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Enbridge Gas Distribution
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VIA COURIER, RESS and EMAIL

May 24, 2018

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

Re: Ontario Energy Board File No. EB-2017-0319
Enbridge Gas Distribution Inc.
Renewable Natural Gas Enabling Program and
Geothermal Energy Service Program – Updated Exhibits

Pursuant to the Ontario Energy Board's (the "Board") Procedural Order No. 1 in the above noted proceeding Enbridge Gas Distribution Inc. ("Enbridge") filed its interrogatory responses with the Board on May 17, 2018. In the cover letter to those interrogatory responses Enbridge indicated that it had discovered an error related to municipal taxes. Further, Enbridge indicated that it would provide the Board with updated evidence reflecting the correct application of municipal tax assumptions the week of May 21, 2018. Enclosed please find Enbridge's updated evidence. The numerical changes shown are a result of updating the municipal tax values. For ease of reference the table below provides a summary of the Exhibits and Appendixes impacted by this correction.

Exhibit	Original	Correction
Exhibit B, Tab 1, Schedule 1 updated 2018-05-24	Exhibit B, Tab 1, Schedule 1	page 19, Table 2 page 20, Table 3 page 28, paragraph 83 page 28, paragraph 86 page 29, paragraph 88
Exhibit B, Tab 1, Schedule 1 Appendix 5, updated 2018-05-24	Exhibit B, Tab 1, Schedule 1 Appendix 5	pages 2 to 4
Exhibit B, Tab 1, Schedule 1 Appendix 6, updated 2018-05-24	Exhibit B, Tab 1, Schedule 1 Appendix 6	pages 1 to 2
Exhibit B, Tab 1, Schedule 1 Appendix 7, updated 2018-05-24	Exhibit B, Tab 1, Schedule 1 Appendix 7	pages 2 to 4
Exhibit B, Tab 1, Schedule 1 Appendix 8, updated 2018-05-24	Exhibit B, Tab 1, Schedule 1 Appendix 8	pages 1 to 2
Exhibit B, Tab 1, Schedule 1 Appendix 11, updated 2018-05-24	Exhibit B, Tab 1, Schedule 1 Appendix 11	pages 2 to 6
Exhibit B, Tab 1, Schedule 1 Appendix 12, updated 2018-05-24	Exhibit B, Tab 1, Schedule 1 Appendix 12	pages 1 to 4

Please contact the undersigned if you have any questions.

Yours truly,

[original signed]

Lorraine Chiasson
Regulatory Coordinator

cc: All Parties to EB-2017-0319

EXHIBIT LIST

A – ADMINISTRATIVE

Exhibit	Tab	Schedule	Contents	Witness(es)
A	1	1	Exhibit List	K. Culbert
	2	1	Application	K. Culbert

B – EVIDENCE

Exhibit	Tab	Schedule	Contents	Witness(es)
B	1	1	Carbon Abatement – Renewable Natural Gas Enabling And Geothermal Energy Service	A. Chagani P. Datta S. McGill
			Appendix 1 - Enbridge's current Undertakings (including the 2006 and 2009 Minister's Directives)	
			Appendix 2 – Fuels Technical Report	
			Appendix 3 – Ontario's Long-Term Energy Plan 2017	
			Appendix 4 - Minister Thibeault's letter	
			Appendix 5 – RNG BMS – Economic Feasibility	
			Appendix 6 – RNG BMS – Revenue and Revenue Requirement	
			Appendix 7 – RNG Injection – Economic Feasibility	

EXHIBIT LIST

B – EVIDENCE

Exhibit	Tab	Schedule	Contents	Witness(es)
B	1	1	Appendix 8 – RNG Injection – Revenue and Revenue Requirement	
			Appendix 9 – Rate Number 400 – Biogas Conditioning and Upgrading Service	
			Appendix 10 – Rate Number 401 – Renewable Natural Gas Injection Service	
			Appendix 11 – Geothermal - Economic Feasibility	
			Appendix 12 – Geothermal – Revenue and Revenue Requirement	

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an application by Enbridge Gas Distribution Inc. for an order or orders related to its Renewable Natural Gas Enabling Program and Geothermal Energy Service Program;

AND IN THE MATTER OF an application by Enbridge Gas Distribution Inc. for an order or orders amending or varying the rates charged to customers for the sale, distribution, transmission, and storage of gas commencing as of January 1, 2018

APPLICATION

1. The Applicant, Enbridge Gas Distribution Inc. ("Enbridge" or the "Company"), is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting and storing natural gas within Ontario.

2. Enbridge hereby applies to the Ontario Energy Board (the "OEB" or the "Board"), pursuant to section 36 of the *Ontario Energy Board Act*, *1998* as amended (the "Act"), for an Order or Orders enabling the Company to commence the operation of its Renewable Natural Gas Enabling Program and Geothermal Energy Service Program.

3. The Company had originally presented its Renewable Natural Gas Enabling Program and Geothermal Energy Service Program proposals as part of its evidence in its 2018 Rate Adjustment Application (EB-2017-0086) which was submitted to the Board on September 25, 2017. On October 16, 2017, the Board notified Enbridge that it wished to separate the Company's Renewable Natural Gas Enabling Program and Geothermal Energy Service Program proposals from the 2018 Rate Adjustment Application and directed the Company to submit these proposals as a separate application under the Docket Number EB-2017-0319.

4. Based on the *Climate Change Mitigation and Low-carbon Economy Act, 2016* ("Climate Change Act"), the Natural Gas Utilities are under a legal obligation to account for their emissions (including the emissions of most of their customers) through the Cap and Trade program. The Natural Gas Utilities are statutorily mandated to procure allowances and offsets and abate emissions as part of regular business operations.

5. The responsibilities of the Natural Gas Utilities are further detailed in the OEB's Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities (the "Framework") which outlines ways in which the OEB has identified the Natural Gas Utilities may meet their Cap and Trade obligations. These include: financial instruments (e.g. allowances, offsets), customer abatement (e.g. renewable natural gas ("RNG"), energy efficiency, fuel switching, new and evolving technologies), and facilities abatement (e.g. leak repairs, capital upgrades). Cap and Trade activities are now part of the Natural Gas Utilities' regulated operations.

6. In the Framework, the Board states that in its evaluation of the cost consequences of the Utilities' Compliance Plans it will consider whether the utility has;
   a. "engaged in strategic decision-making and risk mitigation,"
   b. "considered a diversity (portfolio) of compliance options" and
   c. "selected GHG abatement activities and investments that, to the extent possible, align with other broad investment requirements and priorities of the Utility in order to extract the maximum value from the activity or investment."[1]

7. Given that the applicable costs of a utility meeting its carbon obligations are included in the distribution costs of customers' bills, the Natural Gas Utilities have a responsibility to manage carbon related costs where possible, as part of their efforts in providing cost effective service. This will become increasingly important as the cost of carbon inevitably increases because of the deliberate manner in which the Cap and Trade program has been

[1] Ontario Energy Board: Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities (EB-2015-0363); September 26, 2016, page 21.

structured. With the increasing cost of carbon and the increasing recognition of the value of avoiding GHG emissions, over time the attractiveness of GHG abating activities will become ever more significant.

8. Enbridge has developed two new abatement programs that will contribute to reducing customer GHG emissions. The Renewable Natural Gas Enabling Program is intended to allow Enbridge to provide upgrading and injection services for RNG producers, in an effort to increase the supply and availability of low-carbon RNG in Ontario. The Geothermal Energy Service Program is intended to allow Enbridge to own and maintain geothermal loops to encourage homeowners to choose and use geothermal energy systems for their home heating and cooling requirements as an alternative to natural gas and other fossil fuels.

9. By this application, Enbridge applies to the Board for such final and interim Orders as may be necessary to approve the cost consequences of the Company's Renewable Natural Gas Enabling Program and Geothermal Energy Service Program proposals. This includes approval of the service fees associated with each Program, and approval of including the annual sufficiency/deficiency of the Programs within Cap and Trade Compliance Obligation Variance Accounts.

10. The Company further applies to the Board pursuant to the provisions of the Act and the Board's Rules of Practice and Procedure for such final and interim Orders and directions as may be necessary in relation to the Application and the proper conduct of this proceeding.

11. The persons affected by this Application are the customers of Enbridge. It is impractical to set out the names and addresses of the customers because they are too numerous.

12. Enbridge requests that a copy of all documents filed with the Board by each party to this proceeding be served on the Applicant and the Applicant's counsel as follows:

The Applicant:

Andrew Mandyam
Director, Regulatory Affairs
and Financial Performance
Enbridge Gas Distribution Inc.

Address for personal service:	500 Consumers Road Willowdale, Ontario M2J 1P8
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The Applicant's counsel:

Mr. David Stevens
Aird & Berlis LLP

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DATED January 17, 2018 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: [original signed]

CARBON ABATEMENT – RENEWABLE NATURAL GAS ENABLING AND GEOTHERMAL ENERGY SERVICE

Introduction

1. Based on the *Climate Change Mitigation and Low-carbon Economy Act, 2016* ("Climate Change Act"), the Natural Gas Utilities are under a legal obligation to account for their emissions (including the emissions of most of their customers) through the Cap and Trade program. The Natural Gas Utilities are statutorily mandated to procure allowances and offsets and abate emissions as part of regular business operations.

2. The Ontario Energy Board's ("OEB" or the "Board") Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities (the "Framework") indicates that natural gas utilities have a number of compliance options available to meet their obligations under Ontario's Cap and Trade program. In addition to purchasing allowances and offset credits, natural gas utilities can and are expected to undertake Greenhouse Gas ("GHG") abatement measures to meet their compliance obligations.

3. The Framework states:

> The Utilities are required by the Climate Change Act to be responsible for the GHG emissions related to all natural gas delivered on their distribution systems to customers other than LFEs or voluntary participants. In order to comply with this obligation the Utilities will incur costs. While these costs are not specifically tied to the operation of the gas distribution system, they are an on-going business obligation of a natural gas distributor under the Climate Change Act.[1]

4. This mandate is further articulated by the Framework which outlines several ways in which the Utilities may propose to meet their Cap and Trade obligations which

[1] Ontario Energy Board, Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities (EB-2015-0363), September 26, 2016, page 33.

include: financial instruments (e.g., allowances, offsets), customer abatement (e.g., renewable natural gas ("RNG"), energy efficiency, fuel switching such as geothermal, new technologies), and facilities abatement (e.g., distribution system upgrades).

5. The Company understands customer abatement to include reducing GHG emissions from current customers and potential future customers through installation of energy systems other than those which utilize natural gas.

6. The Framework makes it clear that the utility's Cap and Trade related activities and investments are utility functions; however, the Framework states that these investments will not be approved in conjunction with the OEB's review of a utility's Cap and trade Compliance Plans.

> The OEB will not approve the Utilities' Compliance Plans. Utilities are responsible for deciding on the exact makeup of activities to be included in their Plans, how best to prioritize and pace investments in Cap and Trade compliance options and abatement activities, and how and when to participate in the market.[2]

Further;

> The OEB expects a Utility's Compliance Plans to include a description of the longer term strategy. The actual forecasts of planned capital expenditures related to any investments will, however, be dealt with in a Utility's regular rate application and/or any leave to construct cases. This means that although the Compliance Plans will highlight a Utility's thinking around long-term investments, the actual approval of costs and cost recovery will be dealt with like any other type of investment.[3]

7. In addition, the Board recently issued a Decision in relation to Enbridge's Cap and Trade Compliance plan for 2017.[4] In that Decision the Board

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[2] Ontario Energy Board, Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities, September 26, 2016, page 7.
[3] Ontario Energy Board, Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities, September 26, 2016, page 27.
[4] EB-2016-0296/EB-2016-0300/EB-2016-0330 Decision and Order.

confirmed that it expects the gas utilities to bring forward plans for customer abatement activities (which may include new business activities) as part of its future applications.[5]

8. In 2006 and 2009, the Undertakings between the Province and Enbridge were amended to enable, *inter alia*, Enbridge to provide services that would assist the Government of Ontario in achieving its goals in energy conservation. This included the promotion of cleaner energy sources, alternative energy sources and renewable energy sources. Copies of Enbridge's current Undertakings (including the 2006 and 2009 Minister's Directives) are attached as Appendix 1.

9. Over the past two years, the Province has provided direction and guidance about GHG abatement and adoption of lower or zero carbon technologies. The Company's move toward the implementation of carbon abatement strategies is consistent with the Province's energy and GHG abatement related goals.

10. The Company's 2017 Cap and Trade Compliance Plan (EB-2017-0300) submission made reference to several potential carbon abatement initiatives that the Company had under investigation at the time. Enbridge's 2018 Cap and Trade Compliance Plan submission to the Board (EB-2017-0224) has now been filed. The Company's evidence in that case describes the Abatement Construct framework being utilized to evaluate potential multi-year abatement programs and how Enbridge proposes to integrate these initiatives into its overall Cap and Trade compliance planning to assist in meeting the Company's Cap and Trade obligations.[6]

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[5] Ibid, page 27.
[6] EB-2017-0224, Exhibit C, Tab 5, Schedule 1.

11. The 2018 Compliance Plan proceeding evidence includes a full list and description of the abatement opportunities the Company is currently exploring and summarizes the Company's Renewable Natural Gas ("RNG") Enabling Program and Geothermal Energy Service proposals detailed in this submission.[7] The RNG Enabling Program is intended to allow Enbridge to provide upgrading and injection services for RNG producers, in an effort to increase the supply and availability of low-carbon RNG in Ontario. The Geothermal Energy Service Program is intended to allow Enbridge to own and maintain geothermal loops to encourage homeowners to choose and use geothermal energy systems for their home heating and cooling requirements as an alternative to natural gas and other fossil fuels.

12. Enbridge is of the view that the combined effect of the Framework and the Undertakings support the inclusion of carbon abatement activities such as the RNG Enabling Program and Geothermal Energy Service Program described in this submission in the regulated utility. The purpose of this evidence is to present these programs to the Board and obtain the Board's approval to enable the Company to implement these programs within the regulated utility in 2018.

Context and Background

13. In June 2016 the Ontario Ministry of Environment and Climate Change (the "MOECC") published its Climate Change Action Plan (the "CCAP"). The CCAP consolidated the Province's plans to bring together effective initiatives designed to enable Ontario to achieve its GHG reduction targets. The plan outlines how the Province intends to direct the Cap and Trade proceeds towards projects that will create good jobs, help families and businesses become more energy-efficient, and accelerate Ontario's transition to a low-carbon economy.

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[7] EB-2017-0224, Exhibit C, Tab 5, Schedule 2.

14. Further to the CCAP, the Province recently released its 2017 Long Term Energy Plan (the "2017 LTEP"). One of the significant inputs to the LTEP is a report prepared by Navigant Consulting Inc. on behalf of the Ministry of Energy (the "MOE") called the Fuels Technical Report (the "FTR"). The FTR complemented the IESO's Ontario Planning Outlook the purpose of which was to help the MOE advise as to how the Province's electricity energy demand could be met over the coming twenty years while also enabling the achievement of the Province's GHG emission targets and CCAP strategies. A copy of the FTR is attached as Appendix 2 to this evidence.

15. The 2017 LTEP includes a number of plans and initiatives to encourage innovation and new technologies, and assist in meeting climate change goals. Several of these are directly relevant to this Application, including:

- A direction to build a *"culture of innovation"* in the energy sector and look for ways to allow utilities to make non-traditional and "non-wires" investments and work with customers in scenarios where each party owns part of an energy system.[8]

- A plan to have RNG become part of the Ontario supply mix: *"Ontario is looking at using renewable natural gas to lower the carbon intensity of the natural gas that people burn. …. 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."*[9]

[8] Ontario's Long-Term Energy Plan 2017: Delivering Fairness and Choice ("2017 LTEP"), at pages 69-70.
[9] 2017 LTEP, at page 114.

- A goal to increase the number of geothermal energy systems used for low carbon space and water heating in homes and buildings across Ontario. The 2017 LTEP indicates that *"Natural gas will continue to play a critical role in space and water heating, but we must use it as efficiently as possible and supplement it with the next generation of clean energy technologies, such as ground-source and air-source heat pumps. Proceeds from cap and trade auctions will help fund the further application of these technologies."*[10]

16. The 2017 LTEP indicates that the government is investing proceeds from the auctions in the carbon market to help introduce RNG and ground source heat pumps in the province. Enbridge's proposed RNG Enabling program and Geothermal Energy Service program will complement and expedite the Government's plans as outlined in the 2017 LTEP. A copy of the 2017 LTEP is included as Appendix 3.

17. In this application, the Company is bringing forward a Renewable Natural Gas Enabling program and Geothermal Energy Service program proposal. These new programs have been developed so as to be consistent and compliant with the Framework, existing regulatory principles and OEB guidelines, such as the EBO 188 feasibility test.

18. The OEB's Cap and Trade Framework recognizes that gas distribution utilities will need to meet their Climate Change Act obligations, which suggests an expanded view as to what will constitute core utility business activities. Enbridge's proposed new business activities are provided for under the Undertakings between the Enbridge and the Province and are in support of and will assist the Government of Ontario in the achievement of its goals in regard to carbon emissions reduction and

[10] 2017 LTEP, at pages 109 and 115.

the promotion of clean alternative energy sources and renewable energy. The activities are consistent with the goals and initiatives set out in the 2017 LTEP.

19. With respect to the advancement of RNG production in Ontario, Enbridge sees its role as that of a facilitator that can assist RNG producers in the process of upgrading raw untreated biogas into pipeline quality RNG and the injection and transportation of this gas to market. Over the course of the past eighteen months, the Company has conducted discussions with several municipalities and other potential RNG producers with respect to the services Enbridge could provide to accelerate the development of RNG production capacity in its service area. Enbridge believes this will support the growth of RNG production which will facilitate lower cost RNG to supply market demand. This dialogue has led the Company to develop the RNG enabling program described in this submission which is based on utility investment in RNG upgrading and injection equipment.

20. The Company proposes to offer RNG upgrading services on an optional basis. As such RNG producers will have the choice of upgrading biogas to pipeline quality themselves or having Enbridge perform this function for them. 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 responsibilities as a distributor of natural gas and ensure the safe and reliable distribution of RNG to market.

21. Ground source heat pump heating and cooling systems ("geothermal systems") have been readily available in Ontario for a number of years. However, the adoption of this technology has been hampered by barriers such as high initial costs compared to other building heating / cooling technologies and inconsistent deployment and installation practices. These factors have resulted in low market

penetration of geothermal systems and less than desirable levels of customer satisfaction with this technology.

22. Enbridge has been working with the Ontario Geothermal Association ("OGA"), the MOECC, and the MOE to find solutions that will overcome these barriers faced by the geothermal industry which will lead to further the adoption of ground source heating and cooling systems. The solution that Enbridge has developed is a utility service that combined with financial support from the MOECC's Greenhouse Gas Reduction Account ("GGRA") administered by the Green Ontario ('GreenON") Fund will make this technology cost competitive compared to more traditional building heating and cooling alternatives. Enbridge will own and maintain the geothermal loops while customers will own and maintain the heat pump system.

23. On December 13, 2017, the Ontario Government announced new rebates from the GreenON fund for ground source heat pumps (home geothermal).[11] Homeowners will be eligible for rebates of up to $20,000 for ENERGY STAR certified ground source heat pumps. This will offset the customer's costs under Enbridge's proposed Geothermal Energy Service program.

24. The Company's RNG enabling program and Geothermal Energy Service program both form part of the Company's long term carbon abatement strategy and relate to the Company's contributions towards the Province's *Climate Change Mitigation and Low-carbon Economy Act, 2016* and the OEB's Framework. The Company has used the Board's EBO 188 Guidelines as a guide in the determination of the charges for these services. This approach aims to ensure that existing ratepayers will not subsidize these new programs.

[11] The GreenON announcement can be found at the follow link: https://www.greenon.ca/programs/greenon-rebates-ground-source-heat-pumps.

Regulatory Treatment of RNG Enabling Program and Geothermal Energy Service Program

25. Given Ontario's current carbon reduction objectives, supporting legislation and regulatory framework, the RNG Enabling program and Geothermal Energy Service program are appropriate utility activities. Both programs over their respective lifetimes will reduce the number of Cap and Trade allowances that the Company will need to procure and hence lower the compliance costs for its existing and forecasted customers. Both programs are captured within the scope of the Undertakings between the Company and the Province. These utility investments will significantly contribute towards the attainment of Ontario's CO_2 emission target reductions by abating and displacing the consumption of (non renewable) natural gas in the Company's service area.

26. Through this application Enbridge is seeking approval for and establishment of charges (service fees) for both programs which are contingent on projects within each program attaining a Profitability Index ("PI") equal to or greater than 1.0 (applying the principles set out in the EBO 188 Guidelines). In applying the EBO 188 Guidelines, Enbridge has or will determine the capital, operating and financing cost requirements for these programs over the forecast horizon. These costs are then utilized to derive overall revenue requirements. Enbridge has calculated monthly service fees to recover the revenue requirement over the life of the assets relevant to each program such that the resultant PI for each program is equal to or greater than 1.0.

27. This approach will ensure that the recipients of the RNG and Geothermal services will pay the full cost of these programs. Existing customers are not harmed and will

benefit over the life cycle of these programs. Additionally, there will be broader benefit from increased RNG production and reduced GHG emissions.

28. Enbridge recognizes that in applying the EBO 188 principles there will be a deficiency in terms of the revenues versus the costs of these programs in their early years. However, in later years there will be a sufficiency in terms of the revenues versus the costs of these programs. As time goes on and the assets' net book value decreases, these assets will deliver annual revenues in excess of their revenue requirements thereby returning and to some extent exceeding the revenue deficiency underwritten by ratepayers in the early years.

29. While these programs will be part of the Company's regulated business activities and constitute carbon abatement activities, the best methodology to address their utility revenue requirement implications over their asset lives will be to treat the annual utility revenue sufficiencies and deficiencies associated with these programs as credits or debits to the cost of carbon or costs of carbon abatement.

30. 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**.** The recovery of these amounts through the GHG-Customer VA is appropriate because the objective of these initiatives is to reduce GHG emissions associated with natural gas deliveries and customers' consumption of natural gas.[12]

[12] Under this approach, the costs and revenues associated with these programs would be excluded from the 2018 ESM calculation.

Renewable Natural Gas Enabling Program

31. Enbridge's proposed RNG enabling program is focused on providing services to RNG producers that will expand and facilitate lower cost RNG supply for the Company and other consumers.

The RNG Market in Canada and Ontario

32. RNG is a potential natural gas supply source that offers environmental, economic and waste management benefits. RNG (also referred to as "bio-methane") is refined from biogas produced from organic waste, such as that found on farms, at waste water treatment plants, food processing facilities and in landfills. The process that creates biogas from this waste is called anaerobic digestion.

33. Anaerobic digestion takes place when organic material decomposes in an oxygen-free environment, either controlled within an anaerobic digester, or naturally in a landfill. The main products of anaerobic digestion are methane (CH_4) and carbon dioxide (CO_2), the combination of which is commonly referred to as biogas when produced in digesters, and landfills.

34. RNG has similar physical properties to conventional natural gas, and with respect to GHG emissions provides benefits in two forms; 1) emission reduction; and 2) fuel substitution. Emission reduction is achieved by capturing emissions of methane that would otherwise enter the atmosphere from landfills, the decomposition of organic waste and waste water. The fuel substitution benefit results from the displacement of a more traditional fossil fuel. The origin of RNG therefore has a significant impact on its carbon abatement potential and carbon offset value.

35. In its CCAP, the Ontario Government indicated that it would provide support to encourage the use of cleaner, renewable natural gas in industrial, transportation and buildings sectors. This intent is also echoed in the 2017 LTEP, where the

government has indicated that it will "continue to work with industry partners to introduce renewable natural gas into the province's natural gas supply and expand the use of lower-carbon fuels for transportation."[13]

36. In the near term, most if not all biogas supplies are expected to be produced through anaerobic digestion processes. In the longer term, RNG is expected to also be produced through a process known as gasification. Gasification is a process that converts carbonaceous materials, such as coal, petroleum, or biomass, into carbon monoxide, hydrogen and methane by the reaction of the raw organic feedstock at elevated temperatures with a controlled amount of oxygen (less than stoichiometric). The resulting gas mixture is called synthesis gas or syngas and is itself a fuel. Syngas may be burned directly in internal combustion engines, used to produce methanol and hydrogen, converted via the Fischer-Tropsch process into synthetic fuel, or converted to methane through catalytic methanation.

37. On July 20, 2017, the OEB issued a report developed by ICF Consulting Canada Inc. ("ICF") which provides a Marginal Abatement Cost Curve ("MACC") for natural gas abatement activities in Ontario. The MACC report includes a summary for RNG potential in Canada and Ontario. ICF outlines five feedstocks for RNG and their 10-year potential. The report made the simplifying assumption that RNG production from Landfill Gas ("LFG"), wastewater treatment plants, animal manure, and SSO (source separated organics) would occur via anaerobic digestion. It also assumed that agricultural residue would be converted to RNG via thermal gasification.

38. The ICF report includes an estimate of future RNG production potential in Ontario, based upon a 2013 report from the Canadian Biogas Association. The relevant table from the ICF report is reproduced in Table 1 below.[14]

[13] 2017 LTEP, at page 15.

Table 1: RNG Production Potential in 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**

39. The figures above assume that nearly 100% of the RNG production potential estimated in the Canadian Biogas Study is achievable by 2028 for each feedstock. However, in order for that to be achieved, there will have to be significant new infrastructure to condition the biogas (converting it to pipeline quality) and to enable the injection of the RNG into gas distribution systems.

40. Both the CCAP and the FTR and now the 2017 LTEP identify RNG as a significant contributor to the achievement of the Province's CO_2 emission reduction objectives. These sentiments were expressed to the OEB by Glenn Thibeault, Ontario's Minister of Energy. In his letter of December 10, 2016, Minister Thibeault communicated the Government's interest in the OEB taking steps to examine the prospect of RNG becoming a component of Ontario's natural gas supply. The Minister also encouraged the OEB to move forward in a timely manner to include RNG as a means of helping to reduce GHG emissions by becoming part of the gas utilities' gas supply portfolios. A copy of Minister Thibeault's letter is included as Appendix 4 to this evidence.

[14] Final Report , Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities (EB-2016-0359), released July 20, 2017: Figure 1: RNG feedstock in Ontario and Canada.

41. The Board followed through on the Minister's request by identifying RNG as a key point of interest in formulation its upcoming Framework for the Assessment of Distributor Gas Supply Plans (the "Gas Supply Framework").[15] The Gas Supply Framework working group initially focused on the issues related to RNG as a component of utility gas supply plans and has made an effort to understand the state of the current RNG marketplace and the potential for Ontario sourced RNG to become part of the OEB's system gas supply plan.

42. On May 2, 2017 and May 23, 2017, the Gas Supply Framework working group held meetings focused on communicating issues concerning the RNG sector and how these issues could be overcome in Ontario.

43. Over the past year, Enbridge has been in discussions with a number of RNG producers to better understand the market and needs of the producers. The Company's primary focus has been on municipalities that are required to deal with large waste streams as part of their day to day operations. Below is a list of potential RNG producers and municipalities that have expressed interest in working with Enbridge on RNG opportunities.

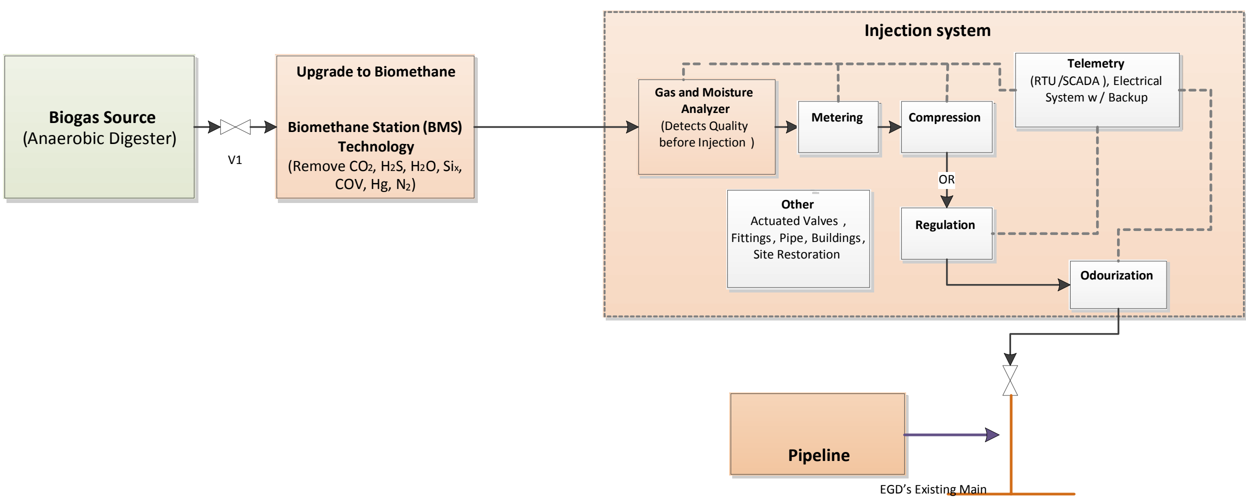
    1. City of Toronto
    2. Region of Peel
    3. Durham Region
    4. Niagara Region
    5. Private Industrial Waste Management Company
    6. City of Peterborough

[15] EB-2017-0129.

44. As already noted, in order to encourage RNG production in Ontario, Enbridge sees that it can play an important role as a facilitator that can assist RNG producers in the process of upgrading raw untreated biogas into pipeline quality RNG and then injecting and transporting that gas to market. These roles require new facilities. The new facilities will provide producers with conditioning and upgrading service, and will enable the RNG (the upgraded biogas) to be injected into the Company's distribution system to be transported to market.

45. Figure 1 provides a schematic of the RNG production process and the RNG services Enbridge proposes to offer producers.

Figure 1: RNG Production Process and Enbridge Service Offerings



46. At a high level, the production of RNG is comprised of the three major steps depicted in Figure 1.

   a. The first step is the production of raw untreated biogas. Typical sources of biogas are landfills and anaerobic digesters that capture the gases released from source sorted organic waste, waste water or agricultural waste.

Witnesses: A. Chagani
P. Datta
S. McGill

b. The second major step in the process is the upgrading of the biogas to pipeline quality. Raw biogas is usually mainly comprised of methane and carbon dioxide. However, it also contains a number of impurities that need to be removed from it to achieve pipeline quality. Impurities such as sulfur compounds, nitrogen, oxygen, volatile organics, ammonia, siloxanes, and other trace elements need to be removed from biogas before it can be safely comingled with traditional natural gas supplies.

c. The third step in the process of bringing RNG to market is the injection of this gas into a gas distribution system. This step entails measurement of the energy content of the gas, ensuring that it meets pipeline quality standards, control of flow and pressure through regulation or compression, odourization and delivery into the gas distribution system.

Enbridge's Proposed RNG Enabling Program

47. The Company's RNG Enabling Program has been designed such that Enbridge can support and help facilitate Ontario RNG production and the injection of RNG into the natural gas distribution system separate and apart from the rate setting implications of including RNG into the Company's gas supply portfolio.

48. Enbridge proposes to offer two services to RNG producers. These services will enable producers to inject pipeline quality RNG (bio-methane) into the gas distribution system. The two services that Enbridge is proposing are: 1) a Biogas Conditioning and Upgrading Service ("Upgrading Service"), and 2) RNG Injection Service ("Injection Service"). The Upgrading Service is complementary to the Injection Service whereas the Injection Service can be stand alone. As set out

below, Enbridge is requesting Board approval of the manner in which service fees will be determined for each of these Services.

49. The Upgrading Service will be offered to potential RNG producers as an optional service. Producers choosing this option will contract with Enbridge to plan, design, procure, construct, own, operate and maintain biogas conditioning and upgrading equipment on the producer's premises. The Upgrading Service, where provided by the Company, will ensure the biogas is treated for safe injection into the distribution network. This is the process of converting the raw biogas to RNG (bio-methane), and encompasses the removal of the impurities such as carbon dioxide, hydrogen sulfide, nitrogen, and other impurities. Once the conditioning is complete, the upgraded gas has the same physical properties as traditional pipeline gas.

50. Under the Injection Service, Enbridge will build the pipeline attaching the producer to the distribution system, odourize the bio-methane, measure the gas volumes and energy content of the gas, manage pressures and ensure that the gas meets required specifications. Enbridge will inject the RNG into the distribution network and transport the RNG to delivery points designated by the RNG producer. Once the RNG is in the Company's gas distribution system, Enbridge will enable the movement of that gas to a terminal location of the producer's choice through the various service offerings Enbridge provides its customers today. All RNG producers requesting to inject RNG into Enbridge's distribution system will be required to contract for the Injection Service, including RNG producers who do not require Upgrading Service.

51. Enbridge will provide these services subject to the Company entering into contracts with the RNG producers for the provision of these service(s). Items to be addressed in the contracts will include but not be limited to: the design, location,

construction, operation, timing and costs of the required upgrading and injection facilities and related services. While the specific contents of each contract will be different (to reflect the details of the relevant facilities), the form of the contracts will be common or similar for all producers receiving Upgrading and / or Injection Service.

