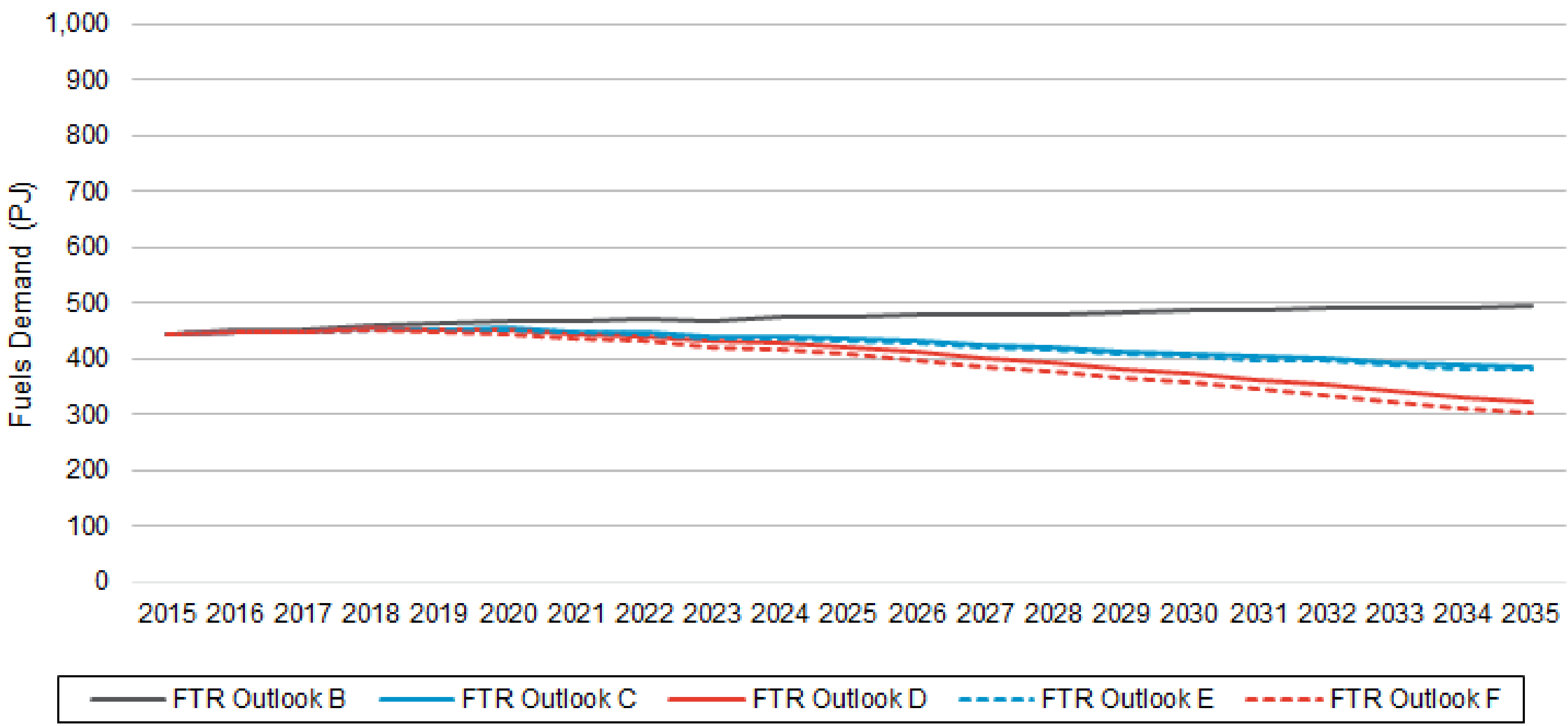
RESIDENTIAL SECTOR

RESIDENTIAL FUELS ENERGY DEMAND 2015-2035: OUTLOOKS B, C, D, E, F



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RESIDENTIAL FUELS ENERGY DEMAND 2015-2035: OUTLOOKS B, C, D, E, F

	Residential (PJ)				
Year	B	C	D	E	F
2015	447	447	447	446	446
2016	451	449	449	449	449
2017	454	450	450	450	448
2018	462	456	455	455	451
2019	464	455	454	453	448
2020	469	456	453	454	446
2021	468	451	447	448	438
2022	472	449	442	446	433
2023	470	442	433	439	423
2024	476	441	429	438	418
2025	476	436	421	431	408
2026	480	432	413	428	400
2027	479	425	402	420	388
2028	482	421	394	416	378
2029	483	415	383	409	367
2030	487	411	374	406	357
2031	488	405	363	399	346
2032	492	402	354	396	336
2033	492	396	342	389	323
2034	494	391	331	384	312
2035	498	388	322	381	302

Note: Historical data used to calibrate the CanESS model are obtained from Statistics Canada and NRCan. Actual values in most cases are available only until 2013, meaning that 2015 values reported here are estimated, and outlook-specific, hence why they differ very slightly across outlooks.

NAVIGANT

RESIDENTIAL SECTOR OVERVIEW

- The principal factor that could drive an increase in residential fuels demand in Outlook B is the forecast growth in households in the province.

- Factors that could decrease residential fuels demand include:
  - Electrification of space- and water-heating;
  - Incremental building envelope improvement* (e.g. more insulation, more energy-efficient doors and windows, better air tightness etc.); and
  - Incremental natural gas equipment efficiency improvements*.

- In Outlook E and F, a substantial proportion of fuels energy shifts from conventional fossil sources (e.g. natural gas) to renewable ones (e.g. renewable natural gas). This shift affects GHG emissions, but does not materially affect total fuels energy use.

*Incremental improvements modeled in Outlooks E and F corresponds to incremental achievable DSM potential identified in the OEB's 2016 Natural Gas Conservation Potential study for the semi-constrained and unconstrained (respectively) achievable potential scenarios, after accounting for the erosion of DSM potential due to electrification.

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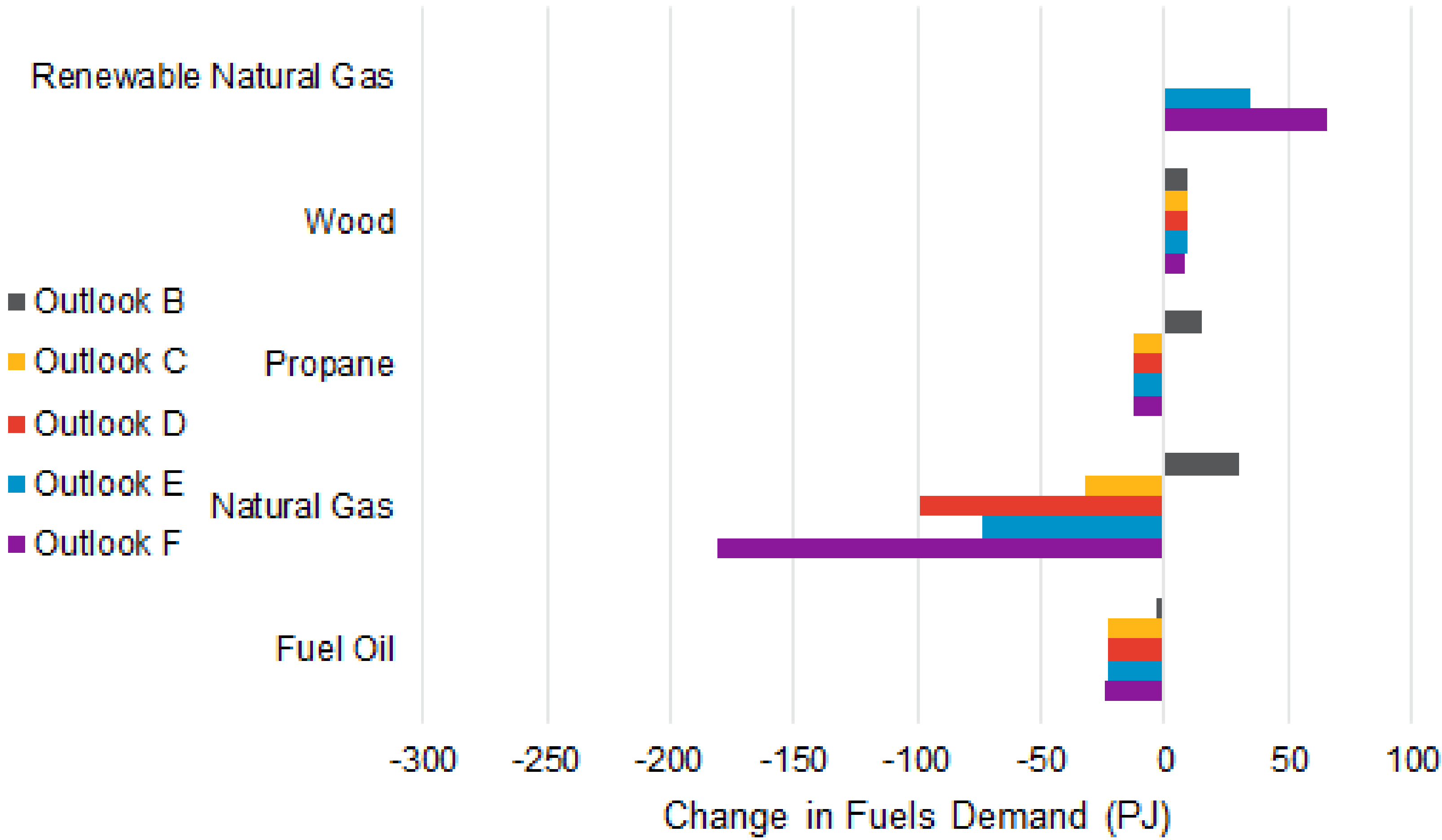
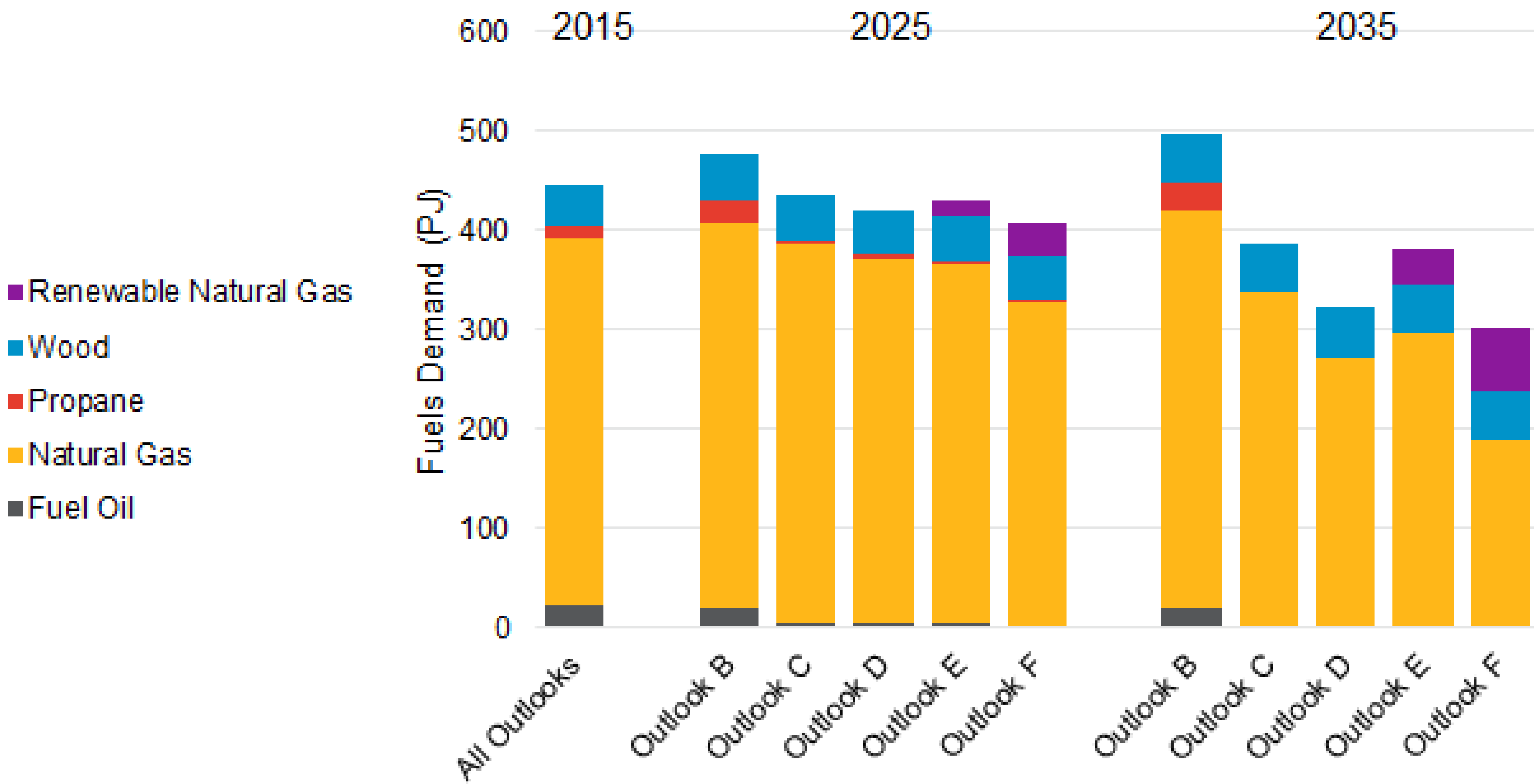
FORECAST CHANGE IN RESIDENTIAL FUELS DEMAND BY FUEL TYPE 2015 - 2035



NAVIGANT

RESIDENTIAL DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F



NAVIGANT

RESIDENTIAL DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F

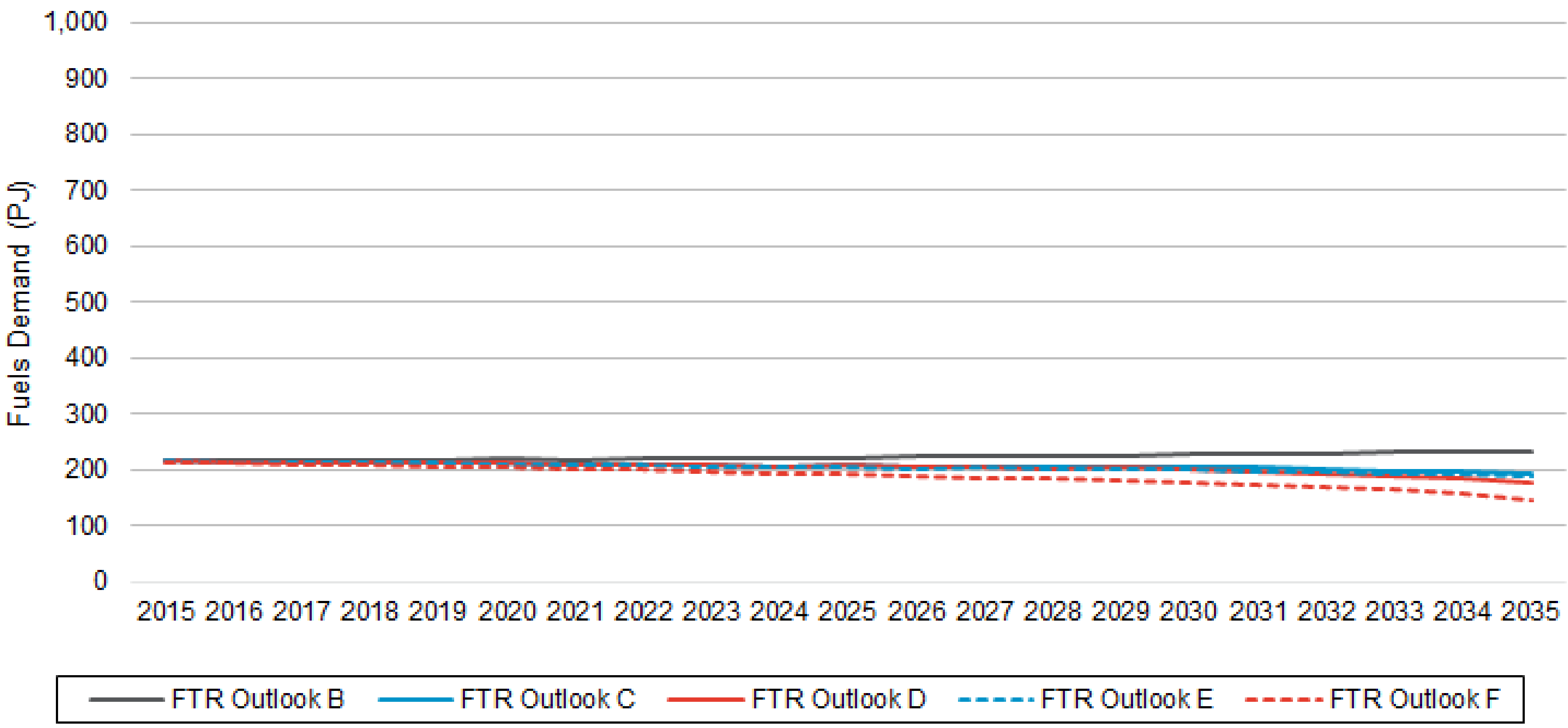
Fuels Demand (PJ)	2015	2025					2035				
	All Outlooks	B	C	D	E	F	B	C	D	E	F
Fuel Oil	24	19	4	4	4	4	21	1	1	1	0
Natural Gas	369	388	383	368	363	324	400	336	270	295	188
Propane	13	24	4	4	4	3	28	0	0	0	0
Wood	41	45	45	45	45	44	50	50	50	50	49
Renewable Natural Gas	0	0	0	0	17	34	0	0	0	35	66
Total	**447**	**476**	**436**	**421**	**431**	**408**	**498**	**388**	**322**	**381**	**303**

NAVIGANT

COMMERCIAL

NAVIGANT

COMMERCIAL FUELS ENERGY DEMAND 2015-2035: OUTLOOKS B, C, D, E, F



NAVIGANT

COMMERCIAL FUELS ENERGY DEMAND 2015-2035: OUTLOOKS B, C, D, E, F

	Commercial (PJ)				
Year	B	C	D	E	F
2015	215	215	215	215	214
2016	215	213	213	213	210
2017	216	213	213	213	209
2018	217	212	212	211	206
2019	218	212	212	211	206
2020	219	210	210	209	203
2021	218	209	209	207	200
2022	218	209	209	207	199
2023	219	208	208	205	196
2024	220	206	206	204	193
2025	221	206	206	204	192
2026	222	205	205	202	189
2027	223	206	203	203	186
2028	224	204	202	201	183
2029	226	203	203	199	182
2030	227	204	199	200	177
2031	228	202	198	198	174
2032	229	201	194	197	169
2033	231	197	190	193	163
2034	232	196	183	191	155
2035	233	192	177	187	147

Note: Historical data used to calibrate the CanESS model are obtained from Statistics Canada and NRCan. Actual values in most cases are available only until 2013, meaning that 2015 values reported here are estimated, and outlook-specific, hence why they differ very slightly across outlooks.

NAVIGANT

COMMERCIAL SECTOR OVERVIEW

- The principal factor that could drive an increase in commercial fuels demand in Outlook B is the forecast growth in commercial floor-space in the province.

- Factors that could decrease commercial fuels demand include:
  - Electrification of space- and water-heating
  - Incremental building envelope improvement*
  - Incremental natural gas equipment efficiency improvements*

- In Outlook E and F, a substantial proportion of fuels energy shifts from fossil sources (e.g. natural gas) to renewable ones (e.g. renewable natural gas). This shift affects GHG emissions, but does not materially affect total fuels energy use.

***Note:** Incremental improvement modeled in Outlooks E and F corresponds to incremental achievable DSM potential identified in the OEB's 2016 Natural Gas Conservation Potential study for the semi-constrained and unconstrained (respectively) achievable potential scenarios, after accounting for the erosion of DSM potential due to electrification.

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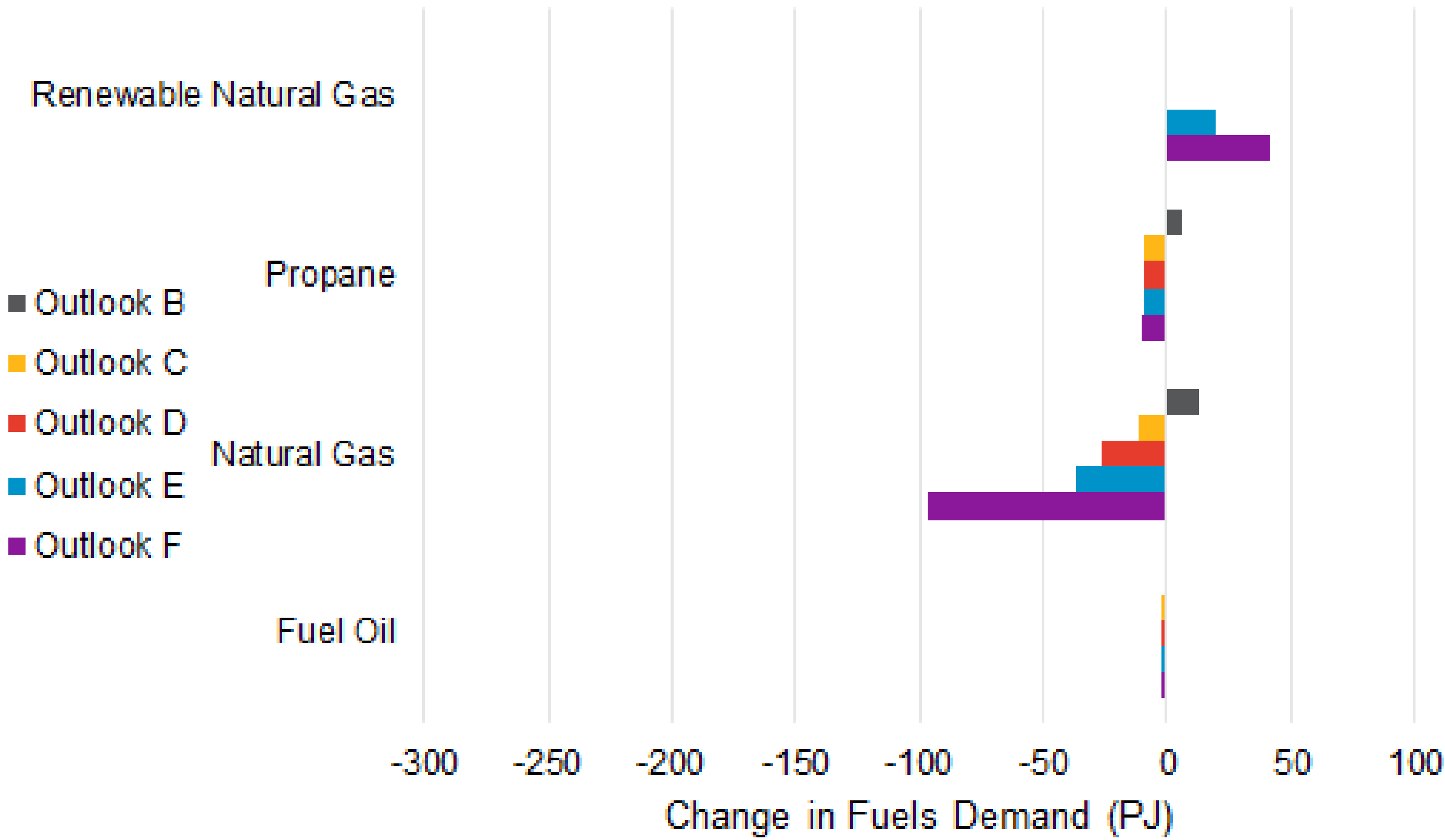
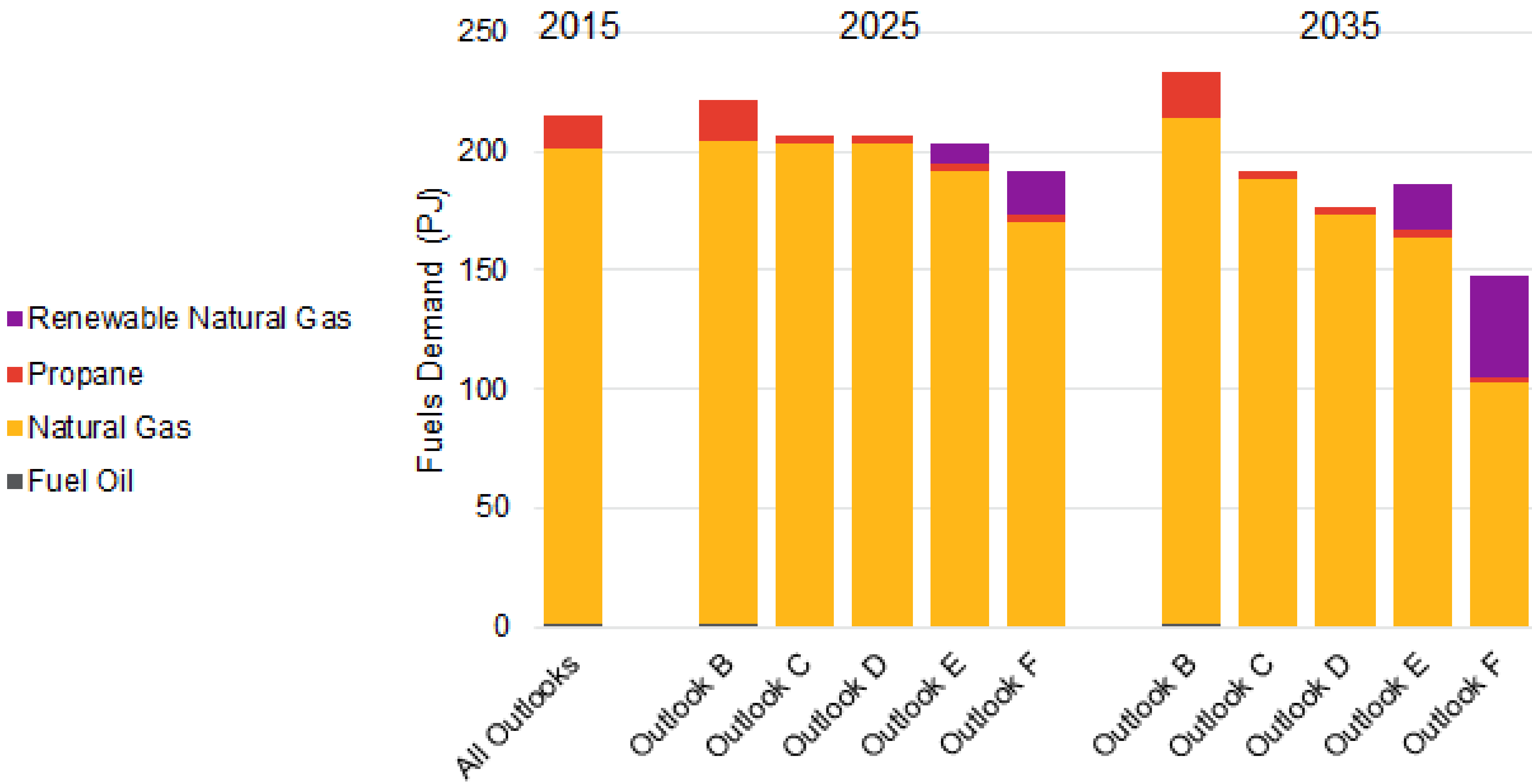
FORECAST CHANGE IN COMMERCIAL FUELS DEMAND BY FUEL TYPE 2015 - 2035



NAVIGANT

COMMERCIAL DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F



COMMERCIAL DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F

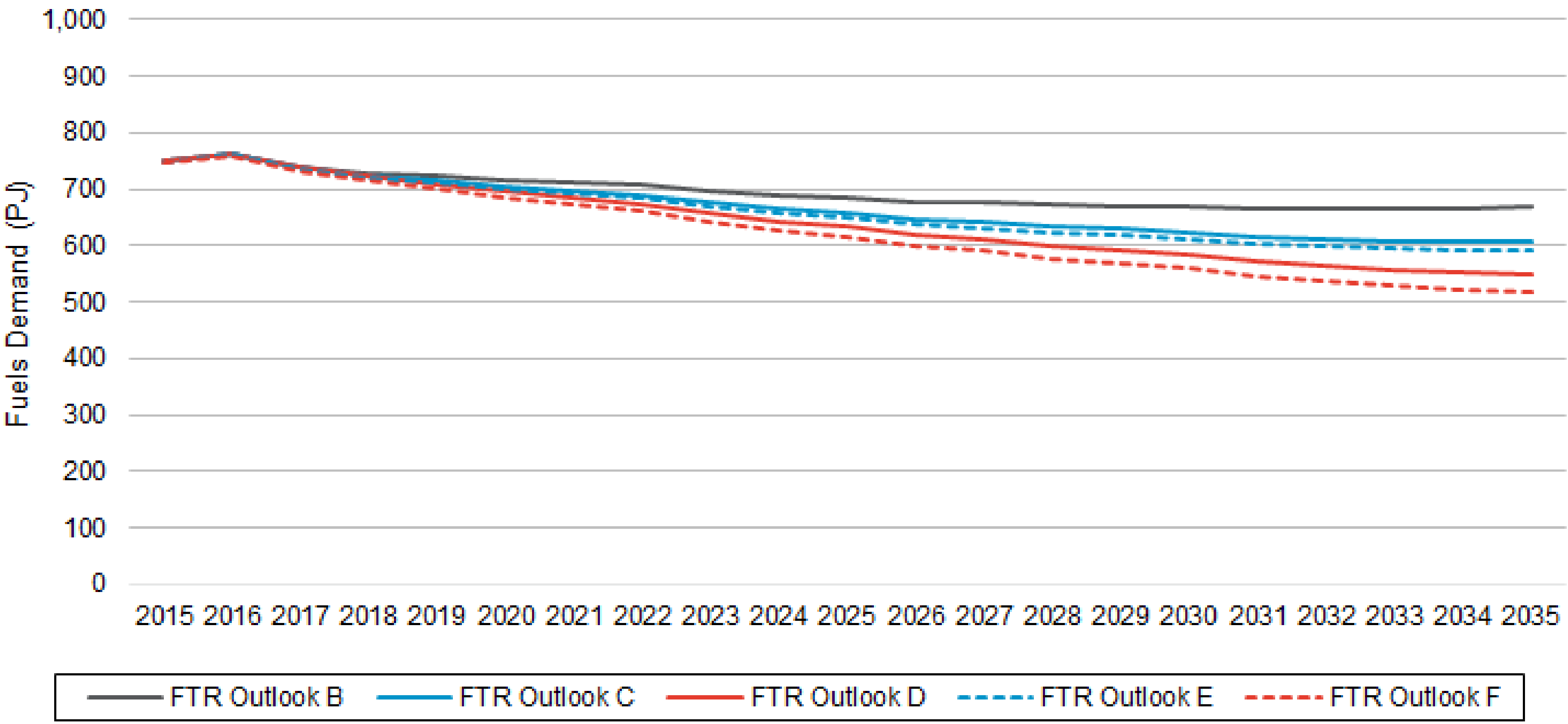
Fuels Demand (PJ)	2015	2025					2035				
	All Outlooks	B	C	D	E	F	B	C	D	E	F
Fuel Oil	2	1	0	0	0	0	1	0	0	0	0
Natural Gas	200	203	203	203	192	170	213	188	173	163	103
Propane	13	16	3	3	3	3	19	4	4	4	3
Renewable Natural Gas	0	0	0	0	9	19	0	0	0	20	42
Total	**215**	**221**	**206**	**206**	**204**	**192**	**233**	**192**	**177**	**187**	**147**

NAVIGANT

INDUSTRIAL

NAVIGANT

INDUSTRIAL FUELS ENERGY DEMAND 2015-2035: OUTLOOKS B, C, D, E, F



Note: does not include industrial non-energy fuels demand

INDUSTRIAL FUELS ENERGY DEMAND 2015-2035: OUTLOOKS B, C, D, E, F

	Industrial (PJ)				
Year	B	C	D	E	F
2015	750	750	750	749	748
2016	763	763	763	761	760
2017	738	738	738	736	733
2018	729	725	722	722	715
2019	722	715	709	711	700
2020	715	704	695	699	685
2021	712	698	685	692	674
2022	708	691	674	684	661
2023	697	677	658	670	643
2024	690	666	644	658	628
2025	686	659	633	650	616
2026	678	648	618	638	600
2027	677	642	610	632	590
2028	672	634	598	623	577
2029	671	629	590	617	568
2030	670	624	583	612	559
2031	665	616	571	603	546
2032	665	612	564	598	538
2033	665	609	558	594	530
2034	667	607	553	592	524
2035	671	607	550	591	519

Note: Historical data used to calibrate the CanESS model are obtained from Statistics Canada and NRCan. Actual values in most cases are available only until 2013, meaning that 2015 values reported here are estimated, and outlook-specific, hence why they differ very slightly across outlooks.

Note: does not include industrial non-energy fuels demand

INDUSTRIAL SECTOR OVERVIEW

- Factors that could increase industrial fuels demand beyond what is examined by the five outlooks include shifts in macroeconomic trends and provincial industrial economic activity.

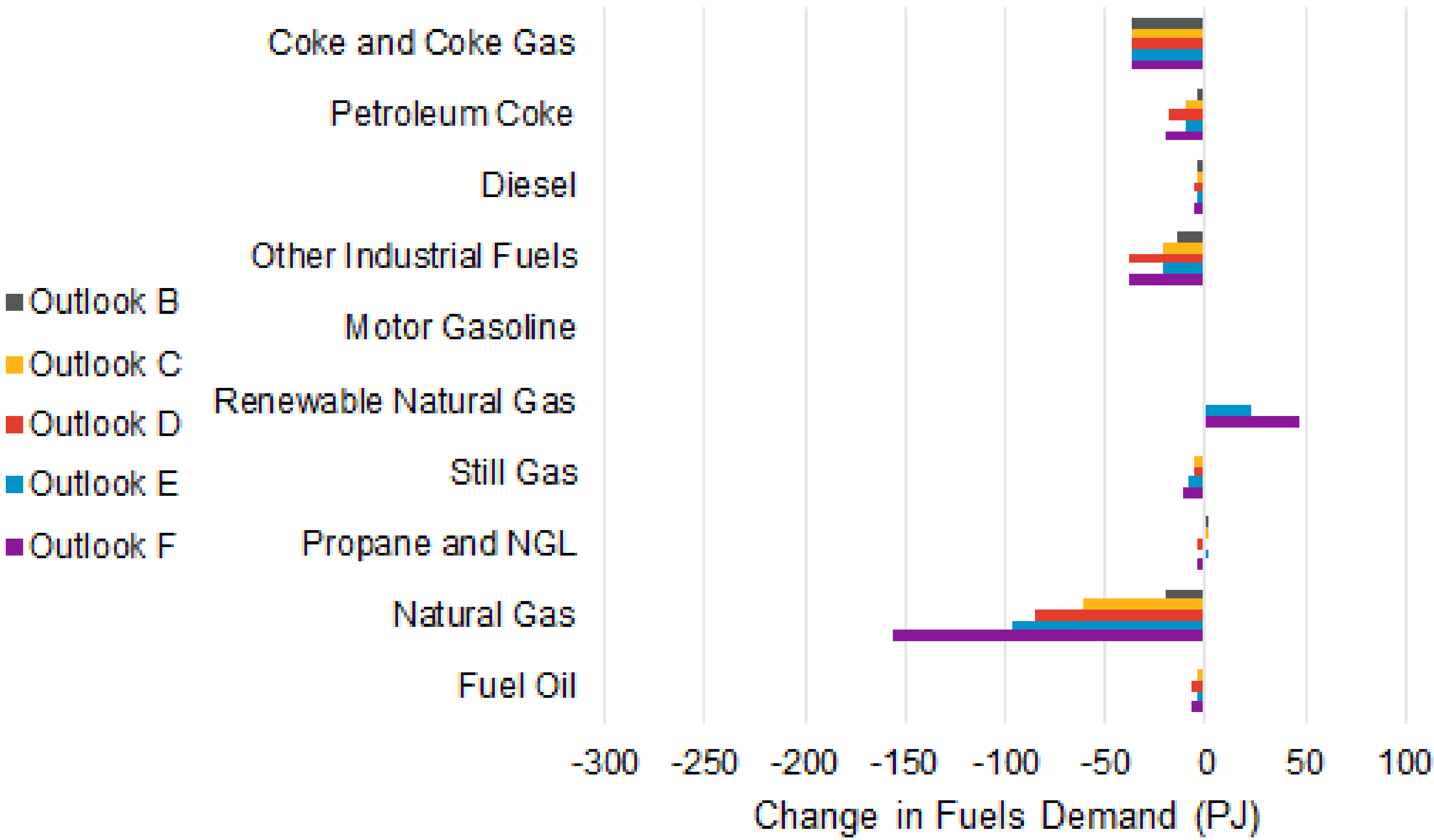
- Factors that could decrease industrial fuels demand include:
  - Electrification of industrial processes
  - Incremental natural gas equipment efficiency improvements*

- In Outlooks E and F, a substantial proportion of fuels energy shifts from conventional fossil sources (e.g. natural gas) to renewable ones (e.g. renewable natural gas). This shift affects GHG emissions, but does not materially affect total fuels energy use.

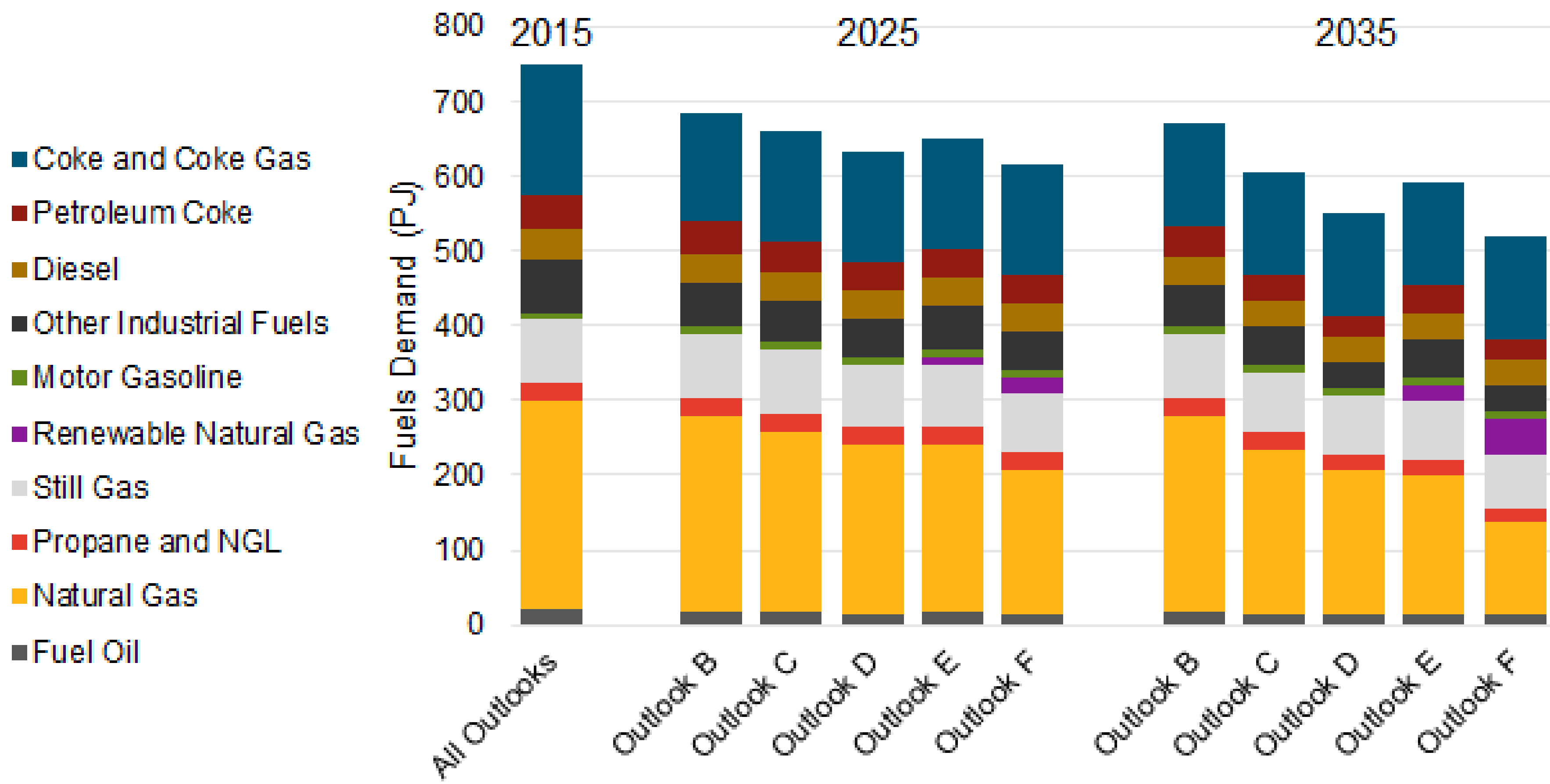
*__Note:__ Incremental improvement modeled in Outlooks E and F corresponds to incremental achievable DSM potential identified in the Ontario Energy Board's 2016 Natural Gas Conservation Potential study for the semi-constrained and unconstrained (respectively) achievable potential scenarios, after accounting for the erosion of DSM potential due to electrification.