52. Enbridge will recover the cost of these facilities (and the associated operating and other costs) through service fees charged to the RNG producer for the Upgrading Service (if applicable) and the Injection Service. Gas distribution charges will apply to the transportation of RNG through Enbridge's distribution system.

53. Through the provision of these services, Enbridge will ensure that the RNG injected into the gas distribution system, at minimum, meets the requirements of CSA Z662 and other applicable codes and standards as specified in the Company's policies. As well, the Company will ensure the natural gas in the distribution network continues to meet the current gas quality requirements for its customers.

Calculation of Service Fees

54. The RNG producer will be charged separate service fees for each of the two services offered by the Company. Each service fee will be derived from a discounted cash flow ("DCF") analysis. The DCF analysis will be based on the principles and parameters set out in the OEB's EBO 188 feasibility guideline. The fee for each service (Upgrading or Injection) will be site specific and set so as to recover operating and maintenance costs, depreciation, utility's return on investment, and taxes while achieving a PI equal to or greater than 1.0 over the service life of the plant. Enbridge will charge a levelized (constant) service fee for each month of the term of the contract.

55. The term of the contract for each service will be negotiated with the producer. It is assumed that the contract term will be equal to the service life of the assets, or (if shorter) the expected lifespan of the feedstock.

56. The determination of the service fees for Upgrading and Injection Services will be site specific and based on the fully allocated costs associated with the services in each particular instance.

57. Tables 2 and 3 set out a hypothetical example for a single RNG production facility to illustrate how the service charges for the Company's Biogas Upgrading and RNG Injection Services are to be determined. The appropriate service charge would be included in the contract with the RNG producer. Details of the calculations and assumptions contained in Table 2 are set out in Appendix 5 to this Exhibit. A revenue requirement calculation is contained in Appendix 6. Details of the calculations and assumptions contained in Table 3 are set out in Appendix 7 and Appendix 8 contains a revenue requirement calculation.

Table 2: Upgrading Service Rate Example

Station Equipment and Construction (includes OH)	$7,420,000
Estimated construction period	12 months
Plant life	20 years
Total O&M	$449,000/year
Monthly Rate	$110,750

/u

Witnesses: A. Chagani
P. Datta
S. McGill

Table 3: Injection Service Rate Example

Injection Station Cost	$3,600,000
Pipeline Cost	$1,440,000
Land	$400,000
Total Injection Service Capital	$5,440,000
Estimated construction period	4 months
Plant life	20 years
Operating and Maintenance	$107,000/year
Monthly Rate	$ 63,083

/u

58. Enbridge is requesting approval of a new Rate 400 for Upgrading Service and Rate 401 for Injection Service. The service fees charged under Rates 400 and/or Rate 401 to each RNG producer will be as set out in the relevant contract. The proposed Rate Schedules for Rate 400 and Rate 401 are attached as Appendix 9 and Appendix 10 respectively.

59. As detailed in the “Regulatory Treatment of RNG Enabling Service and Geothermal Energy Service Program” section of this evidence, Enbridge is also requesting approval of its proposal to record the annual revenue deficiency or sufficiency associated with the RNG enabling service program in the GHG-Customer VA to be periodically cleared to ratepayers. Examples showing relevant amounts can be seen in Appendix 6 and Appendix 8 at Line 18.

Market options for RNG Producers

60. Once the RNG has been injected into Enbridge’s gas distribution system, the producer will have the following four options to sell the RNG, or to use it for their own purposes:

a) The RNG producer can use the RNG to provide all or part of their gas supply requirements at another of their locations served by Enbridge (this will require a Direct Purchase arrangement).

b) The RNG producer can sell the RNG to another Enbridge customer to fulfill all or a portion of their gas supply requirement (this will require a Direct Purchase arrangement).

c) If the RNG producer wishes to move and sell the RNG outside of the Enbridge service area, Enbridge will facilitate the transportation of RNG produced to a trading hub, typically Dawn.

d) In the event that Enbridge is purchasing RNG as part of the Company's gas supply mix, the RNG producer will be able to respond to tenders for the sale of RNG to the Company.

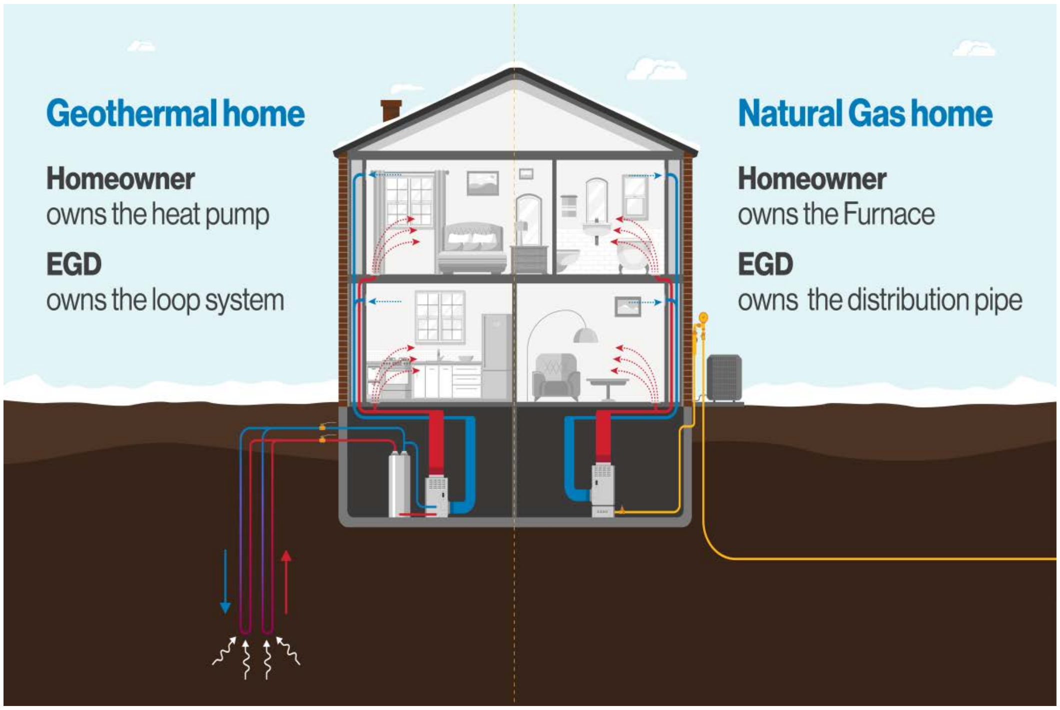
<u>Geothermal Energy Service Program</u>

61. The purpose of this portion of the Company's evidence is to describe the utility based Geothermal Energy Service program that Enbridge plans to implement in 2018 as a GHG emission abatement program to offset natural gas usage. Enbridge's proposed Geothermal Energy Service program is focused on making geothermal systems more broadly available and implemented for customers who would otherwise be using natural gas or other fossil fuels for space and water heating.

62. Enbridge's proposed Geothermal Energy Service program will see complementary investments between customers, Enbridge and GreenON funding. Enbridge will

own and maintain the geothermal loops while customers will own and maintain the heat pump system and will receive GreenON funding to offset some of that cost. This is similar to the current gas distribution system approach, where the utility owns the supply infrastructure and the customer owns the in-home appliances – see Figure 2 below.

Figure 2: Geothermal and Natural Gas Home



Background

63. Geothermal systems provide space heating, water heating and cooling and are typically electrically powered, highly efficient and release no direct GHG emissions. A geothermal system consists of ground source loops ("geothermal loops") which are pipes in the ground; and a heat pump system ("heat pump") that is functionally

similar to a furnace air conditioner combination and is installed above ground in the home and connects to the geothermal loops through pipes that go into the house.

64. Geothermal systems can be used with forced-air and hydronic heating systems. They work by transferring heat from and into the earth by circulating a liquid, such as ground water or an antifreeze solution, via a heat pump system. During the heating season, the heat pump system extracts heat from this liquid. This heat is used to heat indoor air. This process is reversed during summer months when heat is removed from indoor air and transferred to the earth by the ground water or antifreeze solution.

65. Geothermal systems have been available in Ontario for a number of years. However, the adoption of this technology has been hampered by high initial cost compared to other building heating / cooling technologies and inconsistent approaches by different contractors. These factors have resulted in low market penetration and less than desirable levels of customer satisfaction with this technology.

66. Geothermal systems have been identified as an important means of achieving the Province's GHG emission reduction targets. In June 2016, the MOECC issued its Climate Change Action Plan (the CCAP). The CCAP includes a section discussing plans to reduce GHG emissions within the "Buildings and Homes, and indicates that:

> *Ontario will help homeowners purchase and install low-carbon energy technologies such as geothermal heat pumps and air-source heat pumps, solar thermal and solar energy generation systems that reduce reliance on fossil fuels for space and water heating*.

67. The CCAP promises $500 to $600 million in future funding to promote the adoption of geothermal heating, air source heat pumps, solar thermal and solar electricity generation in the Province's residential buildings sector.[16]

68. On December 13, 2017, the Ontario Government announced new rebates from the GreenON fund for ground source heat pumps (home geothermal).[17] As noted above, homeowners will be eligible for rebates of up to $20,000 for ground source heat pumps, which will offset the customer's portion of costs under Enbridge's proposed Geothermal Energy Service program.

69. Enbridge is in a unique position to use its safe, consistent, repeatable and standardized business processes along with its presence in Ontario to enable adoption of geothermal systems as a safe and reliable low-carbon solution for future household heating requirements. The utility can provide this service through its ownership and maintenance of geothermal loops for the residential market.

70. To this end, the Company has been consulting and meeting with the MOECC, the MOE and the OGA to discuss Enbridge's role in facilitating the expansion of geothermal systems to more Ontario homes.

71. The Company will ensure uniform standards are applied to the safety, design, sizing and installation of geothermal systems to achieve a high level of quality assurance and consistent operating and economic performance. For the new construction market, Enbridge can utilize its strong relationship with the home builder community and apply similar business processes to the installation of ground source loops and

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[16] CCAP, at page 67 (http://www.applications.ene.gov.on.ca/ccap/products/CCAP_ENGLISH.pdf)
[17] The GreenON announcement can be found at the follow link: https://www.greenon.ca/programs/greenon-rebates-ground-source-heat-pumps.

heat pump systems as those used to install gas distribution piping and services today. It is anticipated that over time, significant cost reductions can be achieved for the heat pump systems through achievement of scale making geothermal systems more cost effective and less dependent on government support.

72. Enbridge can also bring brand name and recognition to the Ontario geothermal market. This can provide visibility and credibility to the technology as a viable option for home or building owner.

73. As described below, Enbridge is proposing a Geothermal Energy Service program where the utility owns and maintains geothermal loops at customers' homes. The customers will own the heat pump and other geothermal system equipment. This approach will make geothermal technology cost competitive compared to more traditional building heating and cooling alternatives (natural gas space and water heating combined with electric air conditioning) because customers will be able to receive financial support from the GreenON Fund for the ground source heat pump, and will pay for the use of the geothermal loops over time.

74. Enbridge sees geothermal systems as a key way to abate carbon. Deploying geothermal systems where natural gas would otherwise be consumed will offset natural gas usage. Over a 10 year geothermal customer additions forecast (discussed below), the Geothermal Energy Service program is expected to reduce over 2.4 mega tonnes of CO_2 over the asset life. This contributes towards the Company's plan and obligation to abate carbon emissions. As such, the Company's position is that all such geothermal loop assets and operating costs and revenues associated with this program that displace current or future natural gas consumption will be considered as part of the Company's regulated utility activities as abatement assets.

The Enbridge Geothermal Energy Service Program

75. Under Enbridge's Geothermal Energy Service program, the Company will install, own and maintain the geothermal loop component of new geothermal systems. Enbridge will charge the home or building owner a monthly service fee specific to the heating capacity of the ground source loop. The Program is initially targeted to single family homes (both new and retrofit). In the future, the Program may be expanded to multi-residential and commercial markets.

76. Enbridge will supply and install separate geothermal loops for each home or building owner who participates in the Geothermal Energy Service program. The owner will enter into a contract with Enbridge under which the Company will supply and install the geothermal loops, and the owner will provide Enbridge with necessary access to the property over the life of the geothermal loops. Enbridge will own, and maintain the geothermal loops over the term of the contract and the owner will pay a monthly service fee to Enbridge.

77. The home or building owner will arrange for the installation of the ground source heat pump and other equipment necessary to complete the geothermal energy system. Enbridge will provide support to the customer to ensure that the appropriate equipment is procured and installed. The relationship between Enbridge and the customer, where Enbridge owns, and maintains the pipes that supply the home with energy and the home or building owner owns and operates the parts of the geothermal energy system within the home is similar to the current gas distribution business (See Figure 2 above).

78. The required geothermal loop and heat pump size to provide sufficient heating and cooling functions is dependent on the size, amount of insulation and design of the

home. The geothermal systems are sized in tonnes of heating capacity. Typical homes in Ontario will require between 3 and 5 tonnes of heating capacity.

Calculation of Service Fees

79. To calculate the Geothermal Energy Service program service fees, Enbridge has built a DCF model using a 10 year customer forecast, estimates of capital, operating costs and taxes, applying the principles set out in EBO 188.

80. The Company's 10 year customer forecast is based on several factors including expected demand for geothermal systems (which will be driven in part by a GreenON Fund Geothermal Rebate program), current capacity in the market, and ramp-up capability of the market to meet future demand. The Company expects about 170 customers in Year 1 and over a period of 10 years a total of about 18,000 customers.

81. The estimated capital costs for the installation of the geothermal loops are based on unit costs for drilling and trenching based on market information and the Company's experience. The estimated capital costs also include construction management, commissioning and quality assurance with contingencies based on geographical and geological construction uncertainties.

82. The operating and maintenance expenses for the Geothermal Energy Service program includes periodic inspection and maintenance of the geothermal loops, customer care and billing cost, overhead and management costs and costs of other typical utility functions for an ongoing business operation. In addition, Enbridge's DCF model includes one-time system setup and development costs for the Geothermal Energy Service program. For all operating and maintenance expenses

and development costs, Enbridge has applied fully allocated costs in the DCF model.

83. Using the customer forecasts, capital costs and operating costs as described above and using Enbridge's 2018 capital structure and cost rates, Enbridge has calculated the monthly loop service fees that would be required to provide for the 10 year customer addition portfolio to achieve a PI of 1.1. The DCF model is set out at Appendix 11 and the revenue requirement calculation is provided in Appendix 12. Using this methodology the required monthly Geothermal Service Program fee(the "Loop Service Fee") will be $25.07 per tonne for 2018. Terms and conditions will be /u
set out in the customer service agreements supporting this Program.

84. Under the proposed Geothermal Energy Service program model there will be little or no impact to existing ratepayers, as the geothermal customers will pay cost based fees over the life of the geothermal loops, with the fees based on the fully allocated cost of providing the proposed Geothermal Energy Services program.

85. Given that this will be a new program and to protect existing ratepayers from any downside risk, Enbridge is proposing Geothermal Energy Service program service fees that would provide a PI greater than 1.0 as per the principles set out in EBO 188.

86. Appendix 12 shows that the geothermal program is expected to generate a net
revenue deficiency until 2021 and again from 2029 to 2038. From 2022 through /u
2028 and again from 2039 through 2057 (the end of the DCF analysis period), the /u
program returns a net revenue sufficiency. Overall, these cash flows return a PI of
1.1 or a net present value of $16.7 million over the DCF analysis period. /u

Additionally, there is a cumulative revenue sufficiency of $76.2 million over the DCF analysis period which represents an overall net benefit to ratepayers. /u

87. As detailed in the "Regulatory Treatment of RNG Enabling Service and Geothermal Energy Service Program" section of this evidence, Enbridge plans to record the annual revenue deficiency or sufficiency associated with the Geothermal Energy Services program in the GHG-Customer VA to be periodically cleared to ratepayers**.** Relevant amounts can be seen in Appendix 12 at Line 23.

Implementation

88. Enbridge expects that approximately 170 geothermal systems can be put in place under its Geothermal Energy Services program in 2018. Under Enbridge's 10 year customer additions forecast, the program is expected to reduce over 2.4 mega tonnes of CO_2 over the asset life and provides a net sufficiency of $76.2 million to the GHG-Customer VA. The analysis supports this longer term investment as a beneficial and cost-effective abatement program for Enbridge to undertake to manage its Cap and Trade obligations. /u

89. The Company expects that the December 13, 2017 GreenON announcement will prompt increased customer interest in geothermal installations. It is with that in mind that Enbridge is moving quickly so that the Geothermal Energy Services program can be launched as soon as possible. To this end, the Company has been working with the OGA to insure that adequate training, inspection and certification processes are in place to accommodate the increased demand for geothermal Systems that the launch of the rebate program is expected to bring about.

<u>Approvals Requested</u>

90. Based on the foregoing, Enbridge requests that the Board provide the following approvals in this proceeding.

a) Approval of Rate 400 and Rate 401 which will support the utility offering RNG Upgrading and RNG Injection Services respectively, using site specific service fees based on the methodology described in this evidence.

b) Approval of the 2018 Geothermal Energy Service program service fee.

c) Approval to record the annual revenue deficiency / sufficiency associated with the RNG Enabling Program and Geothermal Energy Service program in the GHG-Customer VA. The amounts recorded will be cleared through the annual process of settling the GHG-Customer VA.

Ministry of Energy, Science and Technology

Office of the Minister

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Ministère de l'Énergie, des Sciences et de la Technologie

Bureau du ministre

Édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Téléphone (416) 327-6715
Télécopieur (416) 327-6754

Ontario

DEC 15 1998

Mr. Floyd Laughren
Chair, Ontario Energy Board
2300 Yonge Street
Suite 2601
P.O. Box 2319
Toronto, Ontario
M4P 1E4

Dear Mr. Laughren:

The Government has approved undertakings of Union Gas and Enbridge Consumers Gas to eliminate overlap with the new legislation and to allow Ontario gas utilities to participate in business opportunities with a similar degree of flexibility as is available to electricity utilities. I enclose a copy of the Order in Council and the new undertakings.

Please accept my best wishes.

Sincerely,

Jim Wilson

Jim Wilson
Minister

Attachment

cc: Robert Reid, President and CEO of Union Gas
Rudi Reidl, President of Enbridge Consumers Gas

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil des ministres, décrète ce qui suit :

WHEREAS Westcoast Energy Inc., 1001142 Ontario Inc., Union Energy Inc., Union Gas Limited, and Union Shield Resources Ltd. provided Undertakings dated the 27th day of November, 1992 to the Lieutenant Governor in Council and these Undertakings were referred to in Order in Council No. 3639/92;

AND WHEREAS Enbridge Inc. (previously IPL Energy Inc.) and The Consumers' Gas Company Ltd. provided Undertakings dated the 21st day of June, 1994 to the Lieutenant Governor in Council and these Undertakings were referred to in Order in Council No. 1606/94;

AND WHEREAS, with the receipt of Royal Assent for the *Energy Competition Act, 1998* on the 30th day of October, 1998, it is considered expedient to approve new Undertakings provided by Union Gas Limited, Centra Gas Utilities Inc., Centra Gas Holdings Inc., Westcoast Gas Inc., Westcoast Gas Holdings Inc. and Westcoast Energy Inc. and by The Consumers' Gas Company Ltd., Enbridge Consumers Energy Inc., 311594 Alberta Ltd., Enbridge Pipelines (NW) Inc. and Enbridge Inc.(the "New Undertakings");

NOW THEREFORE the New Undertakings, attached hereto, are accepted and approved.

Recommended Jim Wilson
Minister of Energy, Science & Technology

Concurred R. W. Runciman
Chair of Cabinet

Approved & Ordered DEC 9 - 1998
Date

Hilary M. Weston
Lieutenant Governor

O.C./Décret 2865/98

UNDERTAKINGS OF THE CONSUMERS' GAS COMPANY LTD., ENBRIDGE CONSUMERS ENERGY INC., 311594 ALBERTA LTD., ENBRIDGE PIPELINES (NW) INC. AND ENBRIDGE INC.

TO: Her Honour The Lieutenant Governor in Council for the Province of Ontario

WHEREAS Enbridge Consumers Energy Inc. holds all of the issued and outstanding common shares of The Consumers' Gas Company Ltd. ("Consumers");

AND WHEREAS 311594 Alberta Ltd. holds all of the issued and outstanding common shares of Enbridge Consumers Energy Inc.;

AND WHEREAS Enbridge Pipelines (NW) Inc. holds all of the issued and outstanding common shares of 311594 Alberta Ltd.;

AND WHEREAS Enbridge Inc. ("Enbridge") holds all of the issued and outstanding common shares of Enbridge Pipelines (NW) Inc.;

the above named corporations do hereby agree to the following undertakings:

1.0 Definitions

In these undertakings,

1.1 "Act" means the *Ontario Energy Board Act, 1998*;

1.2 "**affiliate**" has the same meaning as it does in the *Business Corporations Act*;

1.3 "**Board**" means the Ontario Energy Board;

1.4 "**business activity**" has the same meaning as it does under the Act or a regulation made under the Act; and

1.5 "**electronic hearing**", "**oral hearing**" and "**written hearing**" have the same meaning as they do under the *Statutory Powers Procedure Act*.

2.0 Restriction on Business Activities

2.1 Consumers shall not, except through an affiliate or affiliates, carry on any business activity other than the transmission, distribution or storage of gas, without the prior approval of the Board.

3.0 Maintenance of common equity

3.1 Where the level of equity in Consumers falls below the level which the Board has determined to be appropriate in a proceeding under the Act or a predecessor Act, Consumers shall raise or Enbridge and its affiliates shall provide within 90 days, or such longer period as the Board may specify, sufficient additional equity capital to restore the level of equity in Consumers to the appropriate level.

3.2 Any additional equity capital provided to Consumers by Enbridge or its affiliates shall be provided on terms no less favourable to Consumers than Consumers could obtain directly in the capital markets.

4.0 Head Office

4.1 The head office of Consumers shall remain within the franchise area of Consumers.

5.0 Prior Undertakings

5.1 Subject to Article 5.2, these undertakings supersede, replace and are in substitution for all prior undertakings of Consumers, Enbridge and their affiliates.

5.2 The undertakings of British Gas PLC and Consumers dated June 16th, 1994 and approved by the Lieutenant Governor in Council on June 23rd, 1994, remain in full force and effect.

6.0 Dispensation

6.1 The Board may dispense, in whole or in part, with future compliance by any of the signatories hereto with any obligation contained in an undertaking.

7.0 Hearing

7.1 In determining whether to grant an approval under these undertakings or a dispensation under Article 6.1, the Board may proceed without a hearing or by way of an oral, written or electronic hearing.

8.0 Monitoring

8.1 At the request of the Board, Consumers, Enbridge and their affiliates will provide to the Board any information the Board may require related to compliance with these undertakings.

9.0 Enforcement

9.1 The parties hereto acknowledge that there has been consideration exchanged for the receipt and giving of the undertakings and agree to be bound by these undertakings.

9.2 Any proceeding or proceedings to enforce these undertakings may be brought and enforced in the courts of the Province of Ontario and Enbridge, Consumers and their affiliates hereby submit to the jurisdiction of the courts of the Province of Ontario in respect of any such proceeding.

9.3 For the purpose of service of any document commencing a proceeding in accordance with Article 9.2, it is agreed that Consumers is the agent of Enbridge and its affiliates and that personal service of documents on Consumers will be sufficient to constitute personal service on Enbridge and its affiliates.

10.0 Release from undertakings

10.1 Enbridge, Consumers and their affiliates are released from these undertakings on the day that Enbridge no longer holds, either directly or through its affiliates, more than 50 per cent of the voting securities of Consumers or on the day that Consumers sells its gas transmission and gas distribution systems.

11.0 Effective Date

11.1 These undertakings become effective on March 31, 1999.

DATED this 7th day of December, 1998.

THE CONSUMERS' GAS COMPANY LIMITED

by ____________________

____

ENBRIDGE CONSUMERS ENERGY INC.

by ____________________

____

311594 ALBERTA LTD.

by ____________________

____

ENBRIDGE PIPELINES (NW) INC.

by ____________________

____

ENBRIDGE INC.

by ____________________

____

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil des ministres, décrète ce qui suit:

WHEREAS Enbridge Gas Distribution Inc. and related parties ("Enbridge") gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Enbridge Undertakings"), and Union Gas Limited and related parties ("Union") gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Union Undertakings");

AND WHEREAS the Minister of Energy and Infrastructure has the authority under section 27.1 of the *Ontario Energy Board Act, 1998* to issue directives, approved by the Lieutenant Governor in Council, that require the Ontario Energy Board to take steps specified in the directives to promote energy conservation, energy efficiency, load management and the use of cleaner energy sources including alternative and renewable energy sources;

AND WHEREAS The Government of Ontario has, with the passage of the *Green Energy and Green Economy Act, 2009,* embarked upon a historic series of initiatives related to promoting the use of renewable energy sources and enhancing conservation throughout Ontario;

AND WHEREAS certain amendments to the *Ontario Energy Board Act, 1998* provided for by the above-noted statute authorize electricity distribution companies to directly own and operate renewable energy electricity generation facilities with a capacity of ten (10) megawatts or less, facilities that generate heat and electricity from a single source, or facilities that store energy, subject to criteria to be prescribed by regulation;

AND WHEREAS it is desirable that both Enbridge and Union are accorded authority similar to those of electricity distributors to own and operate the kinds of generation and storage facilities referenced above, while clarifying that the latter two activities, namely the ownership and operation of facilities that generate heat and electricity from a single source, or facilities that store energy, are to be interpreted to include stationary fuel-cell facilities each of which does not exceed 10 Megawatts in capacity, as well as to allow Enbridge and Union the authority to own and operate assets required in respect of the provision of services by Enbridge and Union that would assist the Government of Ontario in achieving its goals in energy conservation including where such assets relate to solar-thermal water and ground-source heat pumps;

AND WHEREAS the Minister of Energy has previously issued a directive pursuant to section 27.1 in respect of the Enbridge Undertakings and the Union Undertakings, under Order-in-Council No. 1537/2006, dated August 10, 2006.

NOW THEREFORE the directive attached hereto is approved and is effective as of the date hereof.

Recommended: ______________________
Minister of Energy and Infrastructure

Concurred: ______________________
Chair of Cabinet

Approved and Ordered: SEP 0 8 2009
Date

____
Lieutenant Governor

O.C./Décret 1540/2009

MINISTER'S DIRECTIVE

Re: Gas Utility Undertakings Relating to the Ownership and Operation of Renewable Energy Electricity Generation Facilities, Facilities Which Generate Both Heat and Electricity From a Single Source and Energy Storage Facilities and the Ownership and Operation of Assets Required to Provide Conservation Services.

Enbridge Gas Distribution Inc. and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Enbridge Undertakings"); and Union Gas Limited and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Union Undertakings").

The Government of Ontario has, with the passage of the *Green Energy and Green Economy Act, 2009,* embarked upon a historic series of initiatives related to promoting the use of renewable energy sources and enhancing conservation throughout Ontario.

One of those initiatives is to allow electric distribution companies to directly own and operate renewable energy electricity generation facilities of a capacity of not more than 10 megawatts or such other capacity as is prescribed by regulation, facilities which generate both heat and electricity from a single source and facilities for the storage of energy, subject to such further criteria as may be prescribed by regulation.

The Government also wants to encourage initiatives that will reduce the use of natural gas and electricity.

Pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, and in addition to a previous directive issued thereunder on August 10, 2006 by Order in Council No. 1537/2006, in respect of the Enbridge Undertakings and the Union Undertakings, I hereby direct the Ontario Energy Board to dispense,

- under section 6.1 of the Enbridge Undertakings, with future compliance by Enbridge Gas Distribution Inc. with section 2.1 ("Restriction on Business Activities") of the Enbridge Undertakings, and

- under section 6.1 of the Union Undertakings, with future compliance by Union Gas Limited with section 2.1 ("Restriction on Business Activities") of the Union Undertakings,

in respect of the ownership and operation by Enbridge Gas Distribution, Inc. and Union Gas Limited, of:

(a) renewable energy electricity generation facilities each of which does not exceed 10 megawatts or such other capacity as may be prescribed, from time to time, by regulation made under clause 71(3)(a) of the *Ontario Energy Board Act, 1998* and which meet the criteria prescribed by such regulation;

(b) generation facilities that use technology that produces power and thermal energy from a single source which meet the criteria prescribed, from time to time, by regulation made under clause 71(3)(b) of the *Ontario Energy Board Act, 1998*;

(c) energy storage facilities which meet the criteria prescribed, from time to time, by regulation made under clause 71(3)(c) of the *Ontario Energy Board Act, 1998*; or

(d) assets required in respect of the provision of services by Enbridge Gas Distribution Inc. and Union Gas Limited that would assist the Government of Ontario in achieving its goals in energy conservation and includes assets related to solar-thermal water and ground-source heat pumps;

(e) for greater certainty, the use of the word "facilities" in paragraphs (b) and (c) above shall be interpreted to include stationary fuel-cell facilities each of which does not exceed 10 Megawatts in capacity.

This directive is not in any way intended to direct the manner in which the Ontario Energy Board determines, under the *Ontario Energy Board Act, 1998,* rates for the sale, transmission, distribution and storage of natural gas by Enbridge Gas Distribution Inc. and Union Gas Limited.

George Smitherman

George Smitherman
Deputy Premier, Minister of Energy and Infrastructure

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le con- sentement du Conseil des ministres, décrète ce qui suit:

WHEREAS Enbridge Distribution Inc. and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999; and Union Gas Limited and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998, and that took effect on March 31, 1999;

AND WHEREAS opportunities exist for Enbridge Distribution Inc. and Union Gas Limited to carry on business activities that could assist the Government of Ontario in achieving its goals in energy conservation;

AND WHEREAS the Minister of Energy may issue, and the Ontario Energy Board shall implement, directives that have been approved by the Lieutenant Governor in Council that require the Board to take steps specified in the directives to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources;

NOW THEREFORE the attached Directive is approved.

Recommended: ______________________
Minister of Energy

Concurred: ______________________
Chair of Cabinet

Approved and Ordered: AUG 10 2006
Date

____
Administrator of the Government

O.C./Décret 1537/2006

Minister of Energy

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900 Bay Street
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Ontario

MINISTER'S DIRECTIVE

Re: Gas Utility Undertakings

Enbridge Gas Distribution Inc. and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Enbridge Undertakings"); and Union Gas Limited and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Union Undertakings").

Pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, I hereby direct the Ontario Energy Board to dispense,

- under section 6.1 of the Enbridge Undertakings, with future compliance by Enbridge Gas Distribution Inc. with section 2.1 ("Restriction on Business Activities") of the Enbridge Undertakings, and

- under section 6.1 of the Union Undertakings, with future compliance by Union Gas Limited with section 2.1 ("Restriction on Business Activities") of the Union Undertakings,

in respect of the provision of services by Enbridge Gas Distribution Inc. and Union Gas Limited that would assist the Government of Ontario in achieving its goals in energy conservation, including services related to:

(a) the promotion of electricity conservation, natural gas conservation and the efficient use of electricity;

(b) electricity load management; and

(c) the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources.

.../cont'd

In addition, pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, I hereby direct the Board to dispense, under section 6.1 of the Enbridge Undertakings, with future compliance with section 2.1 of the Enbridge Undertakings in respect of research, review, preliminary investigation, project development and the provision of services related to the following business activities:

(a) the local distribution of steam, hot and cold water in a Markham District Energy initiative; and

(b) the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

Further, pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, I hereby direct the Board to dispense, under section 6.1 of the Union Undertakings, with future compliance with section 2.1 of the Union Undertakings in respect of research, review, preliminary investigation, project development and the provision of services related to the following business activities:

(a) the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

To the extent that any activities undertaken by Enbridge Gas Distribution Limited or Union Gas Limited in reliance on this Directive are forecast to impact upon their regulated rates, such activities are subject to the review of the Ontario Energy Board under the *Ontario Energy Board Act, 1998*.

In this directive, "alternative energy source" and "renewable energy source" have the same meanings as in the *Electricity Act, 1998*.

Dwight Duncan
Minister

Fuels Technical Report

Prepared for:

The Ministry of Energy

September 2016

Submitted by:
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333 Bay Street
Suite 1250
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DISCLAIMER

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.

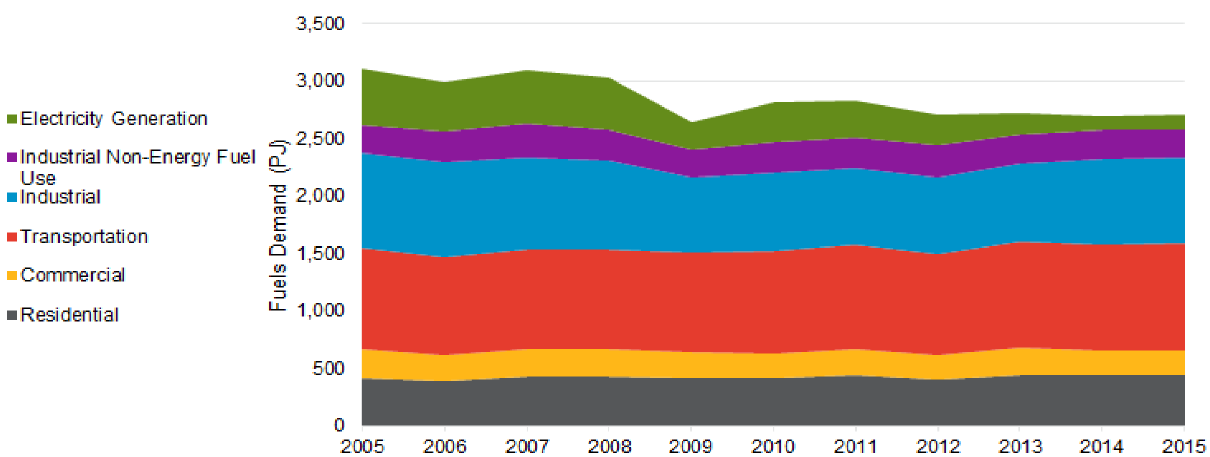
Notes to this Report

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.

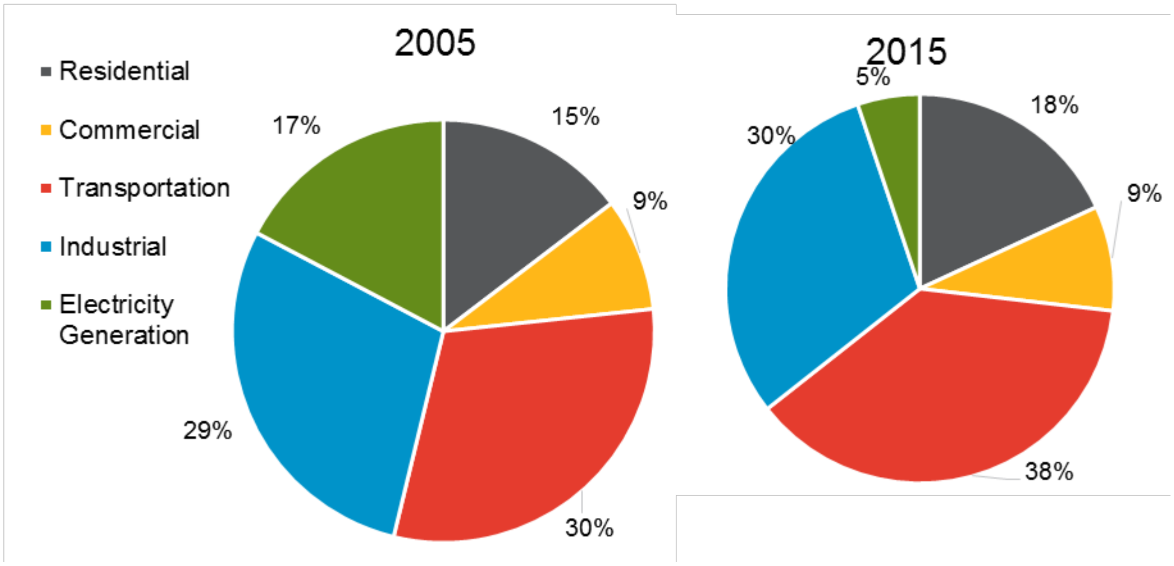
Figure 1: Total Ontario Fuels Energy Demand[1]



Source: CanESS, 2016

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

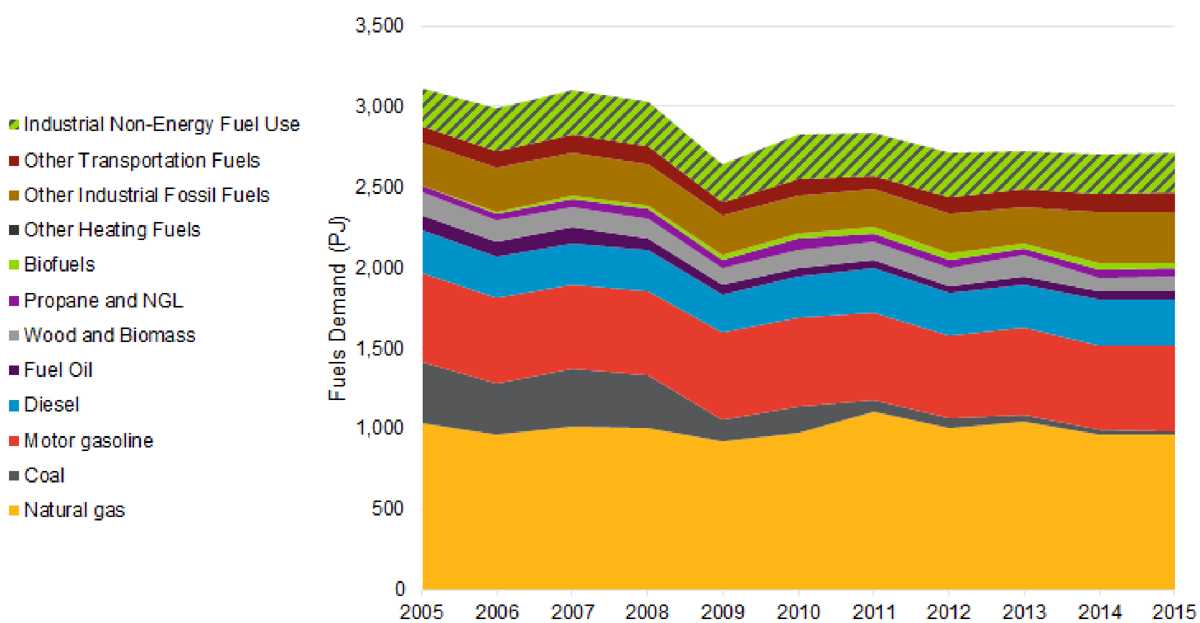
Figure 2: Fuels Energy Demand by Sector 2005 and 2015



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.

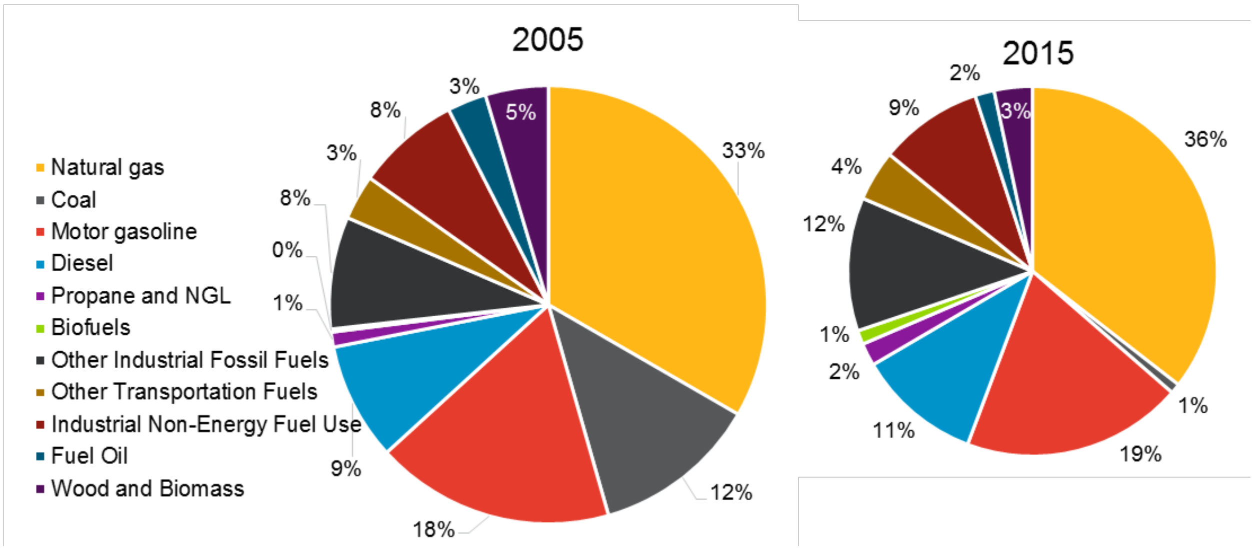
Figure 3: Fuels Energy Demand by Fuel Type



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

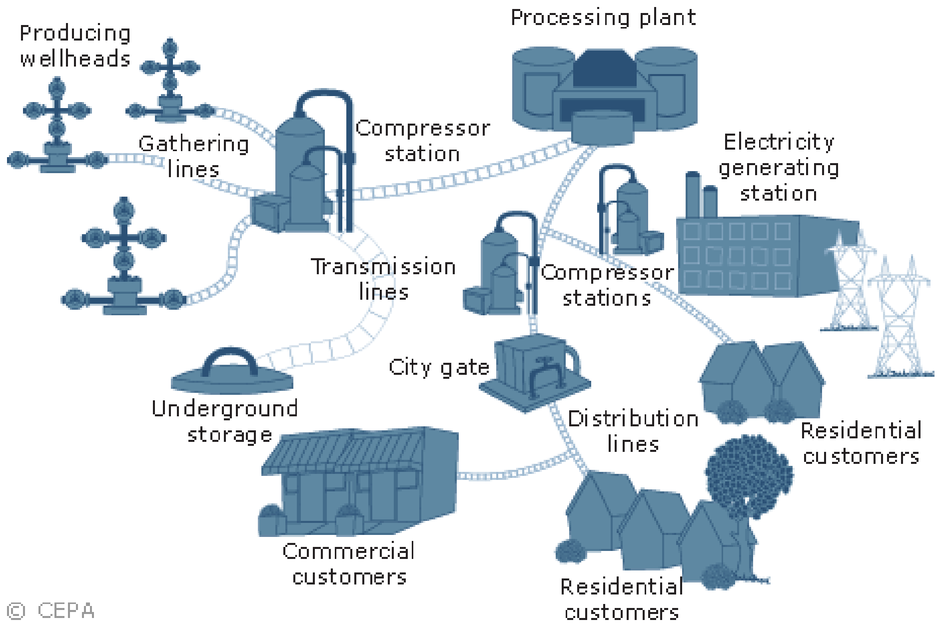
1.2 Natural Gas

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

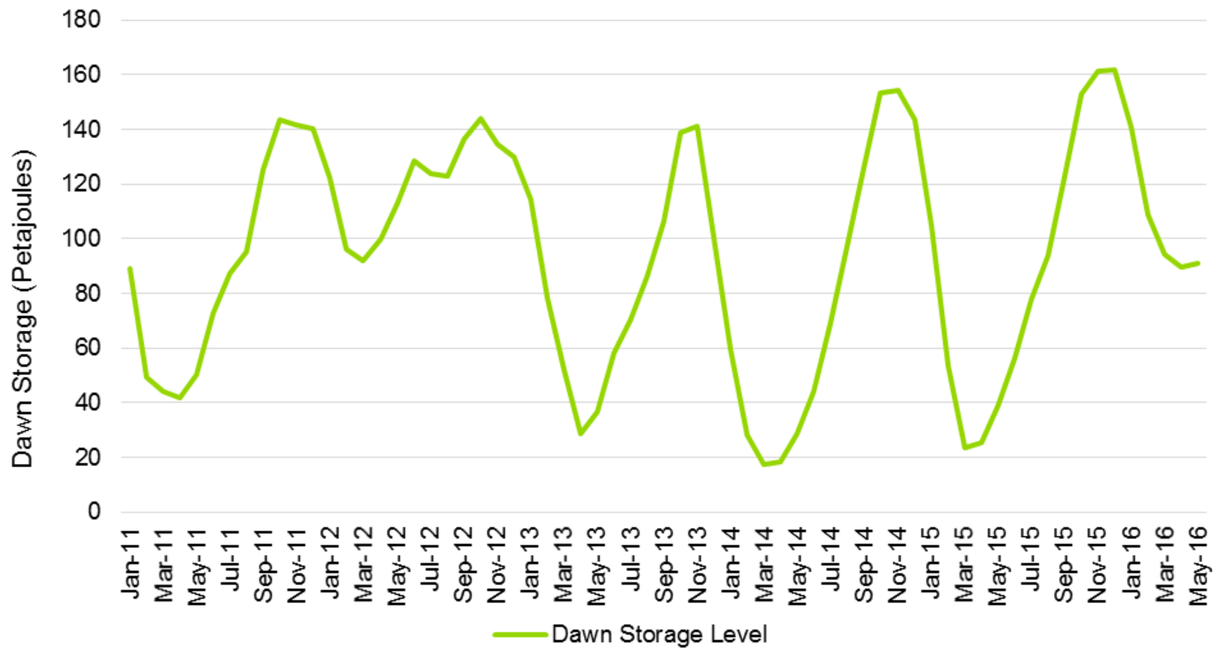


Source: Canadian Energy Pipeline Association (CEPA), 2016.[2]

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

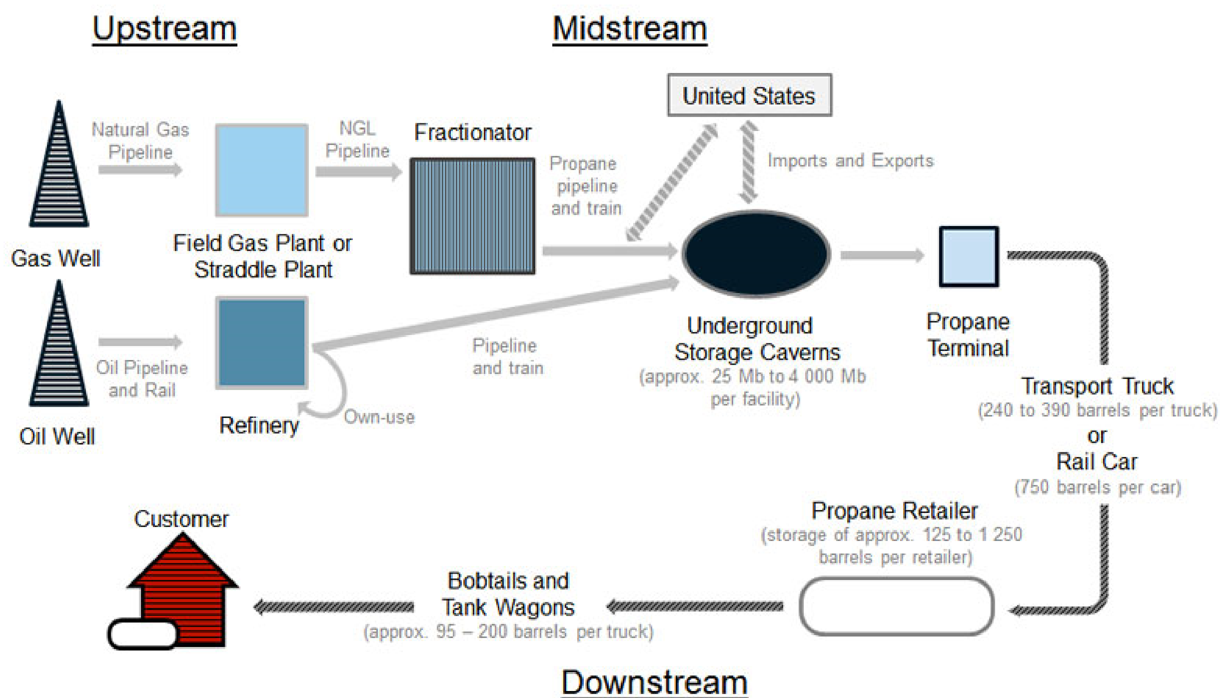
Propane is a natural gas liquid (NGL) that is extracted at natural gas processing facilities. Propane is also a by-product of the petroleum refining process.

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

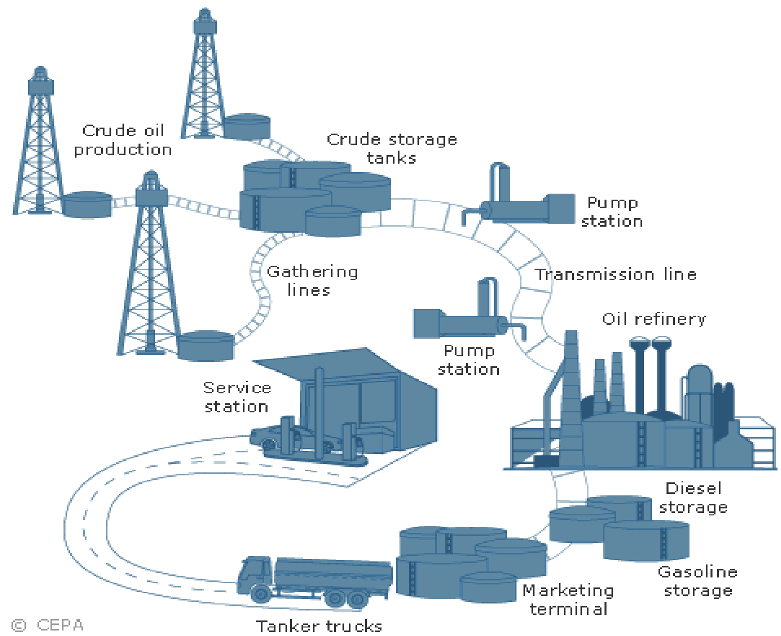
Oil products are produced at petroleum refineries. Petroleum refineries are industrial facilities that process crude oil into finished fuels like gasoline, diesel, jet fuel and fuel oil; and non-energy products like petrochemical feedstocks and asphalt. Crude oil is a fossil fuel, and it exists as a 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

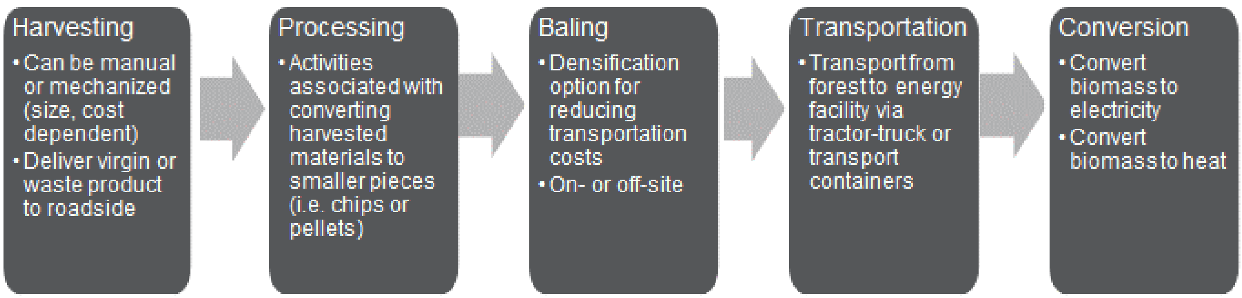
Biomass and wood are renewable resources (e.g., forest or agricultural materials) that are used in a variety of fuel applications.

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.

[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.).

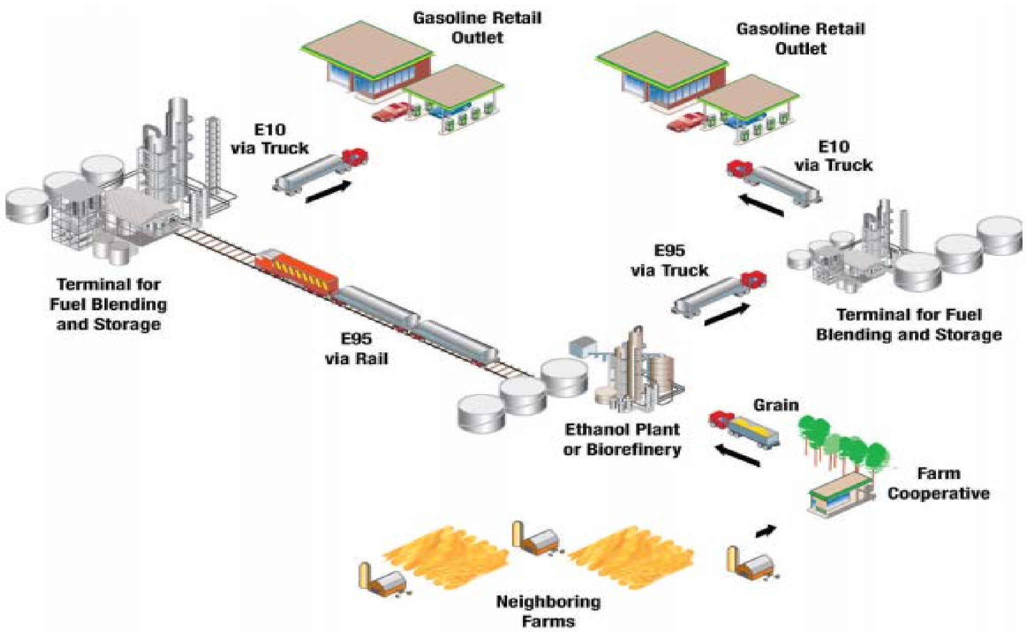
Ontario has six manufacturing facilities in the province. All of the Ontario facilities use corn as the feedstock to produce ethanol. Corn is delivered to ethanol facilities by truck; corn used at Ontario ethanol facilities is mostly domestically produced although there are some imports. Ontario also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

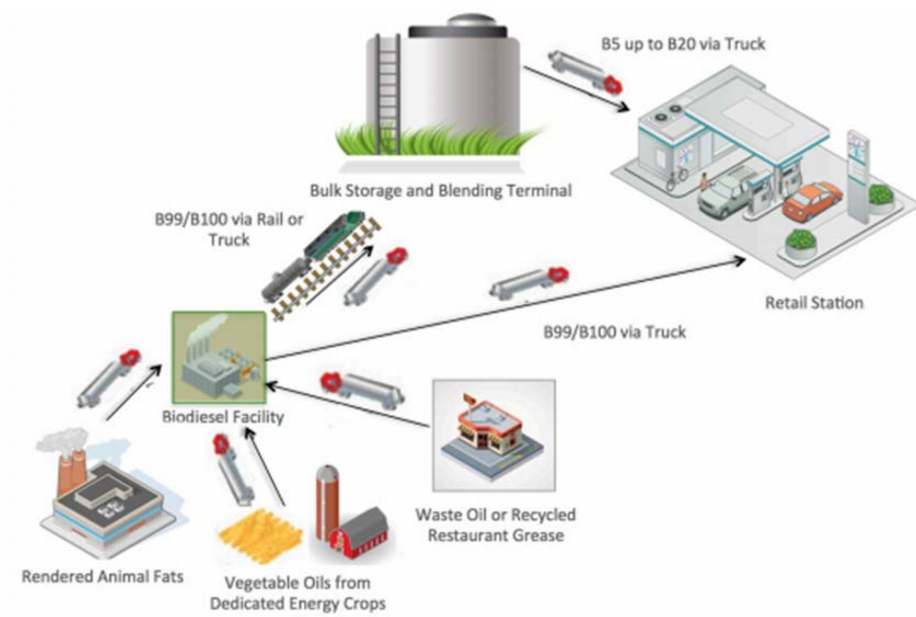
Biodiesel distribution within Ontario is primarily by truck and rail. As with ethanol, biodiesel is blended with diesel at petroleum distribution terminals (**Note:** One biodiesel producer in Ontario is located adjacent to a petroleum distribution terminal and connects to that terminal by pipeline).

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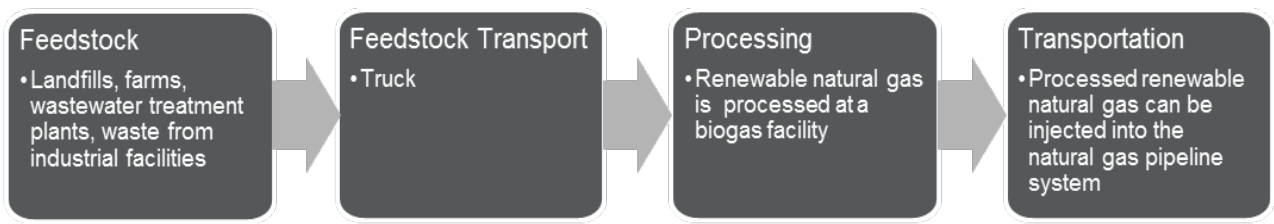
In 2013, there were 37 operating biogas facilities in Ontario. However, production volumes from these facilities were quite small, relative to the size of the province's natural gas system. RNG production requires connections to the province's natural gas system as well as equipment to process the RNG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

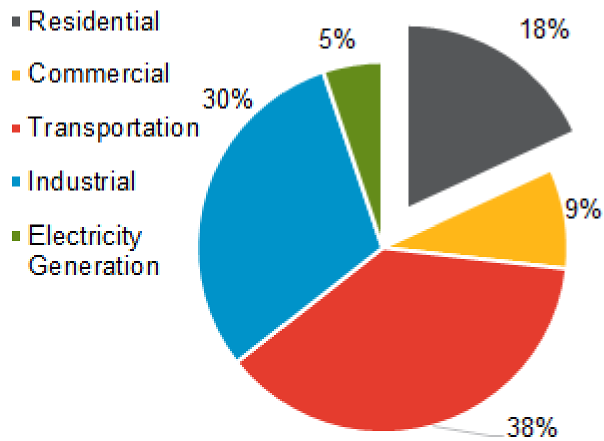
This section of Chapter 1 provides additional detail regarding the fuels energy by four sectors: residential, commercial, industrial, and transportation. Readers interested in the electricity generation sector may refer to the Independent System Operator (IESO) Ontario Planning Outlook (OPO) report.[7]

[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.

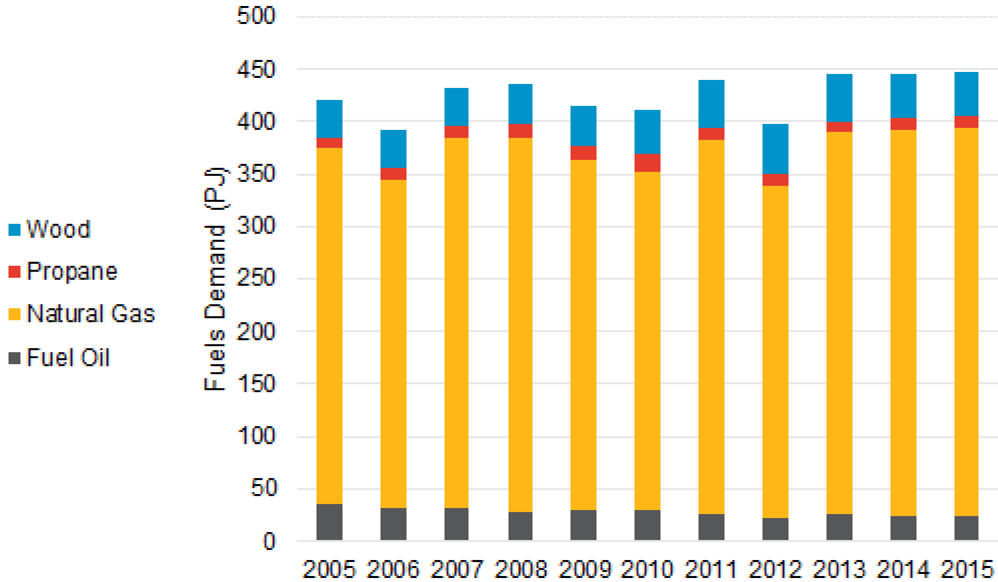
[8] In 2013, the combined fuels energy use for residential space-heating was approximately 320 PJ. The total fuel use by the residential sector in the same year was approximately 428 PJ.

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

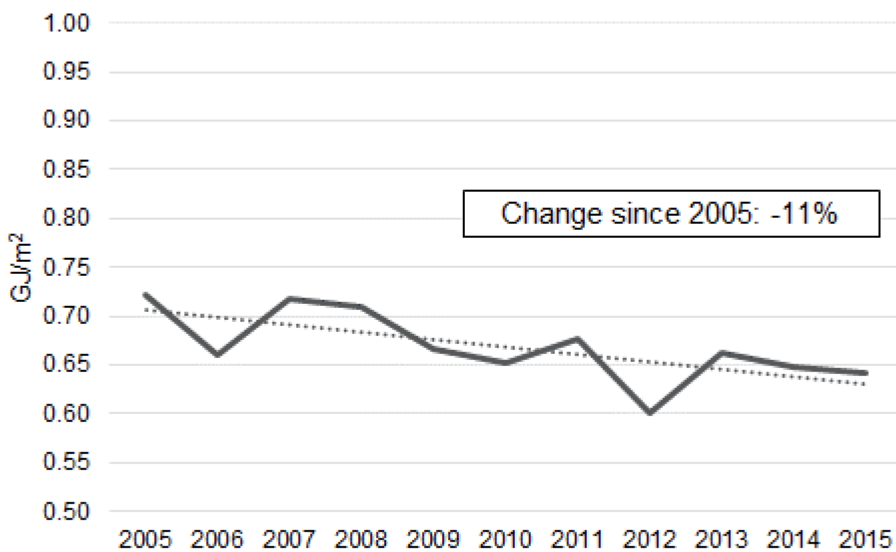
Figure 14: Residential Demand by Fuel Type: 2005-2015



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

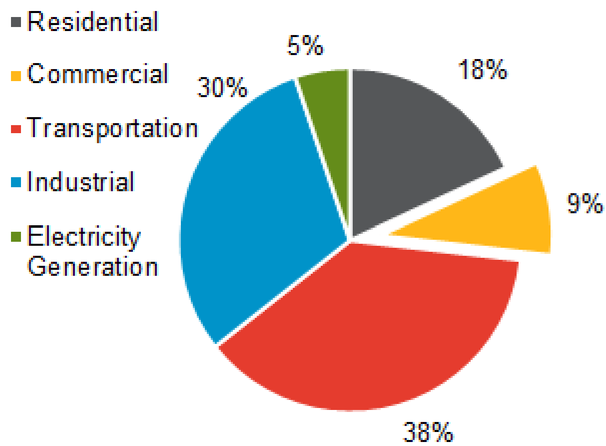


Source: CanESS, 2016

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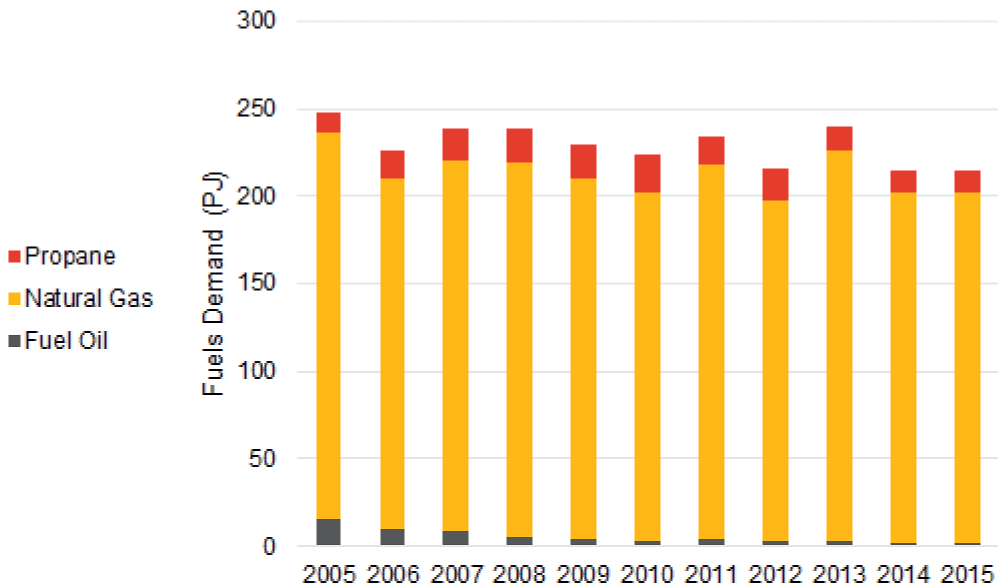
[9] In 2013, the combined fuels energy use for commercial space-heating was approximately 202 PJ. The total fuel use by the commercial sector in the same year was approximately 235 PJ.