NAVIGANT

FORECAST CHANGE IN INDUSTRIAL FUELS DEMAND BY FUEL TYPE 2015 - 2035



INDUSTRIAL DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F



Note: does not include industrial non-energy fuels demand

INDUSTRIAL DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F

Fuels Demand (PJ)	2015	2025					2035				
	All Outlooks	B	C	D	E	F	B	C	D	E	F
Fuel Oil	20	19	18	16	17	16	19	15	13	15	13
Natural Gas	281	260	241	224	224	190	260	220	195	184	124
Propane and NGL	23	25	25	24	25	24	24	23	19	23	19
Still Gas	85	85	84	84	83	81	85	79	79	77	74
Renewable Natural Gas	0	0	0	0	11	20	0	0	0	23	48
Motor Gasoline	10	10	10	10	10	10	10	10	10	10	10
Other Industrial Fuels	71	59	56	53	56	53	57	50	33	50	33
Diesel	40	38	38	37	38	37	37	36	36	36	36
Petroleum Coke	45	42	40	38	40	37	41	36	27	35	26
Coke and Coke Gas	175	147	147	147	147	147	138	138	138	138	138
Total	**750**	**686**	**659**	**633**	**650**	**616**	**671**	**607**	**550**	**591**	**519**

Note: does not include industrial non-energy fuels demand

NAVIGANT

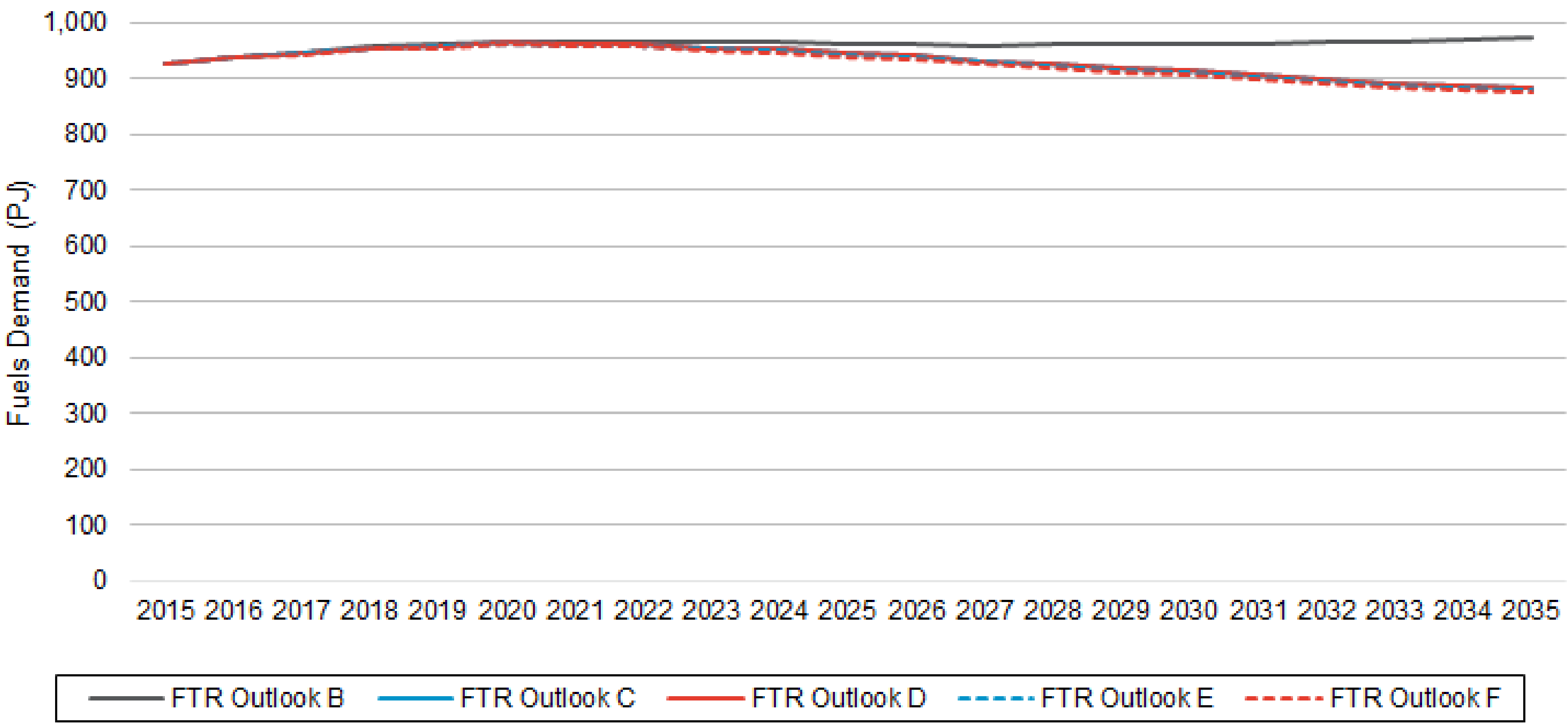
INDUSTRIAL NON-ENERGY FUELS DEMAND:

- In addition to energy and combustion-related demand, a substantial amount of fuels product is used in non-energy processes as a raw material feedstock.

- Industrial non-energy fuels demand is not modeled in the outlooks and is not included in the preceding energy demand charts and tables.

TRANSPORTATION

TRANSPORTATION FUELS ENERGY DEMAND 2015-2035: OUTLOOKS B, C, D, E, F



TRANSPORTATION FUELS ENERGY DEMAND 2015-2035: OUTLOOKS B, C, D, E, F

	Transportation				
Year	B	C	D	E	F
2015	927	926	926	926	926
2016	938	937	937	937	936
2017	945	945	945	944	943
2018	956	955	955	954	952
2019	960	959	959	957	955
2020	966	964	964	962	960
2021	965	961	961	959	957
2022	967	961	961	959	956
2023	964	955	955	952	950
2024	964	952	952	949	947
2025	961	945	945	942	939
2026	962	940	940	937	934
2027	959	932	932	928	925
2028	961	927	927	923	920
2029	960	918	918	915	911
2030	963	913	913	909	906
2031	963	905	905	901	898
2032	966	900	900	896	892
2033	967	892	892	888	884
2034	971	887	887	882	878
2035	975	883	883	878	874

Note: Historical data used to calibrate the CanESS model are obtained from Statistics Canada and NRCan. Actual values in most cases are available only until 2013, meaning that 2015 values reported here are estimated, and outlook-specific, hence why they differ very slightly across outlooks.

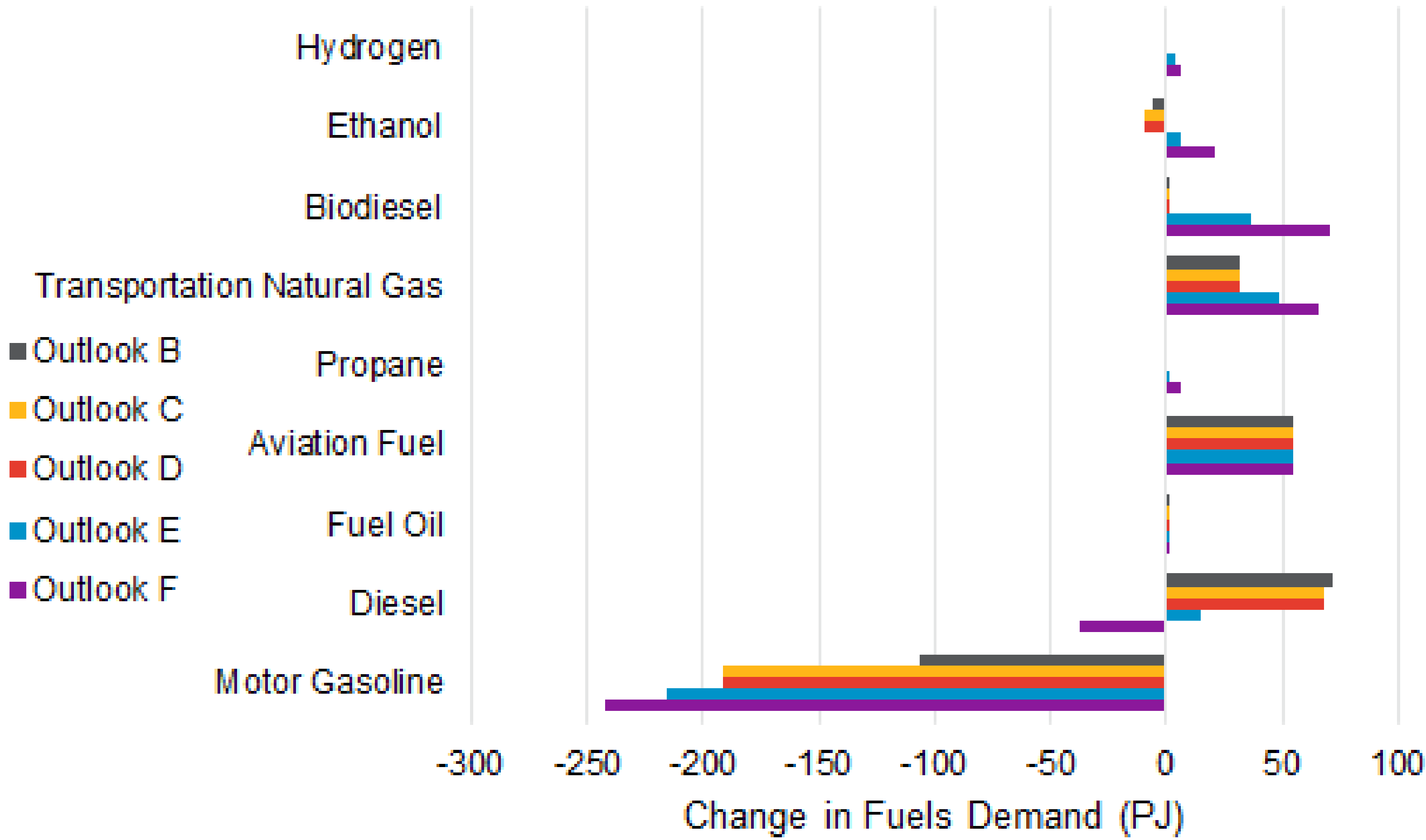
TRANSPORTATION SECTOR OVERVIEW

- Factors that could increase transportation fuels demand include:
  - The forecast increase in the number of households, and associated additional vehicle kilometres travelled.
  - The extension of the current upward trend in freight and air travel fuels use in Ontario.

- Factors that could decrease transportation fuels demand include:
  - Electrification of transportation as a result of increasing numbers of EVs and the use of electrified public transit;
  - Fuel economy standards (e.g., Corporate Average Fuel Consumption); and
  - The shift to fuels used in vehicles with higher levels of combustion efficiency (e.g., hydrogen personal vehicles, LNG freight).

- In Outlooks E and F, a substantial proportion of fuels energy shifts from conventional fossil sources (e.g., gasoline and diesel) to alternative fossil fuels that emit less carbon (e.g., LNG or propane) or to renewable fuels (e.g., ethanol, bio-based diesels). This shift affects GHG emissions, but has little effect on total fuels energy use.

FORECAST CHANGE IN TRANSPORTATION FUELS DEMAND BY FUEL TYPE 2015 - 2035



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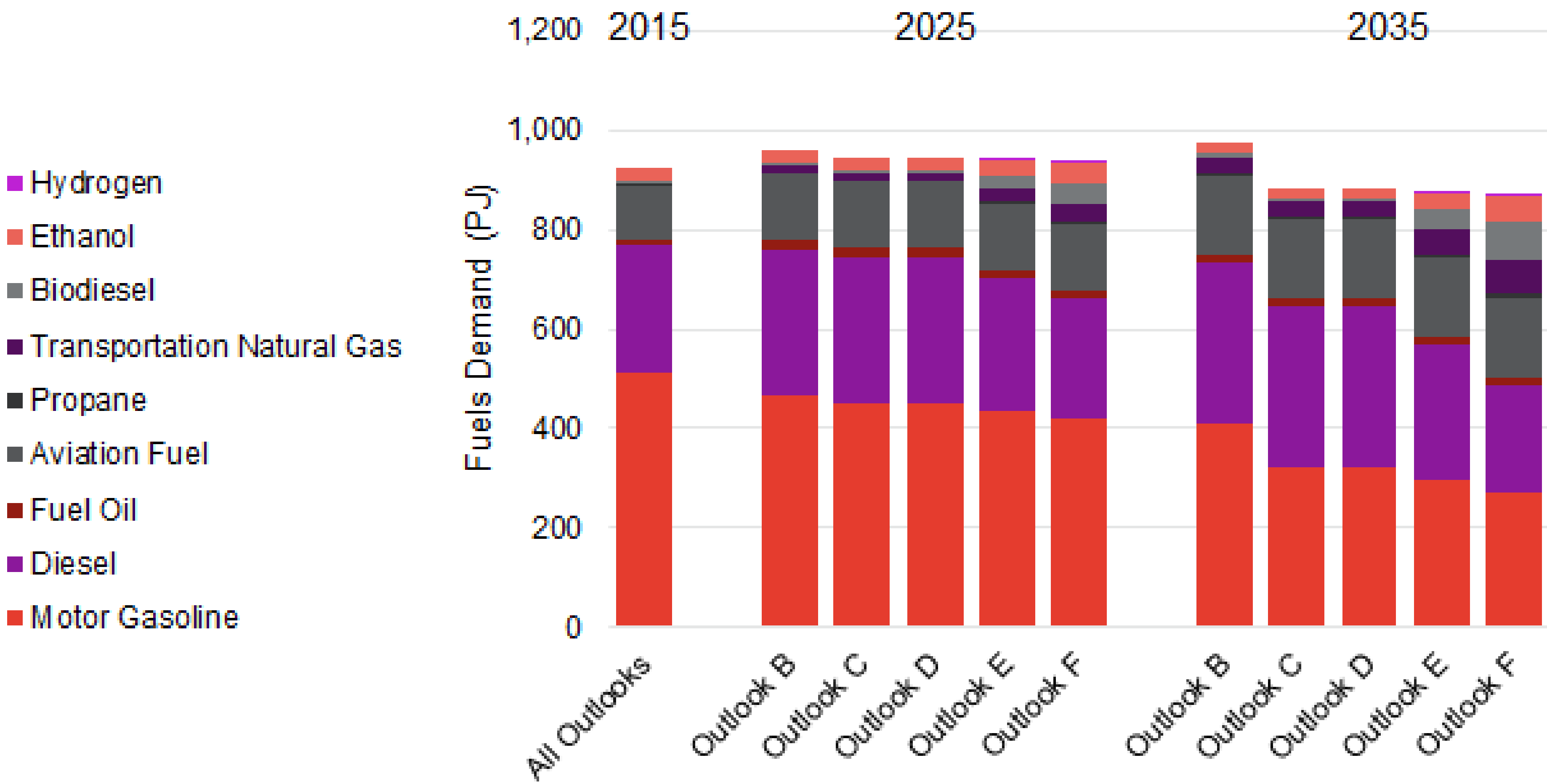
TRANSPORTATION DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F



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TRANSPORTATION DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F

Fuels Demand (PJ)	2015	2025					2035				
	All Outlooks	B	C	D	E	F	B	C	D	E	F
Motor Gasoline	514	467	451	451	437	422	408	323	323	298	272
Diesel	254	295	295	295	266	238	326	322	322	269	217
Fuel Oil	14	16	16	16	16	16	16	16	16	16	16
Aviation Fuel	105	134	134	134	134	134	159	159	159	159	159
Propane	5	5	5	5	6	9	4	4	4	7	11
Transportation Natural Gas	2	13	13	13	23	33	33	33	33	50	67
Biodiesel	5	6	6	6	25	43	7	7	7	42	77
Ethanol	28	25	25	25	32	40	22	19	19	34	49
Hydrogen	0	0	0	0	2	4	0	0	0	3	7
Total	**927**	**961**	**945**	**945**	**942**	**939**	**975**	**883**	**883**	**878**	**874**

NAVIGANT

FUELS TECHNICAL REPORT – MODULE 3: EMISSIONS OUTLOOK

SEPTEMBER 2016

NAVIGANT REFERENCE 187360

NAVIGANT

EMISSIONS OUTLOOK

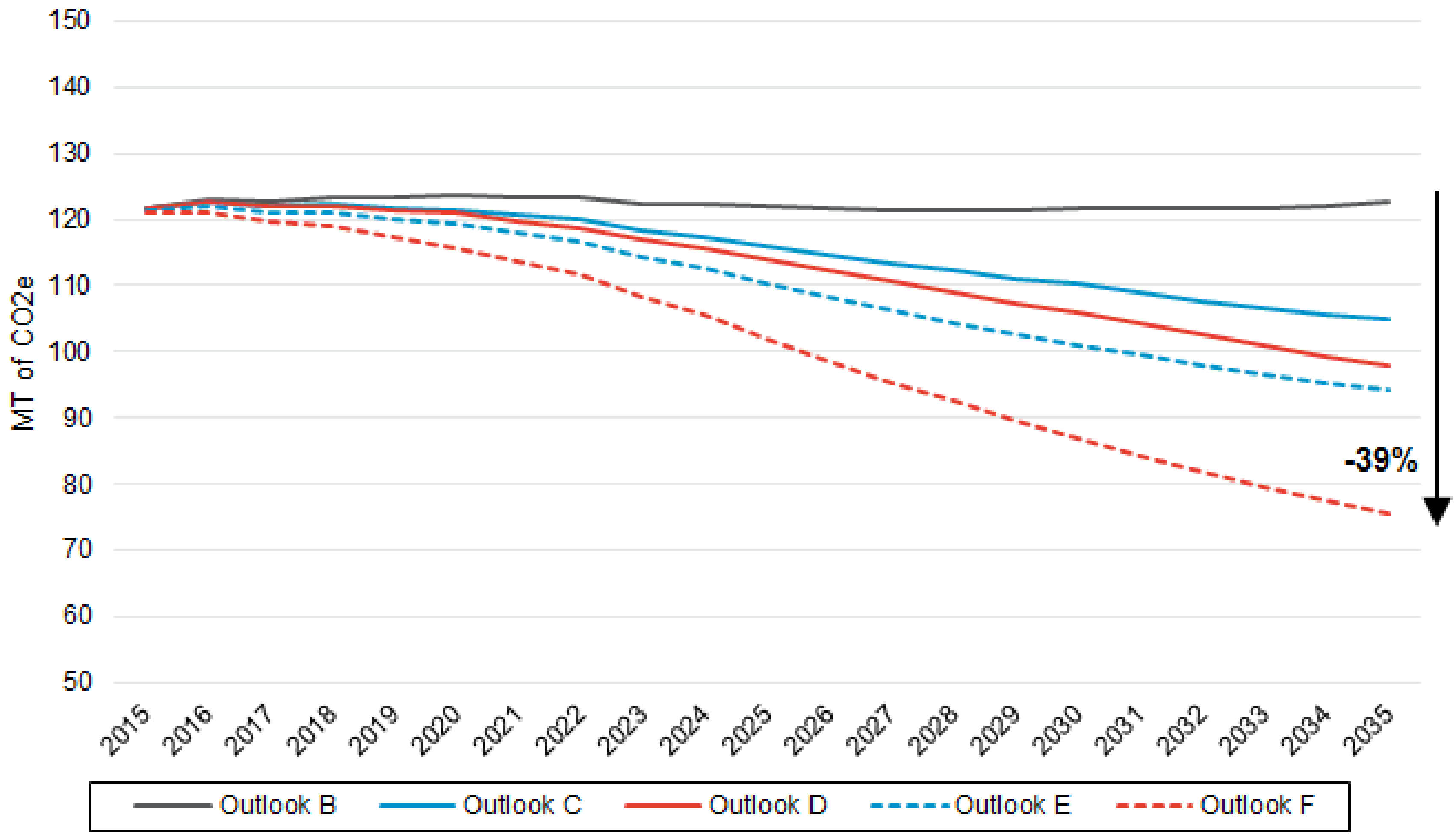
- The following slides provide additional detail on the greenhouse gas (GHG) emissions outlook discussed in the Fuels Technical Report (FTR).

- Total GHG emissions from CO_2, CH_4 and N_2O are presented in megatonnes (MT) of carbon dioxide equivalent (CO_2e) for each demand outlook and sector.

- All graphs are accompanied by the data supporting them.

Note: The GHG emissions outlook does not include emissions from electricity generation, which are addressed in the IESO's Ontario Planning Outlook, or from industrial non-energy fuels demand.

FUELS COMBUSTION GHG EMISSIONS OUTLOOK



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FUELS COMBUSTION GHG EMISSIONS OUTLOOK, MT OF CO_2e

Year	B	C	D	E	F
2015	122	122	122	121	121
2016	123	123	123	122	121
2017	123	122	122	121	120
2018	123	122	122	121	119
2019	123	122	121	120	117
2020	124	122	121	119	116
2021	123	121	120	118	114
2022	123	120	119	117	112
2023	123	118	117	114	108
2024	122	117	116	113	106
2025	122	116	114	110	102
2026	122	115	112	108	99
2027	121	113	111	106	95
2028	121	112	109	104	92
2029	121	111	107	103	90
2030	122	110	106	101	87
2031	122	109	104	99	84
2032	122	108	103	98	82
2033	122	106	101	96	80
2034	122	106	99	95	77
2035	123	105	98	94	75

Note: Historical data used to calibrate the CanESS model are obtained from Statistics Canada and NRCan. Actual values in most cases are available only until 2013, meaning that 2015 values reported here are estimated, and outlook-specific, hence why they differ slightly across outlooks.

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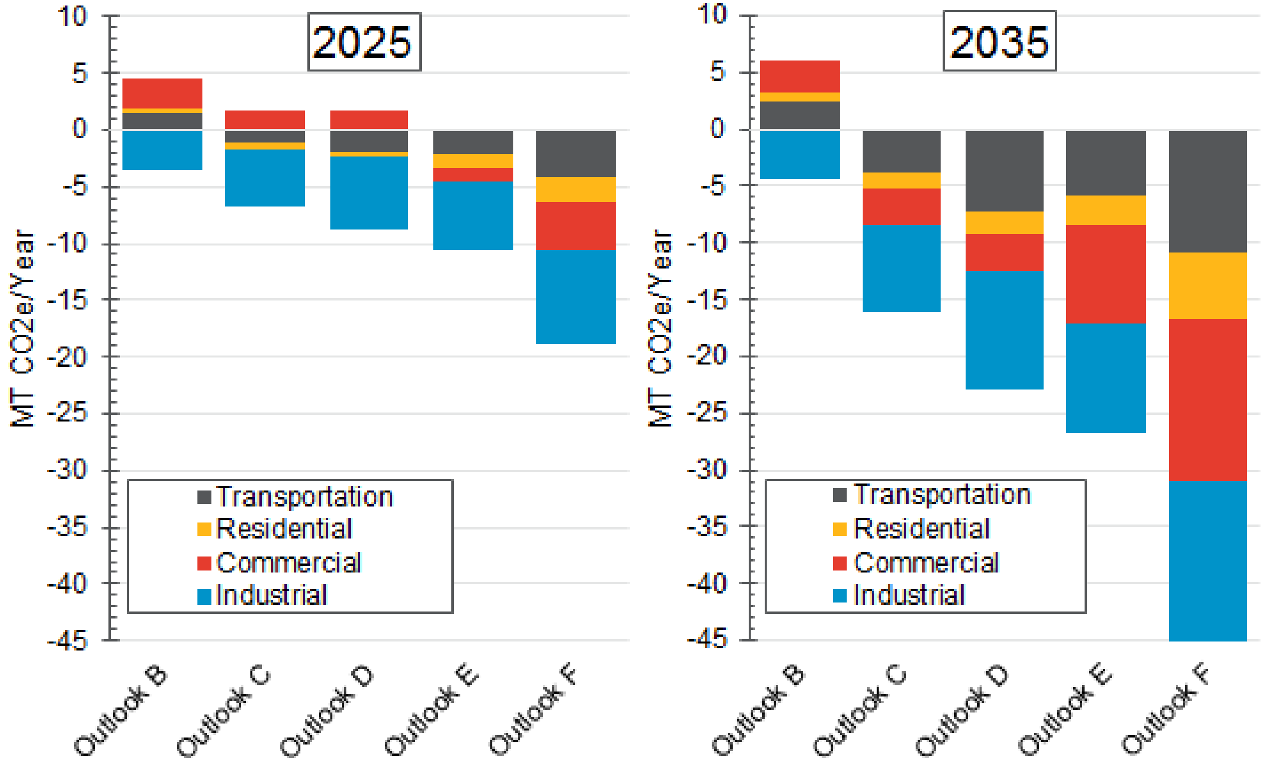
EMISSIONS RELATIVE TO 2014 LEVELS



MT CO_2e/Year	B 2025	C 2025	D 2025	E 2025	F 2025	B 2035	C 2035	D 2035	E 2035	F 2035
Transportation	1	-1	-2	-2	-4	2	-4	-7	-6	-11
Residential	0	-1	-1	-1	-2	1	-1	-2	-3	-6
Commercial	3	2	2	-1	-4	3	-3	-3	-9	-14
Industrial	-4	-5	-6	-6	-8	-4	-8	-11	-10	-15

NAVIGANT

RESIDENTIAL FUELS COMBUSTION GHG EMISSIONS OUTLOOK, MT OF CO_2e

	Residential				
Year	B	C	D	E	F
2015	21	21	21	21	21
2016	21	21	21	21	21
2017	21	21	21	21	21
2018	22	21	21	21	21
2019	22	21	21	21	21
2020	22	21	21	21	20
2021	22	21	20	20	20
2022	22	20	20	20	19
2023	22	20	20	20	18
2024	22	20	19	19	18
2025	22	20	19	19	17
2026	22	19	18	18	16
2027	22	19	18	17	15
2028	22	19	17	17	14
2029	22	18	17	16	13
2030	23	18	16	16	12
2031	23	18	16	16	12
2032	23	18	15	16	11
2033	23	17	15	15	11
2034	23	17	14	15	10
2035	23	17	13	15	10

NAVIGANT

COMMERCIAL FUELS COMBUSTION GHG EMISSIONS OUTLOOK, MT OF CO_2e

	Commercial				
Year	B	C	D	E	F
2015	11	11	11	11	11
2016	11	11	11	11	11
2017	11	11	11	11	11
2018	11	11	11	11	10
2019	11	11	11	11	10
2020	11	11	11	10	10
2021	11	10	10	10	10
2022	11	10	10	10	10
2023	11	10	10	10	9
2024	11	10	10	10	9
2025	11	10	10	10	9
2026	11	10	10	9	8
2027	11	10	10	9	8
2028	11	10	10	9	7
2029	11	10	10	9	7
2030	11	10	10	9	7
2031	12	10	10	9	6
2032	12	10	10	9	6
2033	12	10	9	9	6
2034	12	10	9	8	5
2035	12	10	9	8	5

NAVIGANT

INDUSTRIAL FUELS COMBUSTION GHG EMISSIONS OUTLOOK, MT OF CO_2e

	Industrial				
Year	B	C	D	E	F
2015	29	29	29	29	29
2016	29	29	29	29	29
2017	28	28	28	28	28
2018	28	27	27	27	27
2019	27	27	26	27	26
2020	27	26	26	26	25
2021	27	26	25	26	24
2022	26	26	25	25	24
2023	26	25	24	24	23
2024	25	24	23	23	22
2025	25	24	22	23	21
2026	25	23	22	22	19
2027	25	23	21	22	19
2028	24	22	21	21	18
2029	24	22	20	21	17
2030	24	22	20	20	16
2031	24	22	19	20	16
2032	24	21	19	19	15
2033	24	21	18	19	15
2034	24	21	18	19	14
2035	24	21	18	19	14

Note: Does not include emissions from industrial non-energy fuels demand

NAVIGANT

TRANSPORTATION FUELS COMBUSTION GHG EMISSIONS OUTLOOK, MT OF CO_2e

	Transportation				
Year	B	C	D	E	F
2015	61	61	61	61	61
2016	62	62	62	61	61
2017	62	62	62	62	61
2018	63	63	63	62	61
2019	63	63	63	62	61
2020	64	64	64	62	60
2021	64	64	64	62	60
2022	64	63	63	61	59
2023	64	63	63	61	58
2024	64	63	63	60	57
2025	63	62	62	59	56
2026	63	62	62	59	55
2027	63	61	61	58	54
2028	63	61	61	57	53
2029	63	60	60	56	52
2030	63	60	60	56	52
2031	63	60	60	55	51
2032	63	59	59	54	49
2033	63	58	58	53	48
2034	63	58	58	53	47
2035	64	58	58	52	47

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FUELS TECHNICAL REPORT – MODULE 4: FUELS SYSTEM COST OUTLOOK

SEPTEMBER 2016

NAVIGANT REFERENCE 187360

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OVERVIEW

- The following module summarizes the components of fuels energy system costs for Ontario consumers under the conditions of each of the demand outlooks. **Note**: Further information with respect to the demand outlooks can be found in Module 2 “Demand Outlook”.
- For each Of the demand outlooks, the total cost of energy-related fuel use (excluding costs for electricity generation) and the average unit cost are summarized. **Note:** The cost of non-energy fuel use by the industrial system is not included.
- The cost outlooks illustrated here are not forecasts, and do not address the future volatility of energy prices. They illustrate a range of possible outcomes based on the assumptions made within each outlook.
- The cost outlooks have been developed by applying each demand outlook to a set of projected fuels prices. Fuel price projections were obtained, or adapted, from fuels price projections developed by other (principally public) agencies and represent “delivered” prices (i.e., the actual cost paid by the consumer).
- This module provides additional detail that underlies the total system and average unit costs presented in the Fuels Technical Report and also outlines the underlying price assumptions and inputs that determine the system cost outlooks.
- All currency values provided in this module are expressed as 2016 real Canadian dollars.

FUELS SYSTEM COST OUTLOOK

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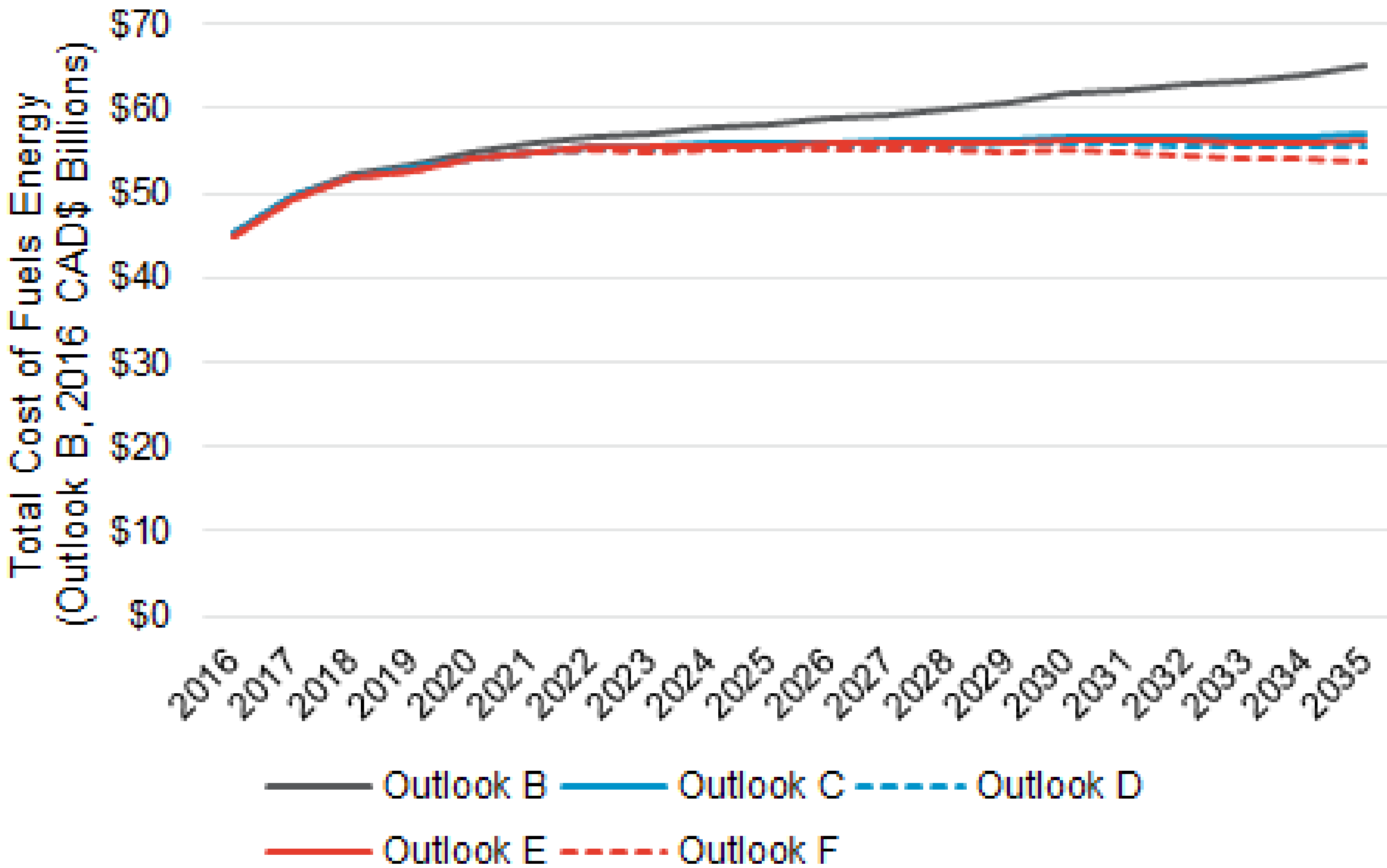
TOTAL SYSTEM COSTS



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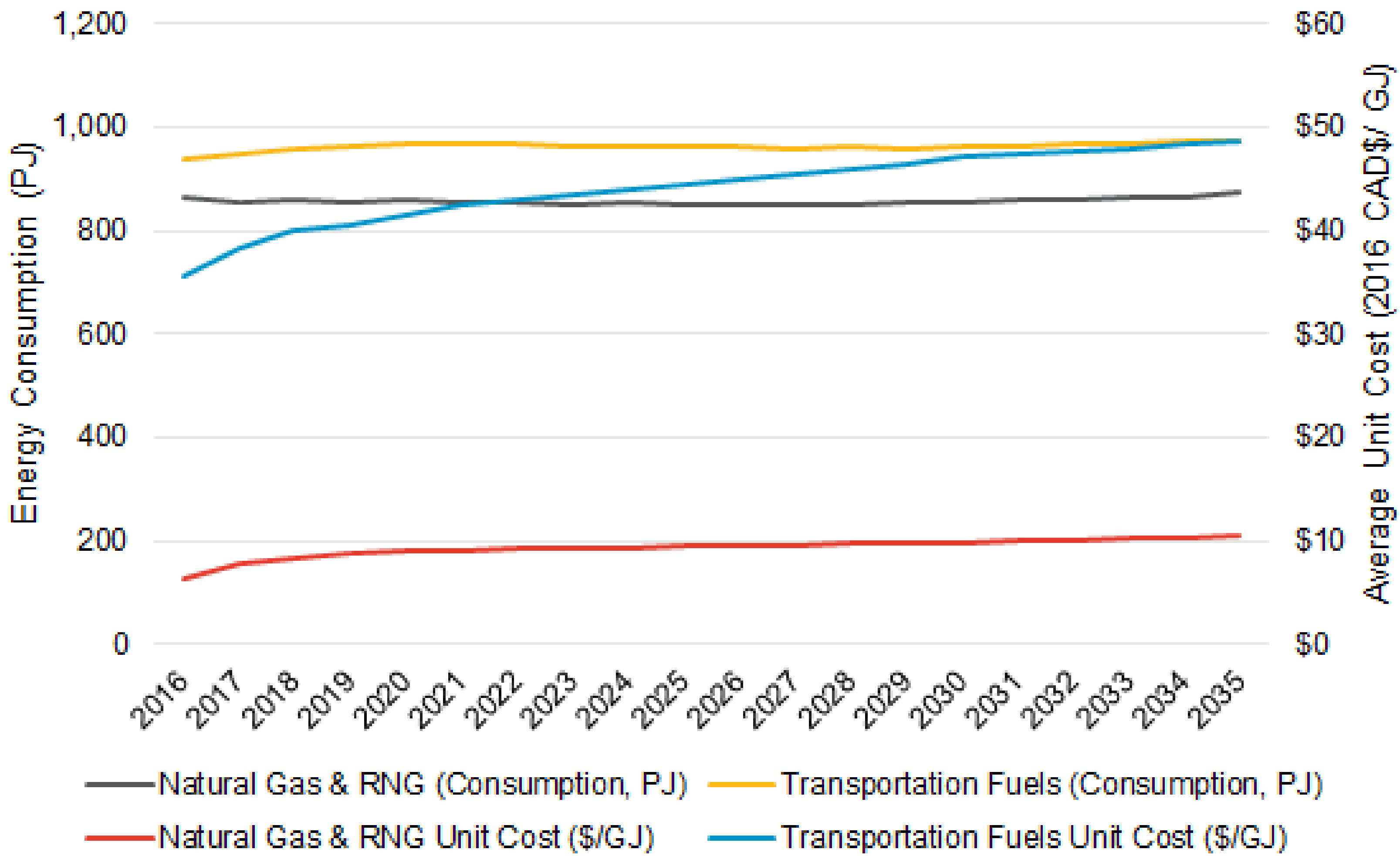
TOTAL SYSTEM COSTS (2016 CAD$ BILLIONS)

Year	Outlook B	Outlook C	Outlook D	Outlook E	Outlook F
2016	$45	$45	$45	$45	$45
2017	$50	$50	$50	$50	$50
2018	$52	$52	$52	$52	$52
2019	$53	$53	$53	$53	$53
2020	$55	$54	$54	$54	$54
2021	$56	$55	$55	$55	$55
2022	$57	$56	$55	$56	$55
2023	$57	$56	$55	$56	$55
2024	$58	$56	$55	$56	$56
2025	$58	$56	$55	$56	$56
2026	$59	$56	$56	$56	$56
2027	$59	$56	$56	$56	$56
2028	$60	$56	$56	$56	$56
2029	$61	$56	$56	$56	$56
2030	$62	$57	$56	$57	$56
2031	$62	$57	$56	$57	$55
2032	$63	$57	$56	$56	$55
2033	$63	$57	$55	$56	$55
2034	$64	$57	$55	$56	$55
2035	$65	$57	$56	$57	$55