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

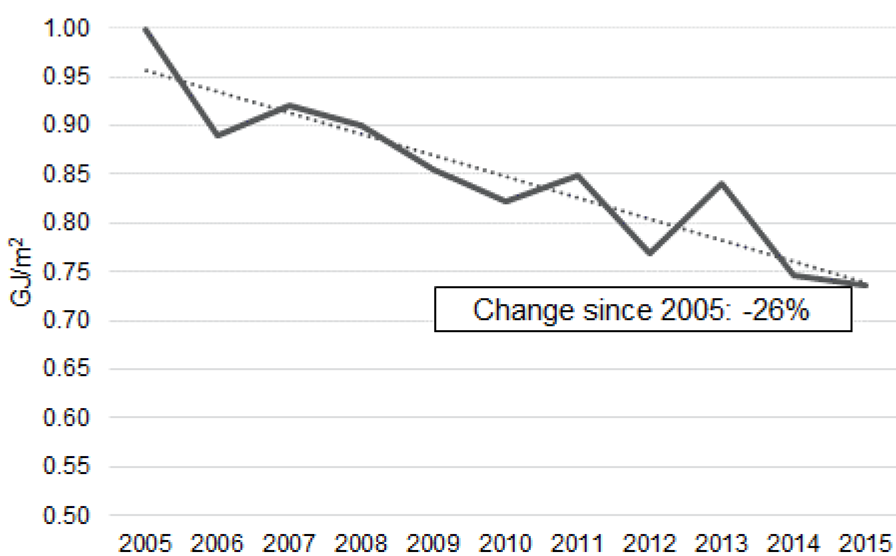
Figure 17: Commercial Demand by Fuel Type: 2005-2015



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

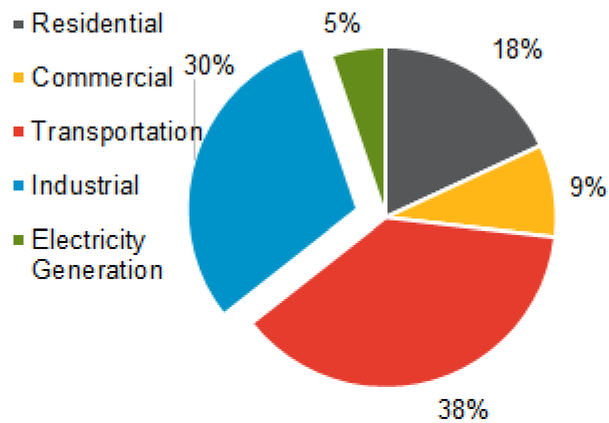


Source: CanESS, 2016

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

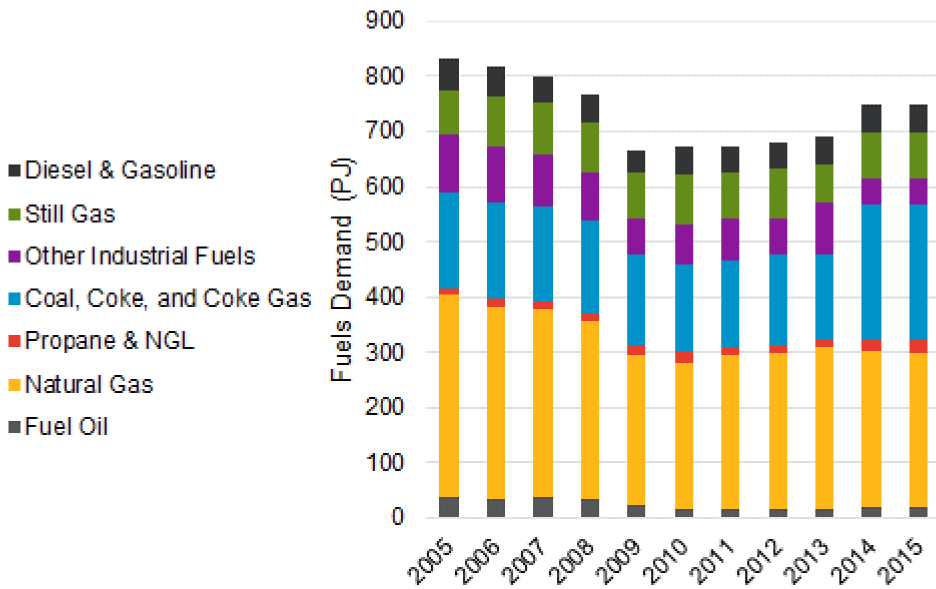


Source: CanESS, 2016

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.

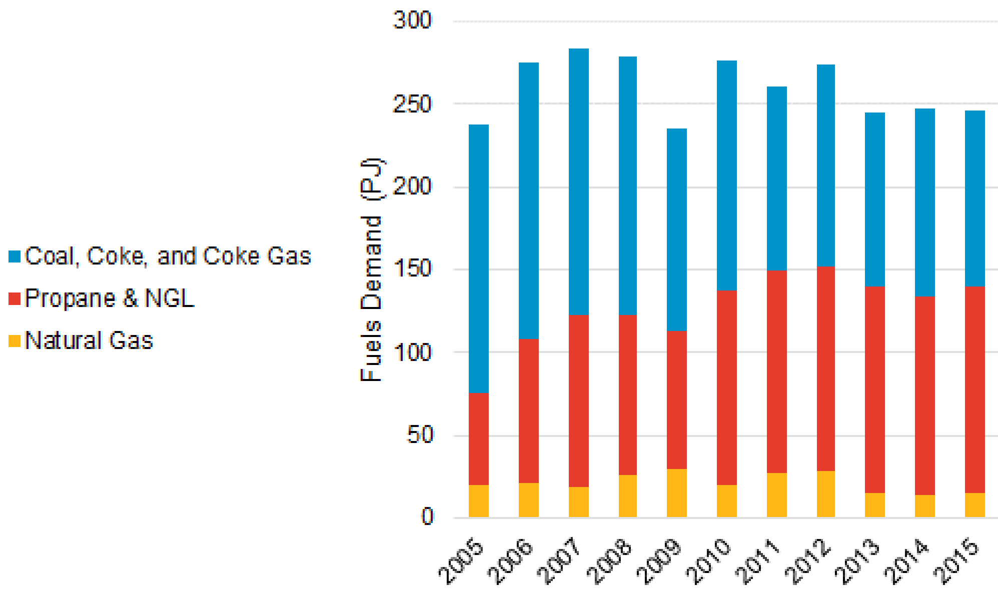
Figure 20: Industrial Energy Demand by Fuel Type: 2005-2015



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.

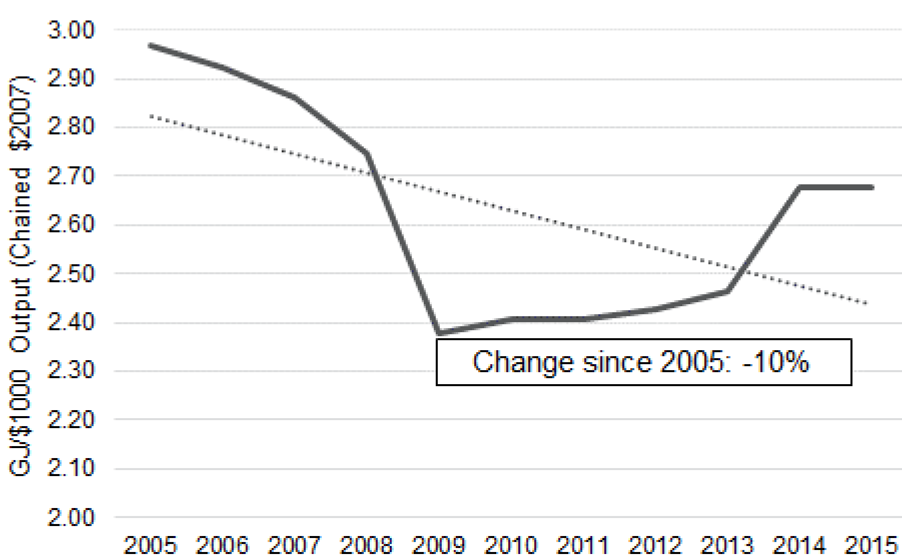
Figure 21: Non-Energy Industrial Demand by Type: 2005-2015



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

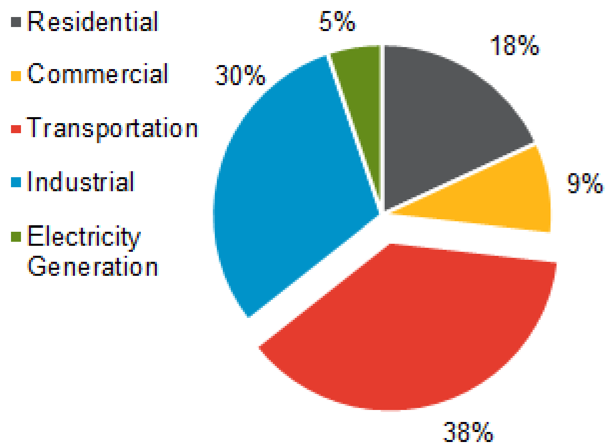


Source: CanESS, 2016

1.7.4 Transportation

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

Figure 23: Transportation Energy Fuel Demand - 2015

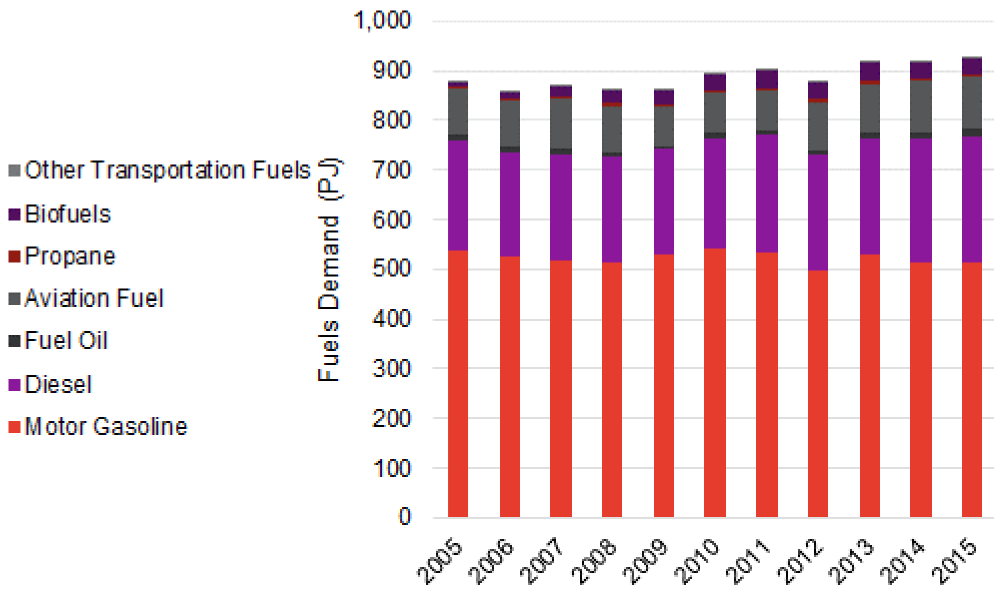


Source: CanESS, 2016

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.

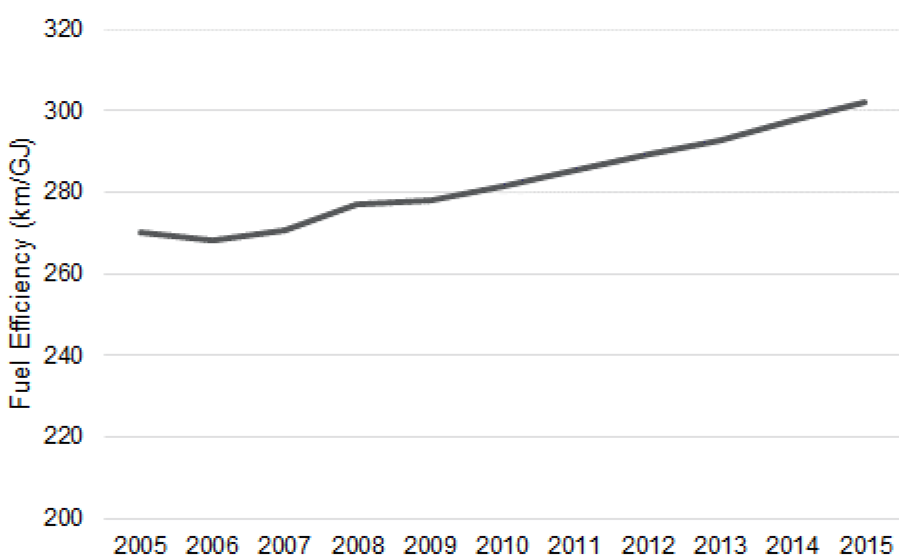
Figure 24: Transportation Demand by Fuel Type: 2005-2015



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

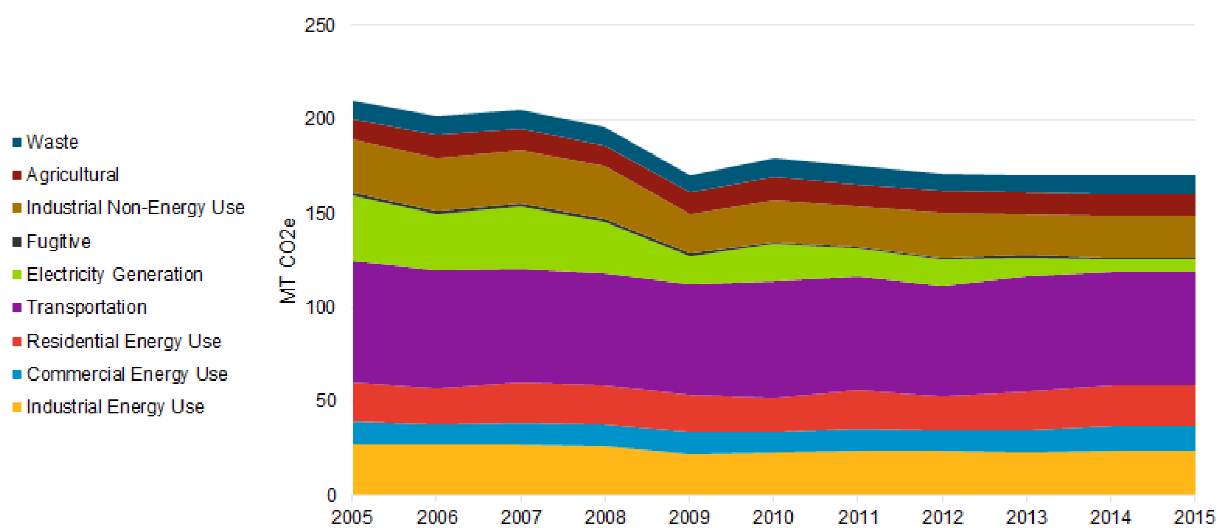
1.8 Historical GHG Emissions

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

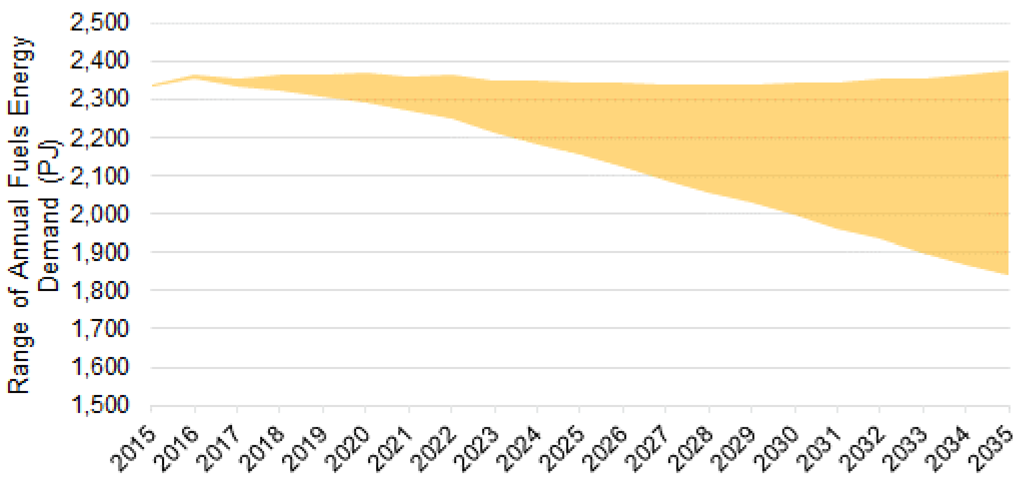
2.1 Demand Outlook

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.

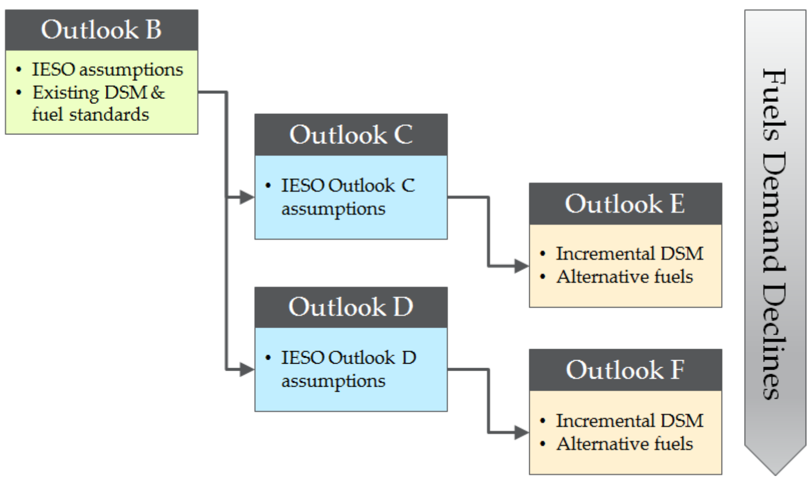
[11] This range includes only fuels used to provide energy. Non-energy fuel use by the industrial sector is not considered in the outlooks.

- 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.

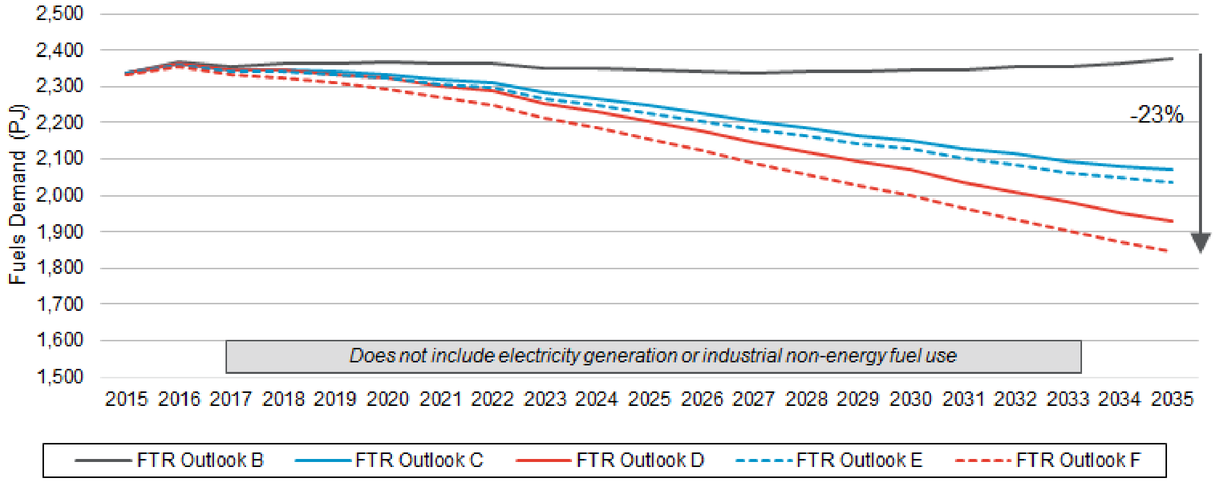
The incremental relationships between these outlooks, and their relative position in the range of fuels energy demand highlighted in Figure 27, above, is illustrated in Figure 28, below.

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

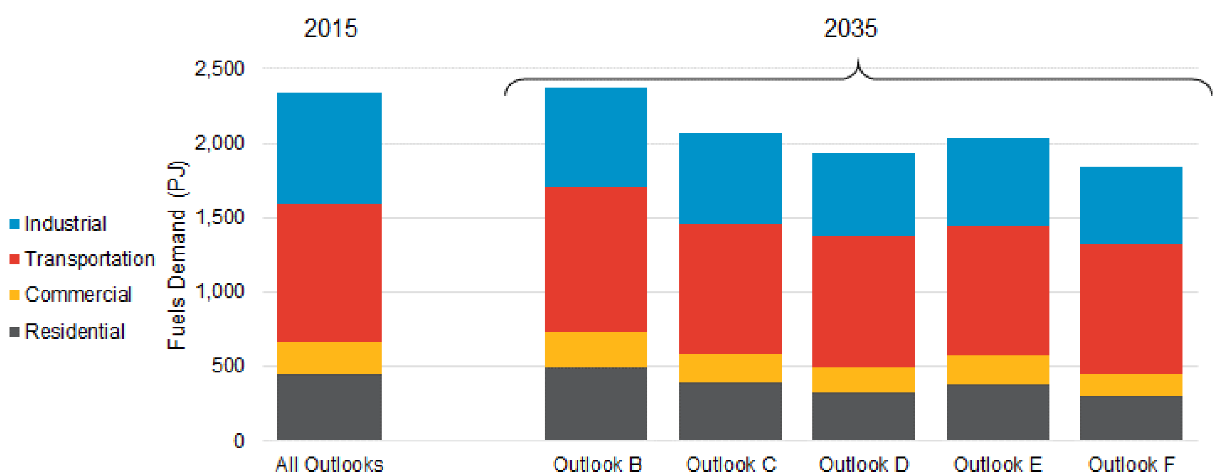


Source: CanESS & Navigant Analysis, 2016

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.

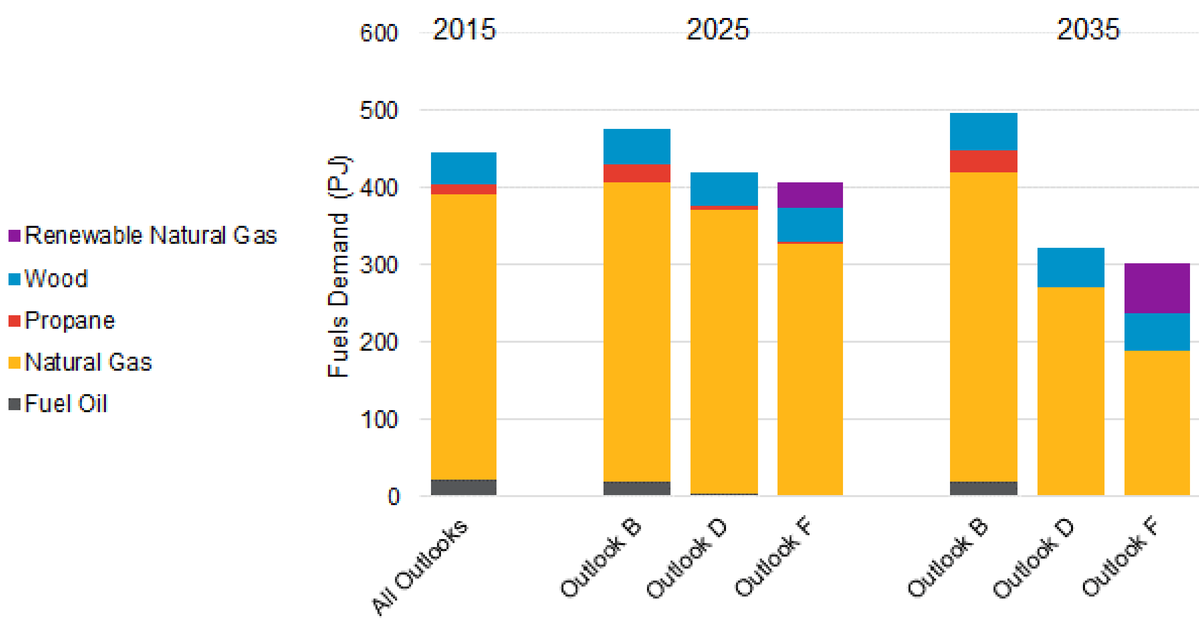
The purpose of this sectoral breakdown is to contrast IESO outlooks (C and D) with those that assume incremental natural gas DSM and additional use of alternative fuels (E and F). Since C and D (and E and F) differ from each other only in degree, only the most extreme outlooks from the two groups (i.e.,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

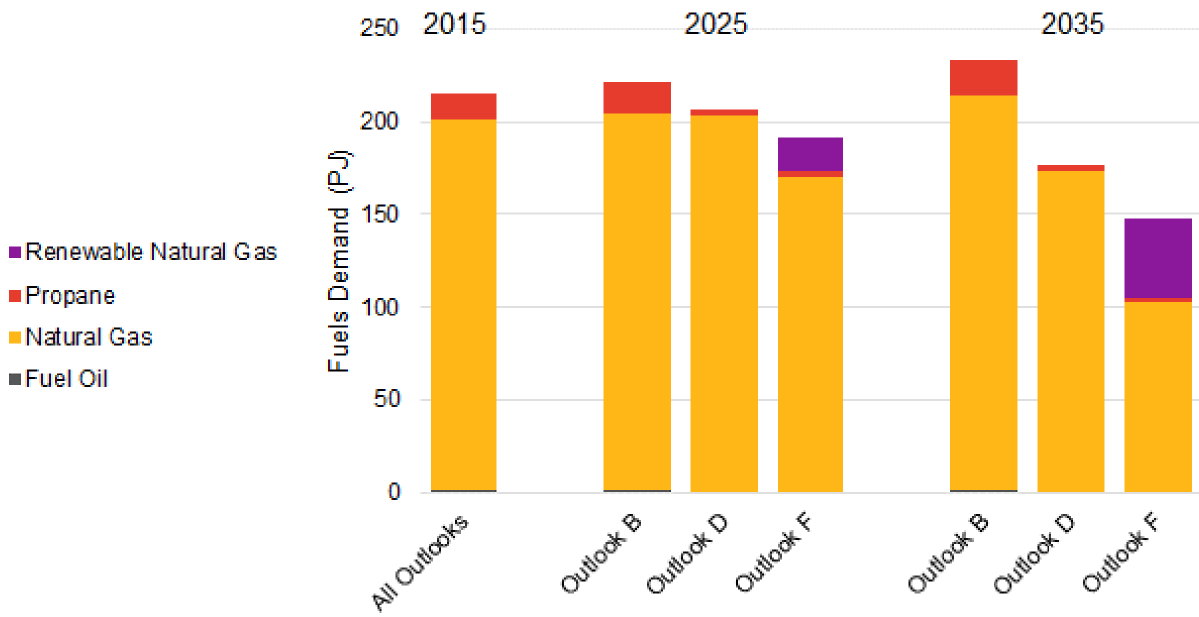


2.1.2 Commercial

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

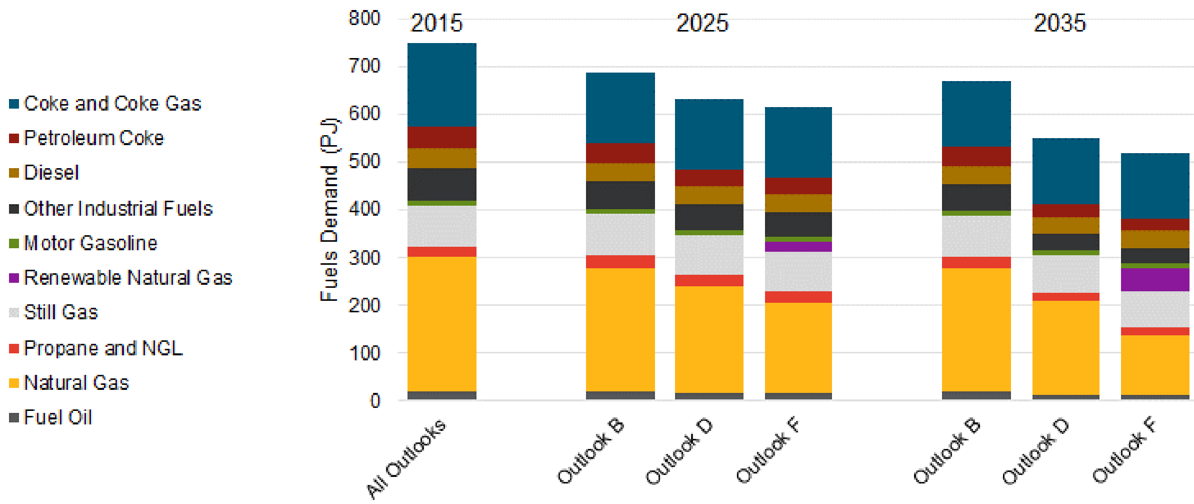
2.1.3 Industrial

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

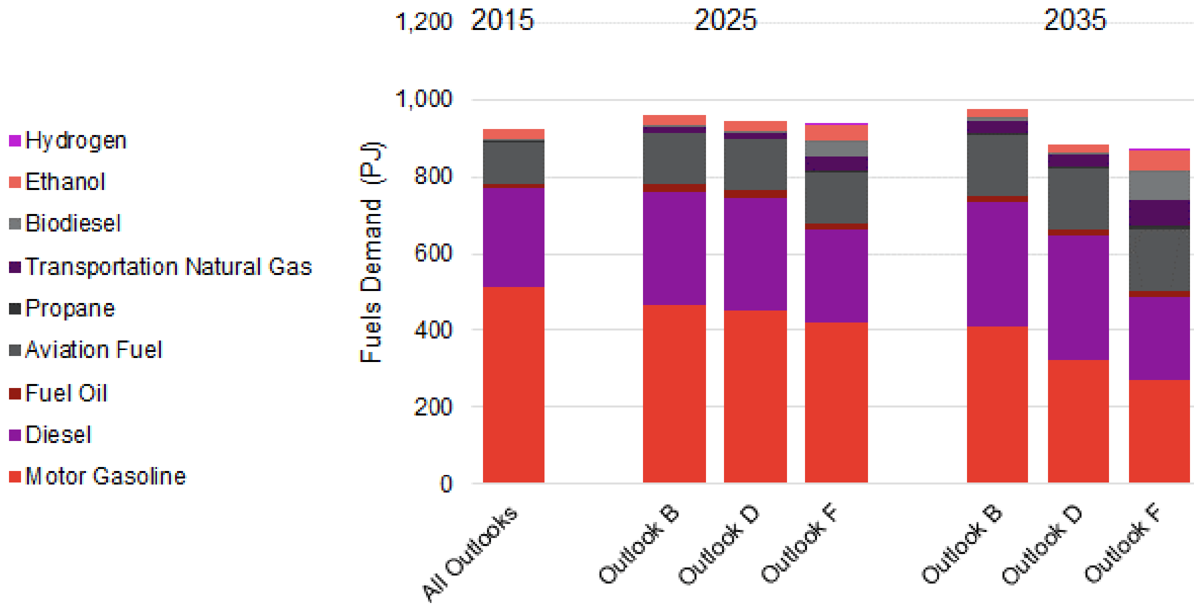
Outlook D results in a moderate reduction in transportation fuels demand (relative to Outlook B) as a result of IESO assumptions regarding the adoption of EVs. Total transportation fuel demand in 2035 is 9.5% lower in Outlook D than it is in Outlook B. As in the case of the industrial sector, this reduction, 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:

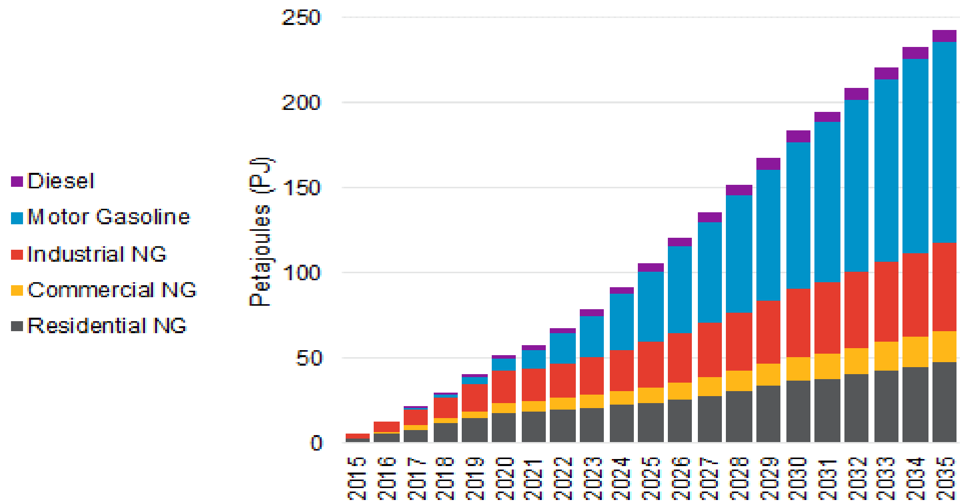
- The Corporate Average Fuel Economy (CAFE) standard. This applies to cars and light trucks.
- The Fuel Efficiency and GHG Emission Program for Medium- and Heavy-Duty Trucks. This applies to medium and heavy-duty trucks.

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

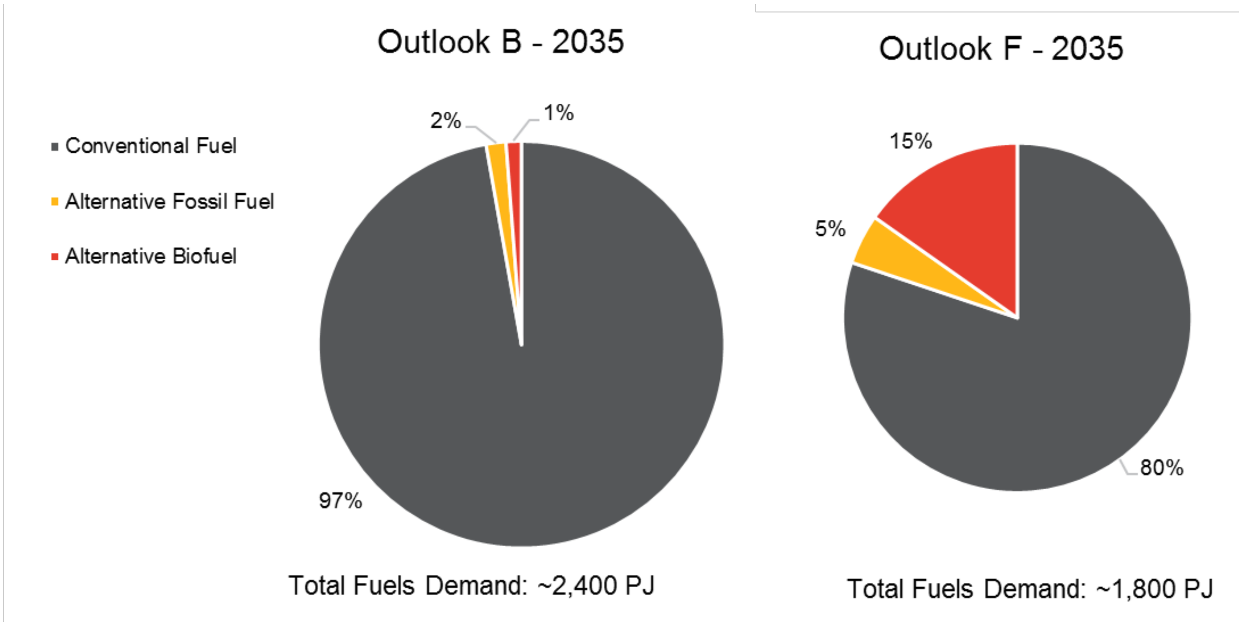
2.3 Supply Outlook

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.