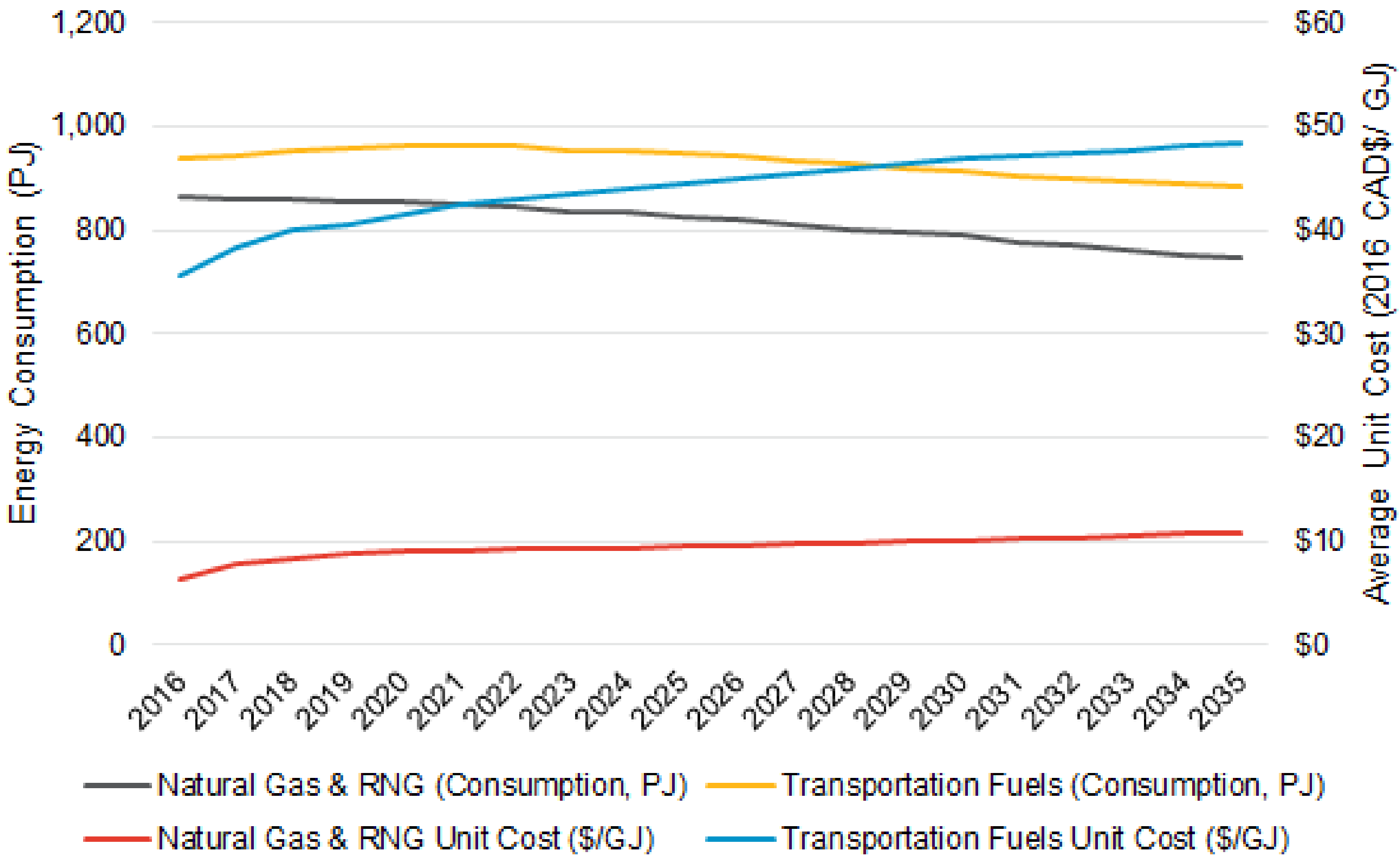
AVERAGE UNIT COSTS – OUTLOOK B



AVERAGE UNIT COSTS – OUTLOOK B

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Natural Gas & RNG (Consumption, PJ)	862	854	857	856	858	855	856	851	853	852
Transportation Fuels (Consumption, PJ)	938	945	956	960	966	965	967	964	964	961
Natural Gas & RNG Unit Cost ($/GJ)	$6	$8	$8	$9	$9	$9	$9	$9	$9	$9
Transportation Fuels Unit Cost ($/GJ)	$36	$38	$40	$41	$41	$42	$43	$43	$44	$44
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Natural Gas & RNG (Consumption, PJ)	852	850	852	853	857	857	861	863	866	873
Transportation Fuels (Consumption, PJ)	962	959	961	960	963	963	966	967	971	975
Natural Gas & RNG Unit Cost ($/GJ)	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10
Transportation Fuels Unit Cost ($/GJ)	$45	$45	$46	$46	$47	$47	$48	$48	$48	$49

AVERAGE UNIT COSTS – OUTLOOK C



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AVERAGE UNIT COSTS – OUTLOOK C

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Natural Gas & RNG (Consumption, PJ)	863	857	858	856	854	848	847	837	832	827
Transportation Fuels (Consumption, PJ)	937	945	955	959	964	961	961	955	952	945
Natural Gas & RNG Unit Cost ($/GJ)	$6	$8	$8	$9	$9	$9	$9	$9	$9	$10
Transportation Fuels Unit Cost ($/GJ)	$36	$38	$40	$41	$41	$42	$43	$43	$44	$44
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Natural Gas & RNG (Consumption, PJ)	819	811	802	794	788	778	771	759	751	744
Transportation Fuels (Consumption, PJ)	940	932	927	918	913	905	900	892	887	883
Natural Gas & RNG Unit Cost ($/GJ)	$10	$10	$10	$10	$10	$10	$10	$11	$11	$11
Transportation Fuels Unit Cost ($/GJ)	$45	$45	$46	$46	$47	$47	$47	$48	$48	$48

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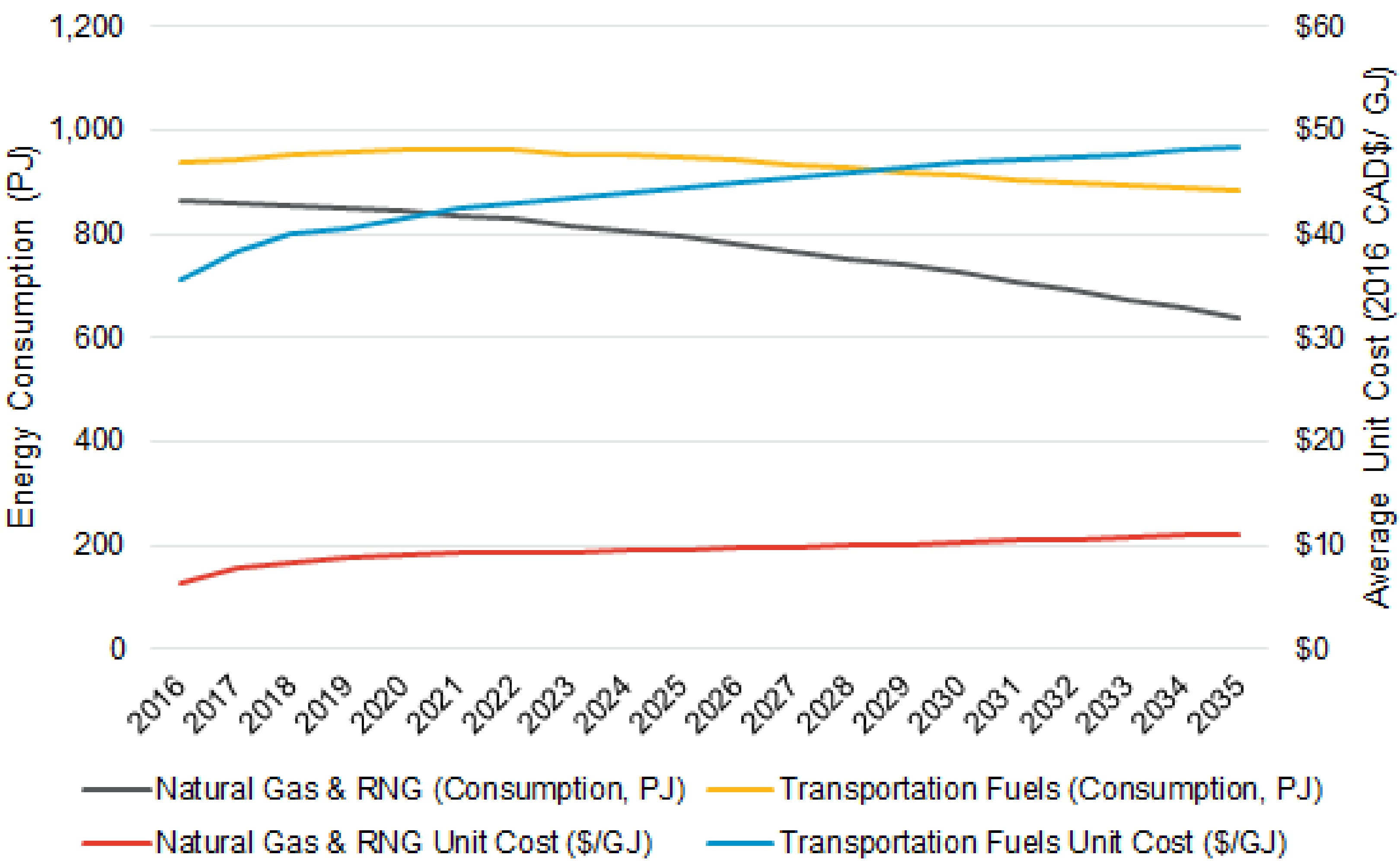
AVERAGE UNIT COSTS – OUTLOOK D



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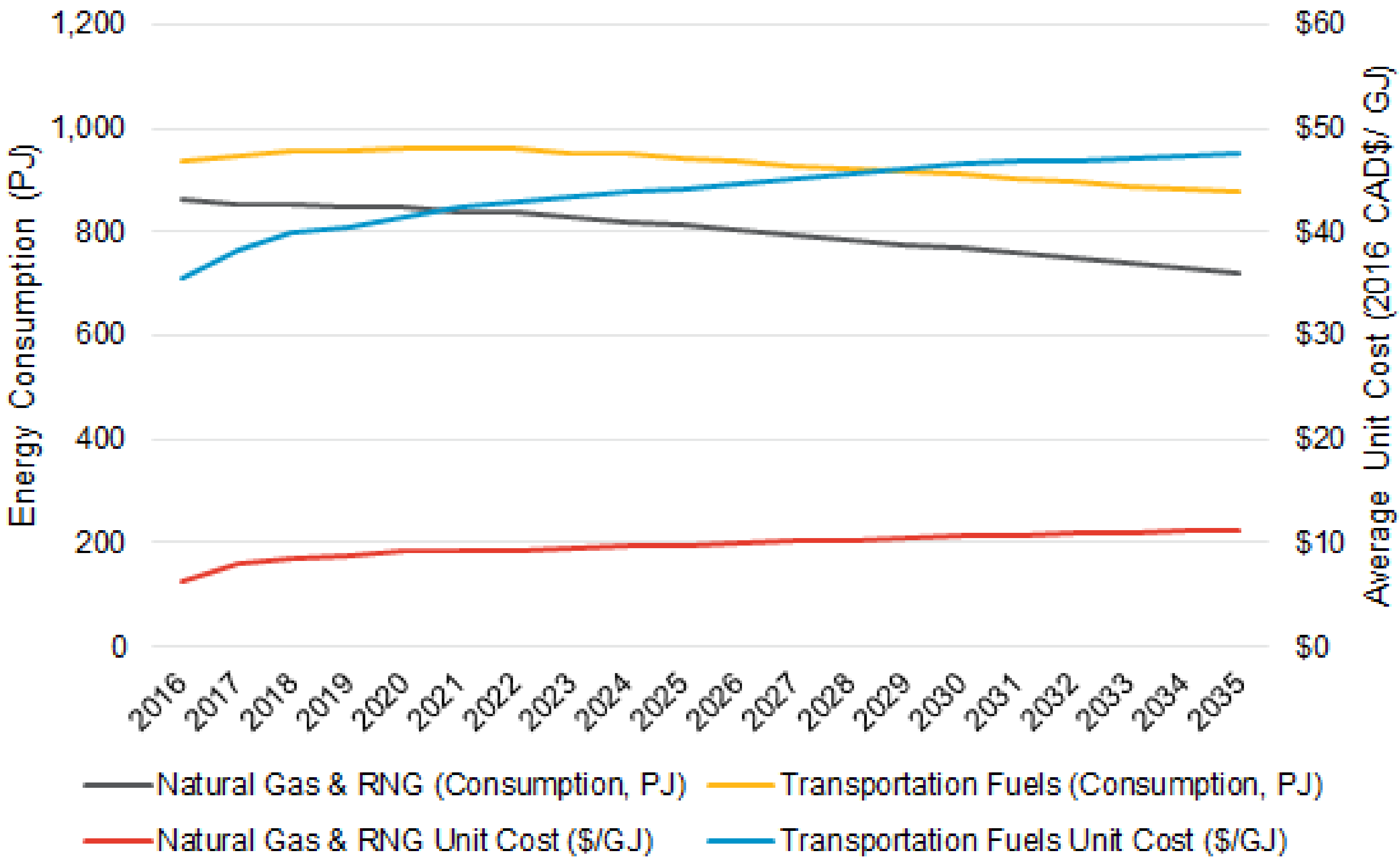
AVERAGE UNIT COSTS – OUTLOOK D

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Natural Gas & RNG (Consumption, PJ)	863	857	855	850	844	834	829	814	805	795
Transportation Fuels (Consumption, PJ)	937	945	955	959	964	961	961	955	952	945
Natural Gas & RNG Unit Cost ($/GJ)	$6	$8	$8	$9	$9	$9	$9	$9	$10	$10
Transportation Fuels Unit Cost ($/GJ)	$36	$38	$40	$41	$41	$42	$43	$43	$44	$44
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Natural Gas & RNG (Consumption, PJ)	781	766	753	740	725	708	692	674	656	639
Transportation Fuels (Consumption, PJ)	940	932	927	918	913	905	900	892	887	883
Natural Gas & RNG Unit Cost ($/GJ)	$10	$10	$10	$10	$10	$10	$11	$11	$11	$11
Transportation Fuels Unit Cost ($/GJ)	$45	$45	$46	$46	$47	$47	$47	$48	$48	$48

AVERAGE UNIT COSTS – OUTLOOK E



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AVERAGE UNIT COSTS – OUTLOOK E

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Natural Gas & RNG (Consumption, PJ)	861	854	854	850	847	840	837	826	821	814
Transportation Fuels (Consumption, PJ)	937	944	954	957	962	959	959	952	949	942
Natural Gas & RNG Unit Cost ($/GJ)	$6	$8	$8	$9	$9	$9	$9	$9	$10	$10
Transportation Fuels Unit Cost ($/GJ)	$36	$38	$40	$41	$42	$42	$43	$43	$44	$44
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Natural Gas & RNG (Consumption, PJ)	805	796	786	776	770	759	750	738	729	721
Transportation Fuels (Consumption, PJ)	937	928	923	915	909	901	896	888	882	878
Natural Gas & RNG Unit Cost ($/GJ)	$10	$10	$10	$10	$11	$11	$11	$11	$11	$11
Transportation Fuels Unit Cost ($/GJ)	$45	$45	$46	$46	$46	$47	$47	$47	$47	$48

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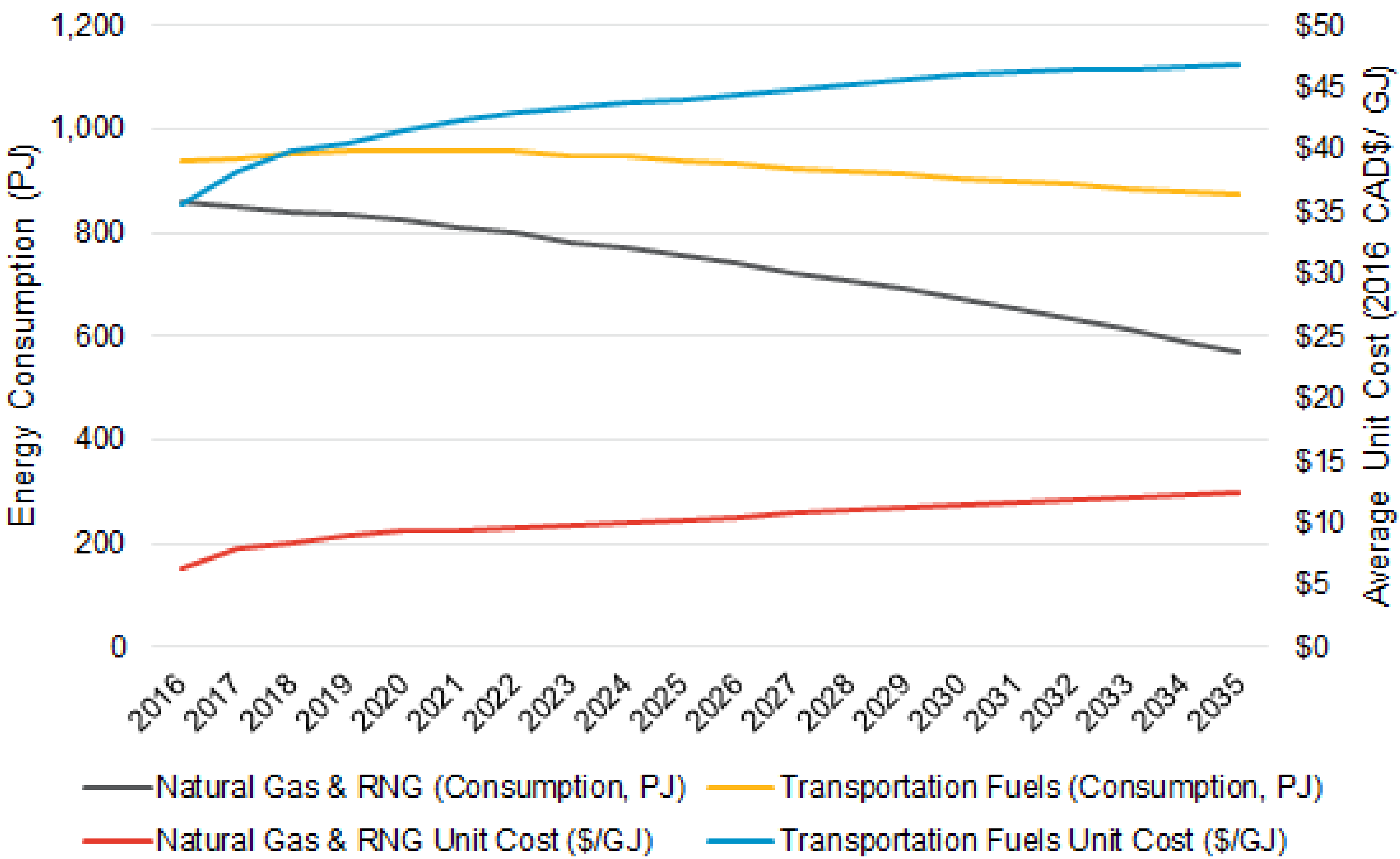
AVERAGE UNIT COSTS – OUTLOOK F



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AVERAGE UNIT COSTS – OUTLOOK F

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Natural Gas & RNG (Consumption, PJ)	857	848	842	832	823	810	800	783	770	757
Transportation Fuels (Consumption, PJ)	936	943	952	955	960	957	956	950	947	939
Natural Gas & RNG Unit Cost ($/GJ)	$6	$8	$8	$9	$9	$9	$10	$10	$10	$10
Transportation Fuels Unit Cost ($/GJ)	$36	$38	$40	$41	$42	$43	$43	$44	$44	$45
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Natural Gas & RNG (Consumption, PJ)	740	722	706	690	671	652	633	612	590	570
Transportation Fuels (Consumption, PJ)	934	925	920	911	906	898	892	884	878	874
Natural Gas & RNG Unit Cost ($/GJ)	$11	$11	$11	$11	$12	$12	$12	$12	$12	$13
Transportation Fuels Unit Cost ($/GJ)	$45	$45	$46	$46	$47	$47	$47	$47	$47	$48

TOTAL SYSTEM COSTS BY FUEL – OUTLOOK B

Total system Costs - Outlook B (Billion 2016 $CAD)										
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Diesel	$11.4	$12.0	$12.6	$12.9	$13.3	$13.7	$14.0	$14.3	$14.7	$15.0
Hydrogen	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Motor Gasoline	$20.0	$20.6	$21.1	$21.2	$21.6	$21.7	$21.8	$21.6	$21.5	$21.3
Natural Gas	$5.4	$6.0	$6.4	$6.8	$7.0	$7.0	$7.0	$7.0	$7.0	$7.1
Other Heating Fuels	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3	$1.4
Other Industrial Fuels	$2.3	$2.3	$2.2	$2.3	$2.3	$2.3	$2.4	$2.3	$2.3	$2.3
Other Transportation Fuels	$2.6	$3.1	$3.5	$3.9	$4.1	$4.4	$4.7	$4.8	$5.1	$5.3
Propane and NGL	$0.8	$0.9	$1.0	$1.1	$1.1	$1.2	$1.2	$1.2	$1.2	$1.2
Renewable Natural Gas	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Transportation Biofuels	$1.4	$1.5	$1.9	$1.9	$2.0	$2.0	$1.9	$1.9	$1.8	$1.8
Carbon Costs	$0.0	$2.1	$2.1	$2.1	$2.3	$2.4	$2.5	$2.6	$2.7	$2.8
Total Cost	$45.2	$49.8	$52.2	$53.4	$55.0	$56.0	$56.8	$57.1	$57.7	$58.1
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Diesel	$15.4	$15.8	$16.1	$16.5	$16.9	$17.2	$17.3	$17.5	$17.7	$18.0
Hydrogen	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Motor Gasoline	$21.2	$21.0	$20.9	$20.8	$20.8	$20.6	$20.5	$20.4	$20.4	$20.4
Natural Gas	$7.1	$7.1	$7.1	$7.2	$7.2	$7.3	$7.3	$7.4	$7.4	$7.5
Other Heating Fuels	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5
Other Industrial Fuels	$2.3	$2.3	$2.3	$2.3	$2.3	$2.3	$2.3	$2.3	$2.4	$2.4
Other Transportation Fuels	$5.5	$5.7	$5.9	$6.1	$6.4	$6.6	$6.8	$7.0	$7.2	$7.4
Propane and NGL	$1.2	$1.3	$1.3	$1.3	$1.3	$1.4	$1.4	$1.4	$1.5	$1.5
Renewable Natural Gas	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Transportation Biofuels	$1.8	$1.7	$1.7	$1.7	$1.7	$1.6	$1.6	$1.6	$1.6	$1.6
Carbon Costs	$3.0	$3.1	$3.2	$3.4	$3.6	$3.7	$3.9	$4.1	$4.3	$4.6
Total Cost	$58.8	$59.3	$60.0	$60.7	$61.7	$62.2	$62.8	$63.3	$64.1	$65.0

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TOTAL SYSTEM COSTS BY FUEL – OUTLOOK C

Total system Costs - Outlook C (Billion 2016 $CAD)										
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Diesel	$11.4	$12.0	$12.6	$12.9	$13.3	$13.7	$14.0	$14.3	$14.6	$15.0
Hydrogen	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Motor Gasoline	$20.0	$20.5	$21.1	$21.1	$21.5	$21.5	$21.5	$21.2	$21.0	$20.6
Natural Gas	$5.4	$6.0	$6.4	$6.8	$7.0	$7.0	$7.0	$6.9	$6.9	$6.9
Other Heating Fuels	$1.3	$1.2	$1.2	$1.1	$1.0	$1.0	$0.9	$0.9	$0.8	$0.8
Other Industrial Fuels	$2.3	$2.3	$2.2	$2.3	$2.3	$2.3	$2.3	$2.3	$2.2	$2.2
Other Transportation Fuels	$2.6	$3.1	$3.5	$3.9	$4.1	$4.4	$4.7	$4.8	$5.1	$5.3
Propane and NGL	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.7	$0.7	$0.6
Renewable Natural Gas	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Transportation Biofuels	$1.4	$1.5	$1.9	$1.9	$2.0	$2.0	$1.9	$1.9	$1.8	$1.8
Carbon Costs	$0.0	$2.0	$2.1	$2.1	$2.2	$2.3	$2.4	$2.5	$2.6	$2.7
Total Cost	$45.1	$49.6	$51.8	$52.9	$54.2	$55.0	$55.5	$55.5	$55.8	$55.8
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Diesel	$15.3	$15.7	$16.0	$16.4	$16.8	$17.1	$17.2	$17.3	$17.5	$17.7
Hydrogen	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Motor Gasoline	$20.3	$19.8	$19.5	$19.0	$18.6	$18.0	$17.5	$17.0	$16.6	$16.3
Natural Gas	$6.9	$6.9	$6.8	$6.8	$6.8	$6.8	$6.8	$6.7	$6.7	$6.7
Other Heating Fuels	$0.8	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7
Other Industrial Fuels	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2
Other Transportation Fuels	$5.5	$5.7	$5.9	$6.1	$6.4	$6.6	$6.8	$7.0	$7.2	$7.4
Propane and NGL	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6
Renewable Natural Gas	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Transportation Biofuels	$1.7	$1.7	$1.6	$1.6	$1.6	$1.5	$1.5	$1.4	$1.4	$1.4
Carbon Costs	$2.8	$2.9	$3.0	$3.1	$3.2	$3.4	$3.5	$3.6	$3.8	$3.9
Total Cost	$56.1	$56.1	$56.3	$56.4	$56.8	$56.7	$56.7	$56.6	$56.7	$57.0

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TOTAL SYSTEM COSTS BY FUEL – OUTLOOK D

Total system Costs - Outlook D (Billion 2016 $CAD)										
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Diesel	$11.4	$12.0	$12.6	$12.9	$13.3	$13.7	$14.0	$14.3	$14.6	$14.9
Hydrogen	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Motor Gasoline	$20.0	$20.5	$21.1	$21.1	$21.5	$21.5	$21.5	$21.2	$21.0	$20.6
Natural Gas	$5.4	$6.0	$6.4	$6.7	$6.9	$6.9	$6.9	$6.8	$6.8	$6.7
Other Heating Fuels	$1.3	$1.2	$1.2	$1.1	$1.0	$1.0	$0.9	$0.9	$0.8	$0.8
Other Industrial Fuels	$2.3	$2.3	$2.2	$2.2	$2.2	$2.3	$2.3	$2.2	$2.2	$2.1
Other Transportation Fuels	$2.6	$3.1	$3.5	$3.9	$4.1	$4.4	$4.7	$4.8	$5.1	$5.3
Propane and NGL	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.7	$0.6	$0.6
Renewable Natural Gas	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Transportation Biofuels	$1.4	$1.5	$1.9	$1.9	$2.0	$2.0	$1.9	$1.9	$1.8	$1.8
Carbon Costs	$0.0	$2.0	$2.1	$2.1	$2.2	$2.3	$2.4	$2.5	$2.5	$2.6
Total Cost	$45.1	$49.6	$51.8	$52.8	$54.1	$54.8	$55.3	$55.3	$55.5	$55.5
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Diesel	$15.3	$15.7	$16.0	$16.4	$16.8	$17.1	$17.1	$17.3	$17.5	$17.7
Hydrogen	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Motor Gasoline	$20.3	$19.8	$19.5	$19.0	$18.6	$18.0	$17.5	$17.0	$16.6	$16.3
Natural Gas	$6.7	$6.6	$6.5	$6.5	$6.4	$6.3	$6.2	$6.1	$6.0	$5.9
Other Heating Fuels	$0.8	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.8
Other Industrial Fuels	$2.1	$2.1	$2.0	$2.0	$2.0	$2.0	$1.9	$1.9	$1.9	$1.9
Other Transportation Fuels	$5.5	$5.7	$5.9	$6.1	$6.4	$6.6	$6.8	$7.0	$7.2	$7.4
Propane and NGL	$0.6	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Renewable Natural Gas	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Transportation Biofuels	$1.7	$1.7	$1.6	$1.6	$1.6	$1.5	$1.5	$1.4	$1.4	$1.4
Carbon Costs	$2.7	$2.8	$2.9	$3.0	$3.1	$3.2	$3.3	$3.4	$3.5	$3.7
Total Cost	$55.6	$55.6	$55.7	$55.8	$56.0	$55.9	$55.7	$55.5	$55.5	$55.6

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TOTAL SYSTEM COSTS BY FUEL – OUTLOOK E

Total system Costs - Outlook E (Billion 2016 $CAD)										
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Diesel	$11.2	$11.7	$12.2	$12.4	$12.7	$12.9	$13.1	$13.3	$13.5	$13.7
Hydrogen	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Motor Gasoline	$19.9	$20.4	$20.9	$20.9	$21.1	$21.1	$21.0	$20.7	$20.4	$20.0
Natural Gas	$5.5	$6.0	$6.4	$6.8	$6.9	$6.9	$6.9	$6.8	$6.7	$6.7
Other Heating Fuels	$1.3	$1.2	$1.2	$1.1	$1.0	$1.0	$0.9	$0.9	$0.8	$0.8
Other Industrial Fuels	$2.3	$2.3	$2.2	$2.3	$2.3	$2.3	$2.3	$2.3	$2.2	$2.2
Other Transportation Fuels	$2.6	$3.2	$3.6	$4.1	$4.4	$4.6	$4.9	$5.1	$5.4	$5.6
Propane and NGL	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.7	$0.7	$0.6
Renewable Natural Gas	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.2	$0.3	$0.4
Transportation Biofuels	$1.6	$1.8	$2.5	$2.5	$2.8	$3.0	$3.1	$3.2	$3.2	$3.3
Carbon Costs	$0.0	$2.0	$2.0	$2.1	$2.2	$2.3	$2.3	$2.4	$2.5	$2.6
Total Cost	$45.1	$49.6	$51.9	$52.9	$54.3	$55.1	$55.6	$55.6	$55.8	$55.9
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Diesel	$13.9	$14.1	$14.3	$14.6	$14.9	$15.0	$15.0	$15.0	$15.1	$15.1
Hydrogen	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.2
Motor Gasoline	$19.6	$19.1	$18.6	$18.1	$17.6	$17.0	$16.5	$15.9	$15.5	$15.1
Natural Gas	$6.6	$6.5	$6.4	$6.3	$6.2	$6.2	$6.2	$6.1	$6.1	$6.0
Other Heating Fuels	$0.8	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7
Other Industrial Fuels	$2.2	$2.2	$2.2	$2.2	$2.2	$2.1	$2.1	$2.1	$2.1	$2.2
Other Transportation Fuels	$5.9	$6.1	$6.4	$6.6	$6.9	$7.1	$7.3	$7.5	$7.8	$8.0
Propane and NGL	$0.6	$0.6	$0.5	$0.5	$0.5	$0.6	$0.6	$0.6	$0.6	$0.6
Renewable Natural Gas	$0.6	$0.7	$0.8	$0.8	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9
Transportation Biofuels	$3.4	$3.5	$3.5	$3.6	$3.7	$3.8	$3.9	$4.0	$4.1	$4.2
Carbon Costs	$2.6	$2.7	$2.8	$2.9	$3.0	$3.1	$3.2	$3.3	$3.4	$3.5
Total Cost	$56.1	$56.2	$56.3	$56.4	$56.7	$56.6	$56.5	$56.3	$56.4	$56.5

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TOTAL SYSTEM COSTS BY FUEL – OUTLOOK F

Total system Costs - Outlook F (Billion 2016 $CAD)										
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Diesel	$11.0	$11.4	$11.7	$11.8	$12.0	$12.1	$12.2	$12.2	$12.3	$12.4
Hydrogen	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.2	$0.2	$0.2
Motor Gasoline	$19.8	$20.2	$20.6	$20.6	$20.8	$20.7	$20.5	$20.2	$19.8	$19.3
Natural Gas	$5.5	$6.1	$6.4	$6.7	$6.8	$6.7	$6.7	$6.5	$6.3	$6.1
Other Heating Fuels	$1.3	$1.2	$1.2	$1.1	$1.0	$1.0	$0.9	$0.8	$0.8	$0.8
Other Industrial Fuels	$2.3	$2.3	$2.2	$2.2	$2.2	$2.3	$2.3	$2.2	$2.1	$2.1
Other Transportation Fuels	$2.7	$3.4	$3.8	$4.2	$4.6	$4.9	$5.2	$5.5	$5.8	$6.0
Propane and NGL	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.7	$0.6	$0.6
Renewable Natural Gas	$0.0	$0.0	$0.0	$0.1	$0.1	$0.2	$0.2	$0.4	$0.6	$0.9
Transportation Biofuels	$1.9	$2.1	$3.1	$3.2	$3.7	$4.0	$4.2	$4.4	$4.6	$4.8
Carbon Costs	$0.0	$2.0	$2.0	$2.0	$2.1	$2.2	$2.3	$2.3	$2.3	$2.4
Total Cost	$45.1	$49.5	$51.9	$52.9	$54.3	$55.0	$55.4	$55.4	$55.5	$55.5
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Diesel	$12.5	$12.6	$12.6	$12.8	$12.9	$12.9	$12.7	$12.6	$12.6	$12.5
Hydrogen	$0.2	$0.2	$0.2	$0.2	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3
Motor Gasoline	$18.8	$18.2	$17.8	$17.2	$16.7	$16.0	$15.4	$14.8	$14.2	$13.8
Natural Gas	$5.9	$5.7	$5.5	$5.4	$5.2	$5.1	$5.0	$4.8	$4.7	$4.6
Other Heating Fuels	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7
Other Industrial Fuels	$2.1	$2.1	$2.0	$2.0	$2.0	$1.9	$1.9	$1.9	$1.9	$1.8
Other Transportation Fuels	$6.3	$6.6	$6.8	$7.1	$7.4	$7.6	$7.9	$8.1	$8.4	$8.7
Propane and NGL	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Renewable Natural Gas	$1.1	$1.3	$1.5	$1.7	$1.9	$1.9	$1.9	$1.9	$1.9	$1.9
Transportation Biofuels	$5.0	$5.2	$5.4	$5.6	$5.8	$6.0	$6.3	$6.5	$6.7	$7.0
Carbon Costs	$2.4	$2.5	$2.5	$2.5	$2.6	$2.6	$2.7	$2.7	$2.8	$2.9
Total Cost	$55.6	$55.6	$55.6	$55.6	$55.8	$55.5	$55.2	$54.8	$54.6	$54.6

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APPENDIX

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FUEL PRICE SOURCES

system	Fuel	Source
Residential, Commercial & Industrial	Natural Gas	IESO (OPO data share)
Residential, Commercial & Industrial	Fuel Oil	National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040 (End-Use Prices Appendix), http://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html
All systems	Propane	U.S. Energy Information Administration, Annual Energy Outlook 2016 (Table: Energy Prices by system and Source), http://www.eia.gov/forecasts/aeo/
Residential, Commercial & Industrial	Wood	Reeb, J. Home Heating Fuels, Oregon State University, June 2009, http://extension.oregonstate.edu/lincoln/sites/default/files/home_heating_fuels_ec1628-e.pdf
All systems	Renewable Natural Gas	Electrigaz in conjunction with Enbridge Gas Distribution Inc. and Union Gas Ltd., Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario - RNG Program Pricing Report, September 2011. PDF page 269/311 https://www.uniongas.com/~/media/aboutus/regulatory/rate-cases/eb-2011-0283-rng/Union_APPL_Rates_20110930.pdf?la=en
Transportation & Industrial	Motor Gasoline	National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040 (End-Use Prices Appendix), http://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html
Transportation & Industrial	Diesel	National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040 (End-Use Prices Appendix), http://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html
Transportation	Fuel Oil	U.S. Energy Information Administration, Annual Energy Outlook 2016 (Table: Energy Prices by system and Source), http://www.eia.gov/forecasts/aeo/
Transportation	Aviation Fuel	U.S. Energy Information Administration, Annual Energy Outlook 2016 (Table: Energy Prices by system and Source), http://www.eia.gov/forecasts/aeo/
Transportation	Bio-Based Diesels	U.S. Department of Energy Alternative Fuels Data Center, Alternative Fuel Price Report, http://www.afdc.energy.gov/fuels/prices.html
Transportation	Ethanol	U.S. Energy Information Administration, Annual Energy Outlook 2016 (Table: Energy Prices by system and Source), http://www.eia.gov/forecasts/aeo/
Transportation	Hydrogen	Papageorogopoulos, D., U.S. Department of Energy Fuel Cell Technologies Office, Hydrogen and Fuel Cell Perspectives for Backup Power Applications, May 2015 http://www.iphe.net/docs/Meetings/SC23/Workshop/2_%20DoE_USA.pdf
Transportation	Natural Gas	U.S. Energy Information Administration, Annual Energy Outlook 2016 (Table: Energy Prices by system and Source), http://www.eia.gov/forecasts/aeo/
Industrial	Fuel Oil (Heavy)	U.S. Energy Information Administration, Annual Energy Outlook 2016 (Table: Energy Prices by system and Source), http://www.eia.gov/forecasts/aeo/
Industrial	Coal	U.S. Energy Information Administration, Annual Energy Outlook 2016 (Table: Energy Prices by system and Source), http://www.eia.gov/forecasts/aeo/

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FUEL PRICE DEVELOPMENT

- All fuels converted to common units (2016 CAD$/GJ) using forecast exchange and inflation rates provided by IESO.

- Natural Gas Prices
  - Prices adapted from OPO pricing forecast (IESO) to vary by outlook.
  - Price changes by outlook adjusted to consider consumption volumes and distribution cost impacts, as well as DSM incremental to that assumed for Outlook B.
  - Total distribution costs in Ontario assumed to be fixed at $2 billion (2016 CAD$) per year (based on approved distribution revenue in EB-2015-0116 and EB-2015-0114)

- Prices drawn from the EIA Annual Outlook are adapted to be representative of Ontario using a comparative scaling approach based on the available NEB (or IESO, in the case of natural gas) Ontario-specific data:
  - Step 1: Determine ratio between NEB and EIA price projections for fuels that are available from both sources (e.g., Motor Gasoline)
  - Step 2: Assign a "representative fuel" (from Step 1) to each fuel with an EIA price projection and no Ontario specific price.
  - Step 3: Apply ratio from the Step 1 "representative fuel" to the Step 2 EIA price projection to scale prices to representative of Ontario.

- EIA E85 price projection used as a proxy for ethanol (no ethanol-only projection).

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FUEL PRICE DEVELOPMENT (CONT'D)

- Bio-based diesels price based on historical comparison of B99/100 prices with E85 prices, applied to EIA-derived ethanol projection.
- Renewable natural gas assumed to be all derived from anaerobic digestion.
- Source document for hydrogen price estimates cost-at-pump of less than $4 per gasoline gallon equivalent (gge). Price assumed to be $4/gge (2015 US$)
- Wood price average of 6 types discussed in study. Assumed commercial and industrial price 80% and 60% (respectively) of residential price due to volume.
- For some industrial fuels (e.g., petroleum coke, still gas, etc.) no third-party price projection was available. In these cases, one of the other price projections developed was assumed to be a reasonable proxy.

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ADDITIONAL COST INPUTS

- Two additional cost inputs:
  - Carbon costs from cap-and-trade: Time series of projected carbon costs assumed in OPO analysis (IESO).
  - Incremental DSM costs for Outlook E and F. Developed based on the approved 2015 – 2020 DSM plans (EB-2015-0029 and EB-2015-0049)

- Incremental (to Outlook B) natural gas DSM:
  - Cost of incremental DSM was defined in terms of incremental DSM achieved in each outlook. For example, if total gas savings in Year 1 is 100, and total gas savings in Year 2 is 110, then DSM cost in Year 2 is 10 (110 – 100) times the DSM cost.
  - Based on Enbridge and Union's approved DSM budgets and targets for 2016 through 2020 the value of incremental achieved DSM in any given year is approximately $16.50/GJ.

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PROJECTED DELIVERED PRICES (2016 CAD$/GJ) (NATURAL GAS)

Table 1 of 4

system	Outlook	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	B	$8.8	$9.6	$10.0	$10.5	$10.8	$10.8	$10.9	$10.9	$11.0	$11.0
	C	$8.8	$9.6	$10.0	$10.5	$10.7	$10.8	$10.8	$10.9	$11.0	$11.1
	D	$8.8	$9.6	$10.0	$10.5	$10.8	$10.8	$10.9	$11.0	$11.1	$11.2
	E	$8.8	$9.6	$10.0	$10.5	$10.8	$10.9	$10.9	$11.0	$11.1	$11.3
	F	$8.8	$9.6	$10.1	$10.6	$10.9	$11.0	$11.1	$11.3	$11.5	$11.8
Commercial	B	$5.0	$5.7	$6.1	$6.4	$6.6	$6.6	$6.6	$6.6	$6.6	$6.8
	C	$5.0	$5.7	$6.1	$6.4	$6.7	$6.6	$6.6	$6.6	$6.7	$6.8
	D	$5.0	$5.7	$6.1	$6.4	$6.7	$6.6	$6.6	$6.6	$6.7	$6.8
	E	$5.0	$5.7	$6.1	$6.5	$6.7	$6.7	$6.7	$6.7	$6.8	$6.9
	F	$5.2	$5.8	$6.3	$6.6	$6.9	$6.9	$6.9	$7.0	$7.1	$7.3
Industrial	B	$4.0	$4.6	$5.0	$5.3	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5
	C	$4.0	$4.6	$5.0	$5.3	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5
	D	$4.0	$4.6	$5.0	$5.3	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5
	E	$4.0	$4.6	$5.0	$5.4	$5.6	$5.6	$5.6	$5.6	$5.6	$5.6
	F	$4.0	$4.7	$5.1	$5.4	$5.6	$5.6	$5.6	$5.7	$5.7	$5.7

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PROJECTED PRICES (2016 CAD$/GJ) (NATURAL GAS)

Table 2 of 4

system	Outlook	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	B	$11.1	$11.1	$11.2	$11.2	$11.3	$11.3	$11.4	$11.5	$11.5	$11.6
	C	$11.1	$11.2	$11.3	$11.5	$11.6	$11.7	$11.8	$12.0	$12.1	$12.2
	D	$11.3	$11.5	$11.6	$11.8	$12.0	$12.2	$12.5	$12.7	$13.0	$13.2
	E	$11.4	$11.6	$11.7	$11.9	$12.1	$12.2	$12.4	$12.5	$12.7	$12.8
	F	$12.1	$12.4	$12.7	$13.1	$13.6	$13.9	$14.3	$14.7	$15.1	$15.5
Commercial	B	$6.8	$6.8	$6.8	$6.8	$6.8	$6.9	$6.9	$6.9	$6.9	$6.9
	C	$6.8	$6.8	$6.8	$6.8	$6.8	$7.0	$7.0	$7.0	$7.0	$7.1
	D	$6.8	$6.8	$6.8	$6.8	$6.9	$7.0	$7.0	$7.1	$7.2	$7.3
	E	$7.0	$7.0	$7.0	$7.1	$7.1	$7.3	$7.3	$7.3	$7.4	$7.4
	F	$7.4	$7.6	$7.7	$7.8	$8.0	$8.2	$8.3	$8.4	$8.6	$8.8
Industrial	B	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5
	C	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5
	D	$5.5	$5.6	$5.6	$5.6	$5.6	$5.6	$5.6	$5.6	$5.6	$5.6
	E	$5.6	$5.6	$5.6	$5.6	$5.6	$5.7	$5.7	$5.7	$5.7	$5.7
	F	$5.7	$5.8	$5.8	$5.9	$5.9	$5.9	$6.0	$6.0	$6.0	$6.1

NAVIGANT

PROJECTED PRICES (2016 CAD$/GJ) (OTHER FUELS)

Table 3 of 4

system	Fuel	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	Fuel Oil	$31.4	$32.1	$32.8	$33.1	$33.6	$34.1	$34.5	$34.9	$35.2	$35.5
	Propane	$16.1	$17.9	$18.6	$19.5	$19.6	$19.9	$20.2	$20.1	$19.9	$19.8
	Wood	$14.2	$14.2	$14.2	$14.2	$14.2	$14.2	$14.2	$14.2	$14.2	$14.2
	Renewable Natural Gas	$18.8	$13.1	$12.7	$12.3	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2
Commercial	Fuel Oil	$27.7	$28.4	$29.0	$29.3	$29.7	$30.2	$30.5	$30.9	$31.1	$31.4
	Propane	$13.5	$14.5	$14.5	$14.7	$14.7	$15.0	$15.3	$15.1	$15.0	$14.9
	Wood	$11.4	$11.4	$11.4	$11.4	$11.4	$11.4	$11.4	$11.4	$11.4	$11.4
	Renewable Natural Gas	$18.8	$13.1	$12.7	$12.3	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2
Transportation	Motor Gasoline	$38.1	$39.4	$40.5	$40.9	$41.8	$42.6	$43.2	$43.7	$44.2	$44.7
	Diesel	$37.8	$39.2	$40.4	$40.8	$41.8	$42.6	$43.3	$43.9	$44.4	$45.0
	Fuel Oil	$12.9	$16.7	$19.0	$20.6	$21.4	$22.3	$23.1	$23.4	$23.8	$24.3
	Aviation Fuel	$19.9	$23.9	$25.9	$28.4	$29.7	$31.0	$32.2	$32.8	$33.5	$34.4
	Propane	$38.1	$39.0	$39.5	$39.0	$39.0	$39.2	$39.8	$40.0	$40.3	$40.6
	Biodiesel	$44.2	$45.7	$59.4	$57.2	$60.7	$61.9	$60.9	$60.3	$59.1	$58.2
	Ethanol	$42.9	$44.4	$57.6	$55.4	$58.9	$60.1	$59.1	$58.5	$57.4	$56.5
	Hydrogen	$43.6	$43.6	$43.6	$43.6	$43.6	$43.6	$43.6	$43.6	$43.6	$43.6
	Natural Gas (CNG/LNG)	$36.5	$34.9	$33.8	$31.3	$30.6	$30.0	$29.7	$29.7	$29.7	$29.6
Industrial	Propane & NGLs	$18.5	$19.2	$19.0	$19.5	$19.2	$20.0	$20.5	$20.0	$19.7	$19.5
	Fuel Oil (Distillate)	$16.8	$17.5	$18.0	$18.3	$18.8	$19.2	$19.6	$19.9	$20.2	$20.5
	Fuel Oil (Residual)	$6.1	$7.7	$8.5	$9.7	$10.7	$11.5	$12.3	$12.6	$12.8	$13.1
	Coal	$5.5	$5.1	$4.7	$4.4	$4.2	$4.3	$4.3	$4.1	$4.0	$4.0
	Wood	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5
	Renewable Natural Gas	$18.8	$13.1	$12.7	$12.3	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2

NAVIGANT

PROJECTED PRICES (2016 CAD$/GJ) (OTHER FUELS)

Table 4 of 4

system	Fuel	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	Fuel Oil	$35.8	$36.2	$36.5	$36.9	$37.2	$37.4	$37.6	$37.8	$38.0	$38.2
	Propane	$19.9	$20.1	$20.2	$20.3	$20.4	$20.7	$21.1	$21.5	$21.8	$22.0
	Wood	$14.2	$14.2	$14.2	$14.2	$14.2	$14.2	$14.2	$14.2	$14.2	$14.2
	Renewable Natural Gas	$12.2	$12.2	$12.2	$12.1	$12.1	$12.1	$12.1	$12.1	$12.1	$12.1
Commercial	Fuel Oil	$31.7	$32.0	$32.3	$32.6	$32.9	$33.1	$33.3	$33.4	$33.6	$33.8
	Propane	$15.0	$15.2	$15.3	$15.3	$15.4	$15.7	$16.1	$16.4	$16.7	$16.9
	Wood	$11.4	$11.4	$11.4	$11.4	$11.4	$11.4	$11.4	$11.4	$11.4	$11.4
	Renewable Natural Gas	$12.2	$12.2	$12.2	$12.1	$12.1	$12.1	$12.1	$12.1	$12.1	$12.1
Transportation	Motor Gasoline	$45.2	$45.7	$46.3	$46.9	$47.4	$47.7	$48.0	$48.3	$48.5	$48.8
	Diesel	$45.5	$46.1	$46.7	$47.3	$47.9	$48.2	$48.5	$48.9	$49.2	$49.5
	Fuel Oil	$24.9	$25.4	$25.8	$26.4	$26.8	$27.2	$27.5	$27.8	$28.3	$28.7
	Aviation Fuel	$35.1	$35.8	$36.5	$37.3	$38.0	$38.7	$39.3	$39.8	$40.6	$41.3
	Propane	$40.6	$40.7	$41.2	$41.5	$41.8	$41.8	$41.8	$41.9	$41.8	$42.2
	Biodiesel	$57.9	$57.9	$57.1	$56.7	$56.8	$56.4	$56.4	$56.5	$56.2	$56.3
	Ethanol	$56.2	$56.1	$55.4	$55.0	$55.1	$54.7	$54.7	$54.8	$54.5	$54.6
	Hydrogen	$43.6	$43.6	$43.6	$43.6	$43.6	$43.6	$43.6	$43.6	$43.6	$43.6
	Natural Gas (CNG/LNG)	$29.0	$28.5	$28.2	$27.9	$27.8	$27.1	$26.6	$26.2	$25.9	$25.9
Industrial	Propane & NGLs	$20.0	$20.4	$20.7	$21.0	$21.2	$21.9	$22.4	$23.2	$23.9	$24.5
	Fuel Oil (Distillate)	$20.8	$21.1	$21.4	$21.7	$22.0	$22.2	$22.3	$22.5	$22.7	$22.8
	Fuel Oil (Residual)	$13.4	$13.6	$13.8	$14.1	$14.3	$14.5	$14.7	$14.9	$15.1	$15.2
	Coal	$4.0	$4.1	$4.1	$4.0	$4.0	$4.1	$4.2	$4.2	$4.3	$4.3
	Wood	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5	$8.5
	Renewable Natural Gas	$12.2	$12.2	$12.2	$12.1	$12.1	$12.1	$12.1	$12.1	$12.1	$12.1

NAVIGANT

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Ontario

MC-2016-2493

DEC 1 6 2016

Ms Rosemarie Leclair
Chair and Chief Executive Officer
Ontario Energy Board
PO Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms Leclair:

Re: Renewable Natural Gas

I am writing to you today to confirm the government's interest in the Ontario Energy Board's (OEB) further examination of renewable natural gas (RNG) as a component of Ontario's natural gas supply.

RNG is interchangeable with conventional natural gas and compatible with the same infrastructure. It has recently been identified by the government in both the May 2016 *Climate Change Action Plan* and the Ministry's September 2016 *Fuels Technical Report* as a potential fuel that could help reduce greenhouse gas (GHG) emissions from the consumption of natural gas. In addition, RNG provides an important step in the decarbonization of Ontario's fuels sector. For example, the *Fuels Technical Report* modelled the results of injecting as much as 155 petajoules (PJs) of RNG into the current natural gas system by 2035, reflecting estimates of Ontario RNG production of 4.3 billion cubic metres per year by 2030. Once injected, RNG can displace conventional natural gas in applications across all sectors.

The *Climate Change Action Plan* noted the government's intention to invest up to $100 million of cap and trade auction proceeds to support the implementation of a renewable content requirement for natural gas and encourage the use of RNG throughout the province. As a low-carbon fuel, RNG can assist in achieving the GHG emission reduction targets specified in the November 2015 *Climate Change Strategy*:

- 15 per cent reduction below 1990 levels by 2020;
- 37 per cent below 1990 levels by 2030; and
- 80 per cent below 1990 levels by 2050.

.../cont'd

I note that in its July 12, 2012 interim decision and order on applications by Union Gas and Enbridge Gas Distribution to include the cost consequences of purchasing RNG in rates, the OEB indicated its willingness to consider the inclusion of RNG in the utilities' gas supply portfolios and provided direction to the gas utilities on the additional evidence that would be needed for the OEB to further consider the matter. Those applications were later withdrawn, and the OEB therefore did not have occasion to finally determine the merits of including RNG in the gas supply mix.

More recently, in its September 2016 *Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities,* the OEB specifically identified RNG as a potential GHG abatement measure that gas utilities can undertake to meet their compliance obligations. The three rate-regulated gas utilities have now filed their first compliance plans under that *Framework*. Both Enbridge and Union have indicated in their filings that they anticipate moving toward the integration of RNG in the future. The OEB will be considering the utilities' initial compliance plans in an adjudicative process based on the evidence before it, and I acknowledge that the process for approving those initial plans is not expected to be the forum for an in-depth examination of RNG.

The government remains supportive of the economic and environmental benefits that RNG can provide in optimizing the use of existing assets while reducing the province's carbon footprint. We intend to consider how RNG will help meet Ontario's future energy needs during the development of the next Long-Term Energy Plan and subsequent implementation directives.

In light of the developments noted earlier in this letter, I encourage the OEB to move forward in a timely manner to include RNG as a potential fuel that could help reduce GHG emissions as a part of the gas utilities' supply portfolios.

Sincerely,

Glenn Thibeault
Minister

c: Serge Imbrogno, Deputy Minister
Carolyn Calwell, Director, Legal Services Branch, Ministries of Energy; Economic Development and Growth; Infrastructure; Research, Innovation and Science; and Accessibility

ENERGY PROBE INTERROGATORY #6

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 2, Page 5

Preamble: ICF identified a range of carbon abatement costs associated with RNG in the range of $77 to $1,990 per tCO2e. In its report ICF indicated that these values were based on a desk top review of studies dating back to 2011. In pages 50 to 53 of its report ICF also noted a number of limitations and caveats relating to its analysis of RNG potential and costs.

a) What range of procurement costs has EGD assumed for the RNG procurement initiative?
b) Please provide the detailed analyses to support the response.

RESPONSE

a) EGD has not assumed specific costs for the RNG procurement initiative as it will go out to a request for proposals (RFP) in which the price discovery will occur. For further information, please see the Company's response to Board Staff Interrogatory #6(a) filed at Exhibit I.C.EGDI.STAFF.6.

b) Please see response to part (a).

Witnesses: A. Chagani
S. McGill

ENERGY PROBE INTERROGATORY #7

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 2, Page 6

Preamble: Enbridge is now ready to proceed with RNG procurement opportunities in 2018, and will look to purchase a portion of its annual gas throughput from renewable sources. The Company's planned activities to support RNG production in Ontario with its proposed RNG Enabling Program are discussed at a high level later in this Exhibit; however, will be fully outlined in the Company's EB-2017-0337 submission to the Board to be made later this year.

a) Please explain in detail why EGD is requesting recovery of costs of RNG procurement in 2018 rates, absent proper/complete evidence supporting this request.
b) In the response please discuss in detail how this pre-approval request differs from pre-approval of major infrastructure/facilities, including feasibility cost control/management and from natural gas supply and transportation contracts.
c) Please provide a detailed outline of the Scope of the EB-2017-0337 Application.

RESPONSE

a) The Company's evidence includes appropriate details to support the request for approval of the RNG procurement model. Approval will allow the Company to move ahead with procuring RNG supply for future years (no RNG supply is expected in 2018 – please see response to Board Staff Interrogatory # 7 filed at Exhibit I.C.EGDI.STAFF.7). As explained in response to Board Staff Interrogatory 7, any delay in commencing procurement of RNG puts into risk the provincial government funding as well as the ability to secure local supply.

b) In this case, Enbridge is seeking approval of its RNG procurement model. This is different from approval of a particular facility or contact.

c) Please refer to the application for RNG Enabling program EB-2017-0319 for a detailed outline of the proposal (Enbridge's evidence inadvertently referred to this as EB-2017-0337).

Witnesses: A. Chagani
S. McGill

ENERGY PROBE INTERROGATORY #8

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 1, page 9

a) Is there a current agreement between Enbridge and the province regarding Renewable Natural Gas (RNG) projects? If so, please provide it.
b) Please provide any correspondence or other communications with the Province to support a joint procurement/RFP
c) How is the cost of RNG going to be calculated? Will it be on an individual project basis or a total envelope encompassing all RNG projects in 2018?
d) Will Enbridge track the difference between forecasted RNG costs and actual costs once the project is functional? Will that cost be covered by Enbridge or provincial funding?
e) Will Enbridge provide an annual review of the actual costs of its various RNG projects? If so, will that review be provided to the Board?

RESPONSE

a) and b) Please refer to the responses to Board Staff Interrogatories #5a and 7 filed at Exhibits I.C.EGDI.STAFF.5 and 7.

c) The total cost of RNG will be the envelope encompassing all RNG supply that is contracted. Ratepayers will not see additional costs for gas supply and/or allowances as the difference between contracted RNG prices and the costs that would be paid for natural gas and allowances will be paid out of a grant provided by the province.

d) The RNG prices will be discovered through a RFP process, and fixed through ten year contracts. Once contracted, there will be no differences between the actual and forecast RNG prices.

e) The Company intends to review all RNG purchases annually. Enbridge expects to leverage existing reporting and will report on the results of the RNG procurement and supply annually through its Compliance Plans and/or compliance reporting. There may also be reporting through the QRAM process.

Witnesses: A. Chagani
S. McGill

ENERGY PROBE INTERROGATORY #9

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 1, page 28

Has Enbridge submitted or designed a revised weighted scorecard formula?

RESPONSE

Yes, Enbridge has submitted a revised weighted scorecard formula as part of the Company's submissions dated September 1, 2017 and January 15, 2018 within the DSM Mid-Term Review (EB-2017-0128).

Witness: D. Johnson

ENERGY PROBE INTERROGATORY #10

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 2.

Preamble: As there is no established RNG market in Ontario, in order to ensure the lowest cost for RNG, Enbridge will utilize a tendering process for RNG supplies. ….. Enbridge is of the view that it would be beneficial if this tendering process was carried out cooperatively with the Province.

a) Please indicate the timing of the RFP(s)
b) Will EGD conduct the RFP/tender(s) with Union Gas and/or EPCOR. Please discuss.
c) Please explain why a 10-year term is appropriate for existing RNG supplies such as landfill gas?
d) Will the tender(s) be based on a landed cost? If so, please provide an example, including gas quality, transportation, clean up and compression. If not, provide details of how the bids will be evaluated.
e) Will EGD request Board Approval of the specific RNG Contracts?

RESPONSE

a) Please refer to the response to Board Staff Interrogatory #7 filed at Exhibit I.C.EGDI.Staff.7.

b) Enbridge intends to conduct its own separate RFP process.

c) Please see the response to Board Staff #9 filed at Exhibit I.C.EGDI.Staff.9 part a and b.

d) Yes, tenders will be based on landed cost to one or more specified delivery areas. Enbridge will be seeking RFP responses that will provide an all-in landed cost and that cost will be a factor in the evaluation of bids received.

e) It is not anticipated that OEB approval will be required for each individual contract.

Witnesses: A. Chagani
S. McGill

ENERGY PROBE INTERROGATORY #11

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 2, Pages 9 &10 and Table 2

Preamble: It is expected that in the short and medium term, RNG will be priced at a premium over conventional natural gas. The RNG funding model proposed by Enbridge will be consistent with the province's CCAP and LTEP.

a) Please provide the natural gas and carbon price forecasts used in Table 2
b) Please indicate the natural gas delivery point assumed and the landed cost/m3, including storage and transportation.
c) Please indicate the assumptions and resulting landed cost for RNG equivalent.
d) Provide the estimated annual Benefit/cost to an average EGD residential customer in the CDA
e) Please provide the annual GHG abatement cost per customer and compare with a carbon tax similar to BC using same assumptions.

RESPONSE

a) The carbon price forecast used is the LTCPF from the OEB. The gas price forecast was established as of the date of evidence preparation. Enbridge will use an up-to-date gas price forecast as of the date of the RFP.

b) The assumed delivery point is the Enbridge CDA. The landed cost per m^3 for RNG would be $0.615, based on an assumed cost of RNG of $16/GJ.

c) See part (b).

d) There is no incremental cost to Enbridge's customers beyond the conventional gas cost and carbon allowance cost that would be paid for conventional supply.

e) Under the Company's proposal, with respect to the RNG supply, customers will pay the OEB's mid-range LTCPF. The 2017 LTCPF mid-range forecast is from $17/tonne in 2018 to $57/tonne in 2028. The current BC carbon tax is $30/tonne.

Witnesses: A. Chagani
S. McGill

ENERGY PROBE INTERROGATORY #12

INTERROGATORY

Reference: Exhibit D, Tab 1, Schedule 1, Table 1

a) Please provide the 2017 and 2018 administrative costs related to RNG.
b) Reconcile 2018 costs to the Referenced Table 1.
c) If there is a projection for 2019 please provide this.
d) Please confirm/explain if the costs assume separate or joint RNG program/procurements with Union as part of Amalco.

RESPONSE

a) In the 2017 Enbridge Compliance Plan, there were no costs for administration related to RNG. In the 2018 Compliance Plan, Enbridge provided for an additional FTE related to RNG procurement activities.

b) The Company expects that the administrative costs associated with the RNG procurement proposal will be for at least one but not more than two additional FTEs in 2018. Enbridge has provided for one FTE for RNG procurement and related activities in 2018 in the Compliance Plan filing. In relation to Table 1, the FTE cost would be a component of the $1.5 million Staffing Resources Cost Element. Where possible, as has been the practice to-date, existing resources will be leveraged. Should actual costs be different than budgeted they would be sought for clearance through the GGEIDA.

c) Enbridge anticipates that the Company will continue to need one to two FTEs each year post 2018 related to RNG.

d) Please refer to the Company's response to CCC Interrogatory #13 filed at Exhibit I.C.EGDI.CCC.13.

Witnesses: A. Chagani
S. McGill

FRPO INTERROGATORY #1

INTERROGATORY

REF: Exhibit C, Tab 5, Schedule 2, page 4

Preamble: We would like to understand better the report that Enbridge is relying upon to substantiate RNG as a significant abatement opportunity.

To Enbridge's knowledge, is a representative of Navigant being made available to test the evidence that Enbridge is relying upon in the above reference?

a) If not, in Enbridge's view, how would it be possible to test the conclusions relied upon by Enbridge in this context?

RESPONSE

No, Enbridge does not anticipate that a representative of Navigant will be made available to speak to the Fuels Technical Report which was prepared by Navigant on behalf of the Ontario Ministry of Energy.

Enbridge's view is that the conclusions reached in the Fuels Technical Report have been relied upon by the Provincial Government as to the potential of RNG to assist the government in the attainment of its GHG emission reduction targets. This is evidenced by the Government's stated objectives in its 2017 Long Term Energy Plan.[1] Also, please see the Company's response to CCC Interrogatory #4 filed at Exhibit I.C.EGDI.CCC.4.

[1] Ontario's Long Term Energy Plan is available at https://www.ontario.ca/page/ontarios-long-term-energy-plan

Witnesses: A. Chagani
S. McGill

FRPO INTERROGATORY #2

INTERROGATORY

REF: Exhibit C, Tab 5, Schedule 2, page 5, paragraph 12

Preamble: We would like to understand better Enbridge's views on the emissions reduction efficacy of RNG. The above reference contains the statement: "*The fuel substitution benefits results from the displacement of traditional fossil fuels ".*

Please provide Enbridge's assessment of what the carbon emissions benefit of burning 1,000 m3 of RNG vs 1,000 m3 of traditional fossil fuel?

RESPONSE

As discussed in response to Board Staff Interrogatory #11a filed at Exhibit I.C.EGDI.STAFF.11, the carbon emissions benefit is 0.001875 tCO_2e per cubic meter, or 1.875 tCO_2e/m^3.

Witness: J. Murphy

FRPO INTERROGATORY #3

INTERROGATORY

REF: Exhibit C, Tab 5, Schedule 2, page 7

Preamble: Enbridge has identified a limitation in the ICF report. As the evidence states: "*A key limitation concerning the economic value of RNG in the MACC report is that ICF does not take into account the potential sale of associated emissions reductions or offset credits that would be associated with avoidance of methane emissions to the atmosphere, which would instead be captured in the production of RNG."*

Please provide Enbridge's assessment of the value of capturing and burning carbon that would otherwise be emitted as methane to the atmosphere. a) Please provide all studies Enbridge has undertaken to review the greenhouse gas effect of these emissions.

RESPONSE

Each greenhouse gas has a certain atmospheric lifetime and heat trapping ability. The combination of these two qualities has been termed Global Warming Potential ("GWP"). In Ontario Regulation 143-16 "*Quantification, Reporting and Verification of Greenhouse Gas Emissions*", the GWP value for CO_2 is 1 and for CH_4 is 21. This means that 1 tonne of CH_4 has the same GHG effect as 21 tonnes of CO_2.

As an example, if 1000 m^3 of landfill gas, which is approximately 50% methane, is upgraded to RNG instead of emitted to the atmosphere, there would be an emissions savings of approximately 5.7 tCO_2e. When this volume of RNG is burned by end-users, a further 0.9 tCO_2e is avoided due to the displacement of fossil natural gas. Please refer to Board Staff Interrogatory #11a filed at I.C.EGDI.STAFF.11 and FRPO Interrogatory #2 filed at I.C.EGDI.FRPO.2 for further information on the emission factor used for calculating the emissions from fuel substitution.

a) Enbridge has not undertaken any studies to review the greenhouse gas effect of methane.

Witness: J. Murphy

FRPO INTERROGATORY #4

INTERROGATORY

REF: Exhibit C, Tab 5, Schedule 2, page 10, Table 2

Preamble: We would like to understand better the cost associated with the cost of the provincial subsidy to equate the value of RNG to current commodity prices. The evidence states: "*Subject to receiving approval for the use of the forecast commodity and carbon cost methodology in this proceeding and successful negotiation of contract terms and funding, the cost implications related to RNG procurement will be incorporated in future proceedings relying upon existing rate setting mechanisms (i.e. QRAM, Compliance Plan.)*

Using the prices, please provide the forecasted provincial subsidy required each year at the volumes that would make up 0.1% of EGD's system gas portfolio.

RESPONSE

Please see the response to Board Staff Interrogatory #8 filed at Exhibit I.C.EGDI.STAFF.8. As can be seen in that response, a subsidy of $50 million over ten years with an assumed cost of $16/GJ for RNG would support the procurement of 4.5PJ over ten years. That is around 0.1% of Enbridge's total throughput over ten years (assuming relatively constant volumes).

Witnesses: A. Chagani
S. McGill

FRPO INTERROGATORY #5

INTERROGATORY

REF: Exhibit C, Tab 5, Schedule 2, page 13

Preamble: We would like to understand more about the access rules for RNG providers to EGD's territory. The evidence states*" All RNG producers who wish to use Enbridge's distribution system to transport RNG will have to contract with Enbridge for RNG injection services. This will enable the Company to meet its basic responsibilities as a distributor of natural gas and ensure the safe and reliable distribution of RNG to market."*

Please file the EGD's proposed standard contracts with Producers.

RESPONSE

Enbridge is currently developing the proposed standard injection services contracts for RNG producers. Enbridge is seeking approval of the injection services as part of its RNG Enabling Program (see EB-2017-0319).

Witnesses: A. Chagani
S. McGill

FRPO INTERROGATORY #6

INTERROGATORY

REF: Exhibit C, Tab 5, Schedule 2, page 13

Preamble: We would like to understand more about the access rules for RNG providers to EGD's territory. The evidence states*" All RNG producers who wish to use Enbridge's distribution system to transport RNG will have to contract with Enbridge for RNG injection services. This will enable the Company to meet its basic responsibilities as a distributor of natural gas and ensure the safe and reliable distribution of RNG to market."*

In Enbridge's view, are the current access rules in GDAR and/or STAR sufficient to ensure appropriate access conditions for RNG? Please explain.

RESPONSE

The reference to using Enbridge's system to transport RNG relates to Enbridge's proposed RNG Enabling Program outlined in EB-2017-0319. In this Application, Enbridge is proposing to purchase RNG from producers at specified delivery areas. Enbridge will then be responsible for any further movement/transportation of the gas.

Witnesses: A. Chagani
S. McGill
D. Small

FRPO INTERROGATORY #7

INTERROGATORY

REF: Exhibit C, Tab 5, Schedule 2, page 13

Preamble: We would like to understand more about this impact and about RNG programs in other jurisdictions. The evidence states: "*The associated utility investments will significantly contribute towards the attainment of Ontario's GHG emission target reductions by displacing the consumption of natural gas in the Company's service area while having minimal effect on Enbridge Gas Distribution rates.*"

If 0.1% of Enbridge's system gas portfolio was sourced from RNG, what percentage contribution would be made to Enbridge's emission target?

RESPONSE

Enbridge does not have an emission target. For discussion on potential GHG abatement amounts that may be achieved by the RNG procurement program, please refer to Board Staff Interrogatory #8a filed at Exhibit I.C.EGDI.STAFF.8.

Witnesses: J. Murphy
F. Oliver-Glasford

FRPO INTERROGATORY #8

INTERROGATORY

REF: Exhibit C, Tab 5, Schedule 2, page 13

Preamble: We would like to understand more about this impact and about RNG programs in other jurisdictions. The evidence states: "*The associated utility investments will significantly contribute towards the attainment of Ontario's GHG emission target reductions by displacing the consumption of natural gas in the Company's service area while having minimal effect on Enbridge Gas Distribution rates.*"

To Enbridge's knowledge, please provide a brief summary of other jurisdictions that promote using natural gas utility investment to facilitate RNG systems and how the approach is structured.

RESPONSE

Please see response to OSEA Interrogatory #2 part h) filed at Exhibit I.C.EGDI.OSEA.2.

Witnesses: A. Chagani
S. McGill

FRPO INTERROGATORY #9

INTERROGATORY

REF: Exhibit C, Tab 5, Schedule 2, page 14

Preamble: We would like to understand better the potential rate impacts of the utility investments in the early years of RNG. The evidence states: "*Enbridge recognizes that in applying the EBO 188 principles there will be a deficiency in terms of the revenues versus the costs of the program in the early years*... and later … "*Enbridge proposes that these differences (deficiencies in early years and sufficiencies in later years) be captured within the Greenhouse Gas Emissions Compliance Obligation-Customer-Related Variance Account ("GHG-Customer VA") and be periodically cleared to ratepayers."*

Assuming Enbridge attains the 0.1% of its supply portfolio in the first 3 years of the program, please provide an estimate of the percentage distribution rate impact for Rate 1 and Rate 6 customers.

RESPONSE

The evidence referenced above related to EBO 188 relates to the manner in which fees and charges are determined for the RNG Enabling Program (for details, please see EB-2017-0319).

As described in response to CCC Interrogatory #10 filed at Exhibit I.C.EGDI.CCC.10, RNG procurement is not expected to cost ratepayers any incremental amounts as government funding will cover the premium between the all-in cost of natural gas (conventional natural gas costs plus the associated carbon cost at the LTCPF rate), and the actual cost of the RNG procurement.

Witnesses: A. Chagani
S. McGill

LPMA INTERROGATORY #1

INTERROGATORY

Ref: Exhibit C, Tab 5, Schedule 2

a) How does the Enbridge proposal for the procurement of RNG differ, if at all, from the Union Gas proposal? Please explain fully any differences.

b) How does the Enbridge proposal for the recovery of the cost of RNG differ, if at all, from the Union Gas proposal? Please explain fully any differences.

RESPONSE

a & b) Enbridge confirms that the utilities' proposals are materially the same. Differences that exist are minor and relate to internal processes of each respective utility.

Witnesses: A. Chagani
S. McGill

NORTHEAST INTERROGATORY #1

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 2, Page 8

Preamble: Enbridge says the typical development timeline for RNG and P2G (power-to-gas) hydrogen projects is expected to range from 18 to 30 months: "Some potential producers of renewable gas supplies are at the early stage of project development in anticipation of market opportunities developing in Ontario while others are closer to fruition."

a. Please provide Enbridge's best estimate for an indicative capital cost for a greenfield RNG supply facility in Ontario, expressed either as a total project cost for daily capacity or on a $/GJ basis.

b. Does Enbridge intend to invest in, build, own, or operate RNG supply facilities, either directly or through an affiliated entity, that would be bidding into the proposed RNG procurement program? If yes, please provide details.

c. Does Enbridge have a financial relationship, co-investment, joint venture, or strategic alliance with a provider of RNG equipment or supply facilities that would be bidding into the proposed RNG procurement program? If yes, please provide details.

RESPONSE

a) Please see the Electrigaz Biogas Plant Costing Report found at EB-2011-0242, Exhibit B, Tab 1, Appendix 4. This report contains the Enbridge's most recent examination of the capital cost of RNG facilities in Ontario.

b) Please see the response to Board Staff Interrogatory #10c filed at Exhibit I.C.EGDI.STAFF.10.

c) Enbridge does not have a financial relationship, co-investment, joint venture or strategic alliance with a provider of RNG equipment. For further information about supply facilities, please see the response to Board Staff Interrogatory #10c filed at Exhibit I.C.EGDI.STAFF.10.

Witnesses: A. Chagani
S. McGill

NORTHEAST INTERROGATORY #2

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 2, Page 9

Preamble: Enbridge's proposed use of an RFP process signifies that the supply of RNG is or will be a competitive market in Ontario: Enbridge says it plans to "conduct a rigourous RFP process to determine the cost, contract term, and other RNG procurement agreement terms and conditions."

a. Please confirm that the supply of RNG is or will be a competitive market in Ontario.

RESPONSE

a. Please refer to the response to CCC Interrogatory #12 filed at Exhibit I.C.EGDI.CCC.12.

Witnesses: A. Chagani
S. McGill

NORTHEAST INTERROGATORY #3

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 2, Page 19

Enbridge appears to see hydrogen injection into pipelines as an analogous or complementary activity to RNG supply and procurement: “Hydrogen produced by P2G [power-to-gas] can complement Ontario’s supplies of both RNG and electricity, while helping to decarbonize the province’s energy infrastructure.”

a. Does Enbridge envision launching a hydrogen procurement program in the future, similar to the proposed RNG procurement program?

b. Please confirm that the supply of hydrogen produced by low-carbon methods is or will be a competitive market in Ontario.

RESPONSE

a) Enbridge believes that low-carbon derived hydrogen is a form of renewable gas, and as such may be a future source of supply under a RNG procurement program.

b) The supply of hydrogen produced by all methods, low-carbon or otherwise, in Ontario is currently a competitive market. Enbridge is not aware that the supply of hydrogen produced by low-carbon methods is currently a competitive market.

Witnesses: A. Chagani
S. McGill

ONTARIO PETROLEUM INTERROGATORY #1

INTERROGATORY

Reference: Enbridge Gas Distribution Inc. (Enbridge)
2018 Cap and Trade Compliance Plan (“Application”)
Ontario Energy Board (“Board”) File Number EB-2017-0224

Questions:

What is the carbon benefit to Enbridge by receiving one 10^3m^3 of locally produced natural gas, regardless of its source, as compared to having to transport that same 10^3m^3 of gas from Alberta?

RESPONSE

As per Ontario Regulation 143/16 *Quantification, Reporting and Verification of Greenhouse Gas Emissions*, Enbridge is required to report on the emissions from Natural Gas Distribution, following the ON.400 quantification methodology outlined in the *Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions* (the “Guideline”). Under this methodology, the same emission factor is used, regardless of the upstream source of the natural gas. This methodology calculates only the emissions from the combustion of the natural gas by the end user, and upstream emissions from production and transportation are excluded. This means that Enbridge does not see a reduction of its GHG emissions by sourcing locally produced fossil natural gas instead of fossil natural gas from Alberta or the eastern United States.

The Guideline does require that “natural gas derived from biomass or gas that does not contain any carbon” is excluded from calculations. Therefore any RNG or hydrogen gas, including locally produced RNG and hydrogen gas, entering Enbridge’s distribution system can be excluded from its natural gas distribution emissions calculations. One 10^3m^3 of RNG or hydrogen would displace one 10^3m^3 of fossil natural gas, for a savings of 1.875 tonnes CO_2e.

Witness: J. Murphy

ONTARIO PETROLEUM INTERROGATORY #2

INTERROGATORY

Reference: Enbridge Gas Distribution Inc. (Enbridge)
2018 Cap and Trade Compliance Plan (“Application”)
Ontario Energy Board (“Board”) File Number EB-2017-0224

Questions:

What is the carbon benefit to Enbridge by receiving one 10^3m^3 of locally produced natural gas, regardless of its source, as compared to having to transport that same 10^3m^3 of gas from eastern United States that has been produced using high pressure fracturing techniques? Please include the impact of the additional GHG produced using these fracturing techniques.

RESPONSE

Please refer to the response to Ontario Petroleum Interrogatory #1 filed at Exhibit I.C.EGDI.OPI.1.

Witness: J. Murphy

ONTARIO PETROLEUM INTERROGATORY #3

INTERROGATORY

Reference: Enbridge Gas Distribution Inc. (Enbridge)
2018 Cap and Trade Compliance Plan (“Application”)
Ontario Energy Board (“Board”) File Number EB-2017-0224

Questions:

What would Enbridge be willing to pay for each of the four forms of locally produced natural gas noted above? What methodology would Enbridge use to establish these four prices?

RESPONSE

As part of the current Gas Supply Plan, Enbridge purchases locally produced conventional natural gas supplies. The price paid for for this supply is comparable to other conventional sources of natural gas which are transported to Enbridge’s franchise area.

For other forms of “locally produced natural gas”, the critical factor in determining the value and willingness to pay is the resulting reduction in GHG emissions. As referenced in response to Ontario Petroleum Institute Interrogatory #1 filed at Exhibit I.C.EGDI.OPI.1, the ON.400 Guideline uses the same emission factor to quantify GHG emissions, regardless of the upstream source of the natural gas. This means that Enbridge does not see a reduction of its GHG emissions by sourcing locally produced fossil natural gas compared with conventional natural gas from other production areas.

The Guideline does require that “natural gas derived from biomass or gas that does not contain any carbon” is excluded from calculations. Therefore any RNG or hydrogen gas, including locally produced RNG and hydrogen gas, entering Enbridge’s distribution system can be excluded from its natural gas distribution emissions calculations.

The Government through the MOE and MOECC has indicated its funding support for RNG, as part of the government’s strategy to transition to a low-carbon economy.

Witnesses: A. Chagani
K. Lakatos-Hayward
S. McGill
A. Welburn

ONTARIO PETROLEUM INTERROGATORY #4

INTERROGATORY

Reference: Enbridge Gas Distribution Inc. (Enbridge)
2018 Cap and Trade Compliance Plan ("Application")
Ontario Energy Board ("Board") File Number EB-2017-0224

Questions:

How will Enbridge ensure that the **quality** of locally produced natural gas, regardless of its source, is treated fairly from a compensation and subsidy perspective, relative to the other sources?

RESPONSE

Please see response to Ontario Petroleum Institute Interrogatory #1 filed at Exhibit I.C.EGDI.OPI.1. Enbridge does not understand how this question relates to its RNG procurement proposal.