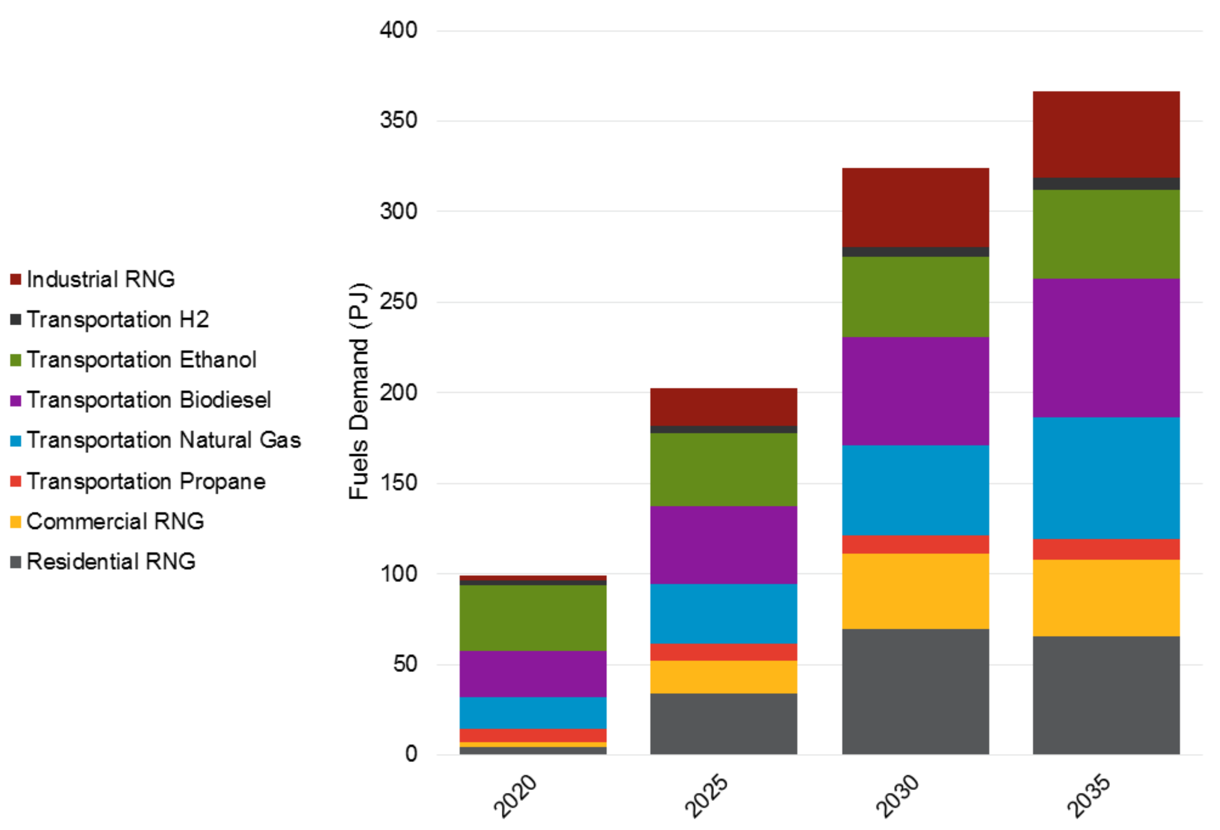
Figure 36: Alternative Fuels in 2035 – Outlook B and F



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

[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

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

[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]

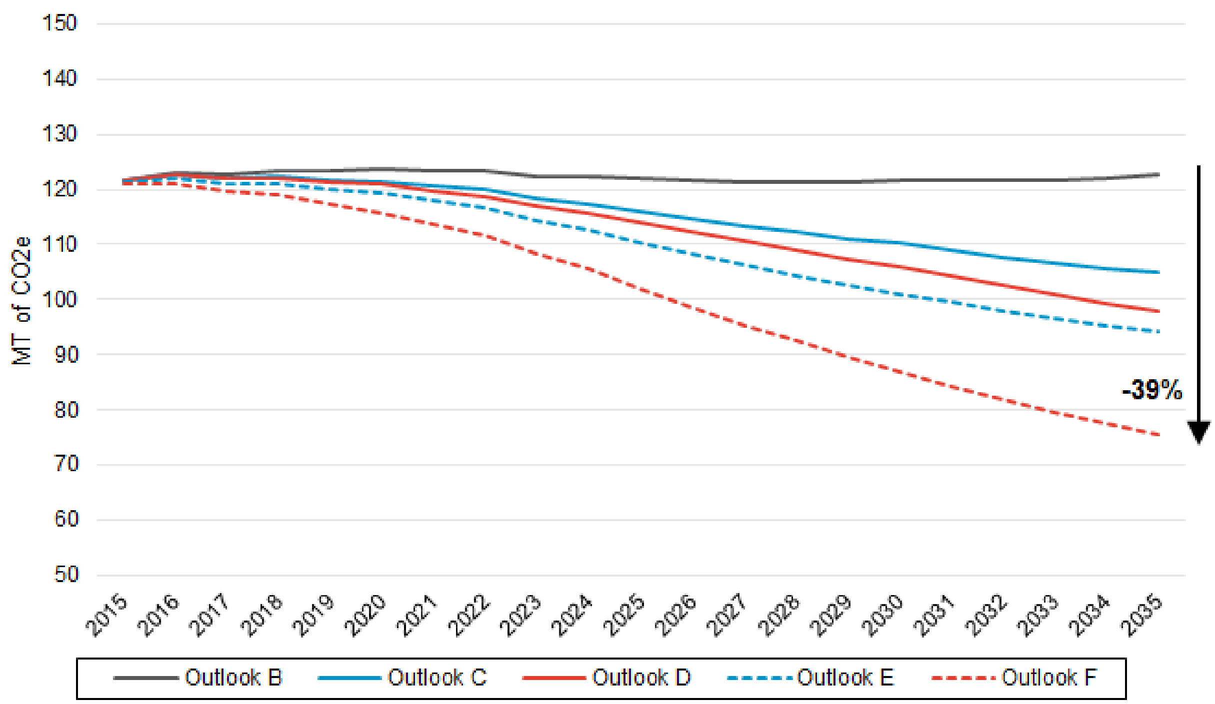
2.4 Emissions Outlook

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

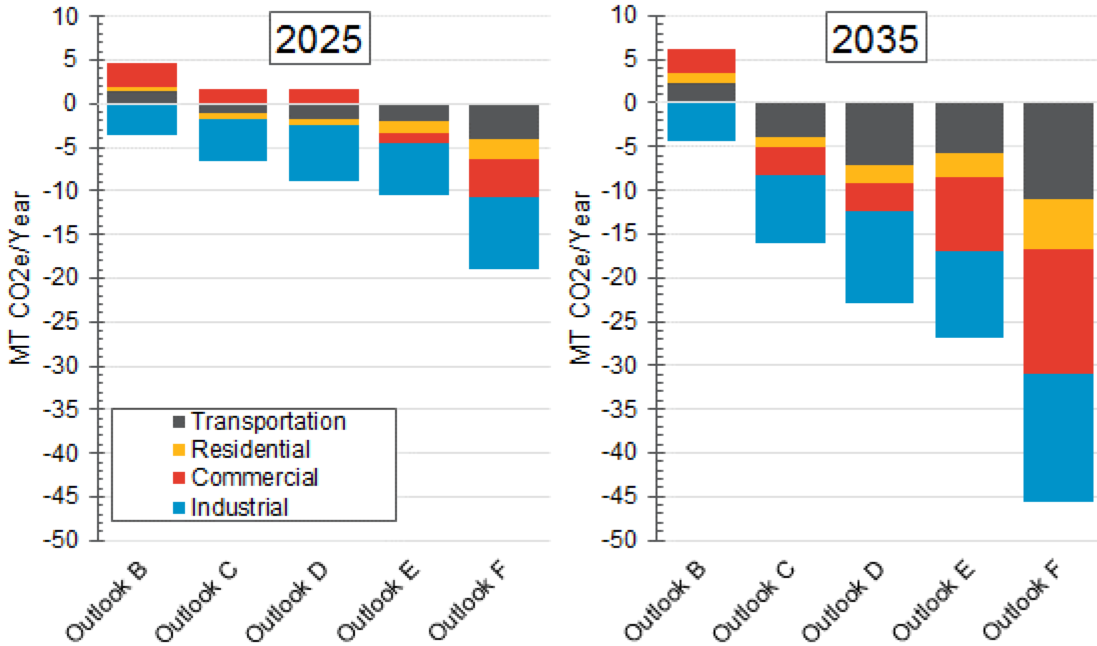


[29] Hydrogen Analysis Resource Center, *Merchant Hydrogen Plant Capacities in North America*, accessed September 2016 http://hydrogen.pnl.gov/hydrogen-data/merchant-hydrogen-plant-capacities-north-america

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

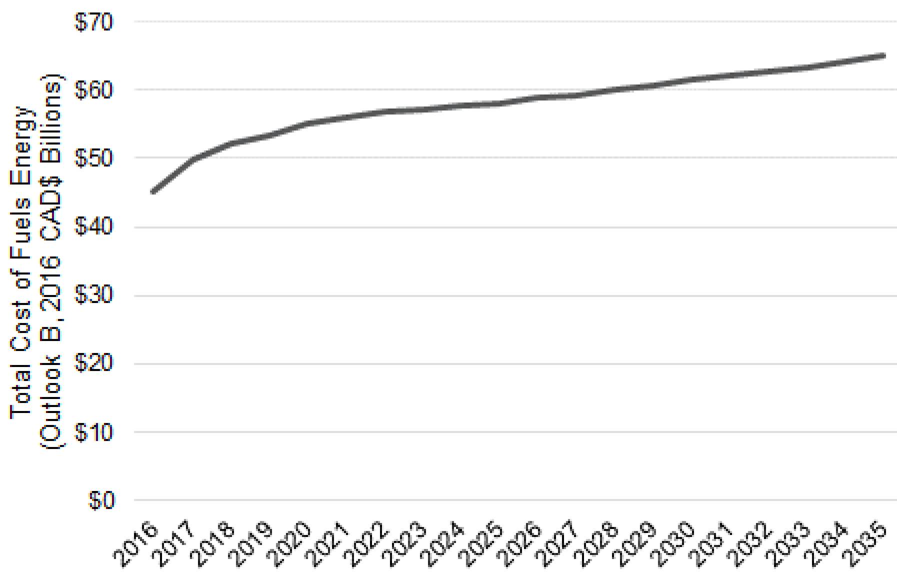
The total cost of fuels service over the planning outlooks will be determined by global fuel prices, the mix of fuels demanded (or mandated) in Ontario, the carbon costs of cap and trade, and the costs of maintaining existing regulated natural gas delivery infrastructure. The growth in these costs across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

[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

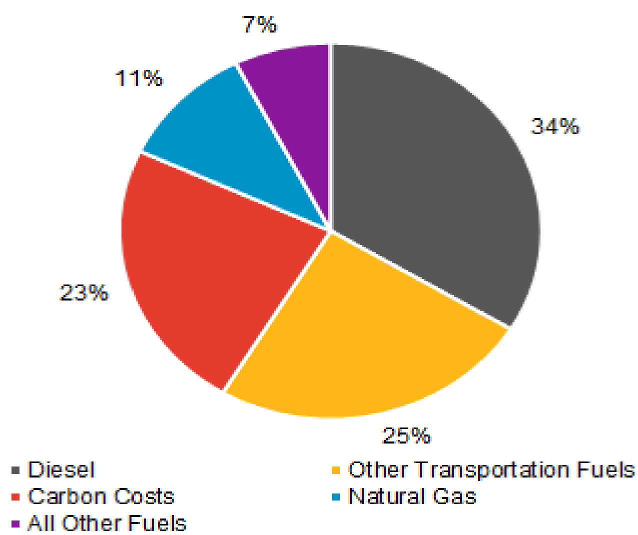
Figure 40: Total Cost of Fuels for Energy in Outlook B



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



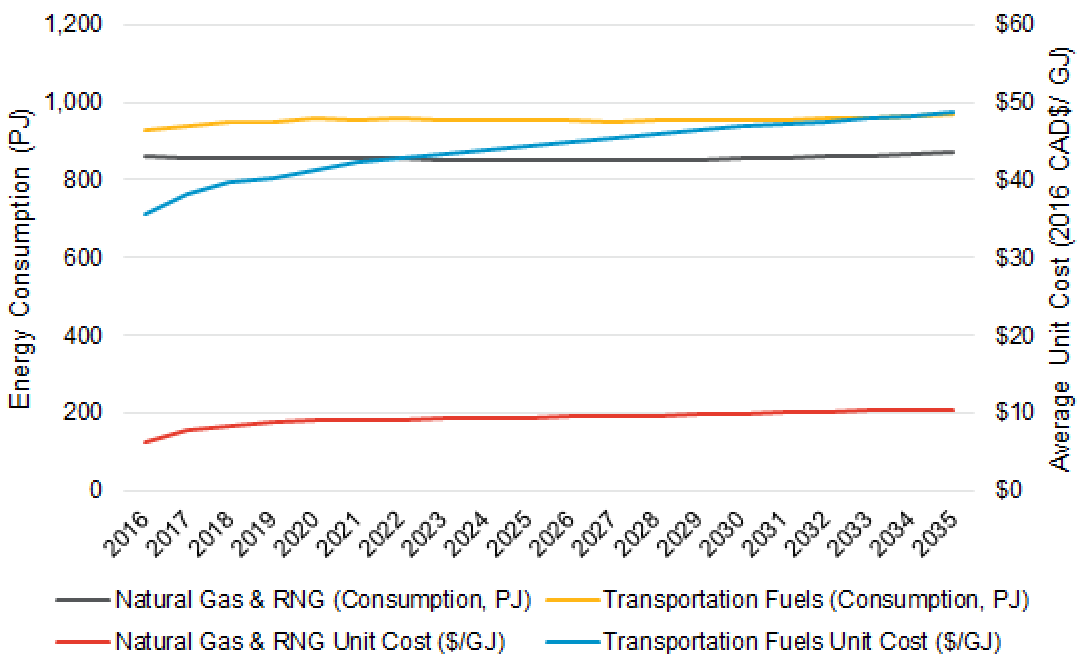
Source: CanESS & Navigant Analysis, 2016

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

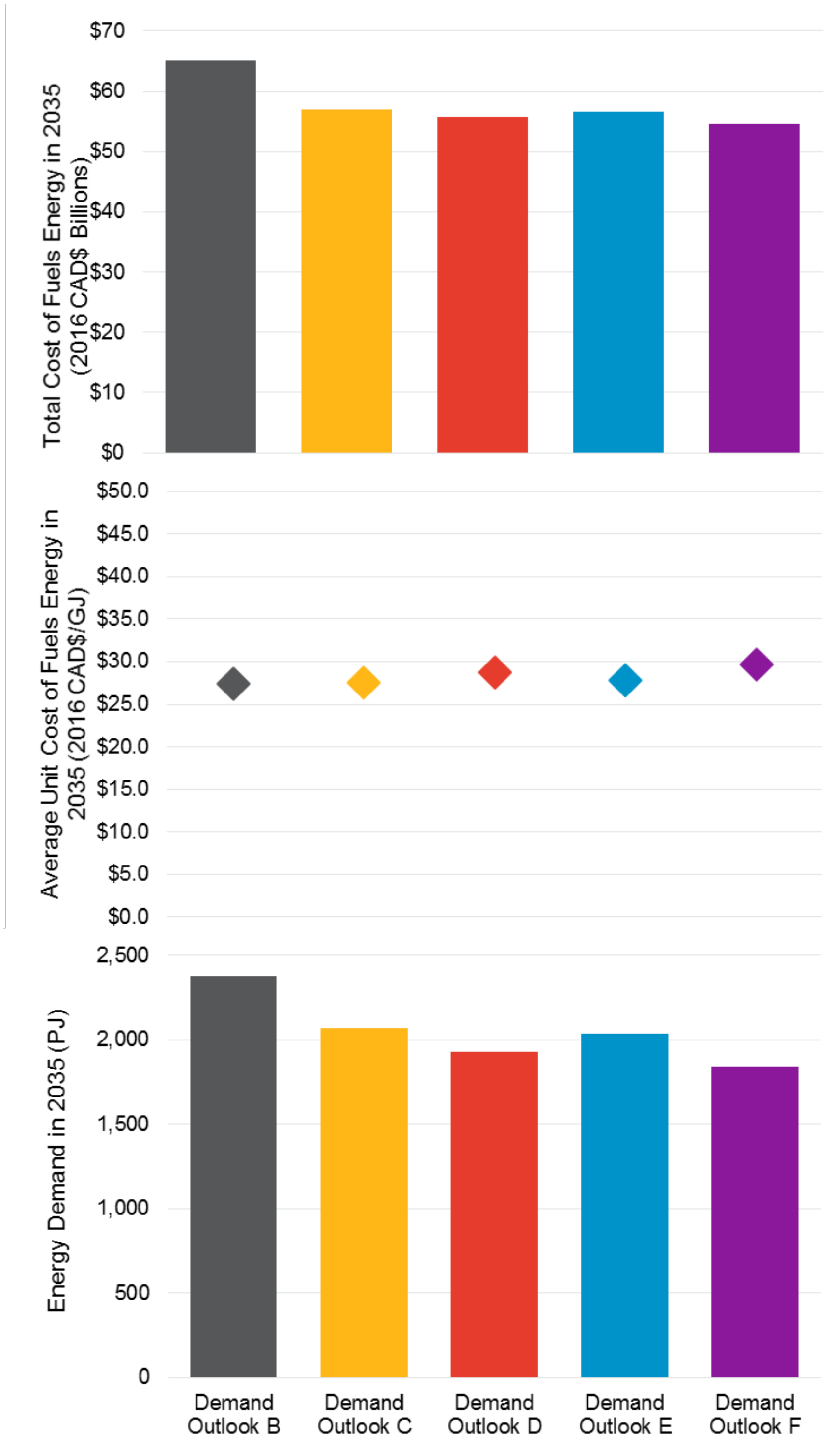
Total fuels energy costs fall substantially in the alternative outlooks, C through F, as may be seen in Figure 43. This is due to a number of factors, principally the reduction in fuel use as a result of electrification of space-heating, industrial processes and light-duty transportation (Outlook C and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

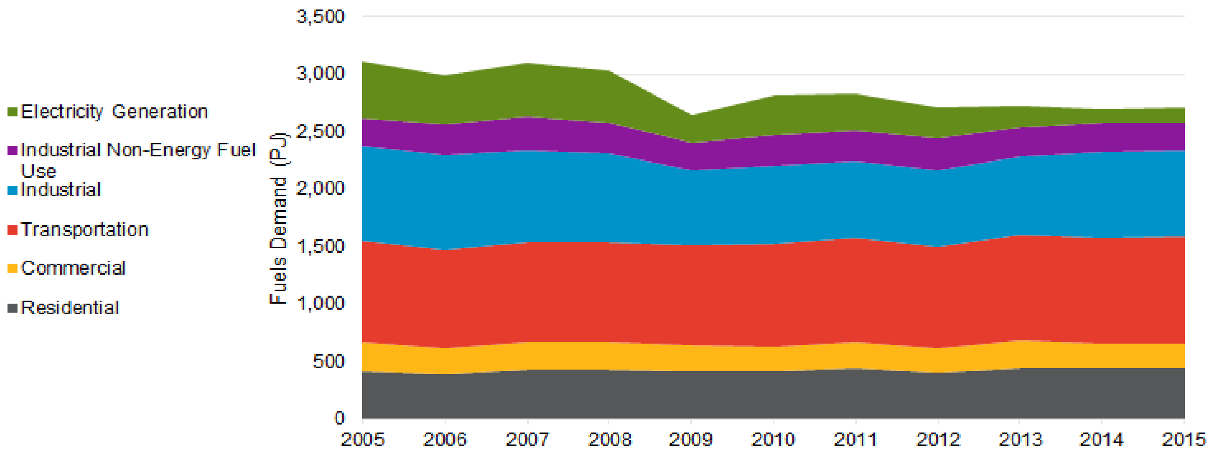
- Many alternative fuel technologies are technically feasible today. This report illustrates the range of fuels and technologies available in Ontario’s fuels sector, as well as regulatory and policy levers that can support adoption.

- 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

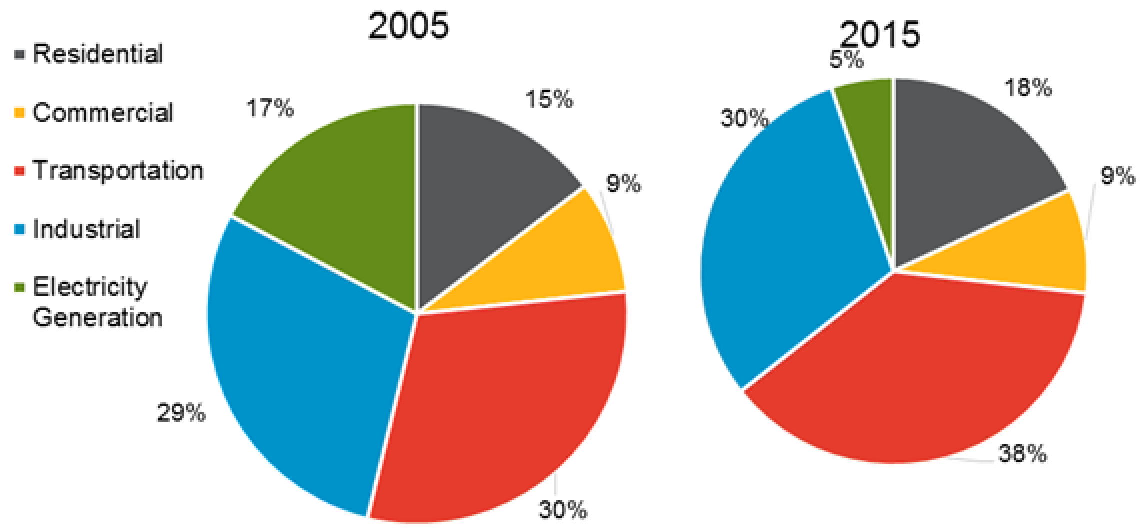
Figure 1: Total Ontario Fuels Energy Demand



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

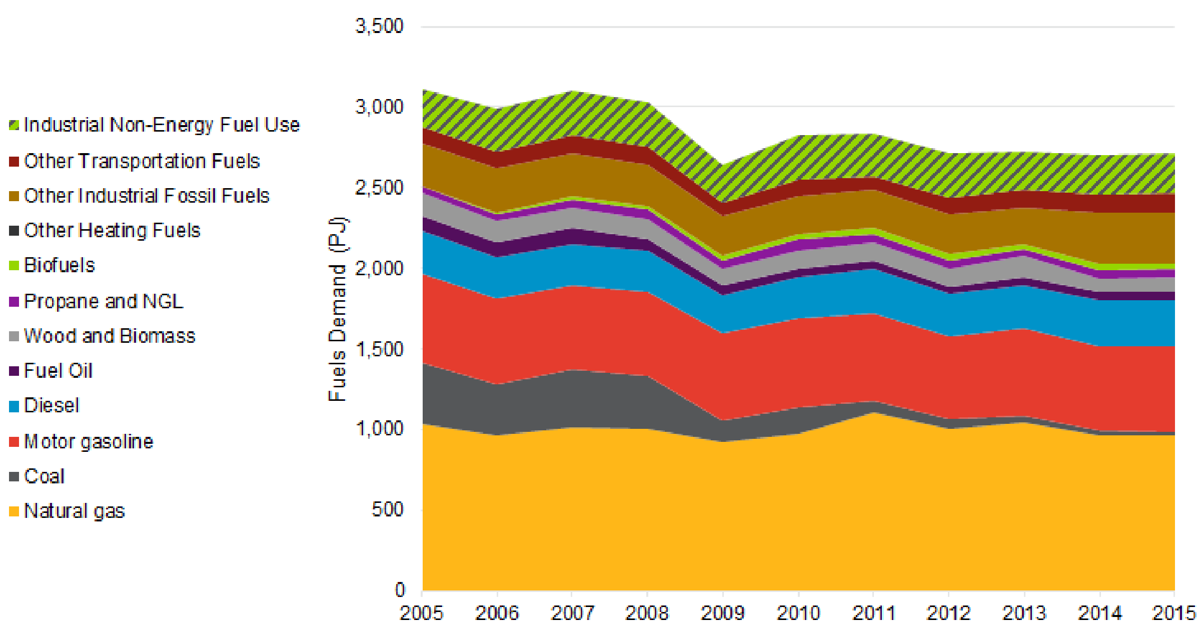
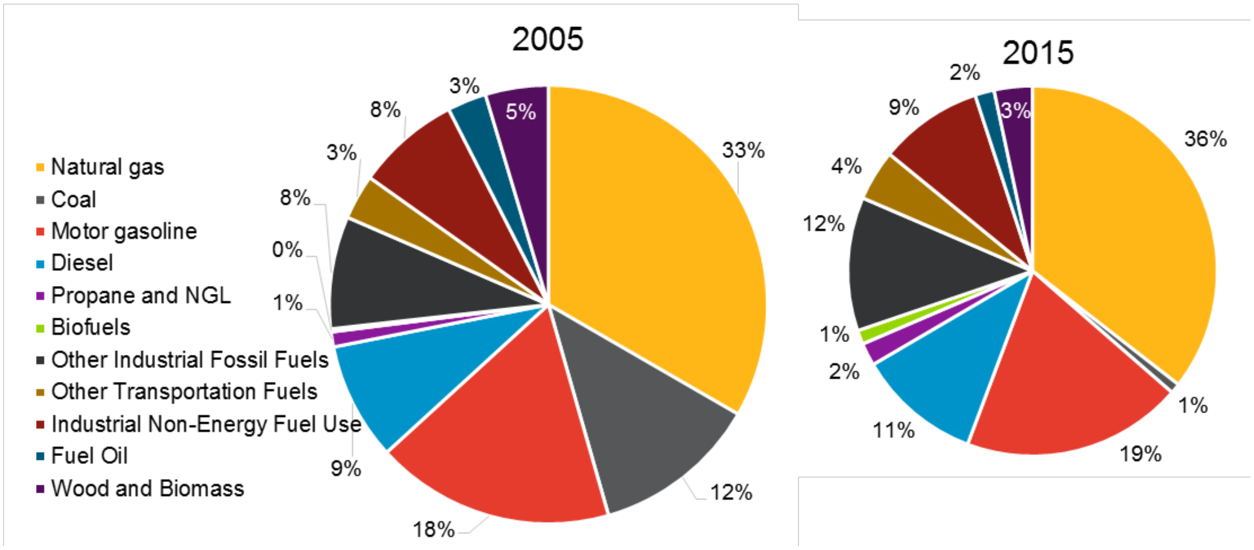


Figure 4: Fuels Demand by Fuel Type 2005 and 2015

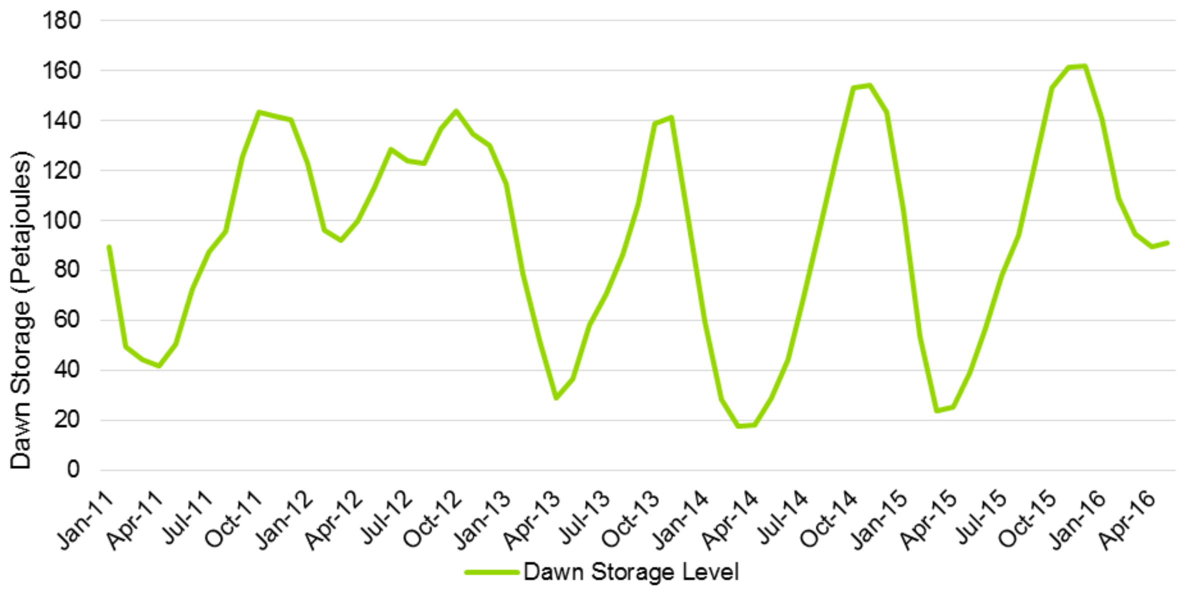


Data for Figure 3 and Figure 4

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

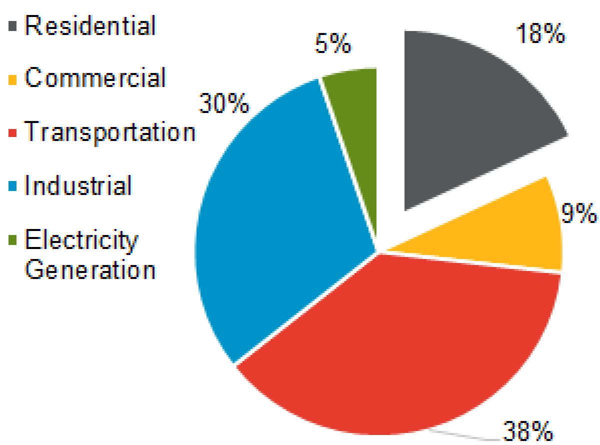


Data for Figure 6: Dawn Storage

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.

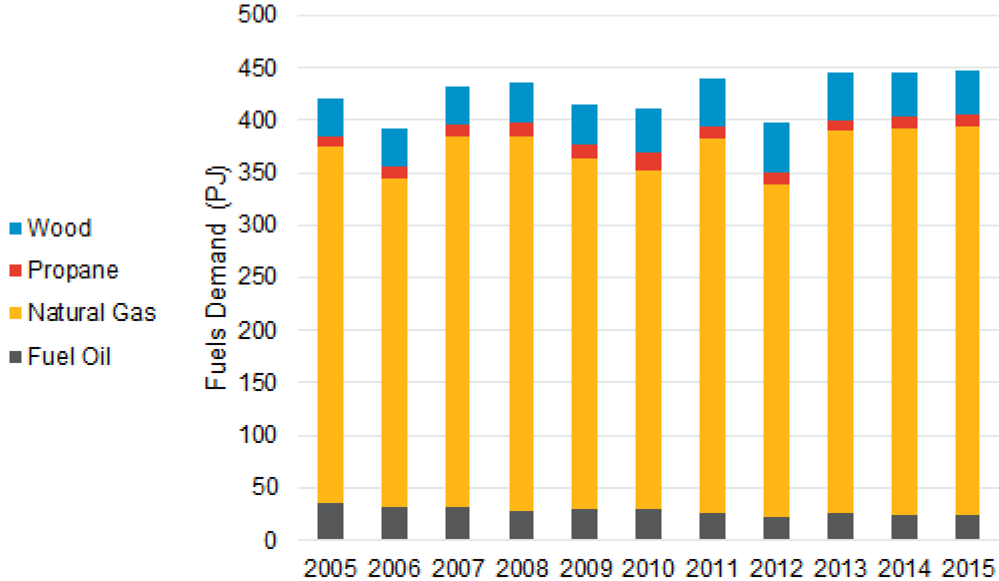
Figure 13: Ontario Residential Fuels Demand - 2015



Data for
Figure 13: Ontario Residential Fuels Demand - 2015

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

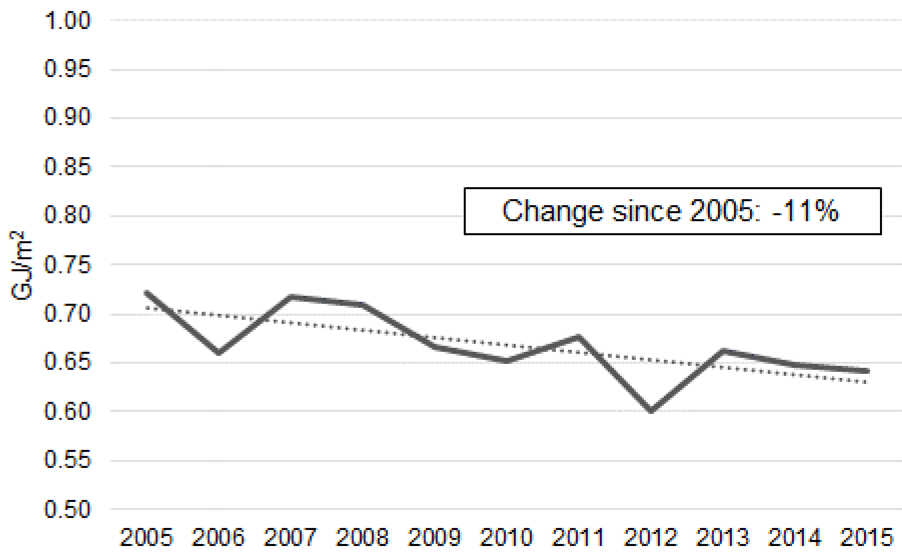
Figure 14: Residential Demand by Fuel Type: 2005-2015



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

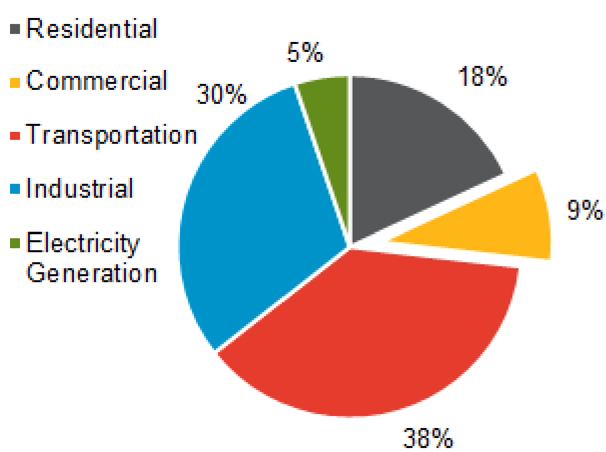
Figure 15: Residential Fuels Energy Use Per Square Metre of Floor-Space



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

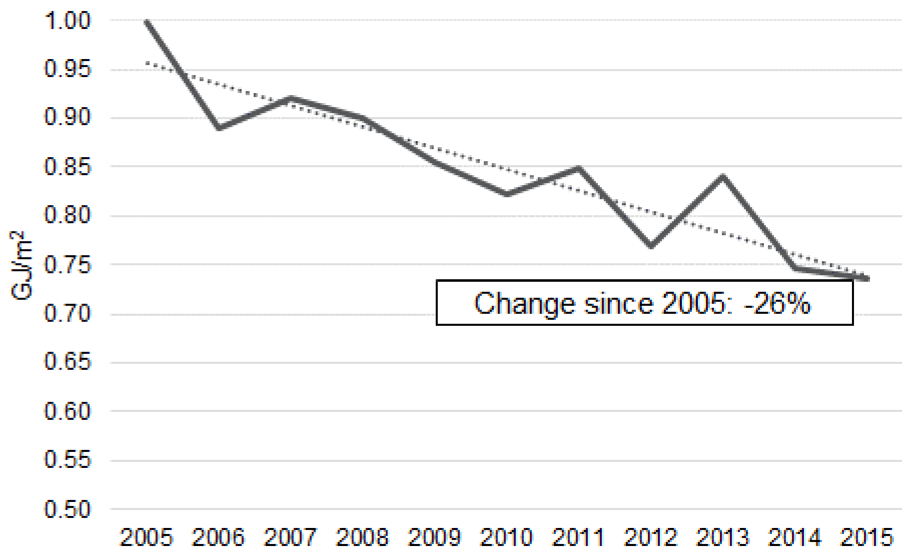
Fuels Demand (PJ)	2015
Residential	447
Commercial	215
Transportation	927
Industrial	750
Electricity Generation	128

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

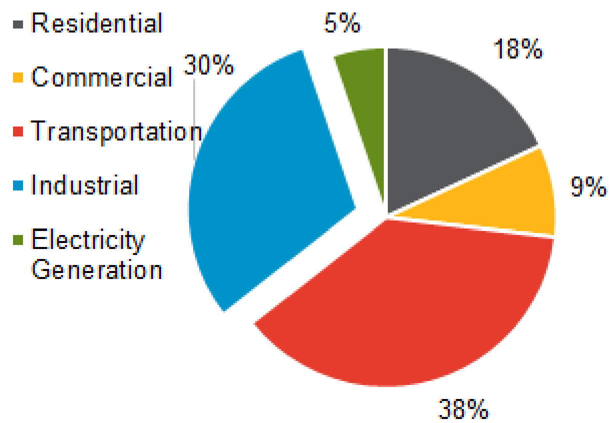
Figure 18: Commercial Fuels Energy Use Per Square Metre of Floor-Space



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

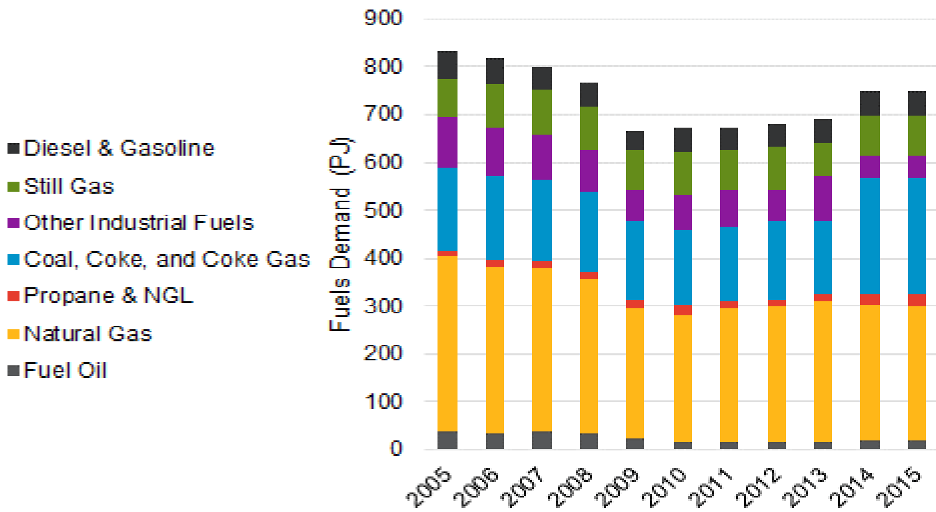


Data for Figure 19: Industrial Fuel Demand - 2015

Fuels Demand (PJ)	2015
Residential	447
Commercial	215

Transportation	927
Industrial	750
Electricity Generation	128

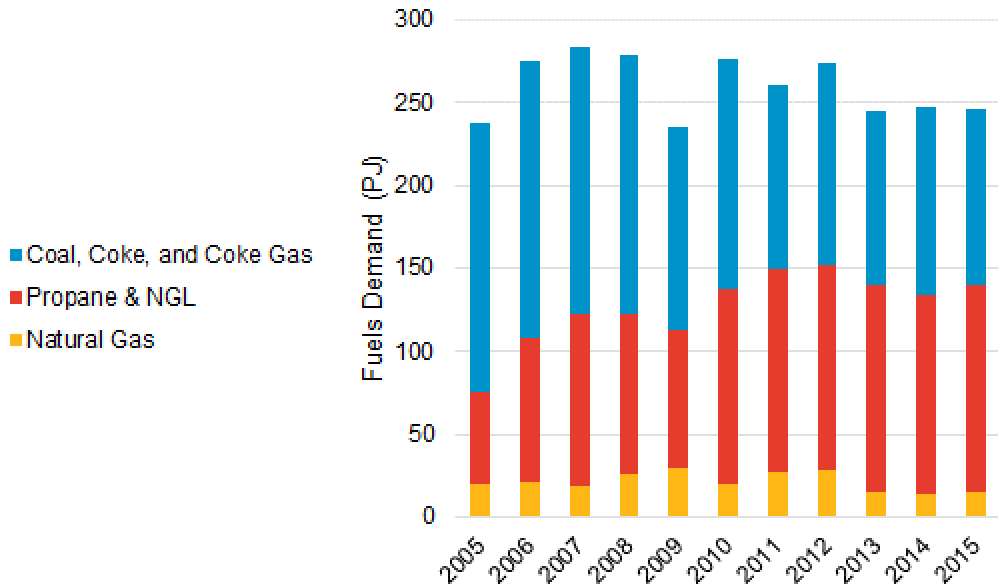
Figure 20: Industrial Energy Demand by Fuel Type: 2005-2015



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

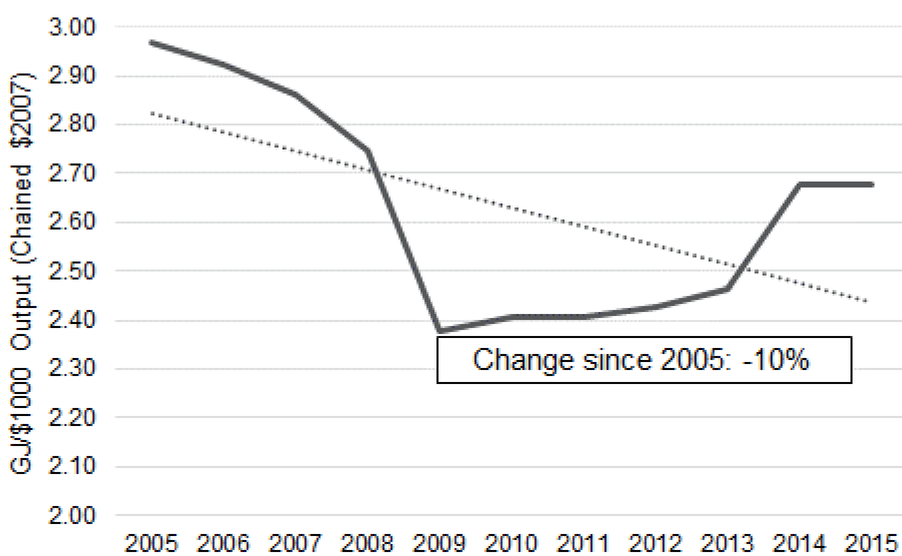
Figure 21: Non-Energy Industrial Demand by Type: 2005-2015



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

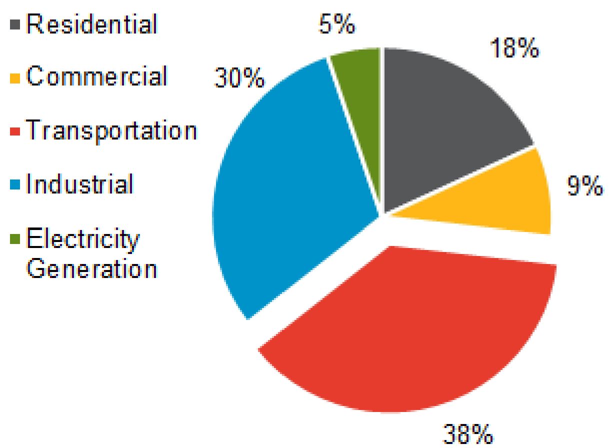
Figure 22: Industrial Fuels Energy Use Per $1,000 of Economic Output



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

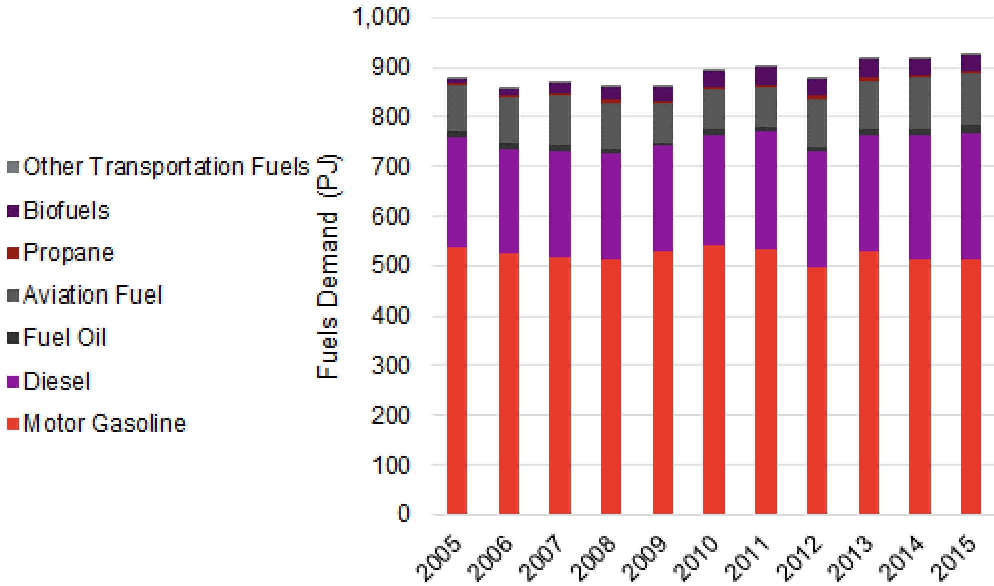
Figure 23: Transportation Energy Fuel Demand - 2015



Data for Figure 23: Transportation Energy Fuel Demand - 2015

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

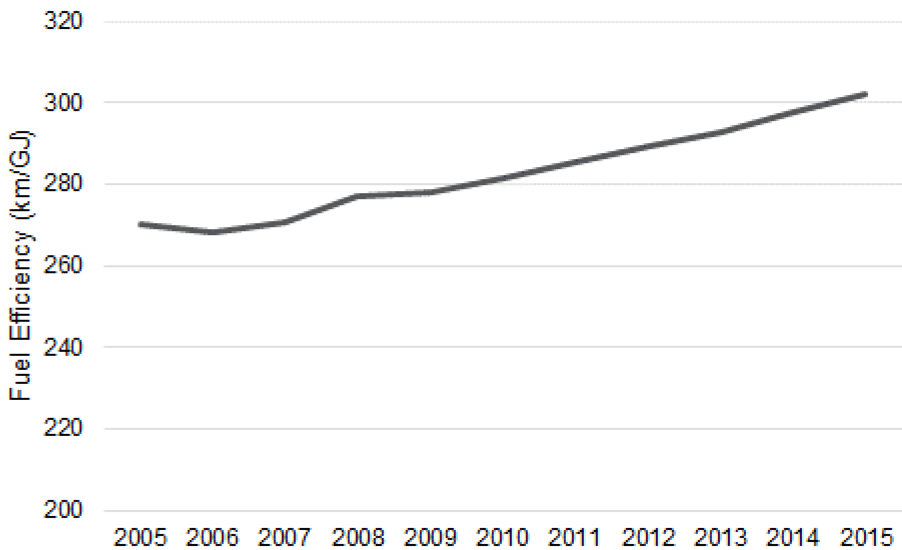
Figure 24: Transportation Demand by Fuel Type: 2005-2015



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

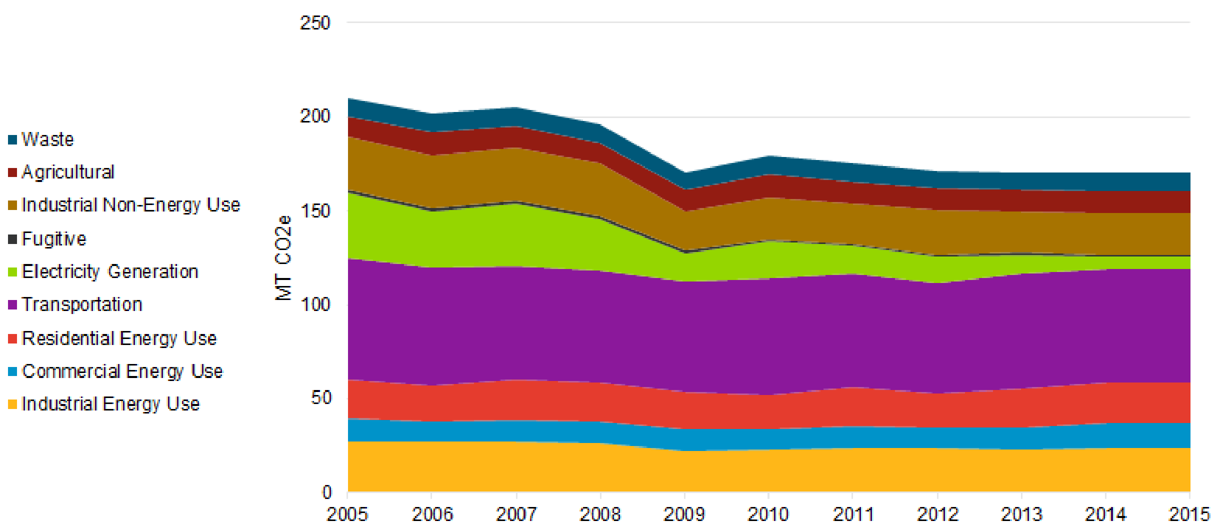
Figure 25: Light Duty Vehicle Efficiency Improvements – 2005 to 2015



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

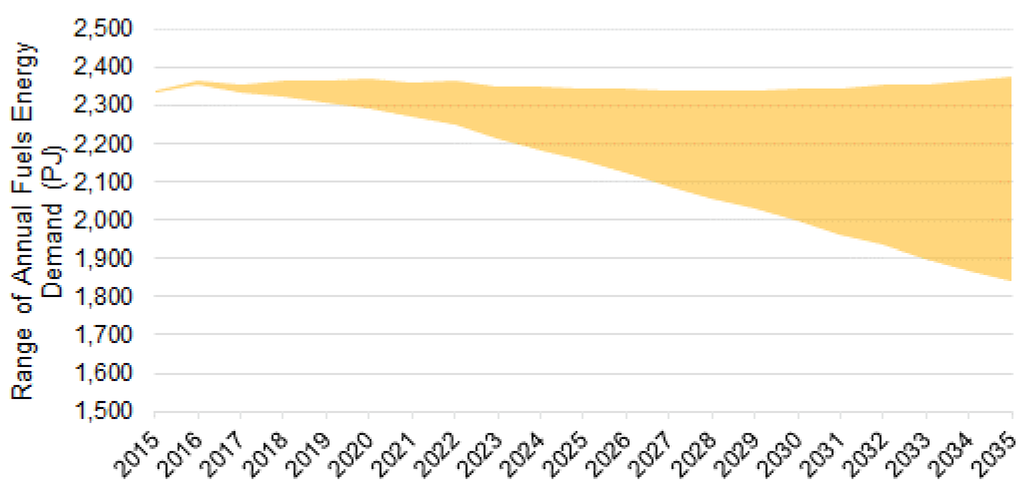
Figure 26: Historical Ontario GHG Emissions



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



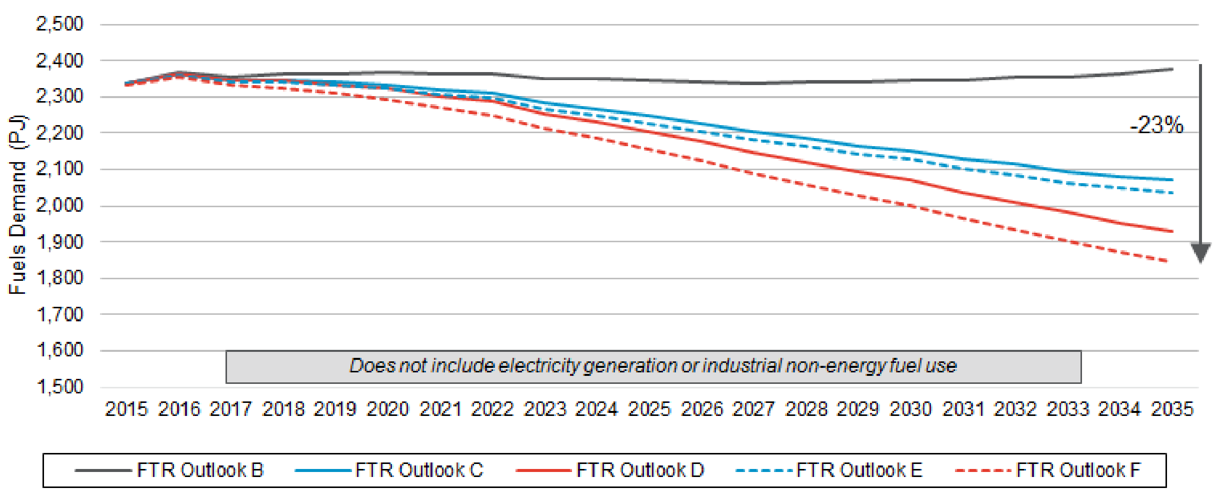
Data for Figure 27: Demand Uncertainty

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

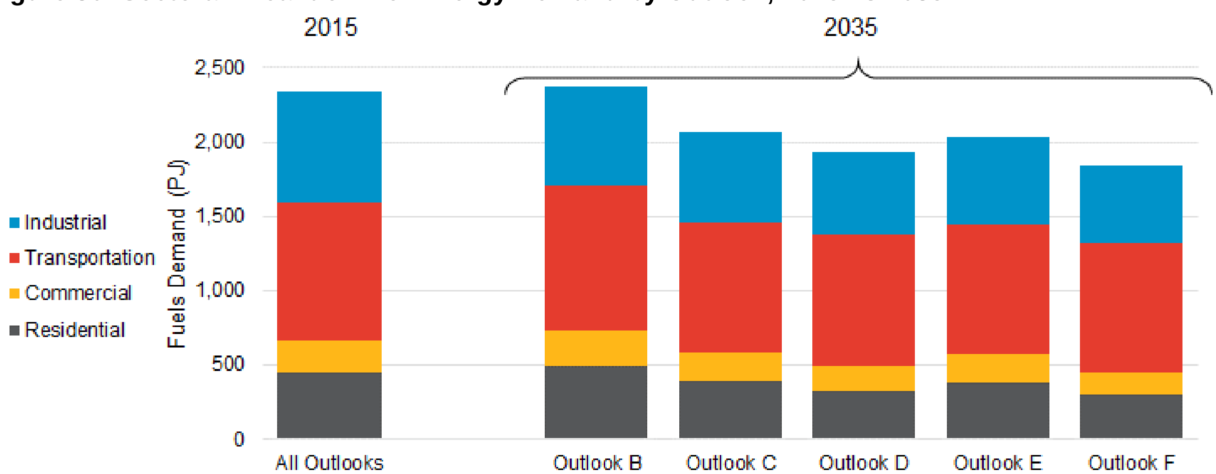


Data for Figure 29: Five Fuels Energy Demand Outlooks

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

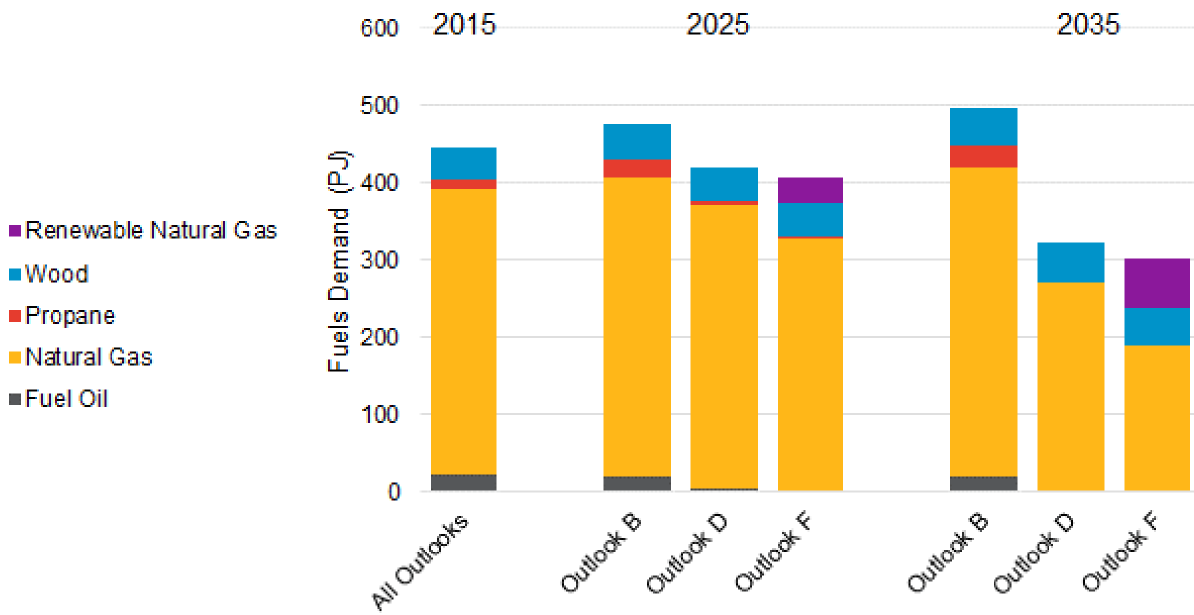


Data for Figure 30: Sectoral Breakdown of Energy Demand by Outlook, 2015 vs 2035

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

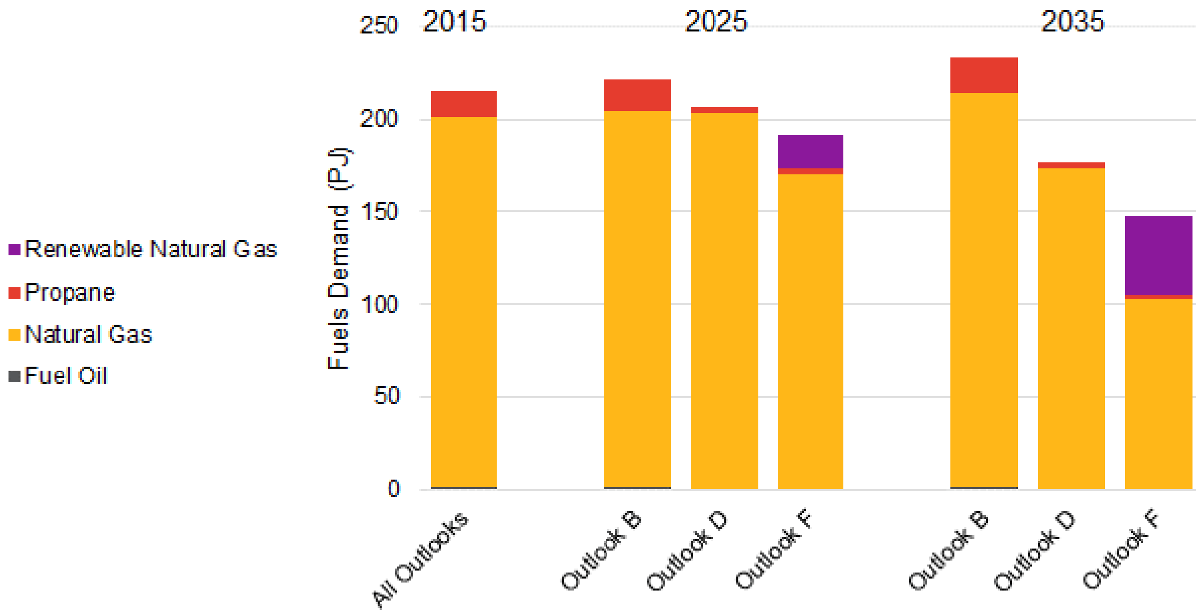
Figure 31: Residential Outlook



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

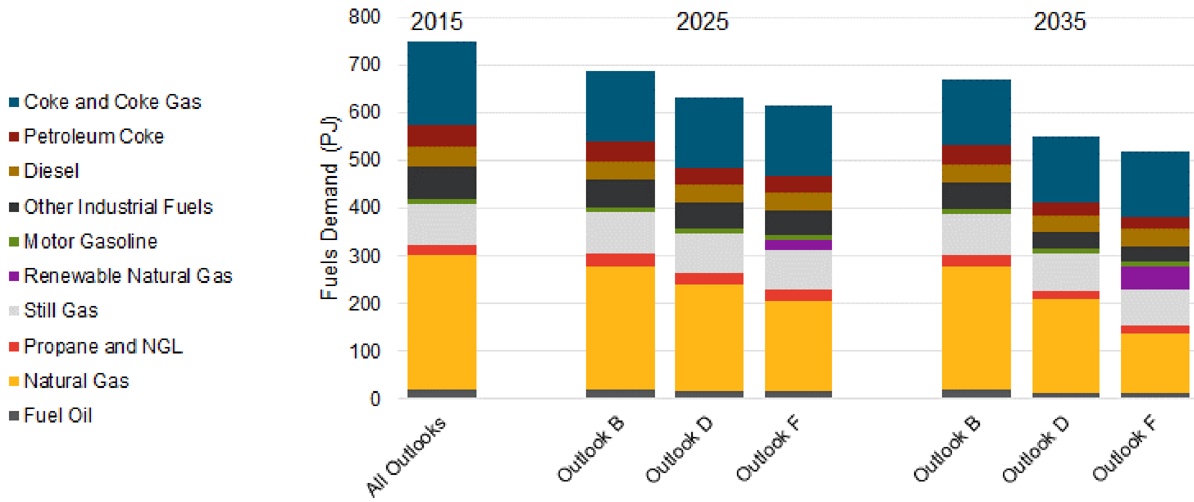
Figure 32: Commercial Outlook



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

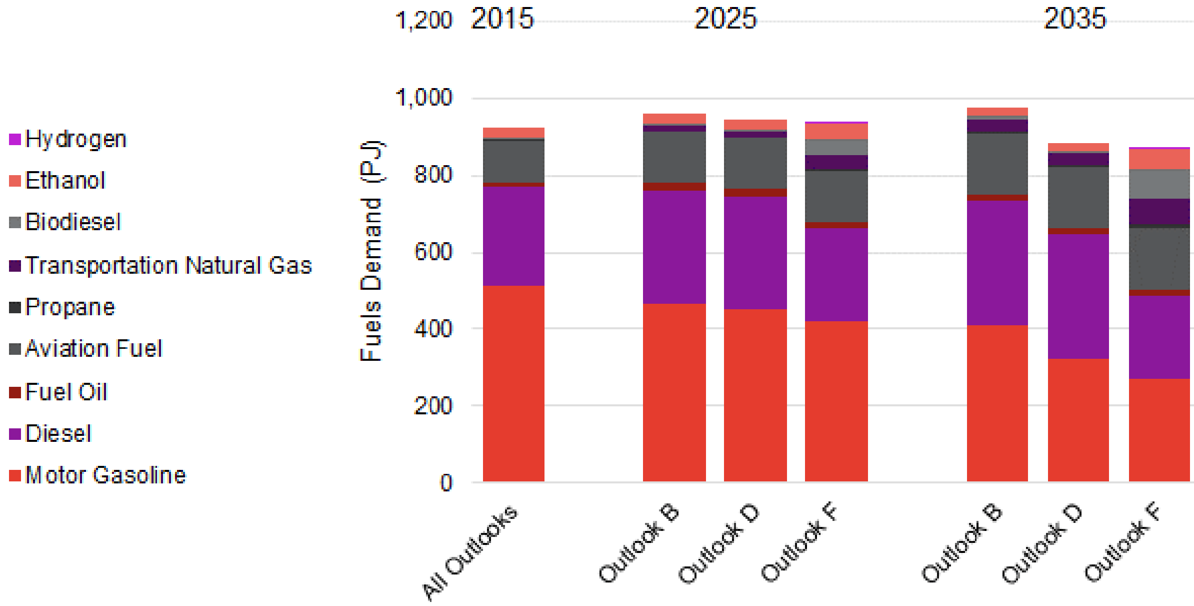
Figure 33: Industrial Outlook



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

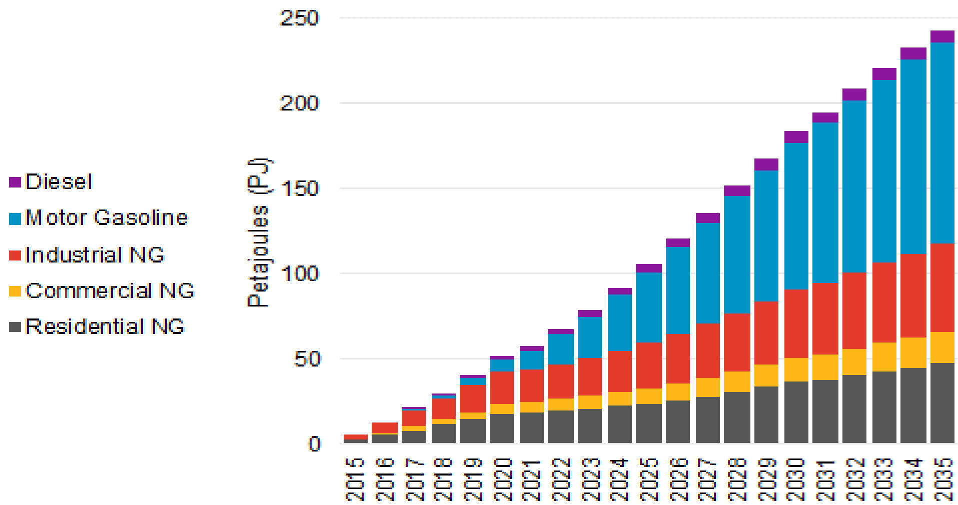
Figure 34: Transportation Outlook



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

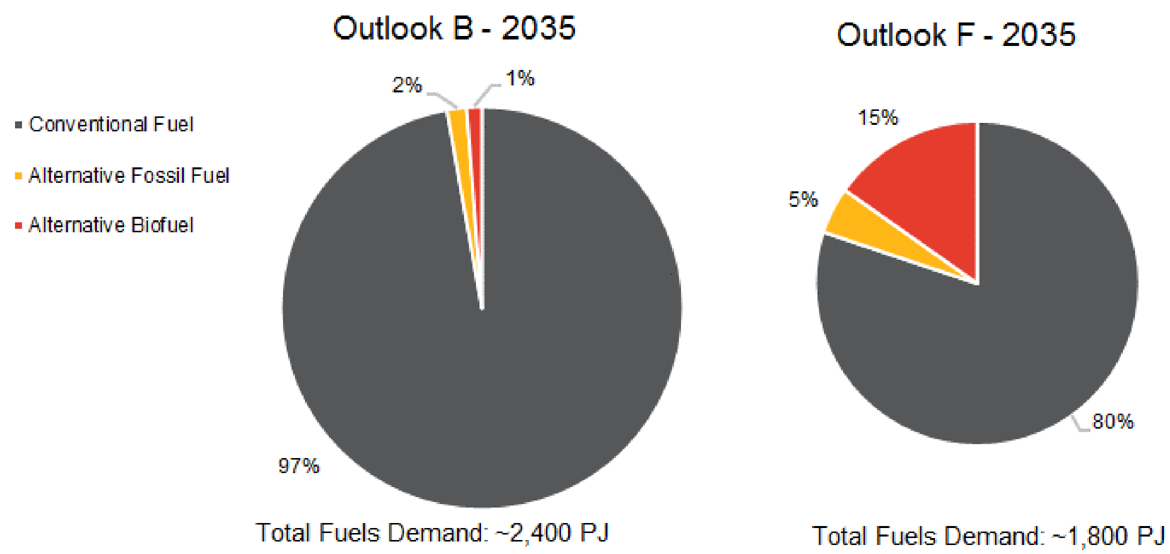
Figure 35: Conservation Achievement and Outlook to 2035 (Outlook B)