Witnesses: A. Chagani
K. Lakatos-Hayward
S. McGill
A. Welburn

ONTARIO PETROLEUM INTERROGATORY #5

INTERROGATORY

Reference: Enbridge Gas Distribution Inc. (Enbridge)
2018 Cap and Trade Compliance Plan (“Application”)
Ontario Energy Board (“Board”) File Number EB-2017-0224

Questions:

How will Enbridge ensure that their tariffs and facility-related interconnect charges are just and reasonable for all locally produced natural gas?

RESPONSE

Enbridge purchases locally produced conventional natural gas today. The price paid for for this locally produced supply is comparable to other conventional sources of natural gas which are transported to Enbridge’s franchise area.

To facilitate RNG produced within Ontario and requiring connection to EGD’s distribution system, the Company is proposing an RNG Enabling Program (refer to EB-2017-0319). Charges for this program will be determined on a project-specific basis.

Witnesses: A. Chagani
K. Lakatos-Hayward
S. McGill
A. Welburn

OSEA INTERROGATORY #1

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 2, Page 8

Preamble: “The typical development timeline for RNG and P2G hydrogen projects is expected to range from 18 to 30 months. Some potential producers of renewable gas supplies are at the early stage of project development in anticipation of market opportunities developing in Ontario while others are closer to fruition. As a result, the 2018 Compliance Plan does not anticipate the introduction of significant RNG volumes into the Company’s 2018 gas supply portfolio.”

a) What are Enbridge’s projections for the annual volumes of RNG it is estimating to introduce in its gas supply portfolio for the next ten years?
b) How many potential producers does Enbridge estimate will be operational and able to supply RNG to Enbridge within each of the next ten years?

RESPONSE

a) Please refer to the response to Board Staff Interrogatory #8 filed at Exhibit I.C.EGDI.STAFF.8.

b) Please refer to the response to Environmental Defence Interrogatory #13a filed at Exhibit I.C.EGDI.ED.13.

Witnesses: A. Chagani
S. McGill

OSEA INTERROGATORY #2

INTERROGATORY

Reference: Exhibit C, Tab 5, Schedule 2, Page 9

Preamble: “Enbridge plans to undertake the following steps in 2018 with respect to the procurement of RNG supplies: (a) Conduct a rigorous RFP process to determine the cost, contract term, and other RNG procurement terms and conditions; (b) Negotiate and enter into a contractual arrangement between the Company and the Province whereby the Province agrees to compensate ratepayers for the difference between the cost of the RNG purchased and the carbon abated cost of natural gas.”

a) At what stage are Enbridge’s negotiations with the Province about funding? Has the Province provided any commitments that it will contribute towards the proposed RNG funding proposal?

b) When does Enbridge expect to have a contractual arrangement finalized with the Province?

c) When does Enbridge expect it will conduct the RFP process?

d) If the Province ultimately does not agree to compensate any or all of the ratepayers for the difference between the cost of RNG purchased and the carbon abated cost of natural gas, how will Enbridge incorporate RNG into its gas portfolio?

e) What is Enbridge’s forecast for the annual subsidy that will be required from the Province based on Enbridge’s volume forecasts for the next 10 years?

f) Does Enbridge propose the Province’s subsidy will be part of the $60-$100 million that the Province proposed in the CCAP for introducing renewable content in natural gas?

g) Has Enbridge considered and/or approached the Province about subsidies for other potential customer abatement measures? If so, please describe each abatement measure and the proposed subsidy.

h) Do the other RNG markets cited by Enbridge (e.g. Europe, California, British Columbia, and Quebec) rely on government subsidies to provide RNG? If not, did Enbridge consider the funding models used in these other jurisdictions? If so, please describe and provide Enbridge’s analysis.

Witnesses: A. Chagani
S. McGill

RESPONSE

a) As discussed in the response to Board Staff Interrogatory #7b filed at Exhibit I.C.EGDI.STAFF.7, Enbridge is still in discussions with the province. The province has not made any commitments at this point in time.

b) Please refer to the response to Board Staff Interrogatory #7b filed at Exhibit I.C.EGDI.STAFF.7

c) Please refer to the response to Board Staff Interrogatory #7b filed at Exhibit I.C.EGDI.STAFF.7

d) Please refer to the response to Board Staff Interrogatory #5d filed at Exhibit I.C.EGDI.STAFF.5.

e) Please refer to the response to APPrO Interrogatory #3a filed at Exhibit I.C.EGDI.APPrO.3.

f) Please refer to the response to APPrO Interrogatory #3a filed at Exhibit I.C.EGDI.APPrO.3.

g) Please refer to the response to Board Staff Interrogatory #1d (i) filed at Exhibit I.C.EGDI.STAFF.1.

h) Below is a table from a 2017 report prepared by Torchlight Bioresources for Natural Resources Canada setting out RNG models in other jurisdictions.[1] Enbridge's proposed model arises from discussions with the Provincial Government and is premised on using proceeds from the Cap and Trade program to support RNG. As noted in response to APPrO Interrogatory #3, this is consistent with the Ontario Government's Climate Change Action Plan.

[1] Renewable Natural Gas (Biomethane) Regulatory Assessment for Selected Canadian and European Jurisdictions, Appendix A: March 31, 2017.

Witnesses: A. Chagani
S. McGill

	Germany	United Kingdom	Canada	Ontario	British Columbia
General Market Status	Developed	Developed	Not Developed	Not Developed	Developing
Technical Grid Access	Legally required; RNG prioritized over natural gas; 96% minimum access required	Offer by utility to producer to connect legally required; moderate profit allowed for utility; terms of access, including availability, must be reasonable	No legal requirement; decision at the discretion of the utility	No legal requirement; decision at the discretion of the utility	No legal requirement; decision at the discretion of the utility
Biogas Upgrading Facility	Owned and operated by biogas producer	Owned and operated by biogas producer	Owned and operated by biogas producer	Utilities not permitted to own or operated facilities	Utility or biogas producer may own and/or operate
Network Entry Facility Ownership and Operation	Owned and operated by utility; biomethane producer must cover 25% of capital cost to a maximum of €250,000 when within 10 km of pipeline; utility must cover remainder and all operating costs	Utility or biomethane producer may own and/or operate, but key equipment in facility must be remotely monitored by utility if owned by biomethane producer; all costs the responsibility of the producer	Unknown, but likely owned and operated by utility	Unknown, but likely owned and operated by utility upon permission by OEB	Owned and operated by utility
Guaranteed Contracts for RNG Producers	Market largely dependent upon electricity Feed-in-Tariff; biomethane used for CHP, with heat utilization required	20-year biomethane injection contracts with government body via Renewable Heat Incentive; contracts at natural gas market prices with utilities	Long-term contracts permissible at the discretion of the utility and approval by the NEB	Utilities not permitted to enter into long-term contracts, unless exception approved by OEB	Utilities permitted into long-term contracts at their discretion and approval by BCUC
Distribution of Costs Across Customer Base	Cost of network entry facility installation and operation incurred by utility spread across all natural gas consumers in Germany	Commodity natural gas price distributed across customer base; RHI payment direct from national government (HR Treasury)	No ability to distribute costs across asset base; buyer of biomethane must assume costs	No additional costs beyond market natural gas price may be distributed across customer base	Utility-owned assets and minority of cost premium distributed across all customers; majority of RNG purchase premium borne by RNG consumers
Low Carbon/Renewable Fuel Standard	Biomethane eligible under renewable fuel standard; must comply with EU Renewable Energy Directive GHG rules	Biomethane eligible under renewable fuel standard; must comply with EU Renewable Energy Directive GHG rules	Renewable fuel standard not applicable to gaseous fuels; low carbon (clean) fuel standard in development	Renewable fuel standard not applicable to gaseous fuels; low carbon fuel standard being considered	Existing renewable fuel and low carbon fuel standards; biomethane is eligible under the LCFS

Witnesses: A. Chagani
S. McGill

SEC INTERROGATORY #1

INTERROGATORY

[C-5-1, p.13] Please provide a copy of the draft MACC Report provided to Enbridge and a copy of any comments Enbridge provided to ICF and the Technical Advisory Group regarding the draft MACC Report.

RESPONSE

Appendices A and B to this response include Enbridge's overall comments on the draft MACC report as well as the draft MACC report itself (with comments from Enbridge embedded).

Witnesses: A. Chagani
S. McGill

Enbridge's Submission on the draft Marginal Abatement Cost Curve Study

June 29, 2018

Enbridge is pleased to have the opportunity to provide comment on the draft Marginal Abatement Cost Curve (MACC) and respectfully provides the following summarized list of considerations for the Ontario Energy Board, Board Staff and ICF in preparation of the final MACC and its subsequent consideration in the 2018 Compliance Plans.

Areas of Strength

1) Well respected and knowledgeable consultants in carbon and economic analysis in Ontario
2) Expert and stakeholder involvement in the process through the Technical Advisory Group (TAG)
3) Solid knowledge base and diversity of perspective of TAG members
4) Allowance for comments to be fed into the process
5) Commitment and focus to providing a MACC within a short timeframe for the Utilities
6) Leverage of the Conservation Potential Study (CPS) which saved time and work from stakeholders

Areas for Improvement/Opportunity

1) Timelines were not laid out at the outset for each meeting and follow-up deadline for comments making it difficult to juggle competing priorities and perhaps not allowing for the full value of input from the TAG members
2) Detailed analysis was difficult to follow as there were some changes to how the data from the CPS was manipulated for the purposes of the MACC. Thus it was difficult to assess the efficacy of those changes and their impacts.
3) The report requires complete clarity to the reader that what is provided for energy efficiency is not the "marginal" cost curve but instead the "average" cost curve. This point is not clear and is absolutely critical given the large investments and targets in play in the existing DSM plans out to 2020 and the additional energy efficiency programming and related savings being proposed to the Green ON Fund.
4) The report fails to discuss that the underlying CPS recognizes what is known as natural conservation built into the utilities forecasts from code changes and the like, but does not capture any recognition of free-ridership values. This is exceedingly difficult to include given free-ridership values vary often from program to program or sector to sector, however, it is an important point that has been raised already in the process and should be captured clearly in the document. When savings opportunities are discounted by 50% for example, the Utility must engage and the customer must fund double the gross savings to see recognition of the 50% net value.
5) On the point of the energy efficiency section of the report being an average cost of abatement versus showing the incremental cost of abatement beyond the DSM Plan, it is critical that the study does not assume that people understand the non-linear relationship between spending and savings in DSM. Natural gas DSM activity is indeed mature in Ontario – which is a good thing. However, it means that the technologies, measures and programs deployed are becoming increasingly expensive as it is necessary to look to less cost effective opportunities and harder to reach markets.
6) It should be pointed out that the timing for investment/spend may not coincide with the achievement of results. This timing mismatch is not necessarily an issue, but ratepayers should be aware of it in any event.

7) Upfront costs have not been identified as occurring in “cost-effective” programs. Up front bill impacts on customers, even participating customers, will not equal savings in the first year(s). Where a financial contribution from customers is required, success relies on customers seeing value and buying in. In addition, volumes of savings are gross, not net (i.e. do not include free ridership)
8) “Un-combusted” methane emissions counted as combusted under current regulations
9) Only counts the displacement of NG, with no additional carbon offset benefits (i.e. for farm based digesters)
10) High cost of RNG in general that is perhaps not adequately informed by recent local information nor inclusive of offset values generated from RNG feedstock
11) The study by ICF is not consistent with the logic of other RNG studies and includes (within battery limits) and thus in the price of equipment that may exist or is practically required or is mandated, and excludes revenues from other sources such as tipping fees.
12) Inclusion of “uneconomic” potential to meet aggressive ramp up of volumes.
13) Prior studies assumed that most feedstocks would be waste and that disposal was part of the inputs of the facility for little to no cost.
14) Hydrogen production is excluded.

Areas of General Observation or Note

1) Enbridge has a carbon obligation that it must, with a 100% certainty meet, with a specific number of “allowances” or “credits” in its compliance account on November 1, 2021 to remit.
2) A MACC is well known to have a useful set of data to be used in conjunction with other inputs towards policy setting – and is designed from first principles to that aim.
3) MACCs are based on a point in time and do not reflect changing energy pathways, evolving policy or changes in market/technology funding that form the basis for different MACC values. Therefore, MACCs are best for point in time analysis versus longer-term planning.
4) The timing of the MACC will help inform Enbridge’s Compliance Plans moving forward but its application to the 2018 Compliance Plan may be limited.
5) The MACC does not, and could not be expected to factor in CCAP funding decisions on energy efficiency and technology incentives.
6) The next MACC would be compiled for the 2021 to 2023 period.

Recommendations

1) Ensure that it is clearly articulated that the energy efficiency information is not “marginal” but is in fact “average”. This does not jump out at the reader and is critical in understanding what is being presented.
2) The budget in order to achieve the level of savings outlined in the MACC is not documented. Although the MACC is from the Utility perspective, it is ultimately the ratepayers that pay the bill and thus they should understand the bill impacts.
3) Document clearly that the values in the CPS are gross, and do not include the applicable net-to-gross (i.e. free-ridership) values.
4) Ensure that it is clearly articulated that a bottom up analysis of RNG, or perhaps location specific updated information on RNG feedstocks may provide more compelling values for RNG as an abatement initiative.
5) Provide more transparency to the analysis/modelling behind the RNG outputs.
6) Allow the Utilities to put forward Utility specific facility related MACCs – 3rd parties can be utilized if deemed appropriate.

7) The OEB, in assessing compliance and cost-effectiveness of the Compliance Plan, can take into account upfront costs of such abatement programs. Or, allow the Utility to pursue the programs via the DSM or CCAP route rather than directly via the C&T Compliance Plan.
8) The OEB, in assessing compliance and cost-effectiveness, can take into account un-combusted methane emissions. Or, allow the Utility to wait until regulations recognizing un-combusted methane before embarking on such programs.
9) The OEB, in assessing compliance and cost-effectiveness, can recognize the site-specificity of RNG projects. Or, allow the Utility to pursue RNG via CCAP.
10) Suggested edits are included in the attached marked up draft MACC study to be helpful

Final Comments

Enbridge Gas Distribution has been pleased to be afforded the opportunity to provide input through the MACC development process via the Technical Advisory Group. It was a strong group of people with a solid knowledge base and a diversity of experience and viewpoints. Although the process was overly condensed given the importance of the resultant document, it was respectful, streamlined and professional in execution.

The resulting draft MACC Report provided to the TAG for final comment contains valuable data that will assist in the screening of potential of abatement programs. However, it should be clearly noted as just one of several inputs that are available to use to inform the design of abatement programs in the Compliance Plan. When using the MACC Report, inherent limitations on it should be recognized as well as planning horizon and spending timeframe and regulations should be taken into account. The solutions may require further discussion among the regulatory bodies, the Utilities and stakeholders.

DRAFT Report

Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities (EB-2016-0359)

June 21, 2017

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Executive Summary

The Executive Summary will be developed once the report language is finalized.

1. Introduction

1.1 Background

Ontario's cap and trade program is a regulatory instrument aimed at meeting the provincial government's greenhouse gas (GHG) emissions reduction targets. Beginning in January 2017, the cap and trade program and resulting price on carbon will impact the price end users pay for transportation fuels, natural gas and other fossil fuels.

Ontario's cap and trade program is based on the cap and trade program design of the Western Climate Initiative (WCI). The government of Ontario has signaled its intention to link with the WCI Partner jurisdictions' (i.e., California and Quebec) joint cap and trade market in 2018.

The cap and trade program defines a compliance obligation for Ontario's natural gas distributors, including Union Gas Limited ("Union Gas"), Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution") and Natural Resource Gas Ltd., collectively referred to as the "utilities". The utilities' compliance obligation includes:

- Facility-related obligations for facilities owned or operated by the utilities; and,
- Customer-related obligations for natural gas-fired generators, and residential, commercial and industrial customers who are not independently covered under the cap and trade program (i.e., that are not Large Final Emitters (LFEs) or voluntary participants).

The utilities' compliance obligations will require that they undertake cap and trade activities. The associated costs will be recovered from customers. Charged with regulating Ontario's natural gas and electricity sectors, including natural gas utility rates, the Ontario Energy Board (OEB) therefore has a new role in assessing the cost consequences of the utilities' cap and trade activities for the purpose of approving cost recovery in rates.

The OEB issued a Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities (the "Regulatory Framework") on September 26, 2016. The Regulatory Framework describes the OEB's expectation for each Utility to develop cap and trade Compliance Plans that include robust information regarding compliance strategies. The OEB will assess these Compliance Plans for cost-effectiveness, reasonableness and optimization in its decision to approve recovery of cap and trade costs from customers. In the Regulatory Framework, the OEB indicated it will provide (committed to providing) a province-wide, generic marginal abatement cost curve (MACC) for the Utilities to use in developing their Compliance Plans, which will also be used by the OEB as a key input into its assessment of the cost consequences of those Plans. The MACC is intended to provide a reasonable snapshot in time of costs for abatement activities versus buying an allowance. The MACC analysis will be different as funding commitments from Climate Change Action Plan (CCAP) are known given their impact on technology and program feasibility.

1.2 Study Scope and Objectives

The objective of this study is to provide the OEB with its first province-wide MACC to inform the Utilities in the development of their Compliance Plans. The MACC will illustrate the full range of customer conservation-related compliance options and renewable natural gas options for the

2018-2020 timeframe (full dataset 2018-2028) along a spectrum of costs presented from the perspective of the Utilities[1]. This MACC has leveraged the work of the comprehensive Conservation Potential Study completed by the Board in concert with a stakeholder advisory group in 2017, as well as market studies and information where appropriate for RNG and Air Source Heat Pumps.

The MACC will ~~also~~ be used by the OEB as on input to support its evaluation of the cost-effectiveness of the Utilities' strategies for complying with the cap and trade program outlined in their Compliance Plans. The MACC will be updated every three years, prior to the start of a new WCI compliance period (next MACC will be due in the spring of 2019).

The approach and any associated limitations and caveats used in the development of the MACC are presented by key study category including customer conservation in Section 2, renewable natural gas in Section 3, and facility abatement options in Section 4.

1.3 Report Organization

This report presents the MACC study results for the 2018-2020 period. It is organized into the next six sections as follows:

- Section 2 presents the background, approach, limitations and caveats and results for the three customer conservation sectors, including industrial, commercial and residential.
- Section 3 presents the background, approach, limitations and caveats and results for the renewable natural gas assessment.
- Section 4 presents the background and approach for facility abatement options.
- Section 5 presents the summary MACCs for all three customer conservation sectors (industrial, commercial and residential) and RNG.
- Section 6 presents study recommendations.
- Appendix A provides the background information on the air source heat pump analysis conducted for this study.

1.4 Definition of Terms

Comment [Enbridge1]: Include definitions for annual savings, cumulative (or persisting) annual savings, and cumulative lifetime savings.

It is important to ensure that readers have a clear understanding of what each of the key terms means in the context of this study. Below is a brief description of some of the most important terms:

Marginal Abatement Cost Curve (MACC) – in this study, the MACC is a diagram presenting the cost of natural gas energy efficiency options in dollars per cubic metre of annual savings[2] (also represented as dollars per tonne of CO_2e of GHG abatement) relative to a baseline. The baseline, or zero dollars line in this study, is the "cost-effective" threshold, which represents the price of an allowance that is tied to the forecasted price of carbon in a given year. Values below

[1] Consideration of costs from the perspective of the Utilities is key to understanding the study results. Given that the MACC is intended to inform the development of Utilities' Compliance Plans *and* assist the OEB in evaluation of those plans, the study focuses on costs to the Utilities, rather than costs to their customers.
[2] Calculated using measure lifetime costs over measure lifetime savings.

the zero-line are deemed cost-effective relative to the price of an allowance, and values above the zero-line are measures that are deemed to be more expensive to implement than purchasing an allowance.

Technical Potential – The technical potential is the estimated level of natural gas savings that would result from the implementation of all technically feasible energy efficiency measures, regardless of cost effectiveness or market acceptance, as calculated in the Conservation Potential Study (CPS).

Achievable Potential – The achievable potential is the estimated level of natural gas savings that would result from the implementation of all economically feasible energy efficiency measures, taking into account realistic market penetration rates over the study period, as calculated in the CPS. The definition of the achievable potential market penetration rates are based on a number of factors including market barriers, customer preference and acceptance based on payback periods, return on investment, investment hurdle rates and other factors.

Reference Year – The reference year in this study was 2017. The natural gas energy efficiency savings for the 2018-2020 study period were calculated by subtracting the natural gas consumption CPS model results for the year 2017 from the natural gas consumption model results for 2020.

Measure Total Resource Cost Test (TRC) – The TRC test is often used to determine whether a measure would be considered economically attractive when factoring in all costs. The measure TRC is a cost/benefit analysis of the net present value of energy savings that result from an investment in an efficiency or fuel choice technology or measure. The measure TRC calculation considers a measure's full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and operation and maintenance costs. It is expressed as a ratio of benefits divided by costs, with both the numerator and denominator calculated as net present values.

Program Administrator Cost Test (PAC) – The PAC test is used to measure the net costs of a program based on the costs incurred by the program administrator, including incentives, marketing budgets, and salaries, and excluding any costs incurred by the participant (or utility customer).

Measure Total Resource Cost-Plus Test (TRC-plus) – The measure TRC-plus test is the measure TRC test with the inclusion of the avoided natural gas price with a 15% non-energy benefit adder, electricity supply costs, the life of the technology, and the selected discount rate. In the 2016 CPS, measure TRC-plus was expressed as a ratio of benefits divided by costs, with both the numerator and denominator calculated as net present values. A technology or measure with a measure TRC-plus benefit/cost ratio of 1.0 or greater was included in the technical, economic, and achievable potential analyses. A measure with a TRC-plus benefit/cost ratio below 1.0 was not considered economically attractive and was therefore included only in the technical potential analysis. Consistent with OEB DSM Guidelines, a lower benefit/cost ratio threshold of 0.7 was used for measures applied to low-income subsectors.

2. Customer Conservation

2.1 Background

The Regulatory Framework indicates that the Utilities are required to set charges for the recovery of costs associated with cap and trade activities based on the weighted average cost of compliance options described in their Compliance Plans for a particular rate year. The MACC developed in this study is designed to assist Utilities in this task by presenting a standard description of compliance options along a spectrum of costs. The foundation for the development of this MACC study was the Conservation Potential Study (CPS) completed by ICF for the OEB in 2016[3] that answered the question of how much natural gas conservation is cost effective in the absence of an explicit carbon price. The CPS is recognized as a best practice approach from the perspective of cost recovery activities under the OEB's oversight. The approach enables the compilation and analysis of market and technology data to generate an assessment of the total technical, economic and/or achievable conservation potential over a specified study time period.

For the 2016 CPS a proprietary model was developed and populated with detailed data representing technologies, operation and maintenance and control measures that save natural gas across energy end uses in each sector of the Ontario economy. More than 50 measures were considered for each of the residential, commercial and industrial sectors, and all of the data inputs and assumptions used to develop the model were reviewed and approved by the OEB and natural gas stakeholders. In order to answer the question of how much natural gas conservation can be achieved (and how much is cost effective) under three different carbon price scenarios, ICF leveraged all of the data inputs and assumptions from utilities and stakeholders that was used to develop the proprietary CPS model, and incorporated the long-term carbon pricing forecasts (LTCPF) developed by ICF and published by the OEB on May 31, 2017. For the MACC study, the CPS approach was applied to assess all technically feasible conservation measures using realistic adoption rates for the purposes of assisting the Utilities in identifying abatement measures that can be delivered cost effectively in comparison to alternate compliance instruments, in addition to informing the OEB's review of utilities' cap and trade compliance plans and associated cost recovery.

This MACC study should be read through the lens of a natural gas utility in Ontario. The MACCs presented here illustrate the average cost per cubic metre of natural gas conserved annually[4] (or cost per tonne of GHGs abated) for each end use category within each sector, relative to the price of carbon over the 2018-2020 timeframe. It does not illustrate an incremental or marginal cost of abatement to be clear. The results have been displayed in this manner to identify which group of measures, classified by end use and including DSM as well as activities beyond DSM, represent a lower cost to the utility than purchasing compliance instruments in the first compliance period in general.

Comment [Enbridge2]: Avoided natural gas and carbon benefits are realized by customers that participate in abatement at the expense of customers that do not participate. In this way costs are lower to society, but may be higher to the utility than allowance purchases (unless the cost of abatement absent the benefits of abatement is less than the cost of allowances)

[3] Natural Gas Conservation Potential Study, July 7, 2016, ICF International, July 2016 (EB-2015-0117), http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Natural+Gas+Conservation+Potential+Study#20160711

[4] Calculated using measure lifetime costs over measure lifetime savings.

The decision to present results by end use category was based on two key factors:

- Consumer choice is unpredictable – there are many different equipment options for customers to pursue efficiency, but most customers will not pursue all of them (e.g., a customer may replace their furnace with a high efficiency furnace OR an air source heat pump, but not both), so savings associated with individual measures based on customer choice may not be good indicators.
- Conservation measure interactions should be considered – if customers install more than one measure for one end use (a high efficiency furnace *and* wall insulation), each subsequent measure saves less cubic metres of natural gas, and will mitigate less GHG emissions than if it was installed in isolation. By grouping measures by end use category, the MACC is designed to illustrate a realistic total GHG abatement potential for a given end use, given measure interactive effects.

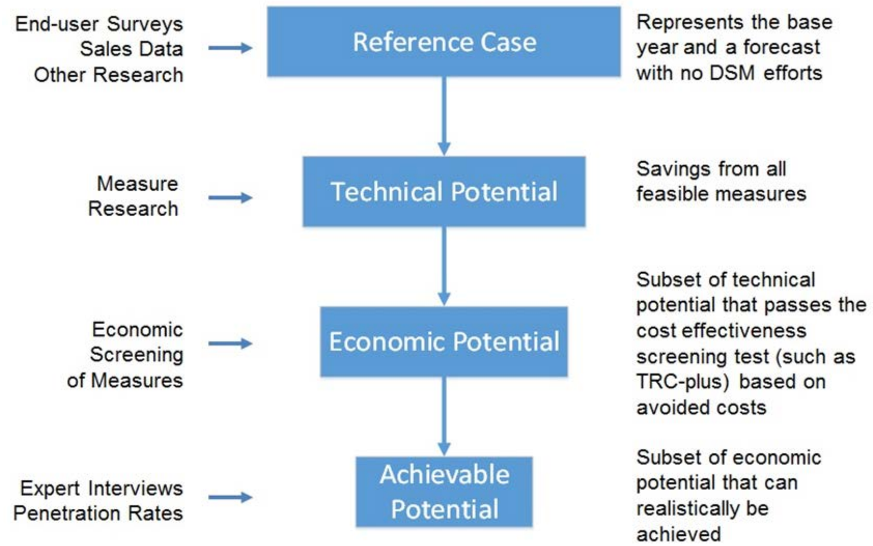
The 2016 CPS methodology for accounting for these interactions was used (see Section 2.6.1 of the 2016 CPS report); however, it should be noted that this is an assumption and other credible approaches could be used and would possibly produce slightly different $/tonne values for each measure (but would likely not have much of an impact on the overall GHG potential of each end use).

This study does not reconcile the volumes and associated costs per tCO_2e with the existing DSM plan in place until 2020. Nor does it consider any incremental energy efficiency the Utilities may be involved in, such as the Green Investment Fund, or Green ON Fund moving forward that again would impact volume and cost. Based on historical findings and the CPS analysis, the cost per m^3 of savings is not linear with increased investment.

2.2 Approach

In order to develop a MACC to illustrate which conservation measures could represent lower costs to the utilities compared to purchasing compliance instruments, ICF used data from the CPS completed for the OEB in 2016 and the associated proprietary model. As was previously noted, the 2016 CPS assessed the savings potential and costs of a full range of natural gas energy efficiency measures available to natural gas utilities in Ontario under several scenarios. The CPS generally followed a traditional approach in determining natural gas conservation potential in Ontario, as shown in Exhibit 1.

Exhibit 1 General Methodology for Conservation Potential Studies



The CPS model is populated with inputs and assumptions that were subject to rigorous review through extensive consultation with the OEB, the two major utilities and other natural gas sector stakeholders before being approved by the OEB during the 2016 CPS. This MACC development study was designed to leverage the 2016 CPS data and assumptions, given the level of rigour and review that was involved, and considering the relatively short timeline for the MACC study. The following data and assumptions remain unchanged from the CPS[5]:

- Lists of conservation measures for industrial, commercial and residential sectors and the associated measure-level assumptions/parameters including:
  - natural gas savings (cubic metres)
  - other fuel savings (including electricity)
  - effective useful life
  - measure applicability
  - operating and maintenance costs, and
  - classification into measure types
- Adoption rates
- End use classification (e.g., industrial HVAC, commercial space heating, etc.)
- Utility program and incentive costs
- Cascade order for treatment of conservation measure interactions
- All economic and market assumptions (including 4% discount rate)
- No explicit net-to-gross or free-ridership was applied to the volumes; so the values are in gross terms

[5] Natural Gas Conservation Potential Study, July 7, 2016, ICF International.

In order to quantify how much natural gas conservation would be cost-effective under different carbon pricing assumptions, it was necessary to implement the following revisions to the CPS model:

1. The cost metric used in the 2016 CPS was revised to incorporate carbon pricing.
   - The 15% adder[6] that accounted for the non-energy benefits associated with DSM programs in the 2016 CPS was removed.
   - The avoided costs[7] from the 2016 CPS (benefit[8]) were used for the MACC study, with the following costs and benefits included:
     i. Program delivery costs (cost[9])
     ii. Incentive costs (cost)
     iii. Three LTCPFs for the study period[10] (benefit)

   By varying the LTCPFs used in the cost metric, the three study scenarios including minimum, maximum and mid-range carbon price, were developed.

2. Estimates of natural gas consumption volumes representing 'covered' participants under Ontario's cap and trade program were developed through consultation with the Utilities and removed from the modelling exercise. Facilities directly covered under the program are excluded from the utilities' compliance obligations, so the associated abatement potential was excluded from the MACCs.

3. Heat pumps were assessed through an analysis separate from the CPS model exercise (refer to Appendix A) because they are currently not cost-effective and are unlikely to be considered by the utilities for an abatement program when compared to other space-heating efficiency options for residential and commercial customers. Given the extremely large abatement potential associated with this technology (irrespective of cost), heat pumps were not included in the MACC to avoid skewing the results for space-heating measures.

4. All technically feasible conservation measures from the CPS were used with an achievable adoption rate for their implementation. For the measures that were deemed cost effective in the 2016 CPS, the achievable potential was used. For measures that were not deemed cost effective, achievable potential savings were developed using the technical potential savings, implemented according to an achievable adoption rate.

The cost-benefit analysis in this study did not use a traditional total resource cost (TRC) or program administrator cost (PAC) test, nor the TRC-plus test that was used in the 2016 CPS[11].

[6] The 15% adder to account for non-energy benefits associated with DSM was selected by the OEB in the 2015-2020 DSM Framework. It is aligned with the cost effectiveness test used by the IESO, as per the Minister of Energy's Conservation First Framework.
[7] For a detailed description of the avoided costs, see chapter 3 of the 2016 CPS Report.
[8] Benefit: because this increases the value of savings from measures
[9] Cost: because this decreases the value of savings from measures
[10] Refer to Long-Term Carbon Price Forecast Report, ICF, May 31, 2017, https://www.oeb.ca/industry/policy-initiatives-and-consultations/consultation-develop-regulatory-framework-natural-gas

As the modelling was completed from the perspective of the utility, a metric similar to the PAC was used – the benefits included the net present values of avoided natural gas, electricity and carbon allowance costs, and the costs included program delivery and incentive costs.

2.3 Limitations and Caveats

The main limitations and caveats used in the development of the MACCs are listed below.

- The study timeframe was 2018-2028 for the CPS modelling exercise and analytics. However, it was determined in consultation with the OEB and Technical Advisory Group (TAG) that it would be more useful to present the results on a MACC representing the first Ontario cap and trade compliance period. While the underlying analytics and results cover the 2018-2028 timeframe and account for lifetime costs over lifetime savings[12], the presentation of the MACC results in this report are confined to the 2018-2020 period.

- The 2016 CPS study used 2014 as the base year and therefore the starting point for the analysis, from which to measure the savings in subsequent years. In this MACC study, the savings presented in the results (see Sections 2.4, 2.5, 2.6 and 5) are calculated based on a reference year of 2017 in order to capture all potential savings associated with customer conservation measures started in 2018, 2019 and 2020.

- The MACCs include existing DSM savings and activities as well as potential future cap and trade-incented abatement activities, i.e. MACCs represent a “menu of options” that can be, and/or are already being used for DSM and for cap and trade abatement activities.

- In the CPS model, assumptions for the industrial sector are defined by subsector, e.g., chemicals. Although the natural gas volumes representing the consumption of ‘covered’ emitters were removed from the model accounting for much of the LFE volume, no revisions were made to market penetration rates for industrial conservation measures[13]. The model uses an average for all sizes of industrial facilities and does not differentiate between LFEs and non-LFEs.

- Heat pumps were analyzed separately from the CPS model exercise and excluded from the MACC because they are currently not cost-effective and are unlikely to be considered by the utilities for an abatement program when compared to other space-heating efficiency options for residential and commercial customers.

2.4 Customer Conservation MACC Results

The customer conservation MACC results are presented by sector (industrial, commercial and residential) in the sub-sections that follow. The MACC diagrams illustrate the estimated

[11] For definitions of the TRC, TRC-plus and PAC cost-benefit tests, refer to Section 1.4 of this report.
[12] Varying measure lifetimes were accounted for from 1 year to beyond 10 years.
[13] Consistent with the approach in the 2016 CPS, average market penetration rates were used for LFEs and non-LFEs alike.

achievable potential savings in m^3 and tonnes CO_2e for natural gas abatement through customer conservation measures (including DSM *and* incremental abatement beyond DSM) for the three different carbon pricing scenarios[14].

On each MACC, the zero dollars line (x-axis) represents the "cost-effective" threshold which includes the price of an allowance. Values below the zero-line are deemed to be less costly than the price of an allowance, and values above the zero-line are measures that are deemed to be more expensive to implement than purchasing an allowance. The height of the bars represents the average of a range of costs per cubic metre of natural gas saved (or tonne of GHGs abated) over the 2018-2020 study period.

It is important to recognize that each end use bar on the MACCs represents a group of conservation measures that are applicable to a particular sector. All measures assessed were included in the quantification of the savings potential (in cubic metres and tonnes abated) that defines the width of the bar. As the abatement potential includes cost effective and non-cost effective measures the figure is not intended to represent the total abatement potential that could/should be delivered by the NG utilities to the benefit of the rate payer.

The labels associated with each bar on the MACCs indicate cumulative potential savings data in m^3 and tCO_2e. Estimates of the proportion of the savings that are associated with cost-effective measures are also provided for each end use (% value in brackets). Each MACC diagram is followed by a table that presents the average cost data and estimated savings used to create the MACC.

Comment [Enbridge3]: Please refer to comment at Section 1.4.

At the end of each of the industrial, commercial and residential sub-sections, a table identifying all of the measures included in each end use category for that sector is provided, as well as measure-level cost data[15] (both $\$/m^3$ and $\$/tCO_2e$) for each LTCPF scenario.

2.4.1 Industrial Results

This section presents the results of the industrial customer conservation analysis for each of the three LTCPF scenarios in the format of a MACC diagram and a supporting data table, which provides the average cost and estimated savings data used to create the MACC. At the end of this section, there is a summary table that identifies all of the measures included in each industrial end use category as well as measure-level cost data for each LTCPF scenario.

Minimum LTCPF Scenario

Exhibit 2 presents the minimum LTCPF MACC for the industrial sector. In this carbon price scenario, the results show that the average cost for a utility to implement the measures in three of the industrial end use categories including HVAC, steam hot water system and direct heating

[14] Three long-term carbon price forecasts were analyzed in this study including minimum, maximum and mid-range carbon price forecasts. For more detail on the LTCPFs, refer to Long-Term Carbon Price Forecast Report, ICF, May 31, 2017, https://www.oeb.ca/industry/policy-initiatives-and-consultations/consultation-develop-regulatory-framework-natural-gas

[15] Tables of measure-level savings are provided to help the reader better understand the MACCs presented. It is important to note that this **measure-specific data is based on cascaded savings**. These values should not be read independently of the full modeled scenario results; they are averaged across multiple subsectors and regions, and the savings depend on the combination of other measures which are simultaneously deployed (cascading).

is lower than the cost of purchasing allowances in the 2018-2020 timeframe. The total potential savings over the 2018-2020 period is 96 million m^3 (or 180,000 tCO_2e). These values also represent the estimated savings associated with measures that are cost effective relative to the carbon price.

Comment [Enbridge4]: Does this imply that from 2018 to 2020 the utility would spend less in rates on abatement than allowances? Is this not correct, as the $/tonne values shown for abatement include benefits of avoided gas and electricity over 10 – 20 years. In a 3 year timeframe alone would abatement be more expensive in rates?

Comment [Enbridge5]: It is recommended that inclusion of expected cost of abatement to achieve 96 million m3 over 2018 to 2020 period be identified. $/tonne presented is a helpful illustration of societal costs and benefits combined. For ratemaking purposes in the Compliance Plan it will be important to understand the costs that ratepayers would be required to pay up front to enable these savings.

Exhibit 2 Industrial MACC for Minimum LTCPF

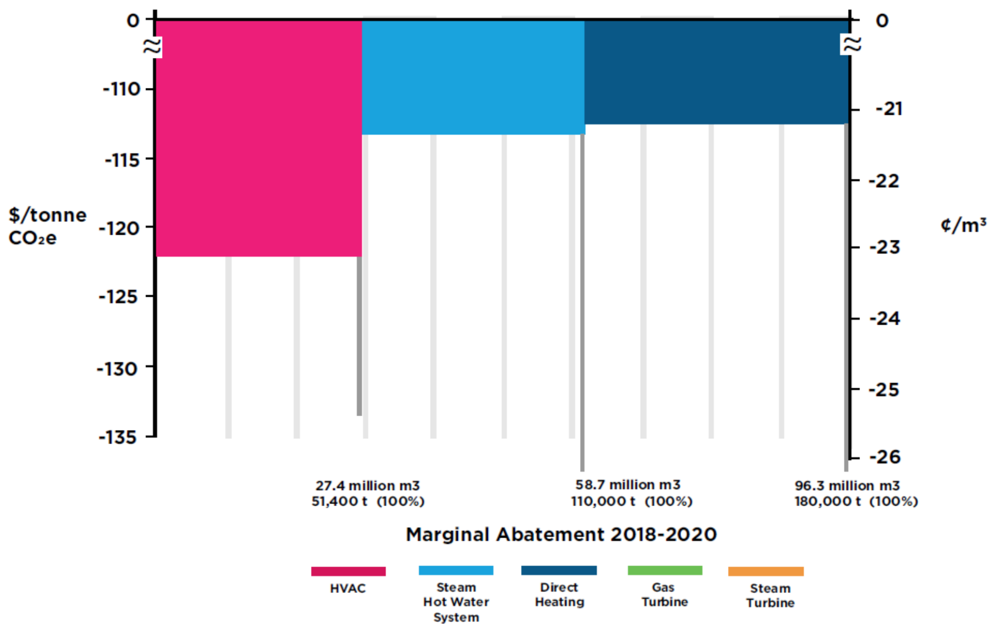


Table 1 Industrial MACC for Minimum LTCPF, Average Cost and Savings Results

Industrial End Use	Average $/t$CO_2$e	Average ¢/m^3	Estimated Savings (tCO_2e)	Estimated Savings (million m^3)	Estimated % Savings <$0/t$CO_2$e
Gas Turbine	-130	-24	550	0.3	100%
Steam Turbine	-130	-24	250	0.1	100%
HVAC	-122	-23	51,400	27	100%
Steam Hot Water System	-112	-21	58,600	31	100%
Direct Heating	-111	-21	69,700	37	100%

Maximum LTCPF Scenario

Exhibit 3 presents the maximum LTCPF MACC for the industrial sector. In this carbon price scenario, the results show that the average cost for a utility to implement the measures in three of the industrial end use categories including HVAC, steam hot water system and direct heating is lower than the cost of purchasing allowances in the 2018-2020 timeframe. The total potential savings over the 2018-2020 period is 96 million m^3 (or 180,000 tCO_2e). These values also represent the estimated savings associated with measures that are cost effective relative to the carbon price.