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

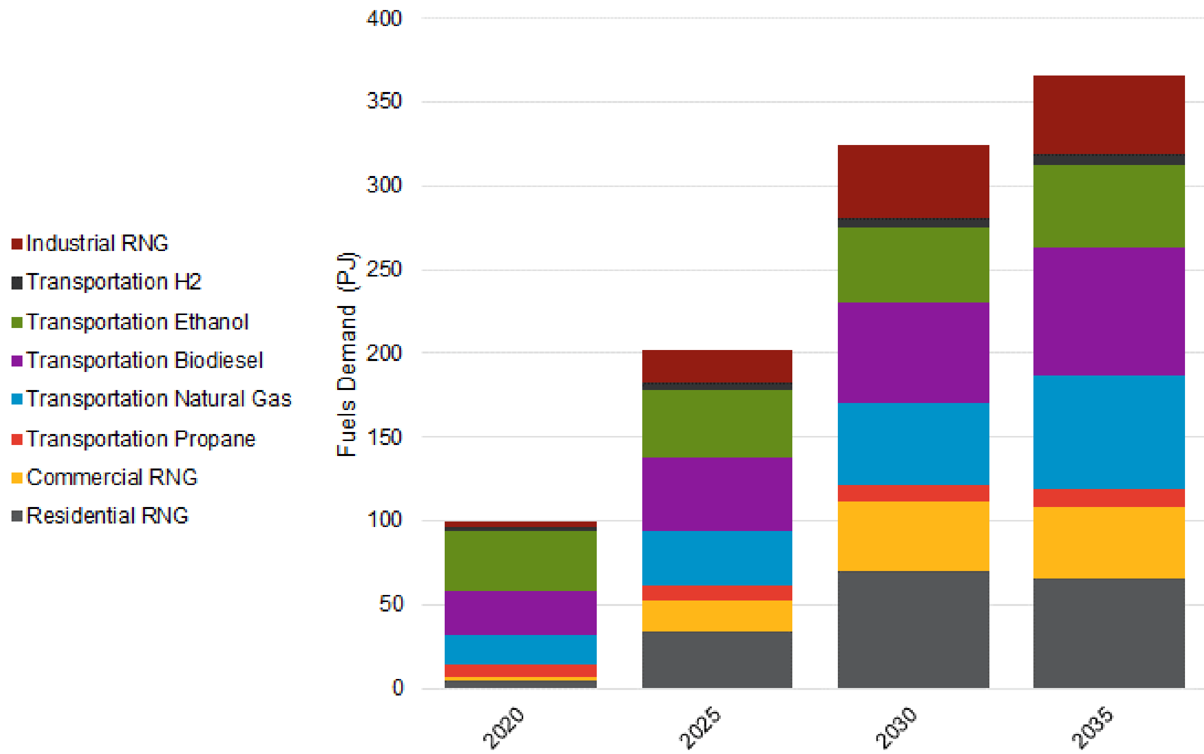
Figure 36: Alternative Fuels in 2035 – Outlook B and F



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

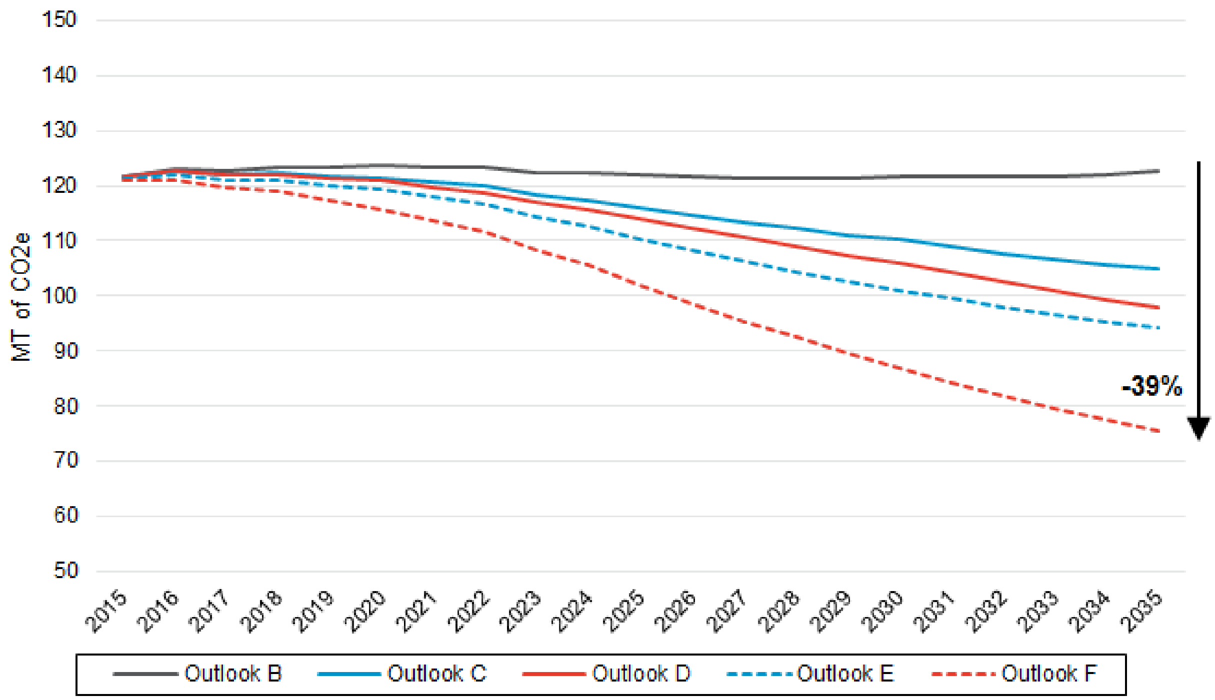
Figure 37: Outlook F Alternative Fuel Breakdown



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

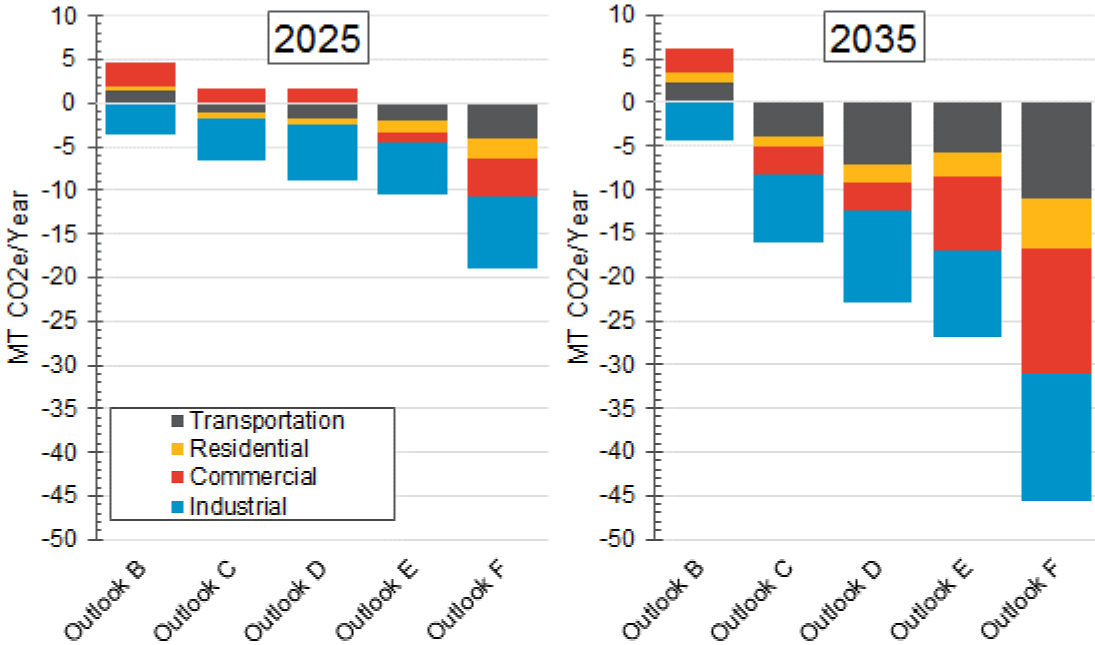


Data for Figure 38: Fuels Combustion GHG Emissions Outlook

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

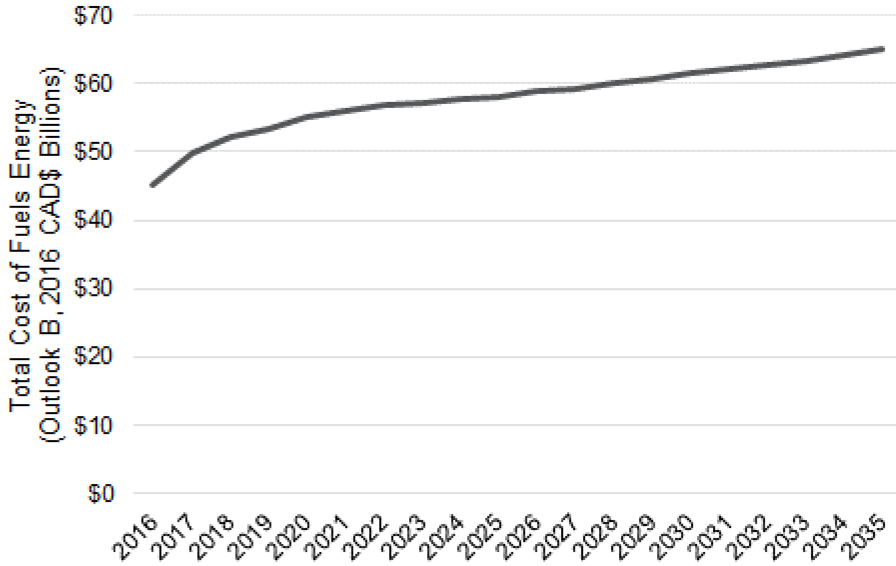
Figure 39: Emissions Relative to 2014 Levels



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

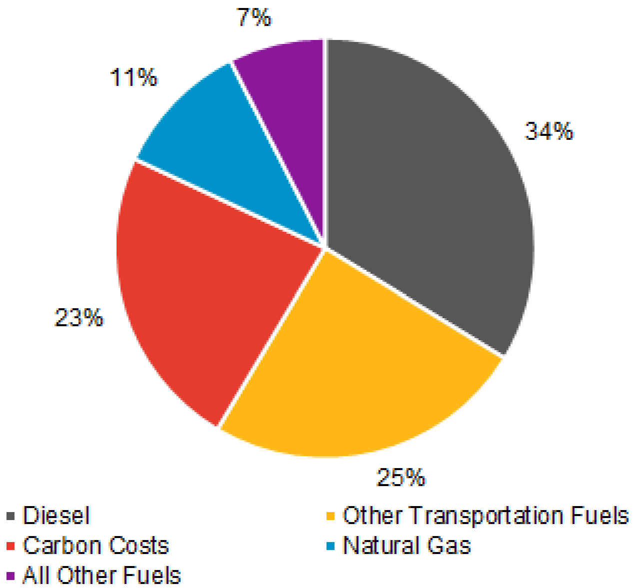
Figure 40: Total Cost of Fuels for Energy in Outlook B



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

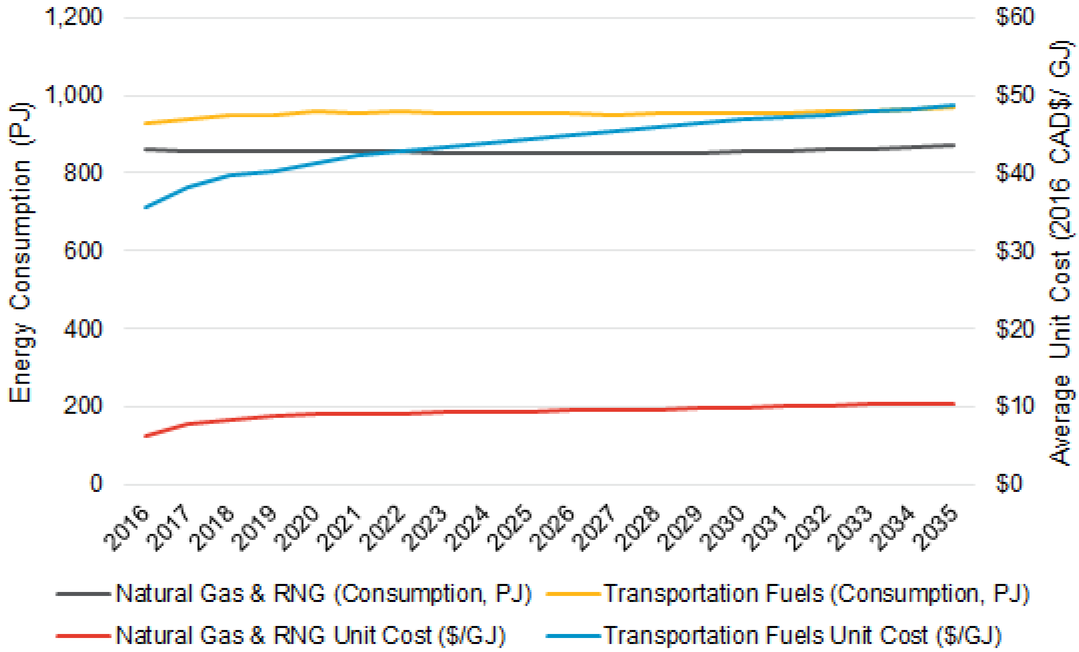
Figure 41: Drivers of System Cost Increases 2016 to 2035



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

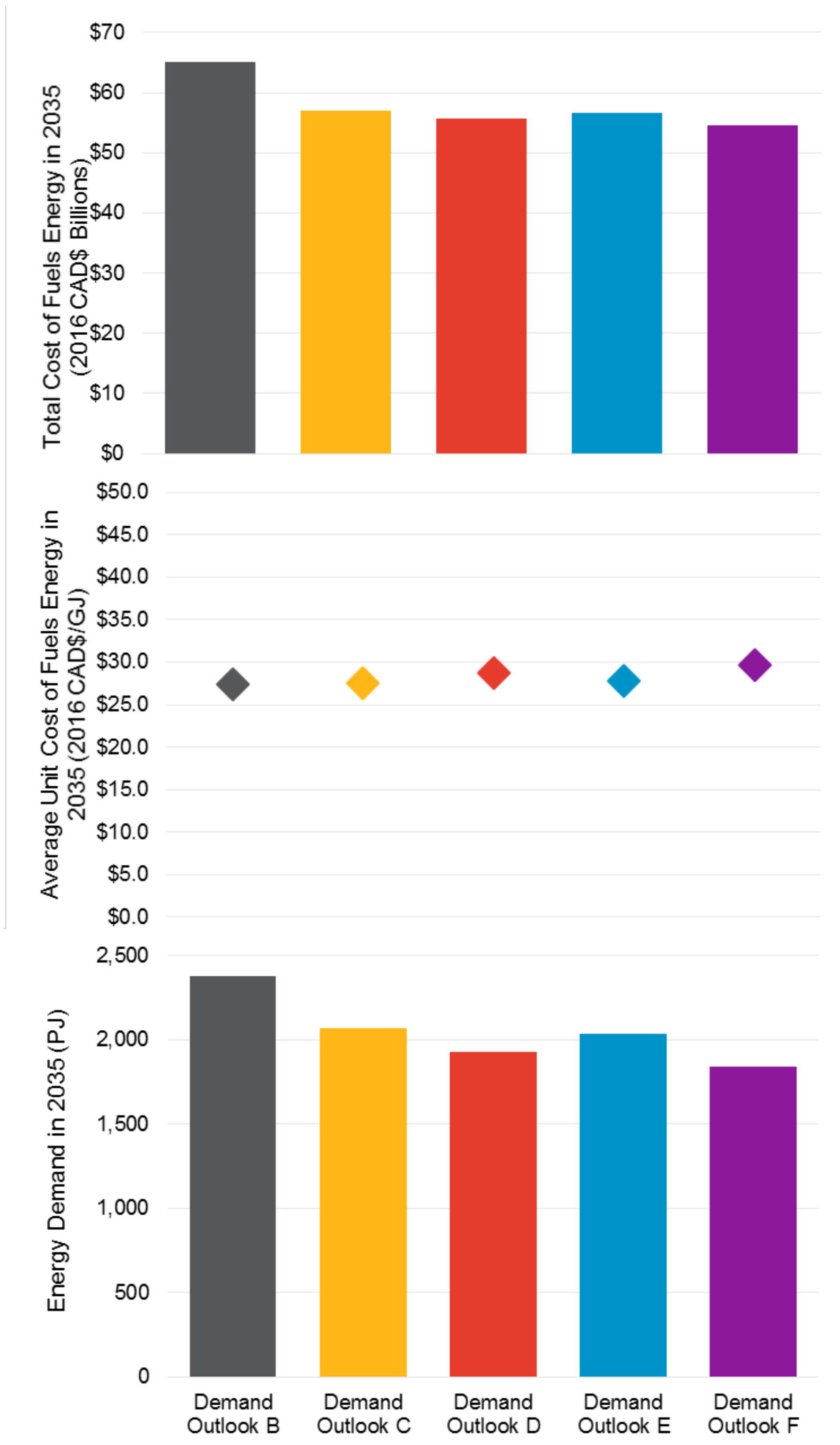


Data for Figure 42: Average Unit Cost of Natural Gas and Transportation Fuels in Outlook B

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:

The Ministry of Energy

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.

.

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.

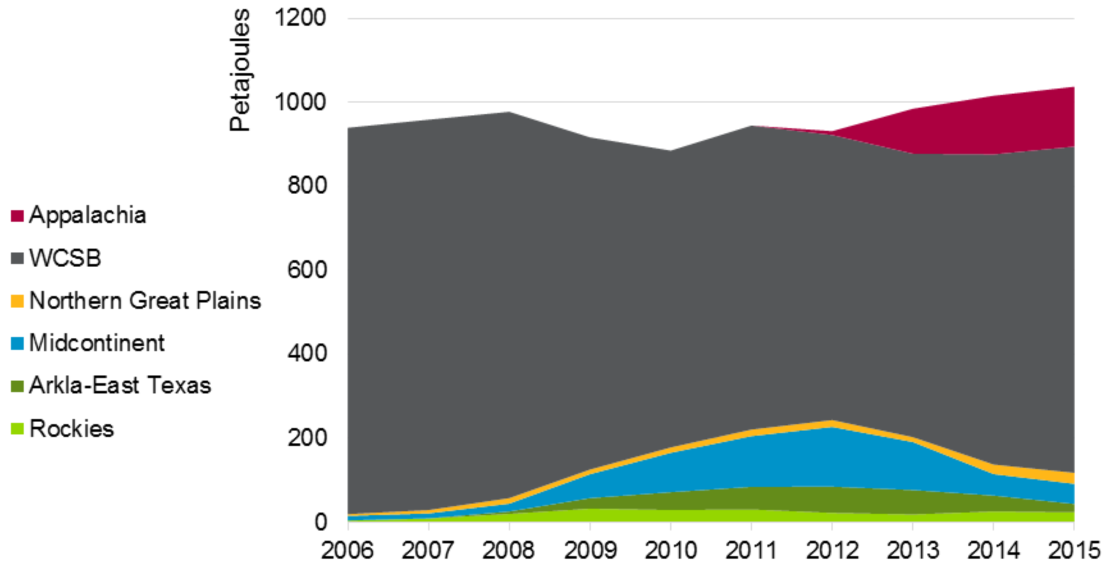
1.1 Natural Gas

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

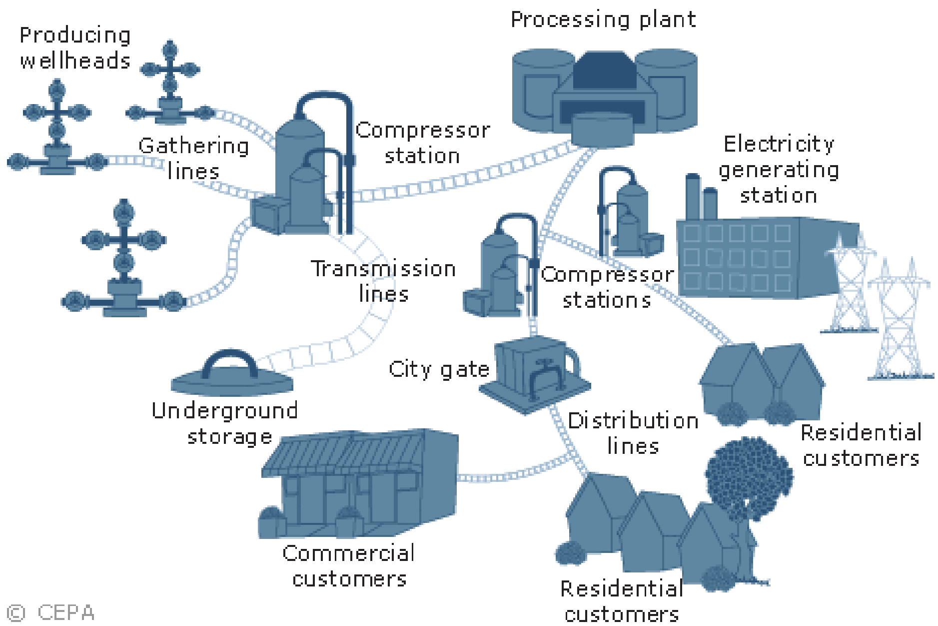
Natural gas is moved across Canada and between Canada and the US along a complex system of pipelines.

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]

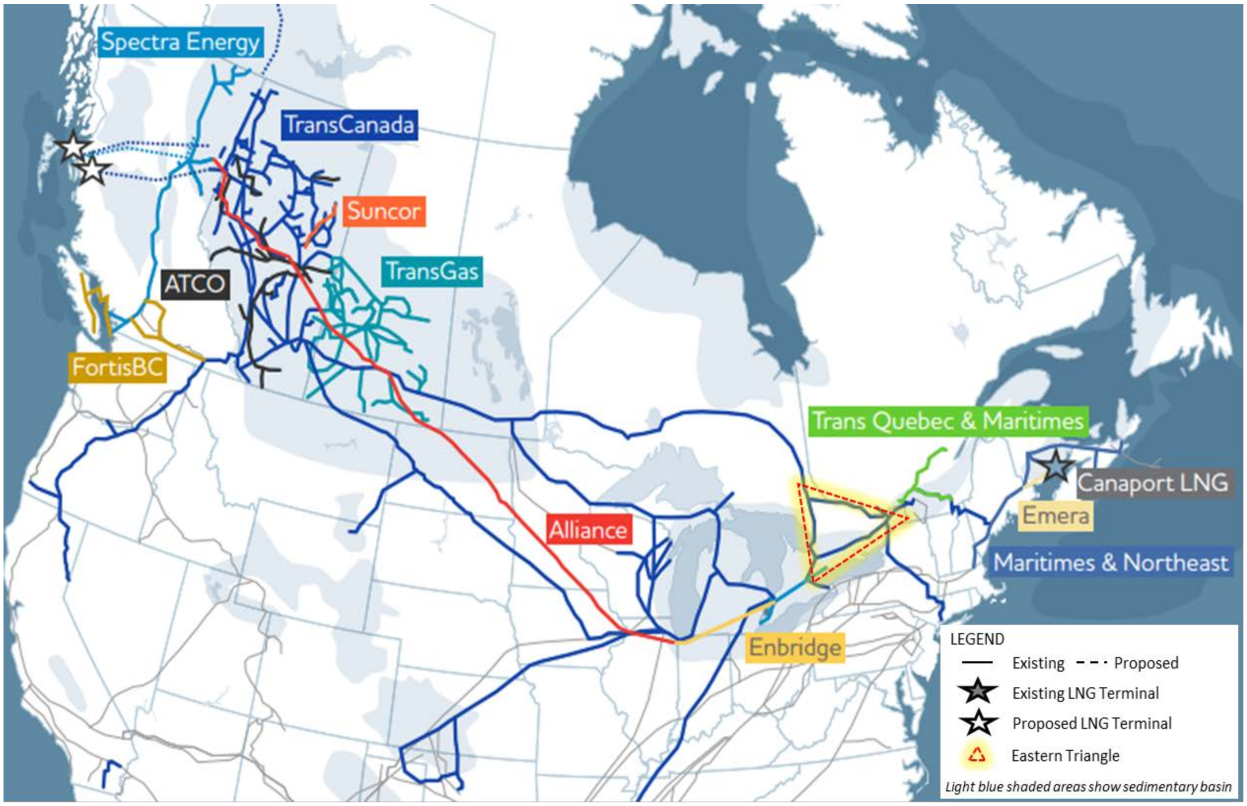
Transmission (Pipelines)

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

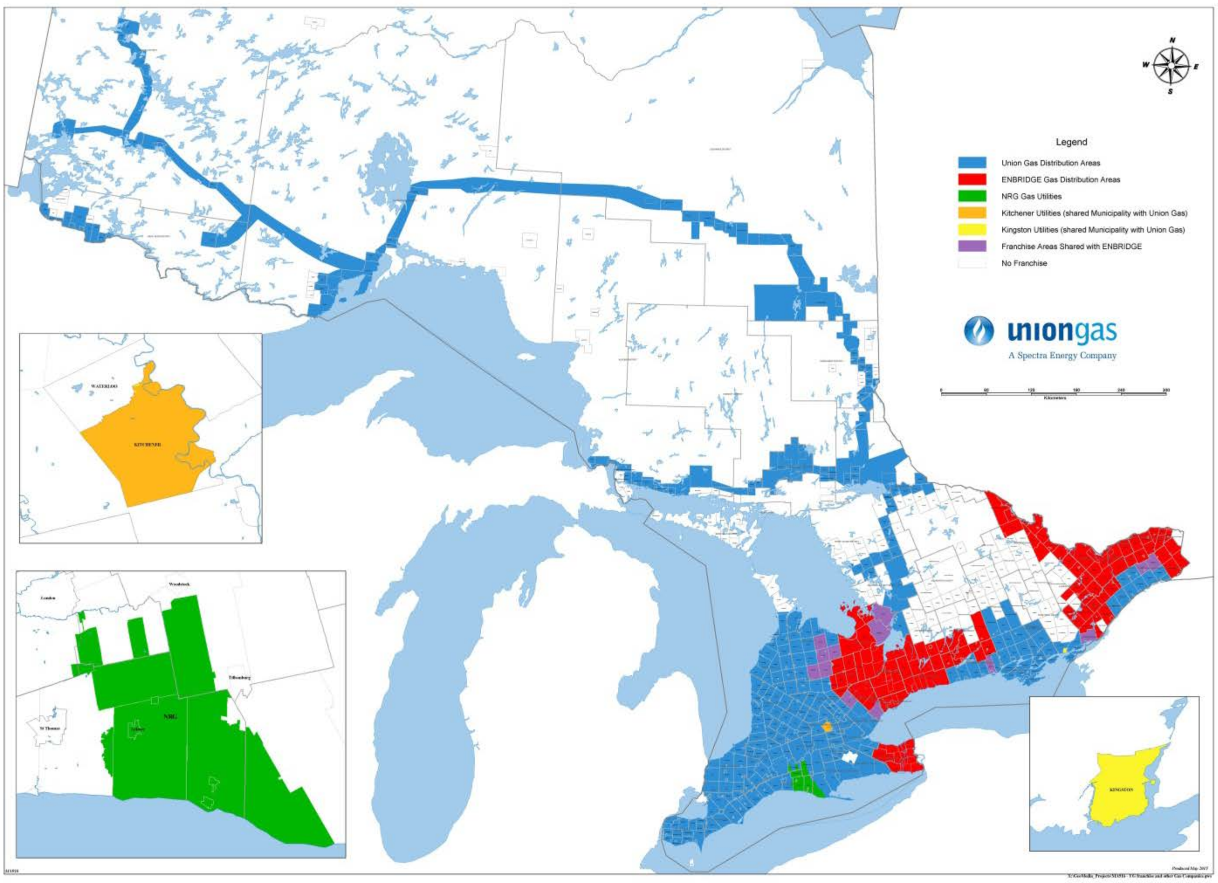
Ontario's regulated local distribution companies have franchise agreements with municipalities across the province. A franchise agreement allows a local distribution company to provide service and must be approved by the OEB. Investor owned local distribution companies are regulated by the OEB in Ontario (**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

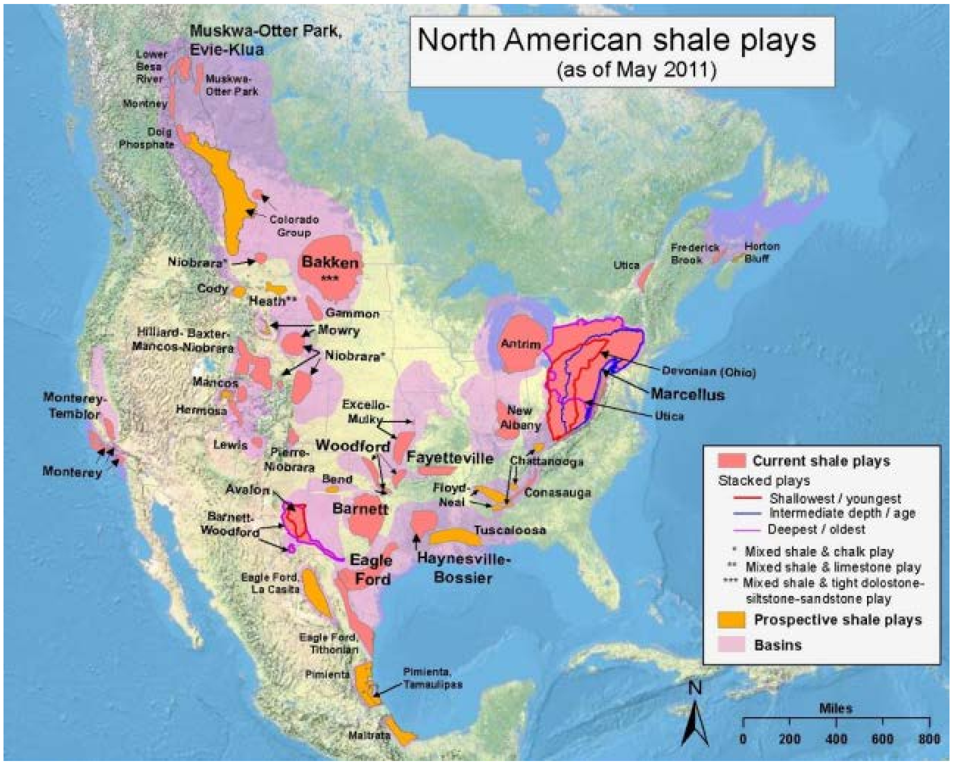
Starting in 2008, North American natural gas supply prospects changed dramatically, from impending scarcity to an era of growing production and supply abundance. The high prices and volatility of the preceding decade encouraged the development of shale gas resources. Prior to that development, shale 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.