Exhibit 3 Industrial MACC for Maximum LTCPF

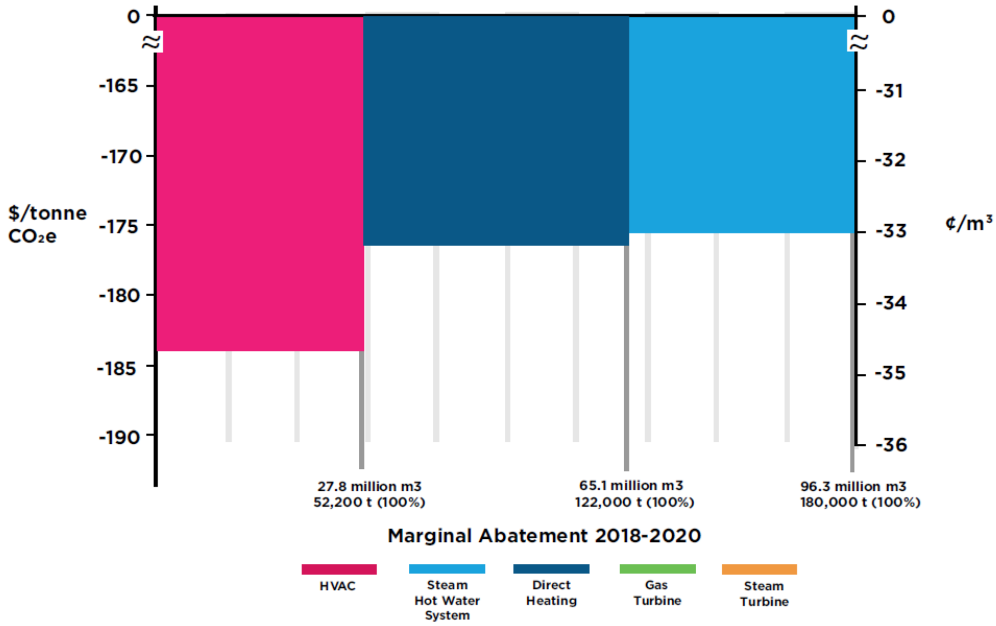


Table 2 Industrial MACC for Maximum LTCPF, Average Cost and Savings Results

Industrial End Use	Average $/tCO$_2$e	Average ¢/m^3	Estimated Savings (tCO$_2$e)	Estimated Savings (million m^3)	Estimated % Savings <$0/tCO$_2$e
Gas Turbine	-186	-35	550	0.3	100%
Steam Turbine	-186	-35	250	0.1	100%
HVAC	-184	-34	51,400	27	100%
Direct Heating	-176	-33	69,700	37	100%
Steam Hot Water System	-175	-33	58,600	31	100%

Mid-Range LTCPF Scenario

Exhibit 4 presents the mid-range LTCPF MACC for the industrial sector. In this carbon price scenario, the results show that the average cost for a utility to implement the measures in three of the industrial end use categories including HVAC, steam hot water system and direct heating is lower than the cost of purchasing allowances in the 2018-2020 timeframe. The total potential savings over the 2018-2020 period is 96 million m^3 (or 180,000 tCO$_2$e). These values also represent the estimated savings associated with measures that are cost effective relative to the carbon price.

Exhibit 4 Industrial MACC for Mid-Range LTCPF

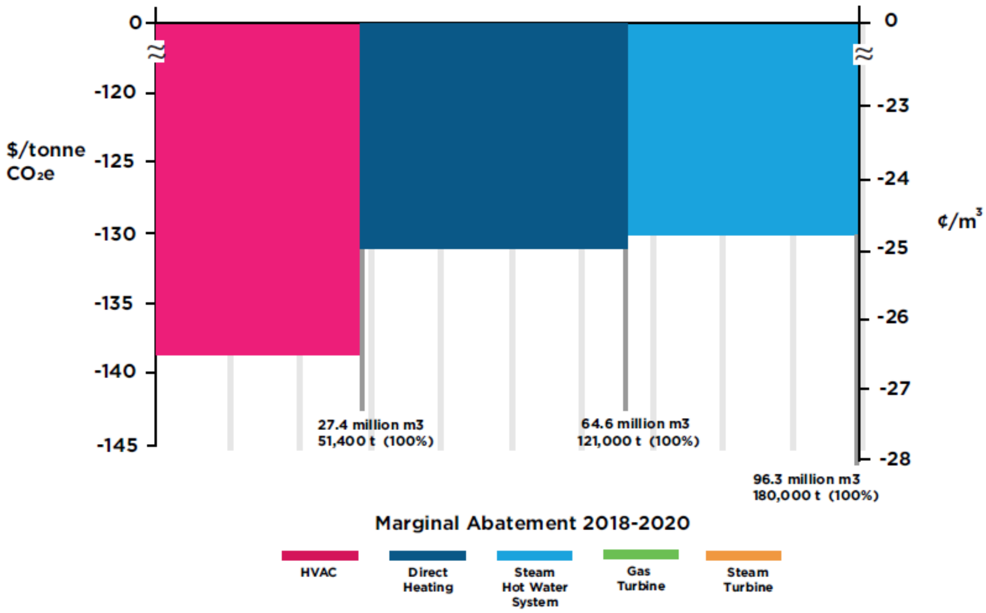


Table 3 Industrial MACC for Mid-Range LTCPF, Average Cost and Savings Results

Industrial End Use	Average $/tCO$_2$e	Average ¢/m^3	Estimated Savings (tCO$_2$e)	Estimated Savings (million m^3)	Estimated % Savings <$0/tCO$_2$e
HVAC	-139	-26	51,400	27	100%
Direct Heating	-132	-25	69,700	37	100%
Steam Hot Water System	-131	-25	58,600	31	100%
Gas Turbine	-130	-24	550	0.3	100%
Steam Turbine	-130	-24	250	0.1	100%

Table 4 Industrial Measure-Level Marginal Abatement Cost Data (Ranges) for 2018-2020 Timeframe

Industrial End Use	Measure Name	Mid-Range LTCPF				Minimum LTCPF				Maximum LTCPF			
		$/m^3$		$/tCO_2e$		$/m^3$		$/tCO_2e$		$/m^3$		$/tCO_2e$	
Direct Heating	High Efficiency Burners (Process)	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Direct Heating	Reduced Furnace Openings (Air & Chain Curtains)	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-107	-0.34	-0.31	-182	-168
Direct Heating	Exhaust Gas Heat Recovery	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Direct Heating	Insulation (Process)	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Direct Heating	Advanced Heating and Process Controls	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Direct Heating	Optimize Combustion	-0.24	-0.22	-131	-118	-0.24	-0.22	-127	-118	-0.35	-0.32	-186	-172
Direct Heating	High-efficiency Ovens & Dryers	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Direct Heating	High-efficiency Furnaces	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Direct Heating	Regenerative Thermal Oxidizers	-0.26	-0.24	-138	-127	-0.21	-0.20	-113	-108	-0.34	-0.32	-182	-169
Direct Heating	Process Heat Recovery	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Direct Heating	Process Improvements (changing cleaning chemicals, set points, exhaust, moisture control, etc.)	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-107	-0.34	-0.31	-182	-168
Direct Heating	Food and Beverage Manufacturing Process Improvements	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-107	-0.34	-0.31	-182	-167
Direct Heating	Refining Process Improvements	-0.26	-0.24	-138	-127	-0.21	-0.20	-113	-108	-0.34	-0.32	-182	-169
Direct Heating	Mining Process Improvements	-0.26	-0.23	-137	-124	-0.22	-0.21	-117	-110	-0.34	-0.31	-181	-167
Direct Heating	Primary Metal Manufacturing Process Improvements	-0.26	-0.24	-138	-127	-0.21	-0.20	-113	-108	-0.34	-0.32	-182	-169
Direct Heating	Non-Metallic Mineral Product Manufacturing Process Improvements	-0.26	-0.24	-138	-127	-0.21	-0.20	-113	-108	-0.34	-0.32	-182	-169
Direct Heating	Asphalt and Cement Manufacturing Process Improvements	-0.26	-0.24	-137	-126	-0.21	-0.20	-113	-107	-0.34	-0.31	-182	-168
Direct Heating	Fabricated Metal Manufacturing Process Improvements	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-107	-0.34	-0.31	-182	-168
Direct Heating	Transportation and Machinery Manufacturing Process Improvements	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-107	-0.34	-0.31	-182	-167
Gas Turbine	Gas Turbine Optimization	-0.25	-0.24	-132	-127	-0.25	-0.24	-132	-127	-0.36	-0.34	-191	-181
HVAC	Air Compressor Heat Recovery	-0.27	-0.25	-145	-133	-0.24	-0.22	-125	-119	-0.36	-0.33	-190	-177
HVAC	Ventilation Optimization	-0.27	-0.25	-146	-134	-0.24	-0.22	-126	-120	-0.36	-0.33	-190	-177

Industrial End Use	Measure Name	Mid-Range LTCPF				Minimum LTCPF				Maximum LTCPF			
		$/m^3		$/tCO$_2$e		$/m^3		$/tCO$_2$e		$/m^3		$/tCO$_2$e	
HVAC	Ventilation Heat Recovery	-0.27	-0.25	-145	-133	-0.23	-0.22	-125	-119	-0.36	-0.33	-190	-176
HVAC	Automated Temperature Control	-0.27	-0.25	-145	-133	-0.23	-0.22	-125	-119	-0.36	-0.33	-190	-176
HVAC	Destratification Fans	-0.27	-0.25	-145	-133	-0.23	-0.22	-125	-119	-0.36	-0.33	-190	-176
HVAC	Warehouse Loading Dock Seals	-0.27	-0.25	-145	-133	-0.23	-0.22	-125	-119	-0.36	-0.33	-190	-176
HVAC	Minimize Door Openings	-0.27	-0.25	-145	-134	-0.24	-0.22	-126	-120	-0.36	-0.33	-190	-177
HVAC	Solar Walls	-0.27	-0.25	-142	-132	-0.21	-0.20	-114	-108	-0.36	-0.33	-194	-179
HVAC	Radiant Heaters	-0.27	-0.25	-145	-133	-0.23	-0.22	-125	-119	-0.36	-0.33	-190	-176
HVAC	Greenhouse Curtains	-0.27	-0.24	-143	-130	-0.24	-0.23	-130	-123	-0.36	-0.33	-191	-178
HVAC	Greenhouse Envelope Improvements	-0.27	-0.25	-141	-133	-0.26	-0.25	-138	-133	-0.37	-0.35	-197	-186
HVAC	Improved Building Envelope	-0.27	-0.25	-145	-133	-0.23	-0.22	-125	-119	-0.36	-0.33	-190	-176
HVAC	High Efficiency Heating Units	-0.27	-0.25	-145	-133	-0.23	-0.22	-125	-119	-0.36	-0.33	-190	-176
Steam Hot Water System	Minimize Deaerator Vent Losses	-0.26	-0.24	-137	-125	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Steam Hot Water System	Insulation (Steam Systems)	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Steam Hot Water System	Boiler Tune Up	-0.24	-0.22	-130	-119	-0.24	-0.22	-127	-119	-0.35	-0.32	-186	-173
Steam Hot Water System	Condensing Economizers	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-107	-0.34	-0.31	-182	-167
Steam Hot Water System	Burn Digester Gas in Boilers	-0.26	-0.24	-138	-127	-0.21	-0.20	-113	-108	-0.34	-0.32	-182	-169
Steam Hot Water System	Steam Leak Repairs	-0.25	-0.22	-133	-120	-0.23	-0.21	-120	-113	-0.34	-0.31	-181	-168
Steam Hot Water System	Feedwater Economizers	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Steam Hot Water System	Boiler Combustion Air Preheat	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Steam Hot Water System	Blowdown Heat Recovery	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Steam Hot Water System	Automated Blowdown Control	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Steam Hot Water System	Condensate Return	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Steam Hot Water System	Steam Trap Survey and Repair	-0.25	-0.23	-131	-121	-0.23	-0.22	-123	-118	-0.34	-0.32	-183	-173
Steam Hot Water System	Boiler Right Sizing and Load Management	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Steam Hot Water System	Reduce Boiler Steam Pressure	-0.26	-0.24	-138	-127	-0.21	-0.20	-113	-108	-0.34	-0.32	-182	-169
Steam Hot Water System	Advanced Boiler Controls	-0.26	-0.23	-137	-124	-0.22	-0.21	-117	-110	-0.34	-0.31	-181	-167
Steam Hot Water System	Condensing Boiler	-0.26	-0.24	-137	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Steam Hot Water System	Direct Contact Water Heaters	-0.26	-0.24	-137	-126	-0.21	-0.20	-113	-107	-0.34	-0.31	-182	-167
Steam Hot Water System	High Efficiency Burners - Boilers	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-107	-0.34	-0.31	-182	-167
Steam Hot Water System	Chemical Manufacturing Process Improvements	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-107	-0.34	-0.31	-182	-167
Steam Hot Water System	Greenhouses Other EE Upgrades	-0.26	-0.24	-138	-126	-0.21	-0.20	-113	-106	-0.34	-0.31	-182	-167
Steam Hot Water System	Pulp and Paper Process Improvements	-0.26	-0.24	-138	-127	-0.21	-0.20	-113	-108	-0.34	-0.32	-182	-169
Steam Turbine	Steam Turbine Optimization	-0.25	-0.24	-132	-127	-0.25	-0.24	-132	-127	-0.36	-0.34	-190	-180

2.4.2 Commercial Results

This section presents the results of the commercial customer conservation analysis for each of the three LTCPF scenarios in the format of a MACC diagram and a supporting data table, which provides the average cost and estimated savings data used to create the MACC. At the end of this section, there is a summary table that identifies all of the measures included in each commercial end use category as well as measure-level cost data for each LTCPF scenario.

Minimum LTCPF Scenario

Exhibit 5 presents the minimum LTCPF MACC for the commercial sector. In this carbon price scenario, the results show that the average cost for a utility to implement the measures in four of the commercial end use categories including food service, systems, service water heating and space heating is lower than the cost of purchasing allowances in the 2018-2020 timeframe. The total potential savings over the 2018-2020 period is 108 million m^3 (or 202,000 tCO_2e), and the estimated savings associated with measures that are cost effective relative to the carbon price is 98 million m^3 (or 184,000 tCO_2e).

Exhibit 5 Commercial MACC for Minimum LTCPF

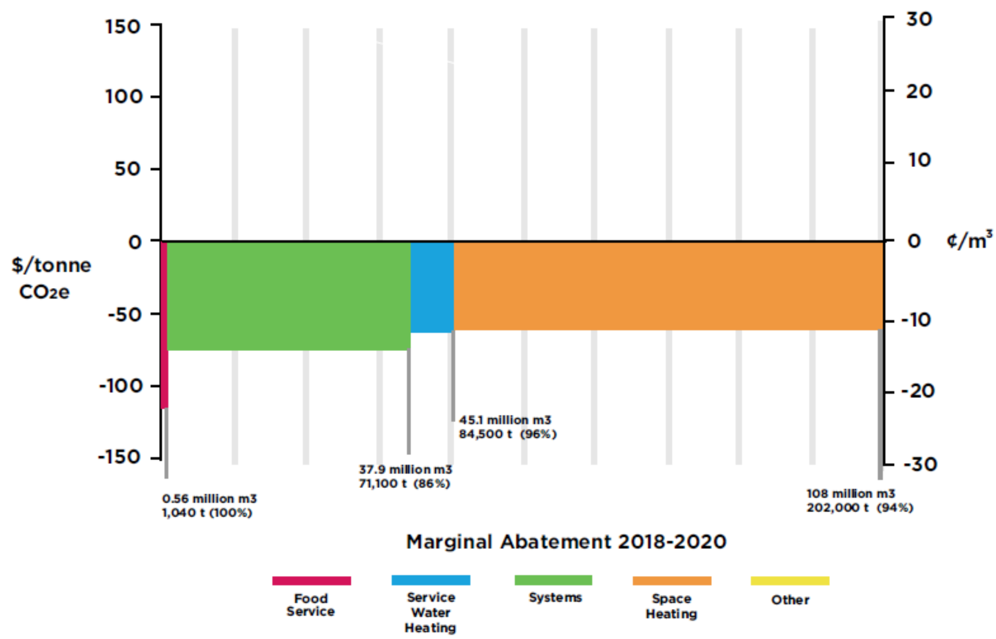


Table 5 Commercial MACC for Minimum LTCPF, Average Cost and Savings Results

Commercial End Use	Average $/$tCO_2e$	Average ¢/m^3	Estimated Savings (tCO_2e)	Estimated Savings (million m^3)	Estimated % Savings <$0/$tCO_2e$
Food Service	-105	-20	1,040	0.6	100%
Systems	-75	-14	70,100	37	86%
Service Water Heating	-62	-12	13,400	7	96%
Space Heating	-62	-12	117,000	63	94%
Other	176	33	3	0.002	0%

Maximum LTCPF Scenario

Exhibit 6 presents the maximum LTCPF MACC for the commercial sector. In this carbon price scenario, the results show that the average cost for a utility to implement the measures in four of the commercial end use categories including food service, systems, service water heating and space heating is lower than the cost of purchasing allowances in the 2018-2020 timeframe. The total potential savings over the 2018-2020 period is 108 million m^3 (or 202,000 tCO_2e), and the estimated savings associated with measures that are cost effective relative to the carbon price is 106 million m^3 (or 198,000 tCO_2e).

Exhibit 6 Commercial MACC for Maximum LTCPF

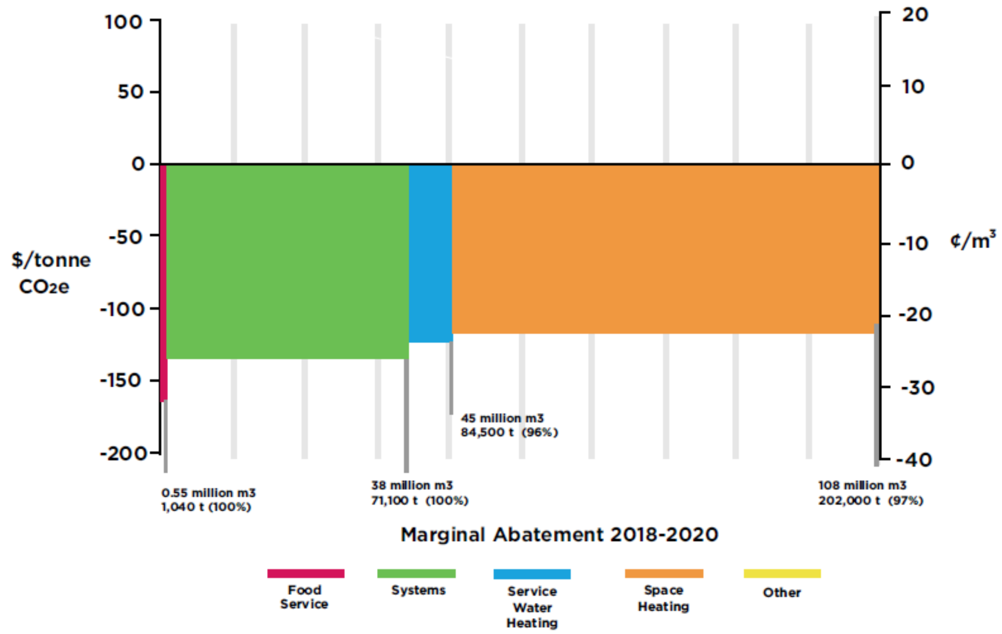


Table 6 Commercial MACC for Maximum LTCPF, Average Cost and Savings Results

Commercial End Use	Average $/t$CO_2$e	Average ¢/m^3	Estimated Savings (tCO_2e)	Estimated Savings (million m^3)	Estimated % Savings <$0/t$CO_2$e
Food Service	-165	-31	1,040	0.6	100%
Systems	-137	-26	70,100	37	100%
Service Water Heating	-127	-24	13,400	7	96%
Space Heating	-127	-24	117,000	63	97%
Other	106	20	3	0.002	0%

Mid-Range LTCPF Scenario

Exhibit 7 presents the mid-range LTCPF MACC for the commercial sector. In this carbon price scenario, the results show that the average cost for a utility to implement the measures in four of the commercial end use categories including food service, systems, service water heating and space heating is lower than the cost of purchasing allowances in the 2018-2020 timeframe. The total potential savings over the 2018-2020 period is 108 million m^3 (or 202,000 tCO_2e), and the estimated savings associated with measures that are cost effective relative to the carbon price is 99 million m^3 (or 186,000 tCO_2e).

Exhibit 7 Commercial MACC for Mid-Range LTCPF

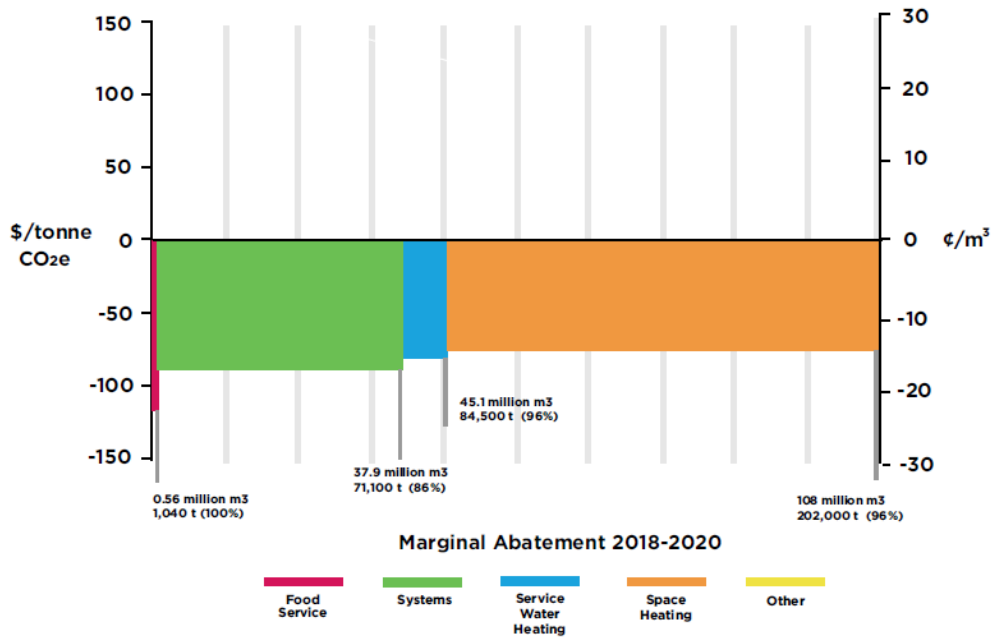


Table 7 Commercial MACC for Mid-Range LTCPF, Average Cost and Savings Results

Commercial End Use	Average $/tCO$_2$e	Average ¢/m^3	Estimated Savings (tCO$_2$e)	Estimated Savings (million m^3)	Estimated % Savings <$0/tCO$_2$e
Food Service	-119	-22	1,040	0.6	100%
Systems	-88	-16	70,100	37	86%
Service Water Heating	-83	-16	13,400	7	96%
Space Heating	-83	-15	117,000	63	96%
Other	151	28	3	0.002	0%

Table 8 Commercial Measure-Level Marginal Abatement Cost Data (Ranges) for 2018-2020 Timeframe

Commercial End Use	Measure Name	Mid-Range LTCPF				Minimum LTCPF				Maximum LTCPF			
		$/m^3$		$/tCO_2e$		$/m^3$		$/tCO_2e$		$/m^3$		$/tCO_2e$	
Space Heating	High-Performance Glazing	-0.26	0.81	-138	431	-0.21	0.85	-110	455	-0.36	0.72	-190	384
Space Heating	Roof Insulation	-0.25	0.88	-132	471	-0.20	0.93	-104	495	-0.35	0.80	-184	425
Space Heating	Wall Insulation	-0.23	0.89	-122	473	-0.18	0.93	-94	497	-0.33	0.80	-174	427
Space Heating	Super-High Efficiency Furnaces	-0.24	-0.22	-130	-120	-0.20	-0.19	-107	-102	-0.33	-0.30	-174	-162
Space Heating	Condensing Boilers (for Space Heating)	-0.26	-0.23	-137	-123	-0.21	-0.19	-113	-104	-0.34	-0.31	-181	-165
Space Heating	Condensing Make-Up Air Units	-0.27	-0.24	-142	-127	-0.22	-0.20	-117	-108	-0.35	-0.32	-186	-169
Space Heating	Condensing Unit Heaters	-0.24	-0.22	-126	-115	-0.19	-0.18	-103	-98	-0.32	-0.29	-170	-157
Space Heating	Destratification Fans	-0.14	-0.12	-72	-62	-0.10	-0.09	-52	-48	-0.22	-0.20	-117	-105
Space Heating	Gas Fired Rooftop Units (Two-Stage)	-0.23	-0.20	-124	-106	-0.19	-0.17	-104	-92	-0.31	-0.28	-168	-150
Space Heating	High Efficiency Boilers (for Space Heating)	-0.26	-0.21	-139	-114	-0.21	-0.18	-114	-94	-0.34	-0.29	-183	-155
Space Heating	Heat Reflector Panels	-0.24	-0.21	-127	-111	-0.20	-0.18	-104	-94	-0.32	-0.29	-171	-153
Space Heating	Boilers - High Efficiency Burners	-0.17	-0.13	-93	-69	-0.13	-0.09	-69	-50	-0.26	-0.21	-137	-111
Space Heating	Infrared Heaters	-0.24	-0.22	-127	-116	-0.20	-0.19	-105	-100	-0.32	-0.30	-171	-158
Space Heating	Boilers - Feedwater Economizers	0.66	0.71	354	377	0.71	0.74	378	396	0.58	0.63	309	335
Space Heating	Boilers - Combustion Air Preheat	0.69	0.73	368	392	0.73	0.76	388	407	0.61	0.65	324	348
Space Heating	Boilers - Blowdown Heat Recovery	0.45	0.49	240	264	0.50	0.53	265	283	0.37	0.42	196	222
Space Heating	Refrigeration Waste Heat Recovery	-0.27	-0.25	-142	-131	-0.23	-0.22	-122	-117	-0.35	-0.33	-186	-174
Space Heating	Heat Recovery Ventilation	-0.22	0.05	-117	27	-0.18	0.08	-98	40	-0.30	-0.03	-162	-17
Space Heating	Energy Recovery Ventilation	-0.25	-0.11	-133	-59	-0.21	-0.09	-114	-46	-0.33	-0.19	-178	-103
Space Heating	Energy Recovery Ventilation (Enhanced)	-0.28	-0.22	-149	-119	-0.24	-0.20	-129	-105	-0.36	-0.30	-194	-162
Space Heating	Ventilation Fan VFDs	-0.27	-0.25	-145	-133	-0.23	-0.22	-125	-119	-0.35	-0.33	-189	-177
Space Heating	Demand Control Kitchen Ventilation	-0.24	-0.22	-131	-120	-0.21	-0.20	-111	-106	-0.33	-0.31	-175	-163
Space Heating	Adaptive Thermostats	-0.25	-0.12	-136	-65	-0.22	-0.09	-116	-51	-0.34	-0.20	-180	-108
Space Heating	Demand Control Ventilation	-0.26	-0.21	-138	-113	-0.23	-0.20	-124	-106	-0.35	-0.30	-185	-161
Space Heating	Demand Control Ventilation (Enhanced)	-0.26	-0.24	-139	-127	-0.22	-0.21	-119	-113	-0.34	-0.32	-184	-171
Space Heating	Air Curtains	-0.27	-0.23	-143	-123	-0.23	-0.20	-123	-109	-0.35	-0.31	-187	-166
Space Heating	Use Shades/Blinds	-0.28	-0.26	-150	-138	-0.28	-0.26	-150	-138	-0.39	-0.36	-208	-190
Systems	New Construction - 25% Better	-0.24	-0.08	-130	-42	-0.19	-0.03	-102	-18	-0.34	-0.17	-182	-88

Commercial End Use	Measure Name	Mid-Range LTCPF				Minimum LTCPF				Maximum LTCPF			
		$/m^3		$/tCO$_2$e		$/m^3		$/tCO$_2$e		$/m^3		$/tCO$_2$e	
Systems	New Construction - 40% Better	-0.25	-0.11	-136	-58	-0.20	-0.06	-108	-34	-0.35	-0.20	-188	-104
Systems	Advanced BAS/Controllers	-0.22	0.33	-119	175	-0.18	0.35	-99	189	-0.31	0.25	-163	132
Systems	Operations and Maintenance (O&M) Improvements	-0.28	-0.26	-150	-138	-0.28	-0.26	-150	-138	-0.39	-0.36	-208	-190
Systems	Building Recommissioning (Standard)	-0.27	-0.26	-142	-136	-0.26	-0.26	-138	-136	-0.37	-0.36	-198	-190
Systems	Building Recommissioning (Enhanced)	-0.27	-0.26	-142	-136	-0.26	-0.26	-138	-136	-0.37	-0.36	-198	-190
Systems	Faucet Aerators	-0.24	-0.22	-131	-116	-0.22	-0.20	-118	-109	-0.33	-0.31	-178	-164
Systems	Low-Flow Showerheads	-0.23	-0.18	-123	-99	-0.21	-0.17	-110	-92	-0.32	-0.27	-171	-147
Service Water Heating	Condensing Boilers (for Service Water Heating)	-0.22	-0.14	-115	-73	-0.17	-0.10	-91	-54	-0.30	-0.22	-160	-115
Service Water Heating	Condensing Storage Water Heaters	-0.22	0.04	-115	24	-0.18	0.07	-95	38	-0.30	-0.04	-160	-20
Service Water Heating	Condensing Tankless Water Heaters	-0.22	-0.03	-120	-18	-0.18	0.00	-95	1	-0.31	-0.11	-164	-60
Service Water Heating	Drain Water Heat Recovery (DWHR)	-0.25	-0.23	-134	-120	-0.20	-0.18	-106	-98	-0.34	-0.31	-181	-163
Service Water Heating	High Efficiency Boilers (for Service Water Heating)	-0.17	0.13	-89	72	-0.12	0.17	-64	91	-0.25	0.06	-133	30
Service Water Heating	Indirect Water Heaters	0.15	0.23	81	121	0.19	0.25	101	135	0.07	0.15	37	78
Service Water Heating	Solar Water Preheat (DHW)	0.28	0.44	152	234	0.34	0.49	179	261	0.20	0.35	105	187
Service Water Heating	Commercial Ozone Laundry Treatment	-0.26	-0.23	-136	-124	-0.22	-0.21	-116	-110	-0.34	-0.31	-181	-168
Service Water Heating	ENERGY STAR Dishwashers	-0.24	-0.21	-126	-114	-0.20	-0.19	-106	-100	-0.32	-0.30	-170	-158
Service Water Heating	ENERGY STAR Clothes Washers	-0.26	-0.22	-140	-116	-0.23	-0.20	-125	-107	-0.35	-0.30	-187	-163
Service Water Heating	CEE Tier 2 Clothes Washers	-0.16	-0.12	-85	-65	-0.13	-0.11	-70	-56	-0.25	-0.21	-132	-112
Service Water Heating	Pre-Rinse Spray Nozzles	-0.22	-0.13	-119	-71	-0.22	-0.13	-116	-68	-0.33	-0.23	-175	-125
Food Service	ENERGY STAR Griddles	-0.25	-0.23	-135	-124	-0.21	-0.20	-114	-109	-0.34	-0.31	-179	-167
Food Service	ENERGY STAR Convection Ovens	-0.22	-0.20	-119	-108	-0.19	-0.18	-102	-98	-0.31	-0.29	-165	-153
Food Service	ENERGY STAR Fryers	-0.21	-0.19	-112	-101	-0.18	-0.17	-96	-91	-0.30	-0.27	-158	-147
Food Service	ENERGY STAR Steam Cookers	-0.25	-0.23	-133	-122	-0.22	-0.21	-117	-112	-0.34	-0.31	-179	-168
Food Service	Pizza/Bakery Oven Insulation	-0.20	-0.18	-108	-97	-0.17	-0.16	-92	-87	-0.29	-0.27	-154	-142
Food Service	High Efficiency Underfired Broilers	-0.24	-0.22	-126	-115	-0.21	-0.20	-110	-105	-0.32	-0.30	-172	-161
Other	Solar Water Preheat (Pools)	0.24	0.49	127	259	0.29	0.53	154	282	0.15	0.41	80	216

2.4.3 Residential Results

This section presents the results of the residential customer conservation analysis for each of the three LTCPF scenarios in the format of a MACC diagram and a supporting data table, which provides the average cost and estimated savings data used to create the MACC. At the end of this section, there is a summary table that identifies all of the measures included in each residential end use category as well as measure-level cost data for each LTCPF scenario.

Minimum LTCPF Scenario

Exhibit 8 presents the minimum LTCPF MACC for the residential sector. In this carbon price scenario, the results show that the average cost for a utility to implement the measures in four of the residential end use categories including clothes dryers, fireplaces, systems and space heating is lower than the cost of purchasing allowances in the 2018-2020 timeframe. The total potential savings over the 2018-2020 period is 144 million m^3 (or 270,000 tCO_2e), and the estimated savings associated with measures that are cost effective relative to the carbon price is 96 million m^3 (or 180,000 tCO_2e).

Exhibit 8 Residential MACC for Minimum LTCPF

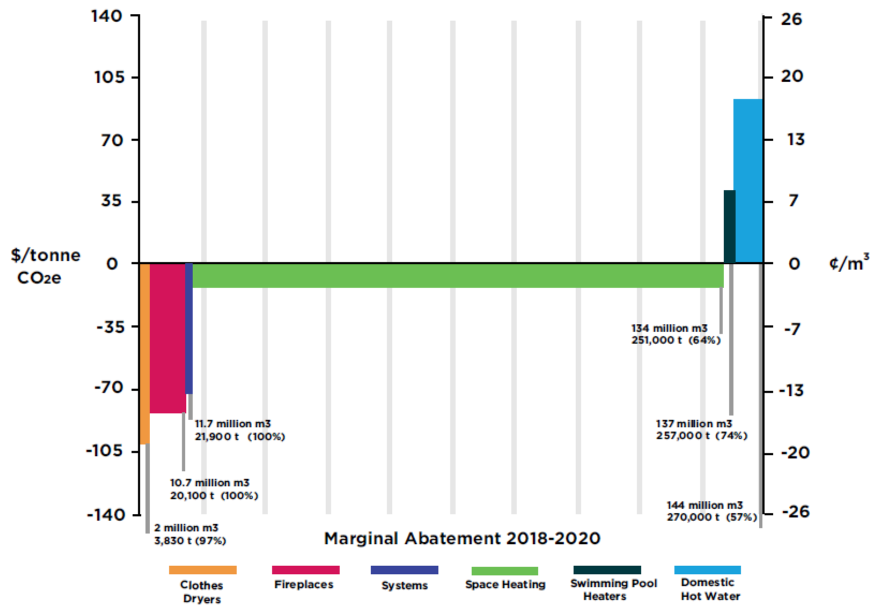


Table 9 Residential MACC for Minimum LTCPF, Average Cost and Savings Results

Residential End Use	Average $/tCO$_2$e	Average ¢/m^3	Estimated Savings (tCO$_2$e)	Estimated Savings (million m^3)	Estimated % Savings <$0/tCO$_2$e
Clothes Dryers	-100	-19	3,830	2	97%
Fireplaces	-83	-16	16,200	8.7	100%
Systems	-72	-13	1,850	1	100%
Space Heating	13	2	230,000	122	64%
Swimming Pool Heaters	40	8	5,480	3	74%
Domestic Hot Water	127	24	12,900	7	57%

Maximum LTCPF Scenario

Exhibit 9 presents the maximum LTCPF MACC for the residential sector. In this carbon price scenario, the results show that the average cost for a utility to implement the measures in five of the residential end use categories including clothes dryers, fireplaces, systems, space heating and swimming pool heaters is lower than the cost of purchasing allowances in the 2018-2020 timeframe. The total potential savings over the 2018-2020 period is 144 million m^3 (or 270,000 tCO_2e), and the estimated savings associated with measures that are cost effective relative to the carbon price is 110 million m^3 (or 207,000 tCO_2e).

Exhibit 9 Residential MACC for Maximum LTCPF

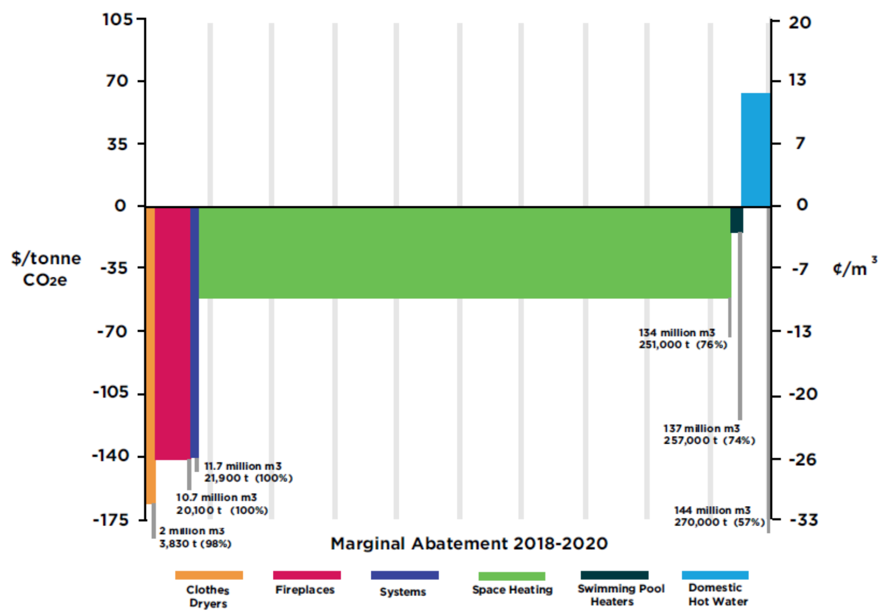


Table 10 Residential MACC for Maximum LTCPF, Average Cost and Savings Results

Residential End Use	Average $/$tCO_2e$	Average ¢/m^3	Estimated Savings (tCO_2e)	Estimated Savings (million m^3)	Estimated % Savings <$0/$tCO_2e$
Clothes Dryers	-166	-31	3,830	2	98%
Fireplaces	-143	-27	16,200	8.7	100%
Systems	-143	-27	1,850	1	100%
Space Heating	-54	-10	230,000	122	76%
Swimming Pool Heaters	-22	-4	5,480	3	74%
Domestic Hot Water	63	12	12,900	7	57%

Mid-Range LTCPF Scenario

Exhibit 10 presents the mid-range LTCPF MACC for the residential sector. In this carbon price scenario, the results show that the average cost for a utility to implement the measures in four of the residential end use categories including clothes dryers, systems, fireplaces and space heating is lower than the cost of purchasing allowances in the 2018-2020 timeframe. The total potential savings over the 2018-2020 period is 144 million m^3 (or 270,000 tCO_2e), and the estimated savings associated with measures that are cost effective relative to the carbon price is 97 million m^3 (or 182,000 tCO_2e).

Exhibit 10 Residential MACC for Mid-Range LTCPF

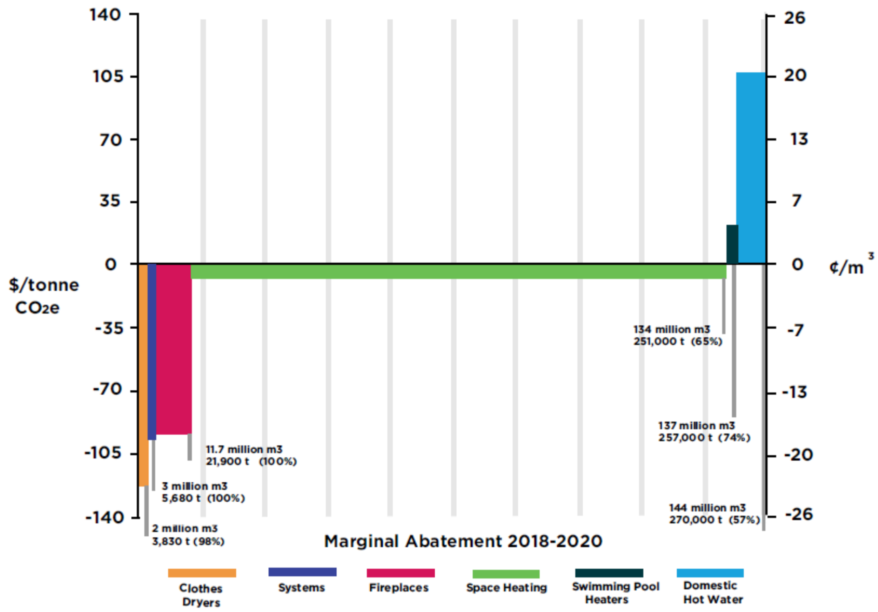


Table 11 Residential MACC for Mid-Range LTCPF, Average Cost and Savings Results

Residential End Use	Average $/t$CO_2$e	Average ¢/m^3	Estimated Savings (tCO_2e)	Estimated Savings (million m^3)	Estimated % Savings <$0/t$CO_2$e
Clothes Dryers	-123	-23	3,830	2	98%
Systems	-97	-18	1,850	1	100%
Fireplaces	-94	-18	16,200	8.7	100%
Space Heating	-7	-1	230,000	122	65%
Swimming Pool Heaters	24	5	5,480	3	74%
Domestic Hot Water	108	20	12,900	7	57%

Table 12 Residential Measure-Level Marginal Abatement Cost Data (Ranges) for 2018-2020 Timeframe

Residential End Use	Measure Name	Mid-Range LTCPF				Minimum LTCPF				Maximum LTCPF			
		$/m³		$/tCO₂e		$/m³		$/tCO₂e		$/m³		$/tCO₂e	
Space Heating	Attic/Ceiling Insulation	-0.12	-0.08	-62.9	-42.3	-0.07	-0.03	-34.8	-18.2	-0.22	-0.17	-115	-89
Space Heating	Basement Wall Insulation (R-12)	-0.17	-0.04	-89.3	-20.5	-0.11	0.01	-61.1	3.6	-0.26	-0.13	-141	-66.8
Space Heating	Crawlspace Insulation	0.62	2.25	330	1,201	0.67	2.30	358	1,227	0.52	2.17	278	1,155
Space Heating	Draft Proofing Kit	-0.19	-0.17	-101	-89.5	-0.19	-0.17	-101	-89.5	-0.30	-0.27	-159	-141
Space Heating	Wall Insulation	-0.19	0.51	-103	272	-0.14	0.55	-75	296	-0.29	0.42	-155	225
Space Heating	Zoned-Up Windows: (ENERGY STAR) Rating for a Colder Climate	-0.24	0.30	-128	162	-0.19	0.35	-100	186	-0.34	0.22	-180	115
Space Heating	Heat Reflector Panels	-0.25	-0.22	-133	-117	-0.20	-0.18	-106	-95	-0.34	-0.30	-180	-160
Space Heating	Air Leakage Sealing and Insulation (Old Homes)	-0.22	-0.10	-116	-54.7	-0.16	-0.06	-88.0	-30.6	-0.31	-0.19	-168	-101
Space Heating	Super High-Performance Windows	-0.55	-0.07	-291	-39.2	-0.49	-0.03	-263	-15.1	-0.64	-0.16	-343	-85.5
Space Heating	Professional Air Sealing/Weather Stripping/Caulking	-0.19	0.14	-101	75.8	-0.14	0.19	-73.4	99.8	-0.29	0.06	-153	29.4
Space Heating	Condensing Gas Boilers	0.27	1.89	146	1,008	0.32	1.94	170	1,033	0.19	1.81	102	964
Space Heating	Early Furnace Replacement - 60% AFUE - 90% AFUE Furnace	-0.09	-0.08	-47.8	-43.5	-0.09	-0.08	-47.8	-43.5	-0.20	-0.18	-106	-96.7
Space Heating	Early Furnace Replacement - 70% AFUE - 90% AFUE Furnace	0.04	0.04	19.7	24.0	0.04	0.04	19.7	24.0	-0.07	-0.05	-38.1	-29.2
Space Heating	High Efficiency Condensing Furnace	0.32	0.49	172	262	0.36	0.53	194	285	0.24	0.41	128	218
Space Heating	95% or Higher Efficiency Furnace	-0.21	-0.08	-110	-40.7	-0.16	-0.04	-87.0	-23.4	-0.29	-0.16	-154	-82.8
Space Heating	Programmable Thermostat	-0.20	-0.16	-109	-86.7	-0.17	-0.14	-89.0	-72.6	-0.29	-0.24	-153	-130
Space Heating	Adaptive Thermostats	-0.30	-0.28	-159	-147	-0.26	-0.25	-139	-133	-0.38	-0.36	-203	-190
Space Heating	Adaptive Thermostats - Direct Install (from base measure Programmable Thermostat)	-0.28	-0.17	-149	-92.5	-0.24	-0.15	-129	-78.4	-0.36	-0.25	-194	-136
Space Heating	Close windows and blinds	-0.29	-0.26	-156	-139	-0.29	-0.26	-156	-139	-0.40	-0.36	-214	-191
Space Heating	Maintain Weatherstripping	0.06	0.86	32.6	457	0.06	0.86	34.2	461	-0.04	0.75	-22.3	402
Systems	High-Efficiency (ENERGY STAR®) Clothes Washers	-0.27	-0.20	-145	-109	-0.24	-0.18	-126	-96.1	-0.36	-0.29	-189	-153
Domestic Hot Water	Faucet Aerator (Bathroom, 1.5 GPM)	-0.23	-0.21	-125	-114	-0.21	-0.20	-111	-107	-0.32	-0.30	-172	-162
Domestic Hot Water	Faucet Aerator (Kitchen, 1.5 GPM)	-0.24	-0.22	-128	-118	-0.22	-0.21	-115	-110	-0.33	-0.31	-176	-165
Domestic Hot Water	High-Efficiency (ENERGY STAR®) Dishwashers	0.65	3.36	346	1,793	0.68	3.39	360	1,808	0.56	3.27	299	1,747
Domestic Hot Water	Low-Flow Shower Head (1.5 GPM)	-0.20	-0.17	-104	-92.7	-0.17	-0.16	-91.1	-85.6	-0.28	-0.26	-152	-141
Domestic Hot Water	Pipe Wrap	-0.25	-0.23	-135	-124	-0.22	-0.21	-115	-110	-0.34	-0.31	-179	-167

Residential End Use	Measure Name	Mid-Range LTCPF				Minimum LTCPF				Maximum LTCPF			
		$/m^3$		$/tCO_2e$		$/m^3$		$/tCO_2e$		$/m^3$		$/tCO_2e$	
Domestic Hot Water	DHW Tank Insulation	0.03	0.60	18.7	317	0.07	0.62	36.2	329	-0.05	0.51	-26.6	273
Domestic Hot Water	Faucet Aerator (Bathroom, 1.0 GPM)	-0.24	-0.22	-128	-118	-0.22	-0.21	-115	-111	-0.33	-0.31	-176	-166
Domestic Hot Water	Faucet Aerator (Kitchen, 1.0 GPM)	-0.24	-0.22	-130	-120	-0.22	-0.21	-117	-113	-0.33	-0.31	-178	-168
Domestic Hot Water	Low-Flow Shower Head (1.25 GPM)	-0.33	-0.31	-178	-165	-0.31	-0.30	-165	-158	-0.42	-0.40	-226	-213
Domestic Hot Water	Early Hot Water Heater Replacement (0.575 to 0.62 EF)	0.44	0.45	232	239	0.44	0.45	232	239	0.33	0.34	177	180
Domestic Hot Water	High Efficiency Gas Storage Water Heater	0.51	0.57	270	305	0.55	0.60	291	321	0.42	0.49	226	263
Domestic Hot Water	Tankless Water Heater (High Efficiency Non-Condensing)	0.63	0.70	337	375	0.68	0.74	361	397	0.55	0.62	292	333
Domestic Hot Water	Condensing Gas Water Heaters	-3.95	2.52	-2,105	1,344	-3.91	2.55	-2,088	1,360	-4.03	2.44	-2,150	1,300
Domestic Hot Water	Tankless Water Heater (Condensing)	-0.98	0.28	-521	147	-0.93	0.31	-497	166	-1.06	0.20	-566	105
Domestic Hot Water	Active Solar Water Heating Systems	0.87	3.05	461	1,629	0.92	3.10	489	1,656	0.78	2.97	415	1,582
Domestic Hot Water	DHW Recirculation Systems (e.g. Metlund D'MAND®)	0.04	0.76	19.7	403	0.08	0.80	42.7	425	-0.05	0.68	-24.2	361
Domestic Hot Water	Wastewater Heat Recovery Systems	0.25	1.34	134	717	0.30	1.40	163	745	0.15	1.25	83	665
Domestic Hot Water	Minimize Hot and Warm Clothes Wash	-0.26	-0.24	-137	-126	-0.26	-0.24	-137	-126	-0.37	-0.33	-195	-178
Domestic Hot Water	Reduce Temperature of DHW	-0.26	-0.24	-137	-126	-0.26	-0.24	-137	-126	-0.37	-0.33	-195	-178
Clothes Dryers	High-Efficiency Gas Clothes Dryers	0.08	0.81	40.7	433	0.12	0.85	63.7	451	-0.01	0.73	-3.2	391
Clothes Dryers	Use sensor for clothes dryer	-0.05	0.34	-24.1	180	0.00	0.37	-1.2	197	-0.13	0.26	-68.1	138
Clothes Dryers	Clothes lines and drying racks	-0.25	-0.21	-133	-115	-0.20	-0.18	-108	-94.7	-0.33	-0.29	-178	-156
Swimming Pool Heaters	Insulating Pool Covers	-0.24	-0.12	-125	-62	-0.21	-0.10	-112	-54.5	-0.32	-0.21	-173	-110
Swimming Pool Heaters	High-Efficiency Gas-Fired Pool Heaters	1.48	2.09	787	1,116	1.48	2.10	790	1,120	1.38	2.00	735	1,064
Swimming Pool Heaters	Solar Pool Heaters	-0.23	-0.19	-123	-101	-0.18	-0.15	-98	-82.1	-0.31	-0.27	-167	-143
Fireplaces	Fireplace Intermittent Ignition Control Retrofit	-0.17	-0.10	-90.9	-55.5	-0.15	-0.10	-81.2	-51.5	-0.26	-0.20	-141	-106
Fireplaces	High Efficiency Fireplace with Pilotless Ignition (freestanding fireplace)	-0.25	-0.21	-131	-110	-0.20	-0.17	-107	-91.3	-0.33	-0.29	-176	-152
Fireplaces	High Efficiency Fireplace with Pilotless Ignition (insert)	-0.25	-0.21	-131	-110	-0.20	-0.17	-107	-91.0	-0.33	-0.28	-175	-152
Fireplaces	High Efficiency Fireplace with Pilotless Ignition (Zero Clearance <40 kBtu/h)	-0.24	-0.21	-131	-110	-0.20	-0.17	-106	-90.5	-0.33	-0.28	-175	-151

Residential End Use	Measure Name	Mid-Range LTCPF				Minimum LTCPF				Maximum LTCPF			
		$/m^3$		$/tCO_2e$		$/m^3$		$/tCO_2e$		$/m^3$		$/tCO_2e$	
Fireplaces	High Efficiency Fireplace with Pilotless Ignition (Zero Clearance ≥40 kBtu/h)	-0.25	-0.21	-135	-114	-0.21	-0.18	-110	-94.8	-0.34	-0.29	-179	-156

3. Renewable Natural Gas

3.1 Background

In order to support the assessment of the utilities' cap and trade costs over the study period, it is important to consider not only the abatement that can be achieved through natural gas conservation measures implemented by natural gas customers (see Section 2), but also opportunities for abatement that utilities provide aimed at reducing the GHG emissions intensity of the fuel, such as procurement of renewable natural gas (RNG). This section describes the potential for abatement through greening the gas grid using RNG. It is important to emphasize that this study was a desk-based literature review, not an in-depth survey or on-the-ground potential assessment.

RNG is biogas that has been processed to match the specifications (energy content and quality) of conventional fossil-derived natural gas, and which can be injected into the natural gas pipeline. It is functionally equivalent to conventional natural gas, and can be used by utilities' customers to meet the same purposes without generating fossil fuel-related emissions of CO_2. By sourcing and procuring RNG, utilities can reduce the emissions intensity of the gas they deliver to customers. While this reduces the cap and trade compliance obligation associated with each m^3 of natural gas delivered to customers, it can also affect the cost effectiveness and emissions abatement success associated with conservation measures. As the emissions intensity of the gas in the pipeline is reduced, each m^3 of conservation potential abates a lesser amount of GHG emissions, thereby reducing the cost effectiveness of customer conservation measures.

RNG is produced over a series of steps – namely collection of a feedstock, delivery to a processing facility for biomass-to-gas conversion, gas conditioning, compression, and injection into the pipeline. ICF developed resource potential curves to estimate the deployment of RNG for pipeline injection. These curves present the cost of greenhouse gas (GHG) abatement (in units of dollars per tonne, $/tonne) as a function of supply (in units m^3). These curves are based on a combination of a) the availability of feedstocks for conversion to RNG and b) the costs of converting feedstocks into RNG using anaerobic digestion and thermal gasification technologies.

3.2 Approach

Resource and RNG Potential

To develop the resource potential for RNG across Canada and in Ontario within the study scope and timeline, ICF completed a desk-based literature review of publicly available documents. Input was also sought from known experts in the field of RNG/renewable fuels as to the usefulness of the available literature. Several studies were reviewed including:

- Canadian Biogas Study: Benefits to the Economy, Environment and Energy, Biogas Association, December 2013.
- Potential Production of Renewable Natural Gas from Ontario Wastes, Alberta Innovates Technology Futures, May 2011.

- Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario: Biogas plant costing report, Electrigaz Technologies, September 2011.

It was determined that the Canadian Biogas Study is the most comprehensive study available publicly regarding feedstock resource potential, with a national focus (and broken down by province). ICF relied on this study for this analysis, largely because the study was given high marks by stakeholders during conversations at the outset of the project. ICF explicitly asked for direction from multiple stakeholders re: other references, and the Canadian Biogas Study was referred to as a reliable basis for our analysis.

The table below provides an overview of the feedstocks considered in this analysis[16]:

Table 13 RNG Feedstocks

Feedstock for RNG	Description
Landfill gas (LFG)	Biogenic waste in landfills produces a mix of gases, including methane (40-60%).
Wastewater treatment (WWT) gas	Wastewater consists of waste liquids and solids from household, commercial and industrial water use. In the processing of wastewater, a sludge is produced, which can be anaerobically digested to produce methane.
Animal manure	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.
Source separated organics (SSO)	Food waste separated from the garbage stream of either residential, commercial, or institutional sources for separate collection and processing.
Agricultural residue	The material left in the field, orchard, or other agricultural setting after a crop has been harvested. Inclusive of unusable portion of crop, stalks, stems, leaves, branches, and seed pods.

ICF used the RNG production estimates from the Canadian Biogas Study to develop the abatement curves; while the study does not explicitly indicate the timeframe by which the resource can be developed, it was assumed that the production potential is limited by investment rather than technological development. In that regard, it was assumed that nearly 100% of the RNG production potential estimated in the Canadian Biogas Study is achievable by 2028 for each feedstock. The table below outlines the annual RNG production potential for pipeline injection used in the analysis, in units of million cubic metres (million m^3).

Table 14 RNG Resource Potential in 2028 for Canada and Ontario

Feedstock for RNG	Canada Resource Potential Estimate (million m^3/y)	Ontario Resource Potential Estimate (million m^3/y)
LFG	290	113
WWT gas	180	71
Animal manure	874	191
SSO (Residential and	300	110

[16] Section 3.3 of this report identifies several feedstocks that have not been included in this analysis with a reason provided for the exclusion.

Feedstock for RNG	Canada Resource Potential Estimate (million m^3/y)	Ontario Resource Potential Estimate (million m^3/y)
Commercial)		
Agricultural residue	774	142
Total	**2,418**	**627**

RNG Production and Cost

ICF considered RNG production via two conversion technologies: anaerobic digestion or thermal gasification.

- Anaerobic digestion is the process whereby microorganisms break down organic material in an environment without oxygen. In the context of RNG production, the process generally takes place in a controlled environment, referred to as a digester or reactor. When organic material is introduced to the digester, it is broken down over time (e.g., days) by microorganisms, and the gaseous products of that process contain a large fraction of methane and carbon dioxide.
- Thermal gasification describes a broad range of processes whereby a carbon-containing feedstock is converted into a mixture of gases referred to as synthetic gas or syngas, including hydrogen carbon monoxide, steam, carbon dioxide, methane, and trace amounts of other gases (e.g., ethane, hydrogen sulfide, and nitrogen). The process occurs at high temperatures (650-1350°C) and varying pressures (depending on the gasification system). There is limited commercial-scale deployment of thermal gasification technologies.

ICF assumed that RNG production occurs via anaerobic digestion for LFG, wastewater treatment plants, animal manure, and SSO. It was assumed that agricultural residue was converted to RNG via thermal gasification.

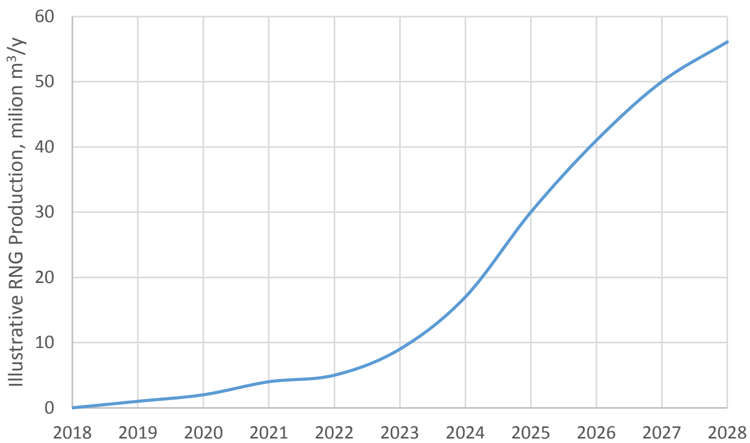
The main cost components considered in ICF's analysis include:

- Collection - This refers to a variety of cost elements, including the capture of gas from landfills or wastewater treatment plants or the collection of a feedstock.
- Upgrading biogas for injection - Broadly speaking, raw biogas needs to upgraded and scrubbed of contaminants prior to injection into a transmission pipeline. The primary cost components for upgrading biogas that ICF included in the analysis are: conditioning the biogas, compression of the biogas, sulfur removal, and a nitrogen rejection system. ICF notes that there are a variety of biogas conditioning systems that are commercially available with different approaches to conditioning gas prior to injection. Our assumptions for conditioning align with what we consider conservative estimates (i.e., our assumed costs are likely higher than other estimates).
- Pipeline interconnect - Pipeline interconnect represents the combination of the point of receipt from the customer pipeline and the pipeline extension to the utility pipeline. These costs vary by project size, complexity, and distance from common carrier pipeline.
- Construction and engineering - The deployment of biogas projects requires significant investments in construction and engineering, including site design, labour to install equipment, etc.
- Operations and maintenance - ICF includes the costs of operating and maintaining the biogas production facility - including collection, conditioning, compression, and injection.

These costs are generally expressed as a percentage of the capital expenditures, and range from 5-15%.

In all scenarios, ICF assumed an s-curve of deployment (see figure below for an example) of RNG production facilities: the underlying principle of this assumption is that the initial investments will be modest over the first 5-7 years (2018-2024), but that deployment in the out-years ramps up. ICF's deployment curves should not be considered a forecast, rather, they are meant to capture plausible investment in RNG production considering the barriers to financing, permitting a project, and completing it (typically with an 18-36 month timeframe between project financing and coming online).

Exhibit 11 Illustrative S-Curve Representing Assumed Deployment of RNG Facilities for One Feedstock Type from 2018-2028



ICF's RNG production cost modelling is dependent on the size of the system, and is linked to the inlet flow of biogas for conditioning. The Canadian Biogas Study has limited information regarding the size of each digester facility assumed, however, ICF extracted feedstock specific data to the extent feasible. The sub-sections below outline the size of digester facilities assumed for landfill operations, wastewater treatment facilities, animal manure, and source separated organics. It also includes our approach to developing thermal gasification costs.

For each feedstock, ICF calculated the levelized cost of energy (LCOE) by incorporating the capital expenditures from equipment, operations and maintenance (O&M), and a discount rate of 4% for our calculations[17].

Landfill gas

ICF developed abatement cost estimates using five different facility size estimates based on a survey of 63 landfill sites reported in the Canadian Biogas Study (which is sourced from a

[17] This treatment of costs is analogous to the treatment of costs in the customer conservation analysis in Section 2.

separate study[18]). The table below includes the assumed biogas flow for each facility in units of standard cubic feet per minute (SCFM) and the calculated annual output of RNG. The table also includes the assumed share of the market for each production facility size. ICF calculates RNG production assuming a methane content of landfill gas of 48% and a capacity factor (i.e., how frequently the system is operational) of 90%. The table below presents ICF's calculated LCOE for each landfill size.

Table 15 LFG Facility Assumptions by Facility Size (from smallest to largest landfill)

Biogas flow (SCFM)	RNG Annual Production (million m^3/y)	Estimated Share of Market	LCOE ($/$m^3$)
360	2.3	10%	$0.82
500	3.2	50%	$0.71
1,200	7.7	20%	$0.46
2,500	13.8	10%	$0.38
3,250	21	10%	$0.33

ICF notes that for the largest landfill category we did not include the costs of collecting biogas in the estimates, because we assume that they are regulated and required to capture and flare biogas rather than allowing it to vent to the atmosphere. It is possible that other landfills have collection systems in place, particularly the larger landfills (e.g., with biogas flow greater than 1,000 SCFM). In that regard, it is conceivable that we have over-stated the LCOE of RNG production because the collection systems can represent a significant share of the cost.

Wastewater treatment gas

ICF developed abatement cost estimates based on four different sized wastewater treatment plants using internal modelling from other jurisdictions. Unfortunately, ICF was unable to identify a reference (e.g., the Canadian Biogas Study) that provided a breakdown of WWT plants. The table below includes the assumed biogas flow for each facility in units of SCFM and the calculated annual output of RNG. Because there was no available information regarding the distribution of WWT plant sizes, ICF made the simplifying assumption that the market share would be split evenly between the four facility sizes considered in our analysis. ICF calculates RNG production assuming a methane content of gas captured from WWT plants of 56% and a capacity factor of 90%. The table below includes our calculated LCOE of each WWT plant size.

Table 16 WWT Facility Assumptions by Facility Size (from smallest to largest WWT facility)

Biogas flow (SCFM)	RNG Annual Production (million m^3/y)	Estimated Share of Market	LCOE ($/$m^3$)
60	0.43	25%	$3.73
110	0.81	25%	$2.34
525	3.94	25%	$0.67
1,170	8.75	25%	$0.48

[18] Identification of Potential Additional Greenhouse Gas Emissions Reductions From Canadian Municipal Solid Waste Landfills. Contract Number K2A82-11-0009. Prepared for Environment Canada By Conestoga-Rovers and Associates, August, 2012

Animal manure

ICF developed abatement cost estimates based on three different sized farms. The farm sizes and number of cattle are based on the Electrigaz study. They define three farms: a baseline agricultural facility with 1,315 dairy cows, a large agricultural facility with 2,616 cows, and an agricultural cooperative with 3,950 dairy cows. The table below includes the assumed biogas flow for each farm size in units of SCFM and the calculated annual output of RNG. Because there was no available information regarding the distribution of farm sizes or a detailed analysis regarding the potential for agricultural cooperatives, ICF made the simplifying assumption that the market share would be split evenly between these three facility sizes. ICF calculates RNG production assuming a methane content of gas captured from dairy manure of 60% and a capacity factor of 95%. The table below includes our calculated LCOE of each agricultural facility size.

Table 17 Livestock Farm Assumptions by Farm Size (from smallest to largest farm facility)

Facility	Dairy Cows	Biogas flow (SCFM)	RNG Annual Production (million m^3/y)	Est Market Share	LCOE ($/$m^3$)
Baseline	1,315	90	0.75	33%	$1.66
Large	2,616	180	1.50	33%	$1.06
Co-op	3,950	265	2.25	33%	$0.87

Source separated organics

The RNG production potential for source separated organics (SSO) was distinguished by residential and commercial applications in the Canadian Biogas Study: residential and commercial applications have been combined here. The anaerobic digestion of SSO requires the development of a separate digester facility – it is not merely the collection of biogas analogous to the functioning of a landfill or WWT plant. This can add significant cost; further, there are different sized facilities in the literature. The Canadian Biogas Study assumes the construction of facilities that can handle 60,000 tonnes of SSO via anaerobic digestion. ICF used that single facility size to develop the abatement curve for SSO; although we note that there are references that suggest facilities could process as much as 100,000 tonnes. In that regard, it is conceivable that the LCOE for RNG from SSO may be over-stated if larger facilities are constructed in response to the appropriate price signal.

ICF assumed that a facility processing 60,000 tonnes of waste would produce approximately 500 SCFM of biogas and calculated yield of about 4 million m^3/year of RNG, assuming a 60% methane content and a capacity factor of 90%. ICF also assumed an additional capital expenditure of organics processing ($14 million) and the cost of the digester ($17.5 million). The total capital costs are on the order of $40-45 million for this type of RNG production. This yields a LCOE of $2.90/$m^3$.

Agricultural residue

As noted previously, ICF made the broad assumption that agricultural residue is converted to biogas via thermal gasification. ICF used a combination of internal estimates on conversion efficiency of a thermal gasification facility and feedstock pricing to develop a series of abatement curves for agricultural residue as a resource for RNG production. These estimates have a high degree of uncertainty for two reasons: 1) thermal gasification of biomass has not been developed at commercial scale, so cost information is scarce, and 2) the market for agricultural residues is not mature (because the residue is primarily used as ground cover as part of agricultural operations for nutrient loadings), therefore feedstock pricing is speculative. To address these uncertainties, ICF developed six estimates of RNG production from a thermal gasification facility, assuming different yields of gasification and different feedstock pricing scenarios.

Table 18 Agricultural Residue Assumptions by Varying Yield and Feedstock Price

RNG Yield	RNG Production (million m^3/y)	Feedstock Price ($/tonne)	LCOE ($/$m^3$)
Low	105	$23.50	$0.90
		$130	$1.57
Medium	115	$23.50	$0.81
		$60	$1.01
High	140	$23.50	$0.66
		$60	$0.83

3.3 Limitations and Caveats

Resource and RNG Potential Data

- While the consensus among RNG experts was that the Canadian Biogas Study was the best available study to provide national and provincial estimates of RNG potential for this analysis, it referenced RNG potential data from other reports that are no longer available for review. With many of the CBS' key references unavailable or inaccessible, it made it difficult for ICF to conduct a critical evaluation of the methodologies employed to build up the national and provincial estimate. Further, because these information and baseline data are not readily available, it makes it impractical for ICF (or other reviewers) to assess the results in the context of revised or updated methodologies to develop resource assessments (e.g., using updated sustainability criteria).

- ICF did not include forest residue as a potential feedstock because it was excluded from the Canadian Biogas Study and due to the uncertainty of availability and accessibility (i.e. the potential costs of transporting the feedstock could be prohibitive). Even if forest residue was added to the possible feedstocks in this study, it would not change the available RNG potential in the 2018-2020 study period, as the timeline on thermal gasification extends several years past 2020.

- ICF did not include the production of hydrogen via steam reformation of biomethane. Renewable hydrogen could also conceivably be produced by electrolysis using renewable energy generation; however, this was not in the scope of consideration as RNG (the focus of this study was on biomethane, not any renewable gas). This was a scoping decision at the outset of the project. ICF notes that renewable hydrogen from either SMR or electrolysis are more expensive (on a dollar per tonne basis) than the RNG abatement opportunities presented in the analysis.

- This analysis did include thermal gasification (of agricultural residue) which is a syngas process. ICF did not consider industrial gases because these are not biogenic or considered renewable.

- This analysis also excluded the consideration of purpose grown energy crops because the uncertainty associated with the potential for this technology and the lack of reliable documentation.

- Two new Ontario policy drivers including an organics ban at landfills and the prohibition of spreading untreated sewage sludge on agricultural fields have not been accounted for in this RNG assessment. These policies could potentially accelerate the development of LFG and WWT facilities that are generating RNG, but they would not likely affect the price to bring the RNG to the grid.

Costs

- Since the RNG originates from all of Canada, this analysis makes a simplifying assumption that the upstream capacity costs associated with RNG are equivalent to fossil-derived natural gas. In reality, these costs would be dependent on the distance and sources of RNG flowing into Ontario. Upstream capacity costs are approximately 10-20% of natural gas commodity costs (in the 2016 CPS assumptions).

- Future changes in technology costs used in the study, i.e. improvement in efficiency and drop in price over time, have not been included in the analysis. This may over-state forecasted $/m^3 and $/t CO_2e estimates in the later years of the study period, making the cost estimates more conservative.

- The estimates of cost to deliver RNG to the natural gas grid in $/m^3, and the equivalent cost in $/tonne CO_2e do not account for the sale of any associated emissions reductions or offset credits in Ontario's nascent offset system. While several of the RNG feedstocks[19] identified in this study may have the potential to generate offset credits through avoidance of methane venting to the atmosphere, in addition to lowering the emissions intensity of the natural gas system, the financial value of those offsets has not been included in the $/m^3 and $/tonne CO_2e estimates. Given that the Ontario offset system is still under development and the protocols[20] expected to be relevant for this study are not yet published, there is still a great deal of uncertainty around what RNG projects might be able to generate offsets vs. those not eligible due to rules that are still unknown.

- Once the Ontario offset program is established and the protocols are available for review, the $/m^3 and $/tonne CO_2e estimates presented here could be re-assessed. Consideration of the improved economics of the proportion of RNG that is also able to generate offsets will

[19] LFG, WWT, Agricultural manure and SSO
[20] An offset protocol is a jurisdiction and cap and trade program-specific set of rules that determine eligibility of an offset credit.

reduce the cost of the resource. Note: at this time, the RNG MACCs in Section 3.4 do not include stacking of environmental benefits.

- This RNG assessment developed $/m^3 and $/tonne CO_2e estimates for 19 RNG feedstock cost categories[21] (including the 5 LFG, 4 WWT, 3 Agricultural manure, 1 SSO and 6 Agricultural residue categories described in the feedstock tables in the Approach section above). While efforts were made to disaggregate feedstock potential into various realistic cost categories, these costs are still averages and should be considered illustrative.

3.4 Results

Table 19 below summarizes the national and Ontario provincial RNG potential in 2028 by feedstock.

Table 19 Summary of the National and Ontario Provincial RNG Potential in 2028 by Feedstock

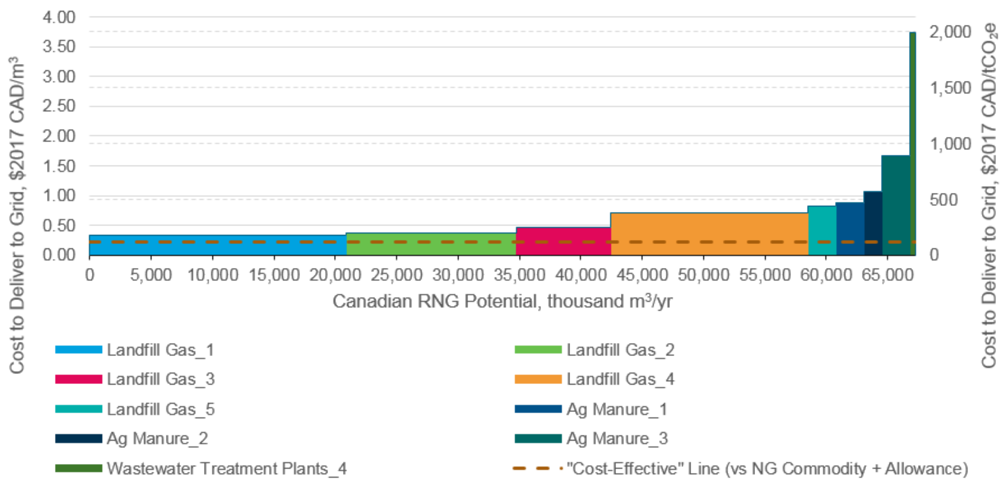
Feedstock	National Potential by 2028 (million m^3/yr)	National Potential by 2028 (tCO_2/yr)	Ontario Potential by 2028 (million m^3/yr)	Ontario Potential by 2028 (tCO_2/yr)	Cost ($/$m^3$)	Cost* ($/$tCO_2$)	Notes
Landfill gas	290	540,000	113	210,000	$0.33-$0.82	$70-$330	Evaluated 5 different sized facilities based on survey referenced in Canadian Biogas Study; linked to study for Environment Canada
WWT gas	180	340,000	71	135,000	$0.48-$3.73	$150-$1,900	Evaluated 4 different sized facilities – ICF analysis
Animal manure	874	1,640,000	191	360,000	$0.87-$1.66	$360-$780	Considered 3 different farms (Electrigaz study): baseline, large, and co-op
SSO residential & commercial	300	560,000	110	210,000	$2.90	$1,450	Assumed a single facility capable of processing 60,000 tonnes/yr per Canadian biogas study. Larger/smaller facilities conceivable
Agricultural residue	774	1,450,000	142	265,000	$0.66-$1.57	$250-$730	Produced via thermal gasification, assuming varying efficiency of processing

[21] Refer to results presented in Exhibits 12 and 13 for the potential disaggregated by feedstock cost category. The results presented in Exhibits 14 and 16 for the RNG LTCPF scenario MACCs aggregate feedstocks by category.

Feedstock	National Potential by 2028 (million m^3/yr)	National Potential by 2028 (tCO_2/yr)	Ontario Potential by 2028 (million m^3/yr)	Ontario Potential by 2028 (tCO_2/yr)	Cost ($/$m^3$)	Cost* ($/$tCO_2$)	Notes
							Included 6 feedstock price estimates: $23.50-$130 per dry tonne

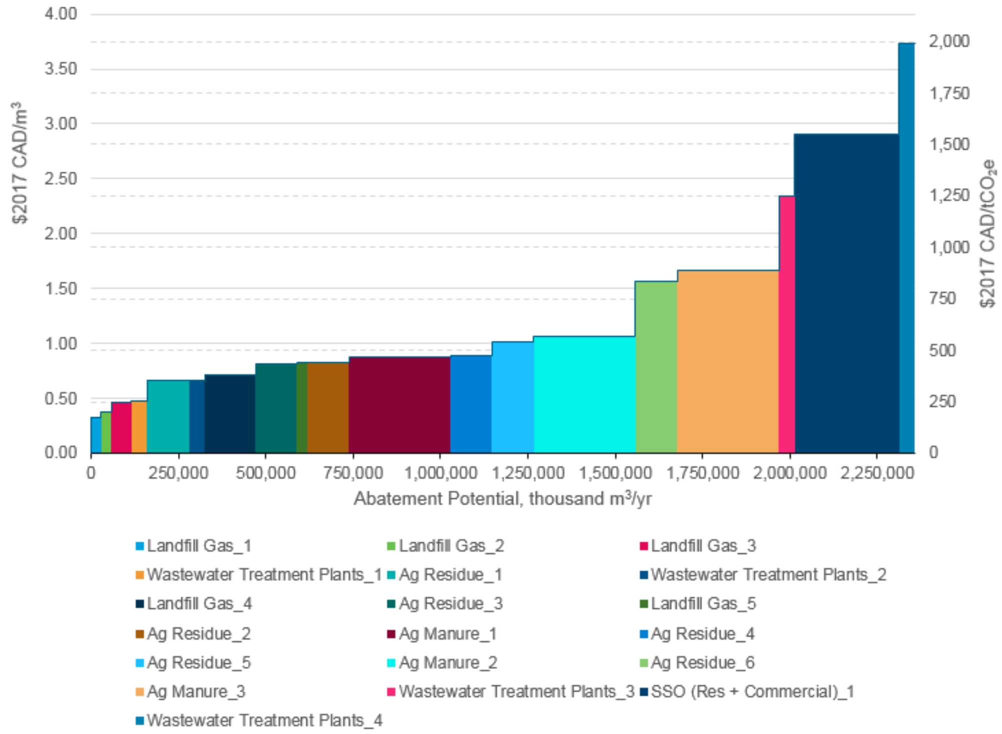
Exhibit 12 below presents the national RNG potential MACC, by feedstock cost category, developed for the 2018-2020 study period and Exhibit 13 presents national RNG potential to 2028. RNG potential (in m^3 and equivalent tCO_2e) from nine out of the possible 19 RNG feedstock cost categories is estimated to become available by 2020[22].

Exhibit 12 Canadian RNG Potential by 2020



[22] The potential by 2020 is based on the potential deployment s-curve starting in 2018 and reaching full deployment potential by 2028. The underlying principle of this assumption is that the initial investments will be modest over the first 5-7 years (2018-2024), but that deployment in the out-years ramps up.

Exhibit 13 Canadian RNG Potential by 2028



If the scope of the feedstock sourcing is confined to Ontario, the RNG potential is significantly reduced from the results presented in Exhibits 12 and 13. Based on the high costs of much of the RNG potential, coupled with an expected modest deployment over the next few years, RNG development in Ontario could benefit immensely from investment of CCAP dollars to fund better province-specific analytics and potential assessments. Additionally, funding is required for pilot projects such as the G4 Insights' RNG Demonstration plant in Edmonton[23], and as described by the Ontario Ministry of the Environment and Climate Change as a part of $20 million to be invested over the next four years in RNG pilot projects to reduce emissions associated with transportation and goods movement.

Successful realization of RNG potential requires the appropriate policy, market, regulatory and technology funding support aligned with this emergent RNG renewable energy supply. Developing and retaining this renewable resource to Ontario's marketplace will require

[23] Two projects advance wood waste to biocrude, renewable natural gas technologies, Maurice Smith, March 15, 2017 (http://www.jwnenergy.com/article/2017/3/two-projects-advance-wood-waste-biocrude-renewable-natural-gas-technologies/, accessed June 13, 2017)

supportive government and regulatory policies, suitable market support mechanisms and substantive technology development funding.

3.4.1 Minimum and Mid-Range LTCPF Scenario

Exhibit 14 below presents the minimum (and mid-range[24]) LTCPF MACC for national RNG abatement potential. In this carbon price scenario, the results show the average cost to bring the RNG to market over and above the price of an allowance and the natural gas commodity cost for the 2018-2020 timeframe[25]. The potential savings by 2020 period is 67 million m^3 (or 126,000 tCO_2e). Table 20 presents the average cost data and estimated savings used to create the MACC.

Exhibit 14 RNG MACC for Minimum and Mid-Range LTCPF

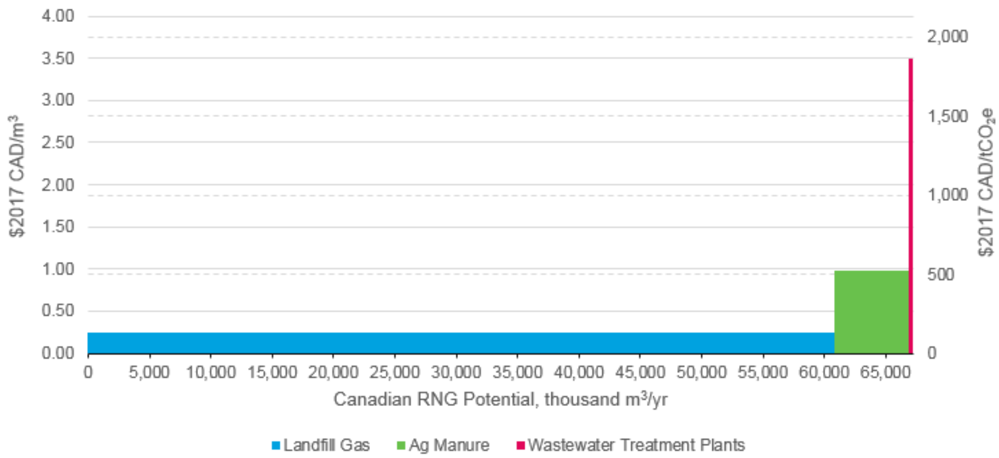


Table 20 RNG MACC for Minimum and Mid-Range LTCPF, Average Cost and Savings Results

RNG Feedstock	Average $/tCO_2e$	Average $/m^3$	Estimated Savings (tCO_2e)	Estimated Savings (million m^3)
Landfill Gas	133	0.25	114,000	61
Agricultural Manure	527	0.99	11,200	6
Wastewater Treatment Gas	1,867	3.50	800	0.4

3.4.2 Maximum LTCPF Scenario

[24] For the RNG MACC, the minimum and mid-range scenarios for 2018-2020 are identical because the price of carbon in those years is identical in these two scenarios.
[25] The zero-line in the RNG MACC in Exhibits 13 and 14 is equivalent to the zero-line in the customer conservation MACCs in Section 2.

Exhibit 15 below presents the maximum LTCPF MACC for national RNG abatement potential. In this carbon price scenario, the results show the average cost to bring the RNG to market over and above the price of an allowance and the natural gas commodity cost for the 2018-2020 timeframe. The potential savings by 2020 period is 67 million m^3 (or 126,000 tCO_2e). Table 21 presents the average cost data and estimated savings used to create the MACC.

Exhibit 15 RNG MACC for Maximum LTCPF

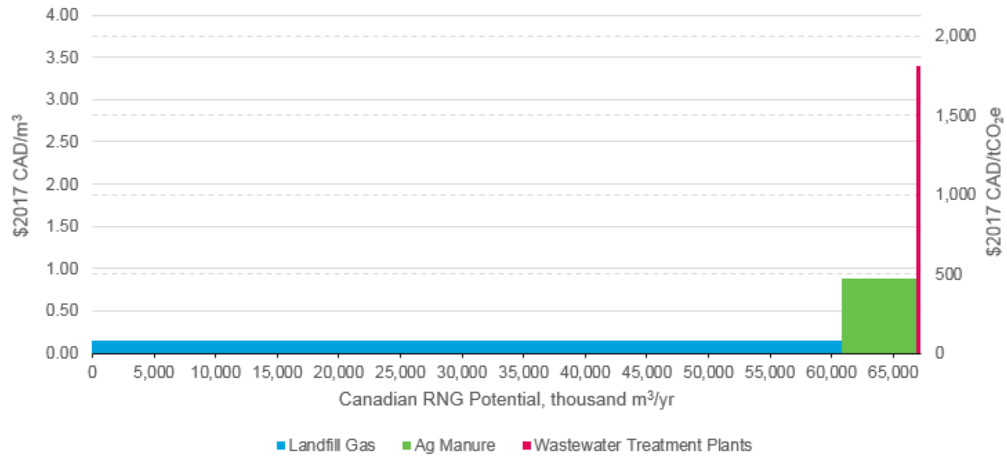


Table 21 RNG MACC for Maximum LTCPF, Average Cost and Savings Results

RNG Feedstock	Average $/tCO_2e$	Average $/m^3$	Estimated Savings (tCO_2e)	Estimated Savings (million m^3)
Landfill Gas	77	0.14	114,000	61
Agricultural Manure	471	0.88	11,200	6
Wastewater Treatment Gas	1,811	3.40	800	0.4

4. Facility Abatement Options

4.1 Background and Approach

Under Ontario's Quantification, Reporting and Verification of Greenhouse Gas Emissions Regulation (O. Reg. 143/16) (Reporting Regulation) gas distributors have a duty to report two types of emissions:

- Emissions that result from the combustion of the quantities of natural gas provided to end users who are not capped participants, and
- Emissions resulting from all specified GHG activities at distribution system facilities, or "facility emissions".

The gas distributors are required to acquire and remit allowance for both sources of emissions over the 2017-2020 timeframe. Total cap and trade compliance allowance obligation of Ontario's natural gas distribution companies is in the 40Mt CO_2/yr range. The vast majority of this obligation (>99%) results from the residential, commercial and small industrial (<10,000 t CO_2/yr) customers (end users) as well as consumption by the natural gas-fired generating stations.

Facility emissions, which include emissions associated with transmission, storage, and distribution segments, total between 250,000 and 350,000 t CO_2/yr or less than 1% of total cap and trade compliance obligation.

With regard to facility emissions the gas distributors operate in distinct regions and distinct business areas / operations with distinct emission profiles. In Ontario these include:

- Natural Gas Transmission,
- Natural Gas Storage, and
- Natural Gas Distribution.

There are 4 main categories of emissions from these operations;

- Fugitive emissions from piping and associated equipment components. These emissions include unintentional leaks from underground pipeline, seals, packings or gaskets resulting from corrosion, faulty connection, inadequate maintenance or wear.
- Vented emissions are intentional releases to the environment (by design or operational practice). Sources include equipment and pipeline blowdowns and purging, M&R station control loops, accidental third party dig-ins, and gas operated devices that use natural gas as the supply medium.
- Combustion emissions include CO_2, CH_4 and N_2O emitted from the combustion of fossil fuels to fire compressor station engines, turbines and pipeline heaters.
- Miscellaneous (other) emissions include emissions from vehicles, domestic fuel consumption for building heating and indirect emissions associated with electrical usage.

Gas distributor facility emissions can include combustion emissions (e.g., fuel used at compressor stations), flaring (e.g., at a battery or storage facility), venting (e.g., gas-driven pneumatic devices) and fugitives (e.g., unintentional leaks). In Ontario's reporting Regulation, these fall under the specified activities of 'general stationary combustion', and 'operation of equipment related to the transmission, storage and transportation of natural gas.'

However, under Ontario's cap and trade program as currently defined, the utilities' compliance obligation for facility emissions is limited to general stationary combustion emissions only. The compliance obligation is based on the verification amount, as defined in the Reporting Regulation, which excludes the portion that is emitted during the operation of equipment related to the transmission, storage and transportation of natural gas (which comprises flaring, venting and fugitives).

As such only the activities that reduce emission where the distributors have a compliance obligation reduce the requirement to acquire allowance and therefore cap and trade cost. Thus at the provincial level, the focus is constrained. The majority of Facility emissions result from natural gas combustion in compressor station engines and turbines associated with the transmission system, storage facilities, and distribution pipeline heaters. Other minor sources include emissions from domestic fuel consumption for building heating. Facility emissions vary significantly between the individual natural gas distribution companies based on differing infrastructure / assets under management and annually based on operational requirements.

There are a number of efficiency opportunities that could reduce utilities' combustion emissions, including upgrades and/or replacements of compressors, prime movers, controls, capacity/operational optimization; pipeline layout and maintenance; and waste heat recovery. Fuel switching to electric compressors is likely not a feasible option in Ontario, due to cost and other barriers. While there may be opportunities to reduce gas distributors' combustion emissions, these emissions are typically a small to medium proportion in the emissions profile of gas distributor facility emissions. For example even assuming a 10% decrease in facility emissions would only reduce the entire compliance burden by [~30,000 t CO_2e/yr].

A high-level assessment of facility emissions abatement options was planned for inclusion in the scope of this study.

However, recognizing;

- the relatively small contribution of Facility emissions (and associated abatement potential),
- the unique emissions profile and thus abatement potential and options afforded each distribution company,
- the fact that abatement opportunities afforded utility commercial buildings within Facilities emissions are included within the relevant Customer Conservation measures discussed in Section 2, and
- limited publicly available information on emissions by technology and utility specific activity data that could inform an illustrative high level MACC for Facilities.

It was concluded that a high-level illustration of abatement cost without utility context would be of limited applicability and relevance to the objective of this study. Entity-level information (historic and forward planning) relevant to assessing abatement options (research and estimates that have been conducted to date related to Facility abatement opportunities) was requested from the gas utilities.

This context was not available in time to inform this study. However, the utilities are in the process of completing facility abatement opportunity studies along with descriptions of GHG abatement measures implemented and available to inform their 2018 Compliance Plans. The results will be available within their Compliance Plans but NOT within the timeline of this MACC development study. As such it was concluded to re-assess this area upon release of the relevant facility level context.

5. Summary MACCs

Exhibit 16 Summary MACC Including Customer Conservation Measures and RNG Potential for Minimum LTCPF

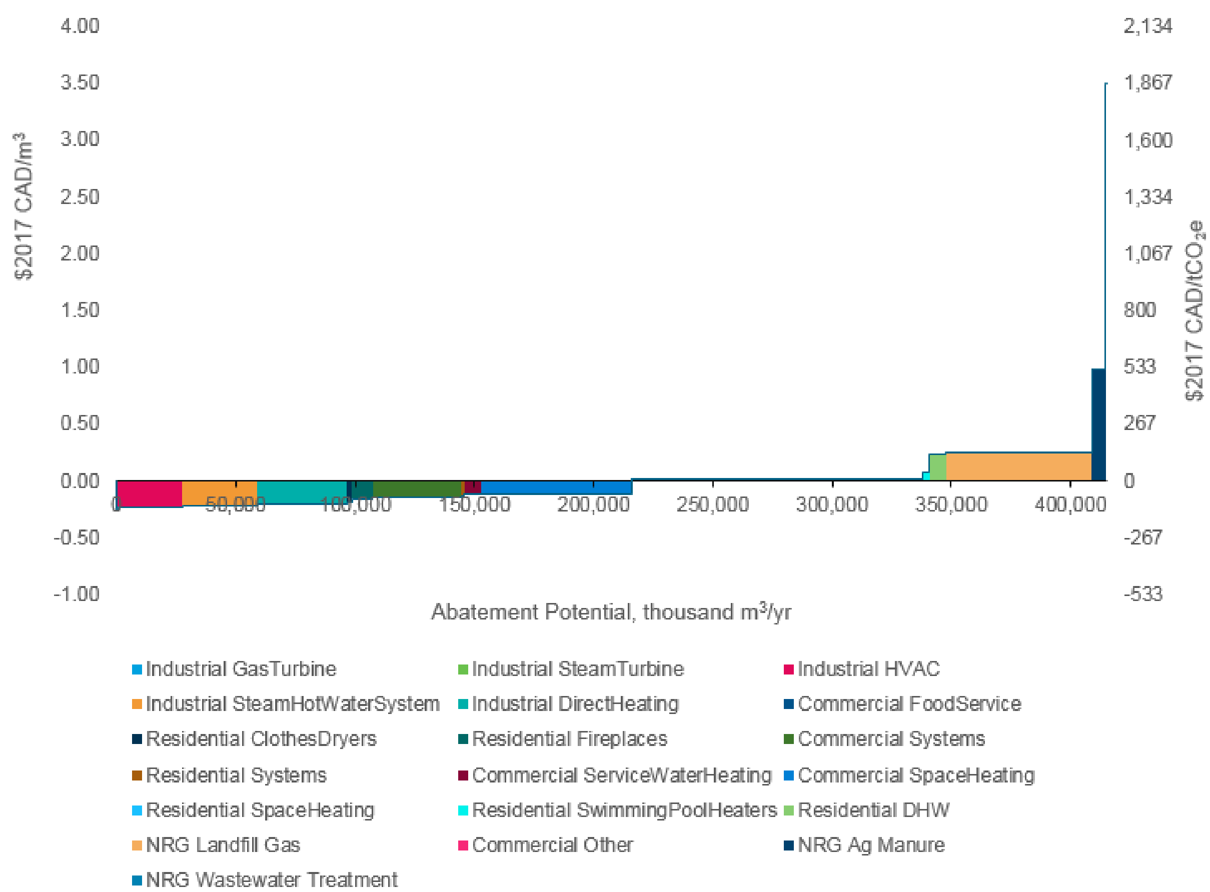


Exhibit 17 Summary MACC Including Customer Conservation Measures and RNG Potential for Maximum LTCPF

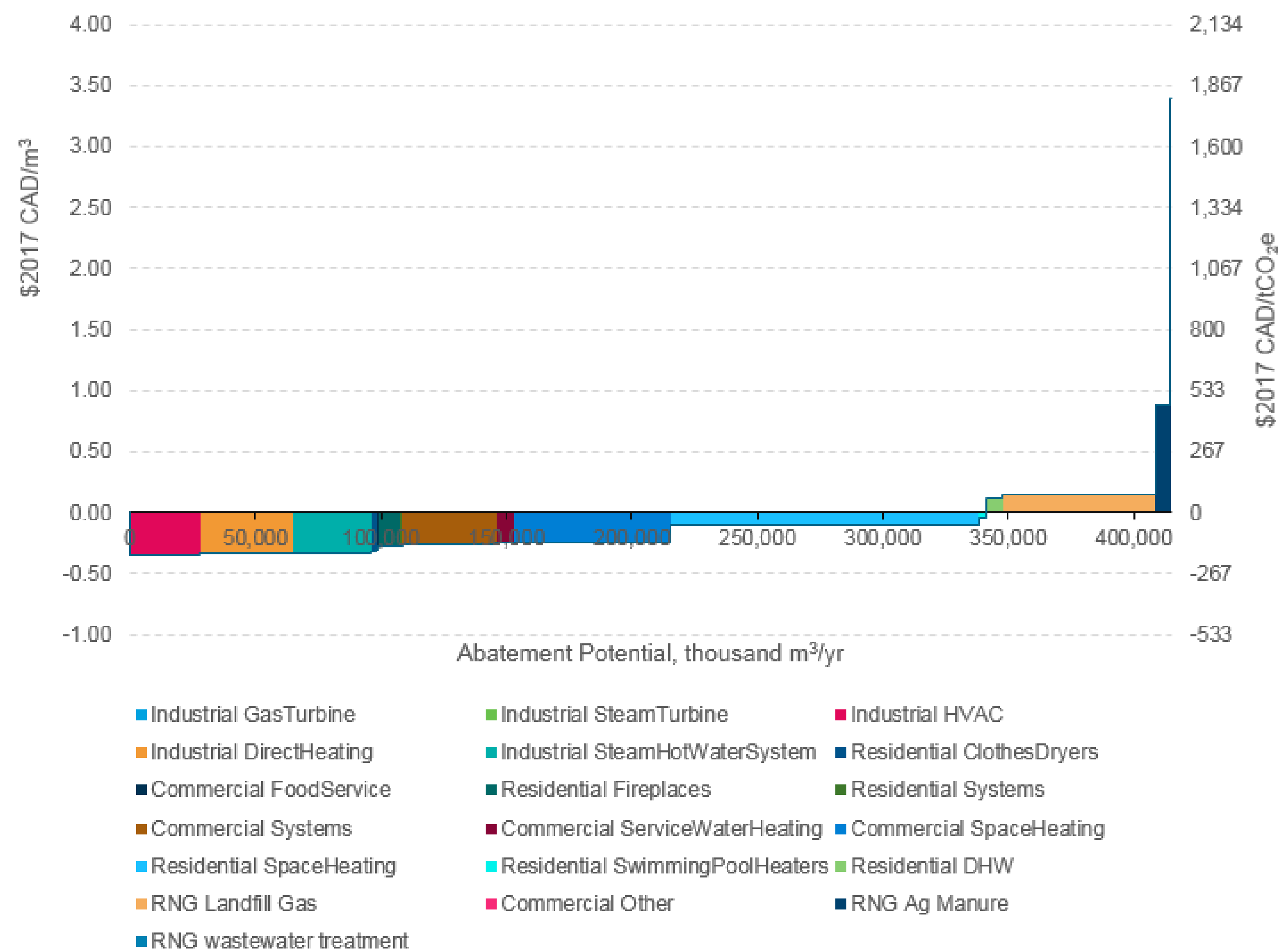
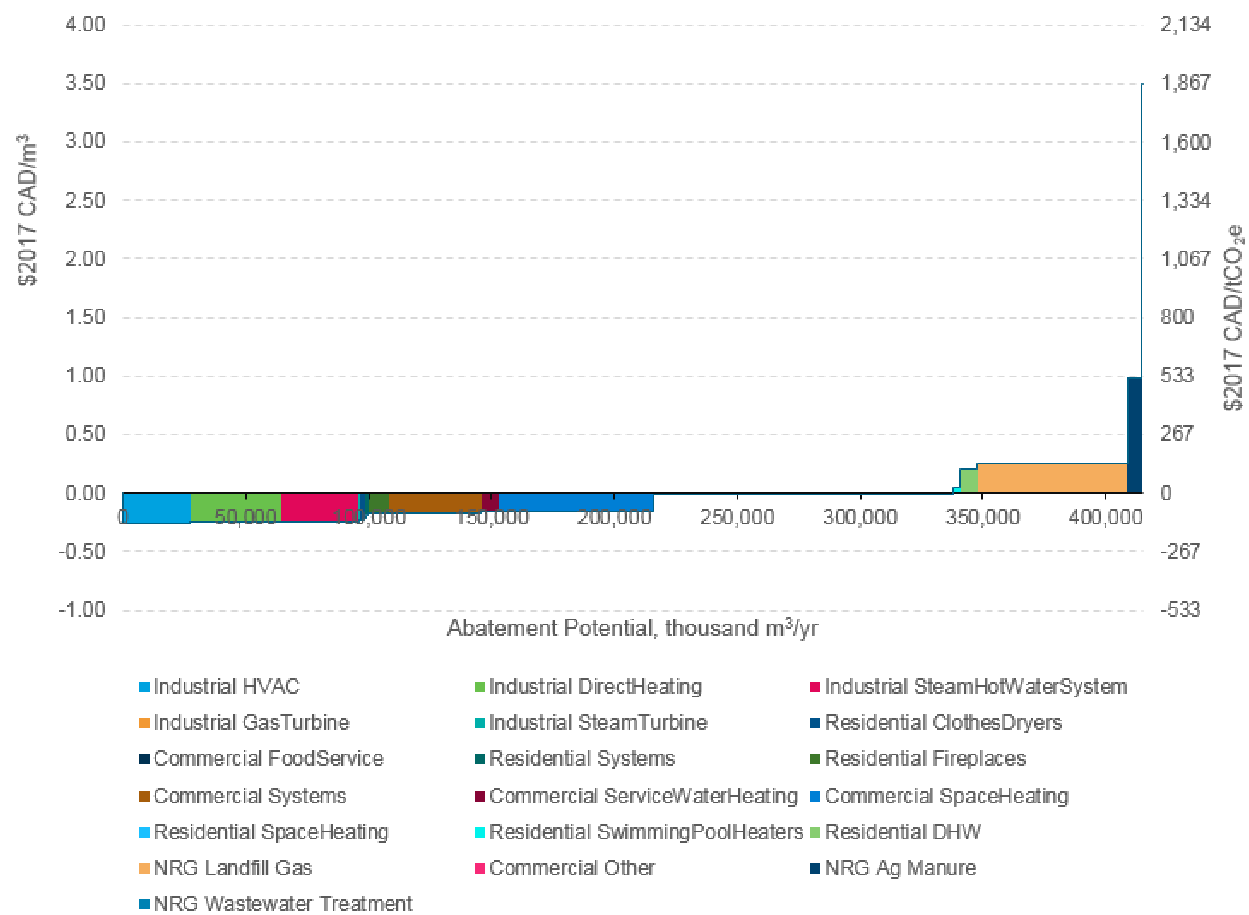


Exhibit 18 Summary MACC Including Customer Conservation Measures and RNG Potential for Mid-Range LTCPF



6. Recommendations

The development of a province-wide MACC for Ontario is expected to be conducted on a three-year cycle. The purpose of this section is to identify ways to enhance the next MACC study, both by capturing some of the successful features of this exercise and by improving on other aspects.

6.1 Successes to Retain

Features of the current study that ICF found greatly assisted the work include the following:

- The Technical Advisory Group was dedicated to producing a good study, and provided review and constructive feedback (during and after the TAG meetings) that the consultants found extremely valuable. It was important that the group represented a variety of perspectives.

6.2 Recommended Improvements

Aspects of the current study that could be improved in the next study include the following:

- The next study should have a longer timeframe for completion. In particular, this extended period would allow for more detailed review and more flexibility for the contractor to make modelling changes in response to feedback.
- Subsequent studies and any updates to this study should account for the impacts of the Ontario government's Climate Change Action Plan (CCAP), once details of the plan are made public. CCAP is expected to underpin new programs and policies designed to reduce provincial emissions through allocation of revenues from the cap and trade program.
- The model uses an average for all sizes of industrials and does not differentiate between LFEs and non-LFEs. Given more time, market penetration rates, measure savings, and cost effectiveness values that might be more reflective of non-LFEs should be developed and used to model the industrial sector.
- Once the Ontario offset program is established to support the cap and trade program, and the protocols are available for review, the $/m^3 and $/tonne CO_2e estimates presented in the analysis in Section 3 could be re-assessed. Consideration of the improved economics of the proportion of RNG that is also able to generate offsets will reduce the cost of the resource.
- Ontario is a vast province and more detailed, locally relevant feedstock availability and cost data would significantly improve the estimates presented in this study.

Appendix A Air Source Heat Pumps

Air source heat pumps (ASHPs) are a residential and commercial heating and cooling technology which are technologically similar to central air conditioners (CACs). In cooling mode, ASHPs are identical to CACs; CACs intake air from indoors, remove its heat using a compressor/condenser, and transfer the heat outside. When in heating mode, this process works in reverse; ASHPs intake air from outdoors, remove the heat using a compressor, and push the heat through a duct system in the same fashion as a furnace. ASHPs can also be “ductless,” comprising an outdoor unit and one or more indoor units which intake and disburse the cool or warm air. When using multiple units, ductless ASHPs can also transfer heat from a warm part of the house to a colder one (e.g. second floor to the basement).

Of relevance to Ontario at lower temperatures, the heating process becomes less efficient, to the point where all ASHPs require backup resistance heating coils when temperatures are extremely low. ASHP technology has developed significantly over the last 5 years with more efficient and lower cost units and better cold climate solutions that can be 20-30% more efficient than resistance electric even at temperatures in the -20 °C range.

ASHPs have a significant energy efficiency benefit however they are considered distinctly from the Customer Conservation measures (discussed in Section 2 of this report) as the technology is electric fired and therefore the measure is fundamentally a fuel switch measure (natural gas to electric). Further some natural gas conservation measures include electricity co-benefits as avoided costs and some add cost due to increased electrical consumption. However in the latter example the electricity burdens are typically immaterial. The ASHP measure reduces natural gas consumption however the increased cost of electricity will be material and a key factor in cost effectiveness. This measure must be thought through from the benefit to the residential energy consumer as opposed to the natural gas rate payer.

The GHG abatement potential is driven by the amount of energy required to fire the heating / cooling system and the GHG intensity of the energy (natural gas vs electric). The ASHP requires less energy on an annual basis that conventional heating / cooling technology and natural gas consumed in the home is more GHG intensive (~0.2t CO_2/MWh) than Ontario’s electricity system (0.05t CO_2/MWh). As such the technology has GHG abatement potential.

However, the appropriateness and cost effectiveness of this technology is driven by capital cost (conventional heating / cooling vs ASHP), avoided cost of energy (natural gas), and unlike pure energy efficiency measures added cost of electrical energy must considered. As the technology costs have become close to equivalent the measures level cost effectiveness is predominantly driven by the energy cost spread between natural gas and electricity. As depicted in the analysis below the delivered cost of electricity in Ontario at ~$140/MWh (IESO Ontario Planning Outlook, September 2016) vs. that of natural gas at ~$30/MWh equivalent challenges the cost effectiveness of ASHPs in Ontario. Given Ontario’s capacity mix it is important to note that natural gas-fired electricity (0.4t CO_2/MWh) has a higher GHG intensity than when natural gas is consumed in the building as a result of the loss of efficiency in converting thermal to electrical energy as well as minor energy loss in electricity transmission.

The analysis below is not intended to illustrate all ASHP applications nor get into significant detail on the electric grid supply or cost of electricity (current or forward). Key forward assumptions on cost of electricity are taken from the IESO's Ontario Planning Outlook (September 2017). Additionally,

- Capital costs include equipment purchase, installation, and a cost to upgrade amperage service for all-electric ASHP
- Annual costs are based on current gas and electricity rate structures and assumptions of time of use/seasonality
- ASHP application in the existing home is considered distinctly from the new home
- Full system lifetime is 15 years; no discount rate is applied to calculate lifetime costs
- Emission factor of 0.418 t/MWh for natural gas-fired electricity (based on 45% conversion efficiency and 5% T&D losses); emission factor of 0 t/MWh for zero-carbon electricity
- Per home lifetime costs do NOT include an impact on electricity rates as a result of any new electricity generation capacity required to meet a winter peaking load.
- Assumptions related to ASPH capital cost intended to illustrate cost over 2017-2020.

Table 20 Assessment of Abatement Cost Associated with Residential ASHPs – Capital Cost Assumptions

Type of Home:	Existing Homes				New Homes			
Scenario:	Base Case	ASHP	ASHP + HPWH	Intgrtd ASHP + NG	Base Case	ASHP	ASHP + HPWH	Intgrtd ASHP + NG
Source of household heat	Natural Gas Furnace	ASHP	ASHP	ASHP with Auxiliary NG Furnace	Natural Gas Furnace	ASHP	ASHP	ASHP with Auxiliary NG Furnace
Source of household cooling	Electric A/C	ASHP	ASHP	ASHP	Electric A/C	ASHP	ASHP	ASHP
Heating/Cooling System Capital Costs	$9,000	$7,000	$7,000	$8,000	$9,000	$6,000	$6,000	$7,000
Source of household hot water	NG Storage	NG Storage	Heat Pump (HPWH)	NG Storage	NG Storage	NG Storage	Heat Pump (HPWH)	NG Storage
Hot Water System Capital Costs	$1,500	$1,500	$2,250	$1,500	$1,500	$1,500	$2,250	$1,500
Average Cost of Amperage Upgrade	$0	$2,000	$2,000	$0	$0	$0	$0	$0
Total Capital Costs	$10,500	$10,500	$11,250	$9,500	$10,500	$7,500	$8,250	$8,500

The table above illustrates the capital costs associated with different home heating technology deployments. Over all we have been conservative on the price of the ASHP technology (so as not to overestimate the cost) and we have assume a standard ASHP technology deployment vs

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a cold climate ASHP that would come with improved performance and higher cost. The base case represents the conventional gas fired furnace and hot water and electric driven AC. The ASHP scenario replaces the conventional heating and cooling with an ASHP (hot water remains natural gas storage tank type). The ASHP + HPWH is a full electrification scenario that also assumes that hot water is provided via an electric high performance water heater. The integrated solution ASHP + NG assumes a natural gas fired furnace is also available and deployed to meet cold day heating requirements when the ASHP performance degrades to a low COI.

The results illustrate that in most scenarios there is little delta in capital cost between the base case and the ASHP solutions.

In addition the following assumptions were made with regard to peak day demand and performance.

- Peak temperature of -26°C
- Furnace input rate of 54,200 BTU/h for an existing home and 40,000BTU/h for a new home at peak design conditions
- Blended COP of 1for all-electric air source heat pump (ASHP) at peak day design conditions (includes contribution of electric resistance heating to overall heat pump performance)
- COP of 1.63at operating peak of hybrid ASHP, which occurs just above a switch-over temperature of -8°C (zero power draw on Ontario's peak design day)
- Water heating peak based on an average daily hot water usage profile, where 10% of total daily energy consumption occurs in the peak hour
- Heating profile over the peak design day based on typical variation of temperature over a cold day (based on all days under 0°C in CWEC data)

Based on the above, the following table illustrates the results of GHG abatement potential and cost ($/t CO_2) analysis. Annual operating costs for the ASHP technology deployment scenarios will be up to $1000/yr higher than that of the base case as a result of the high cost of electric energy in Ontario relative to natural gas.

Table 21 Assessment of Abatement Cost Associated with Residential ASHPs – The Existing Home

Type of home:		Existing Homes		
Scenario:		ASHP	ASHP + HPWH	Integrated ASHP + NG
Capital Costs (delta vs NG Base Case)		$0*	$750*	-$1,000
Annual Energy Costs (delta vs NG Base Case)		$930/yr	$1,000/yr	$600/yr
Total Measure Spend (= Capital Cost + Lifetime Energy Costs)		$14,000	$16,000	$7,900
Annual Emissions from NG		0.82 tCO_2e/yr	0 tCO_2e/yr	1.6 tCO_2e/yr
Annual Emission Reductions (Reduction=negative)	Gas-Fired Elec.	0.09 tCO_2e/yr	-0.19 tCO_2e/yr	-0.15 tCO_2e/yr
	Zero-Carbon Elec.	-4.3 tCO_2e/yr	-2.7 tCO_2e/yr	-1.9 tCO_2e/yr
Emission Reductions over Measure Life (15 yrs)	Gas-Fired Elec.	1.3 tCO_2e	-2.8 tCO_2e	-2.3 tCO_2e
	Zero-Carbon Elec.	-65 tCO_2e	-40 tCO_2e	-28 tCO_2e

Electricity Consumption		+8,700 kWh/yr	+11,000 kWh/yr	+5,900 kWh/yr
Natural Gas Consumption		$-1{,}900m^3$	$-2{,}300m^3$	$-1{,}400m^3$
Lifetime Cost of Emission Reduction	Gas-Fired Elec.	$-12,000 / tCO_2e	$2,800 / tCO_2e	$1,900 / tCO_2e
	Zero-Carbon Elec.	$240 / tCO_2e	$200 / tCO_2e	$150 / tCO_2e

Assuming non-emitting source of electricity emissions can be reduced by up to 4.3 tCO_2e/home/yr for the typical single family home in Ontario. The cost of abatement would be up to $270/$tCO_2e$ and $200/$tCO_2e$ where an integrated ASHP and NG furnace were deployed. The text in red illustrates an increase in emissions where the incremental electric load is met with natural gas-fired electricity vs non-emitting generation.

Within the new home the ASHP applications are more cost effective due to a decrease in capital cost and operating costs associated with cost of energy. As such emissions can be reduced by up to 3.3t CO_2e/home/yr and at between $130 to $180/$tCO_2e$.

Table 22 Assessment of Abatement Cost Associated with Residential ASHPs – The New Home

Type of home:		New Homes		
Scenario:		ASHP	ASHP + HPWH	Integrated ASHP + NG
Capital Costs (delta vs NG Base Case)		-$3,000	-$2,250	-$2,000
Annual Energy Costs (delta vs NG Base Case)		$650/yr	$570/yr	$410/yr
Total Measure Spend (= Capital Cost + Lifetime Energy Costs)		$6,700	$6,300	$4,200
Annual Emissions from NG		0.82 tCO_2e/yr	0 tCO_2e/yr	1.4 tCO_2e/yr
Annual Emission Reductions (Reduction=negative)	Gas-Fired Elec.	0.08 tCO_2e/yr	-0.03 tCO_2e/yr	-0.15 tCO_2e/yr
	Zero-Carbon Elec.	-2.5 tCO_2e/yr	-3.3 tCO_2e/yr	-1.9 tCO_2e/yr
Emission Reductions over Measure Life (15 yrs)	Gas-Fired Elec.	1.2 tCO_2e	-0.51 tCO_2e	-2.3 tCO_2e
	Zero-Carbon Elec.	-37 tCO_2e	-49 tCO_2e	-28 tCO_2e
Electricity Consumption		+6,100 kWh/yr	+7,800 kWh/yr	+4,100 kWh/yr
Natural Gas Consumption		$-1{,}300m^3$	$-1{,}800m^3$	$-1{,}000m^3$
Lifetime Cost of Emission Reduction	Gas-Fired Elec.	$-5,500 / tCO_2e	$12,000 / tCO_2e	$1,900 / tCO_2e
	Zero-Carbon Elec.	$180 / tCO_2e	$130 / tCO_2e	$150 / tCO_2e

The integrated ASHP + NG solution could minimize the need for incremental winter peaking capacity and electric system transmission and distribution upgrades where the measure taken to an economy wide scale. Rather than the full-electric air source heat pump (ASHP) exclusively, leverage ASHP efficiency for spring, fall and most winter days and integrated natural gas fired technology for extreme cold periods. This option could reduce GHG emissions by ~60%versus a home that currently heats with natural gas alone.

Incremental assessment of associated with commercial ASHPs was not carried out. However, the following should be considered related to commercial application.

- Commercial application of the ASHP is technically feasible and shown to be economic in markets with a more favorable energy price delta between natural gas and electric
- ASHP units can be scaled (2-100 tons) to meet the higher demand load of larger buildings such as care homes, schools, offices, hospitals, community and public buildings
- Larger three phase models incorporate twin or quadruple compressors for multiple stages of power
- Due to the variety of building types and sizes within Ontario a simple illustration of technical and cost effectiveness are not relevant as they are in the less diverse residential sector
- Similarly little pricing information is available in the public domain due to issues related to applicability
- For the purposes of this study we suggest that costs in the range of \$100/t CO_2 to \$250/t CO_2 provide a reasonable range depending size of building and heating/cooling demand

Concluding comments:
While ASHPs have recently reached levels of performance that make them a viable alternative to electric resistance heat in Ontario's climate, they are not yet a cost-effective alternative to natural gas furnaces in residential or commercial settings. At current price/performance ratios, and given existing shares of natural gas on the electricity grid, ASHPs have both higher capital and operating costs, and may increase emissions if the marginal electricity generation is supplied mainly by natural gas. If electricity were carbon-free, it would require a carbon price above \$200/t CO_2e for the existing home and \$130/tCO2 for the new home for the lifetime cost to be equivalent (at current retail electricity prices).

This analysis assumes no improvements in ASHP technology over the study timeframe (through 2020 and 2028). Further focus on the cold climate ASHP would be warranted where the prices for these come into comparison with conventional technology.

The abatement costs associated with ASHPs presented in the above are illustrative and based on several simplifying assumptions. The following context should be considered with regard to residential and commercial applications and the overall objective of this analysis.

- Programmatic costs associated with the delivery of an ASHP deployment project are NOT included in the above analysis
- ASHP technology cost and efficiency are likely to improve throughout the 2018-2028 period
- The cost of electric energy to the rate payer is a key input to cost of abatement – \$/Kwh and rate structure are relevant
- The proliferation of ASHP deployment will drive the Ontario electric system to a winter peaking from summer peaking and require the addition of considerably more peak reliable capacity – potentially adding to system cost
- The GHG intensity (t CO_2/MWh) of the electrical system's winter peak supply is critical to determining abatement potential and cost
- Where winter peaking capacity is met by natural gas fired generation total GHG emissions are likely to increase (along with demand for natural gas)

- Where winter peaking capacity is met by natural gas fired generation and existing capacity the cost per marginal demand for electricity to the system could be lower significantly than $140/MWh
- The electrical distribution system infrastructure and behind the meter technology in the home will need to be re-thought to accommodate +14kW peak load attributed to an ASHP (in parallel with other issues like home charging for EVs)
- Dedication of proceeds of sale of allowance to the ASHP could improve cost effectiveness.

SEC INTERROGATORY #2

INTERROGATORY

[C-5-2, p.4] Please provide a copy of the internal business case that was developed for the RNG proposal.

RESPONSE

The Enbridge RNG procurement proposal does not lend itself to a traditional business case analysis, and as such the Company has not prepared a business case in support of this initiative. Analysis and documentation in support of the RNG procurement proposal is set out in documents filed as appendices to the response to Board Staff Interrogatory #5 filed at Exhibit I.C.EGDI.STAFF.5.

Witnesses: A. Chagani
S. McGill

SEC INTERROGATORY #3

INTERROGATORY

[C-5-2, p.4] Please explain and justify any differences between the Enbridge RNG procurement proposal and the Union RNG procurement proposal.

RESPONSE

Please refer to the response to London Property Management Association Interrogatory #1 filed at Exhibit I.C.EGDI.LPMA.1.

Witnesses: A. Chagani
S. McGill

SEC INTERROGATORY #4

INTERROGATORY

[C-5-2, p.7-8] Enbridge has identified, in its view, limitations with the Board's MACC Report with respect to its evaluation of RNG:

a. Please provide a comprehensive analysis on the limitations of the MACC Report discussed in the evidence identified regarding RNG.
b. Has Enbridge conducted its own analysis on the cost effectiveness of RNG that corrects for these limitations? If so, please provide details including a detailed explanation of the calculation.

RESPONSE

a. Enbridge submitted comments to the Board and the Technical Advisory Group members on the Board's draft MACC as is found in the Appendices to Exhibit I.C.EGDI.SEC.1. The comments as well as the evidence highlight some key limitations with respect to the treatment of RNG in the MACC. The limitations related to RNG included:
    a. Compressed timeline for the study
    b. Lack of inclusion of any policy or funding (i.e., GreenON subsidies, etc.)
    c. Lack of consideration of offset value streams (see response to FRPO Interrogatory #3 at Exhibit I.C.EGDI.FRPO.3).
    d. Lack of inclusion of gasification as a viable longer term source of RNG
    e. Ground up analysis of specific location of RNG feedstocks
    f. Need for increased transparency behind the modelling/analysis

b. No, Enbridge has not conducted its own analysis since the issuance of the Board's MACC.

Witnesses: A. Chagani
S. McGill
F. Oliver-Glasford

SEC INTERROGATORY #5

INTERROGATORY

[C-5-2, p.9] Please detail the minimum requirements to be included in an agreement with the Province for Enbridge if it is to go ahead with its RNG procurement.

RESPONSE

Please refer to the response to Board Staff Interrogatory #5a filed at Exhibit I.C.EGDI.STAFF.5, Appendix 6.

Witnesses: A. Chagani
S. McGill

SEC INTERROGATORY #6

INTERROGATORY

[C-5-2, p.9] Please provide all communications that Enbridge has had with the Province regarding RNG procurement.

RESPONSE

Please refer to the response to Board Staff Interrogatory #5a filed at Exhibit I.C.EGDI.STAFF.5.

Witnesses: A. Chagani
S. McGill

SEC INTERROGATORY #7

INTERROGATORY

[C-5-2, p.9] Please detail any unique features that Enbridge expects to include in its procurement contracts with RNG producers.

RESPONSE

Please see response to Board Staff Interrogatory #5a filed at Exhibit I.C.EGDI.STAFF.5, Appendix 6 ("The Draft Renewable Natural Gas Discussion Paper").

Witnesses: A. Chagani
S. McGill