[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:

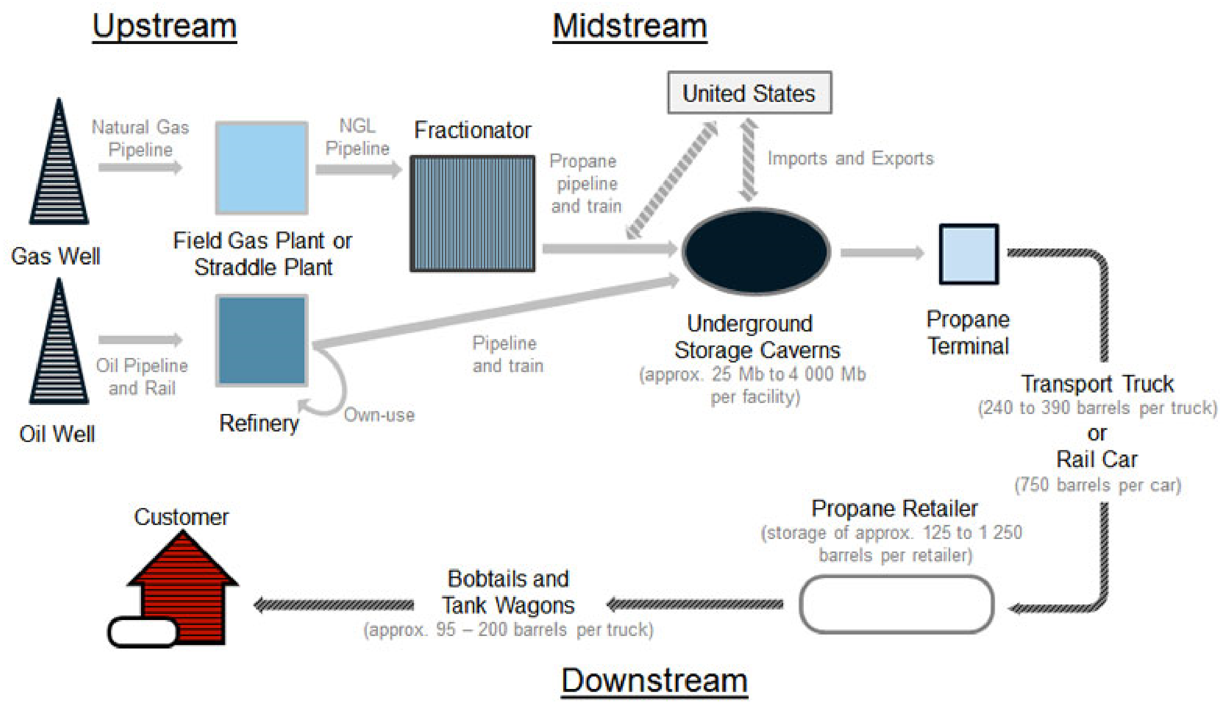
[6] Gas Processing Management Inc. Prepared for the Canadian Propane Association, *Canadian Propane Market Review*, October 2014

[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]

[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.

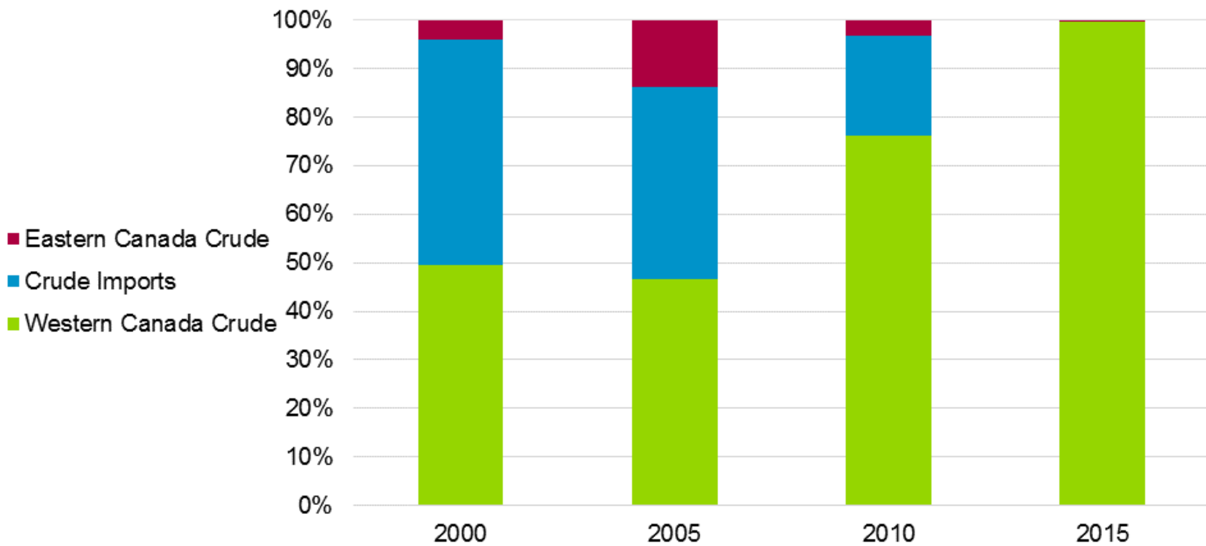
This sub-section discusses supply chain considerations for both crude oil and oil products.

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

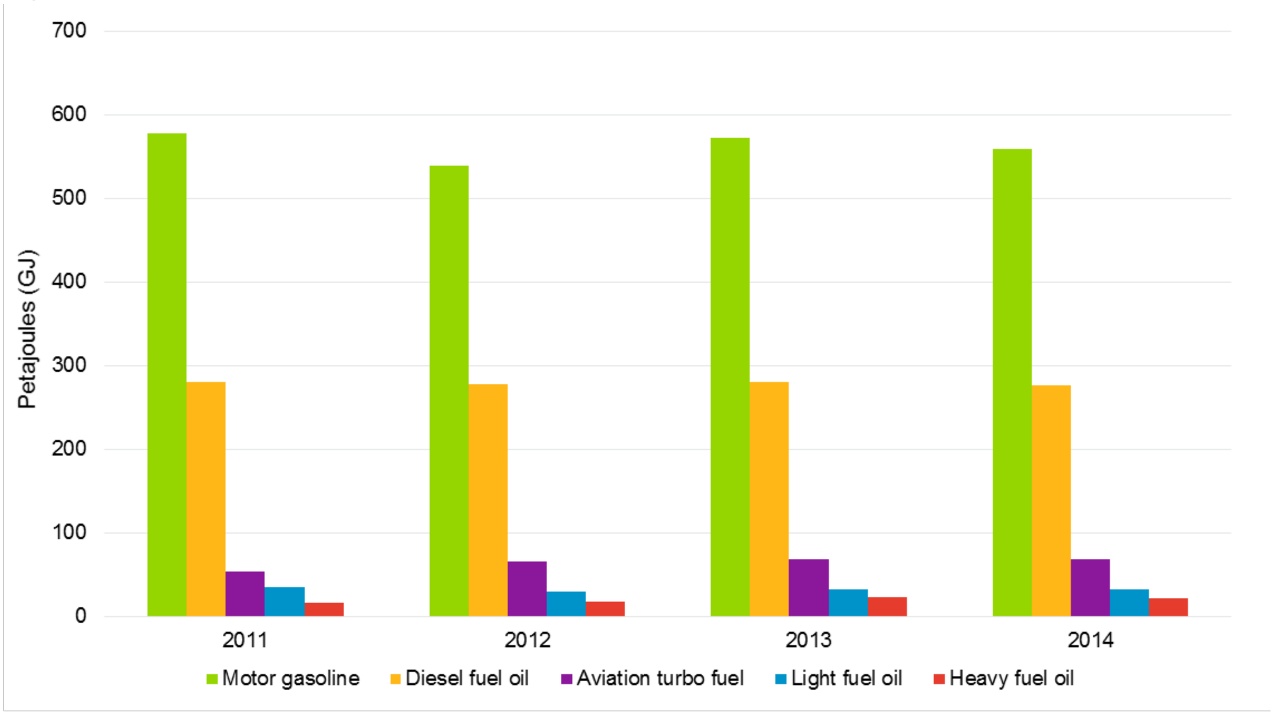
[12] Statistics Canada, Table 134-0001: Refinery Supply of Crude Oil and Equivalent, Annual

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]

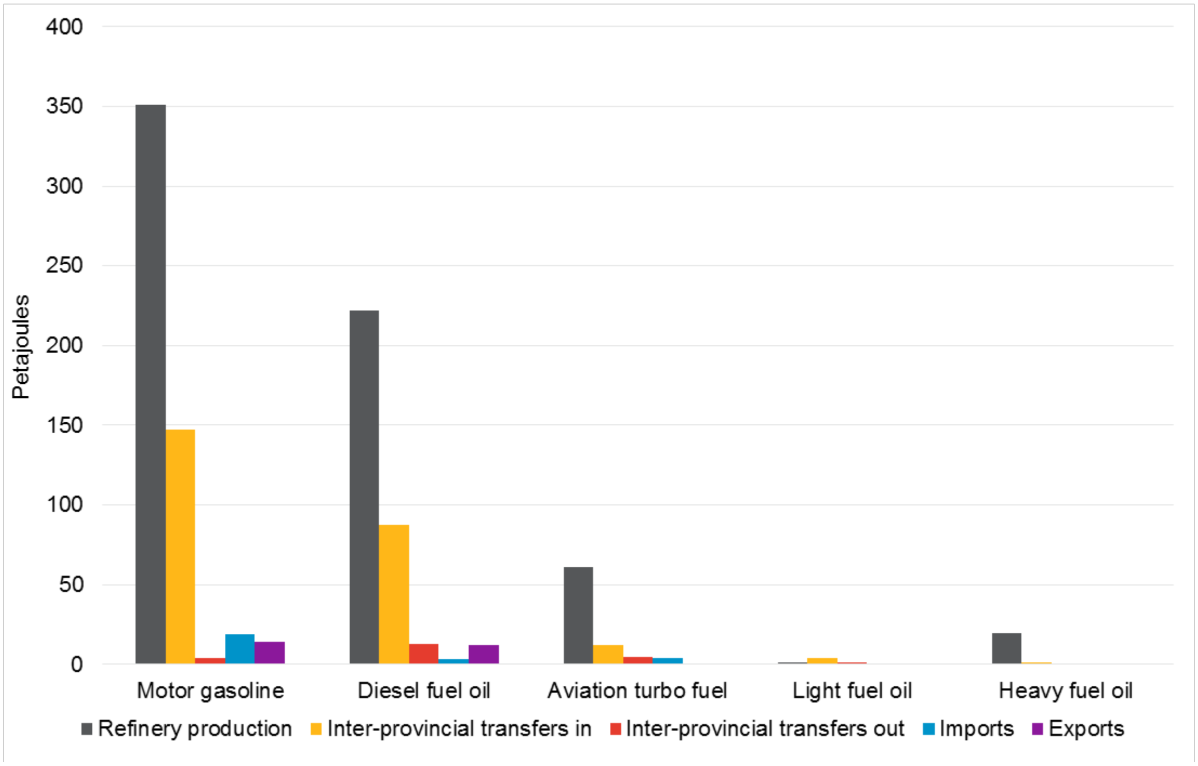
Ontario refiners produce the majority of oil products used in Ontario, but do not produce enough oil products to supply Ontario's total demand. The province relies on out-of-province supply to fully satisfy demand, primarily supplied from Quebec. Given Ontario's reliance on imports, price and supply 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.

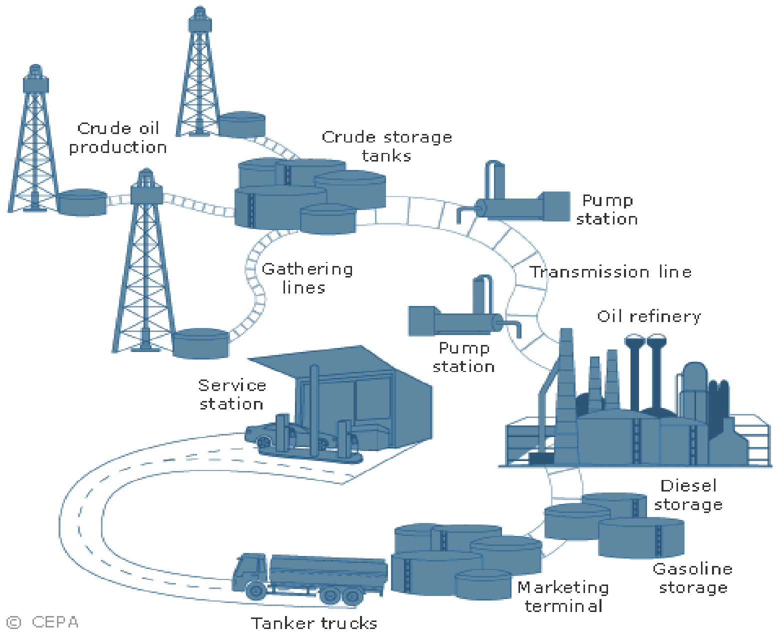
Once at a refinery, crude oil is processed into a variety of oil products. Oil products are then transported by pipeline, rail, marine and truck to end-users and distribution terminals. From primary distribution terminals, oil products are typically delivered to the final distribution point (e.g., gas 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



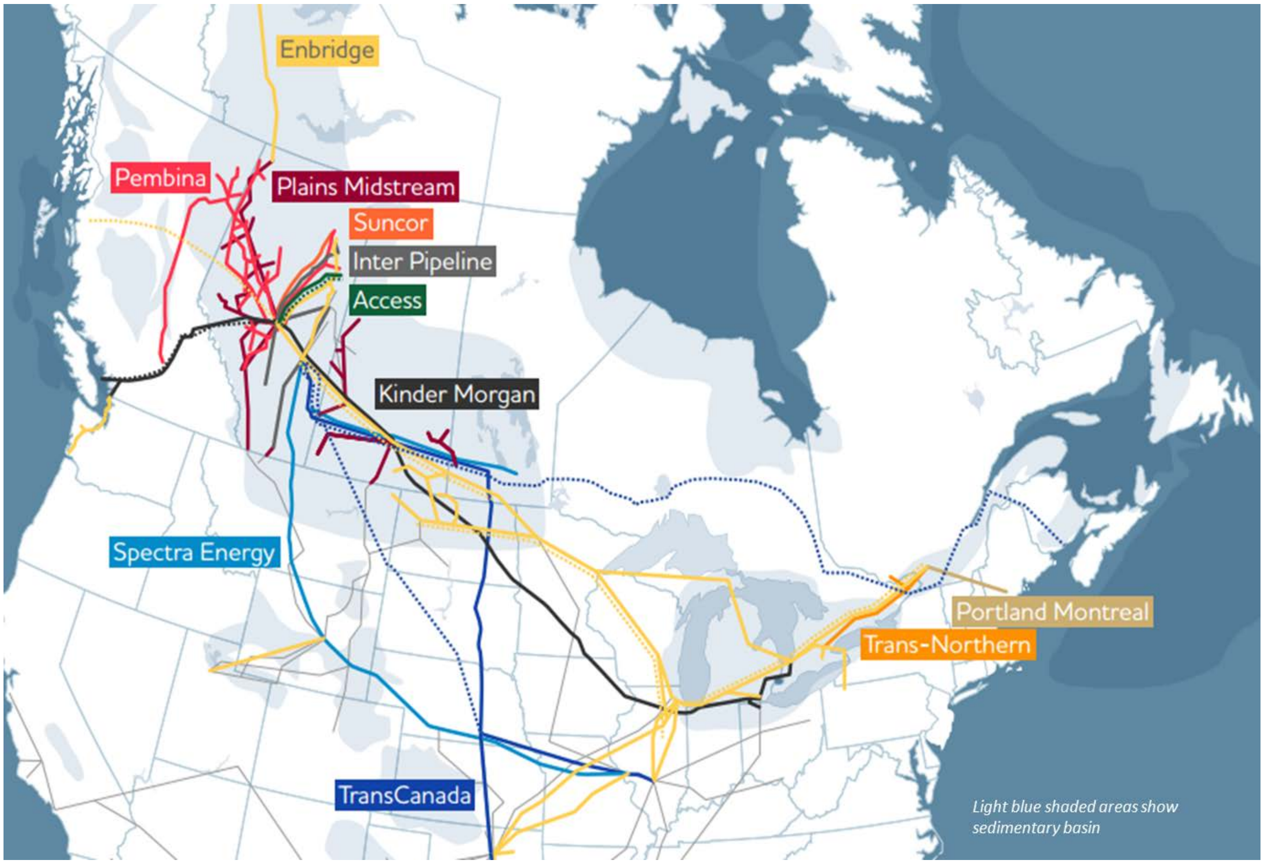
Source: Canadian Energy Pipeline Association (CEPA), 2016.[17]

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

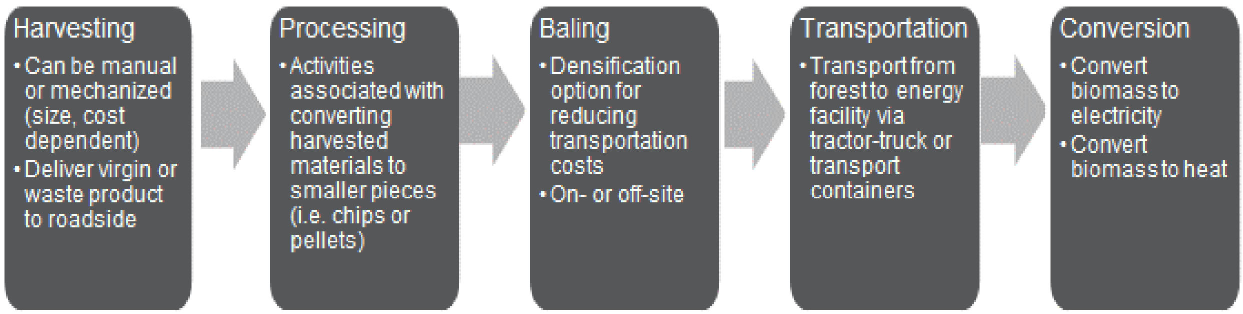
In 2015, Ontario consumed approximately 91 PJ of wood and biomass energy supplied primarily by local sources for residential, commercial and industrial processes.

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.

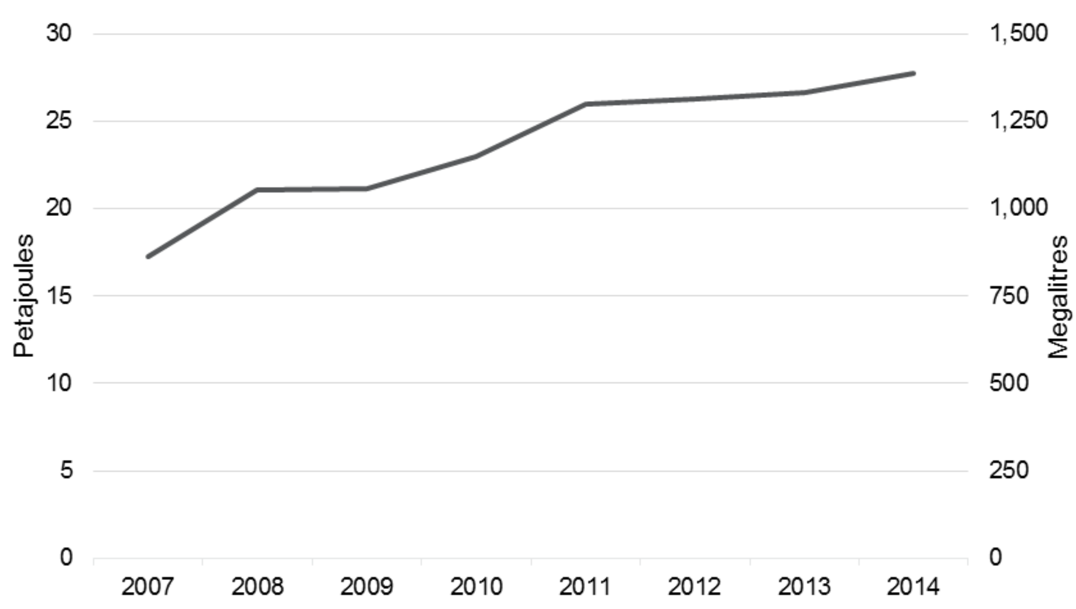
Due to differences between the renewable fuels, each of ethanol, biodiesel/renewable diesel and biogas / RNG are discussed in turn.

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**	

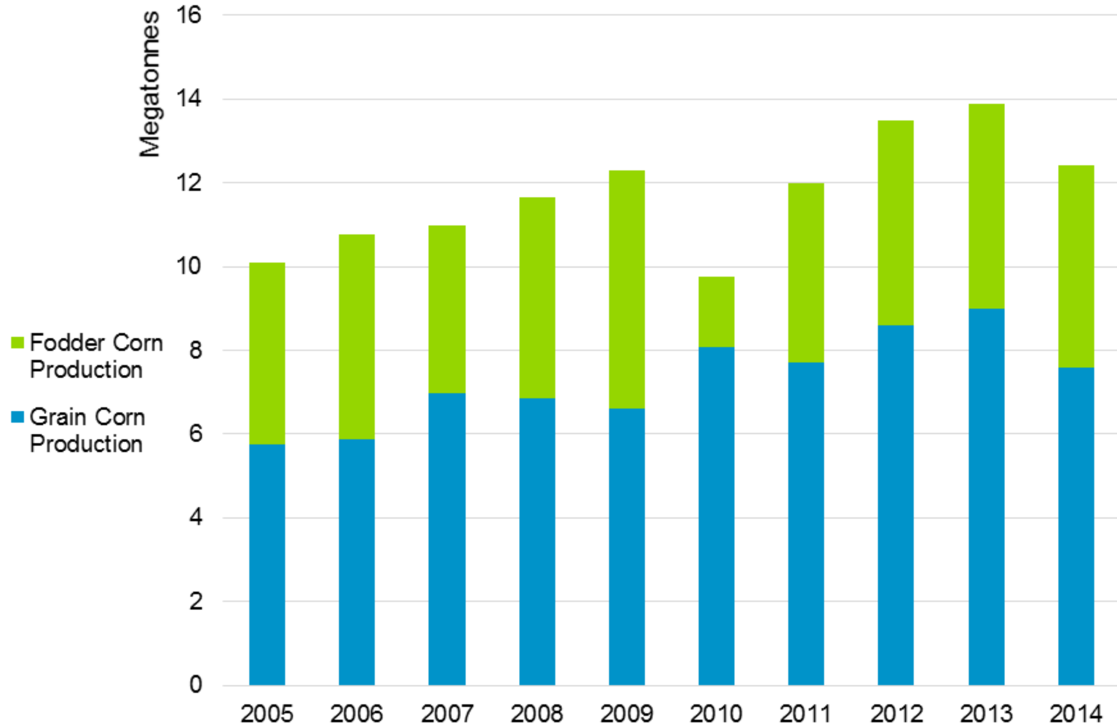
1.5.1.2 Delivery

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.

[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

DEMAND OUTLOOKS - GLOSSARY

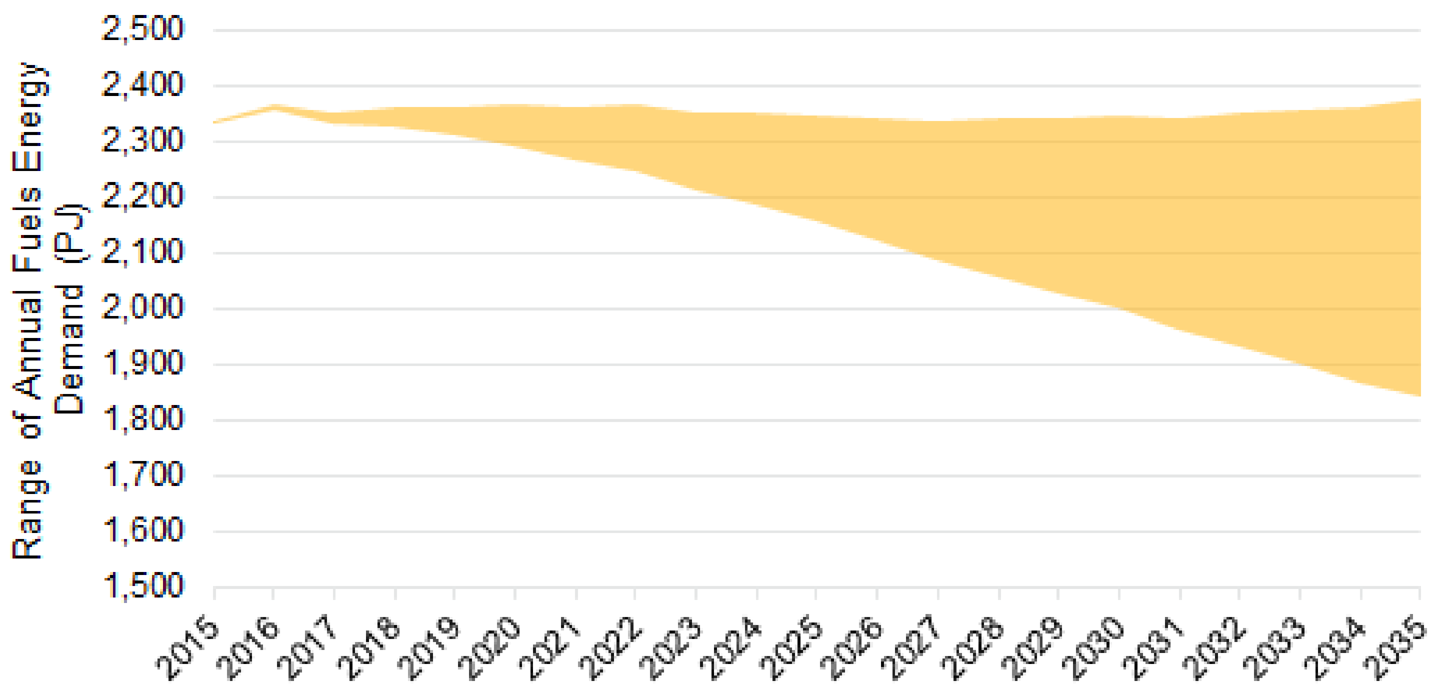
The following acronyms appear throughout this module:

- 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

ALL SECTORS

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.

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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.

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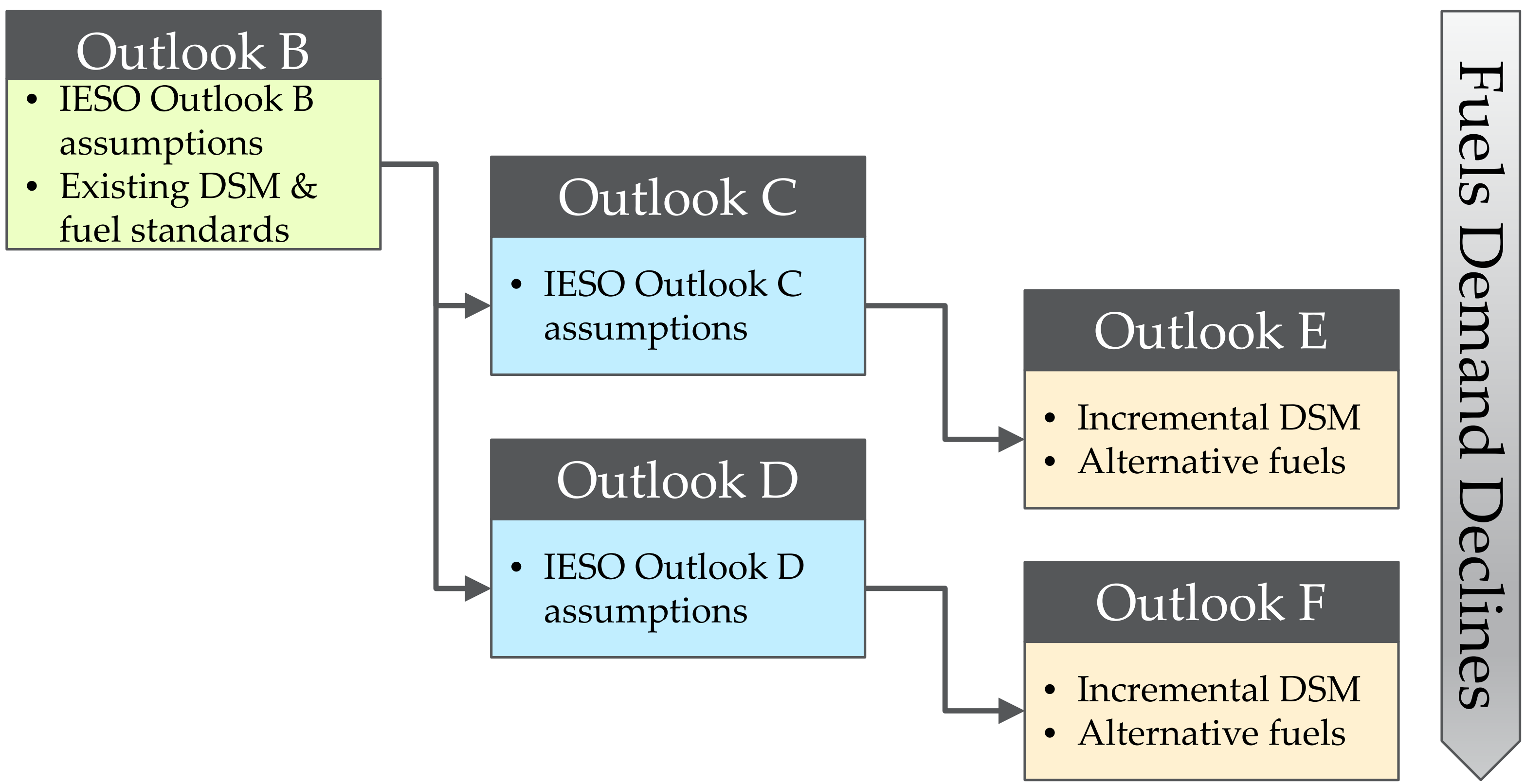
DEMAND OUTLOOK (CONT'D)

- 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.



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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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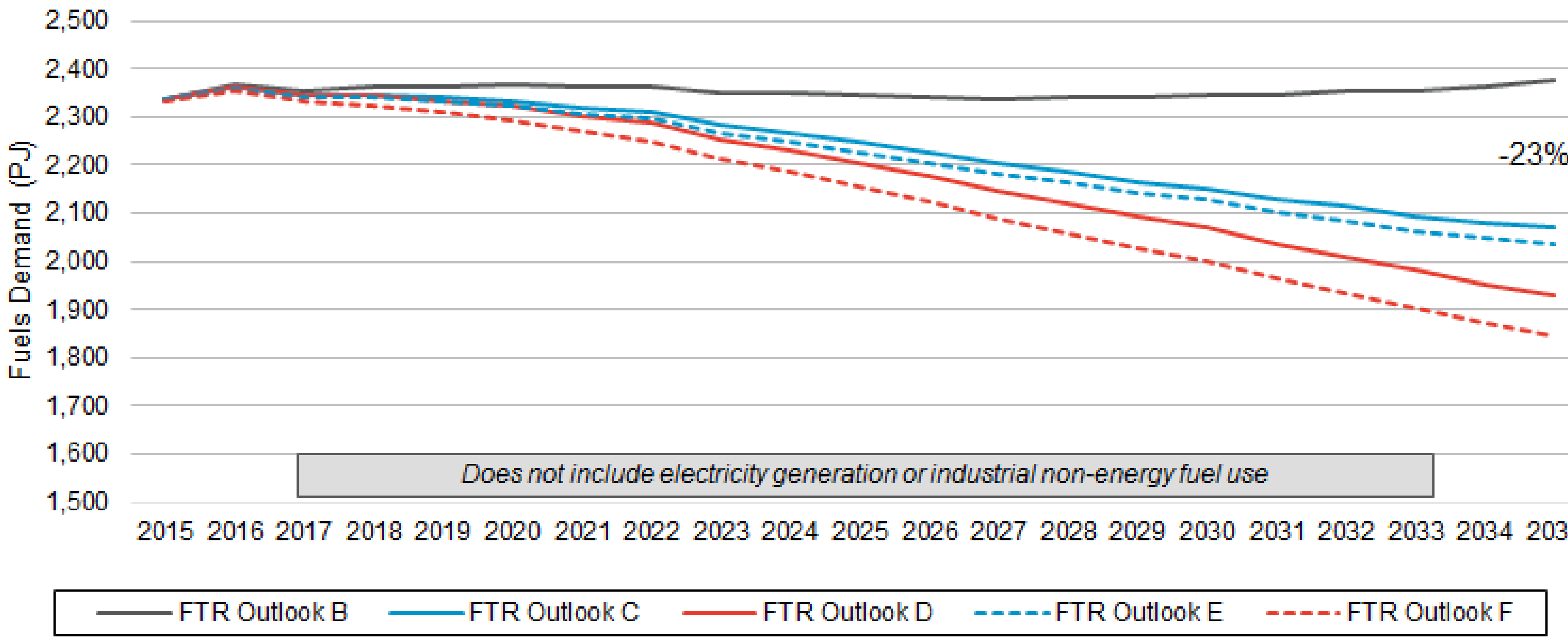
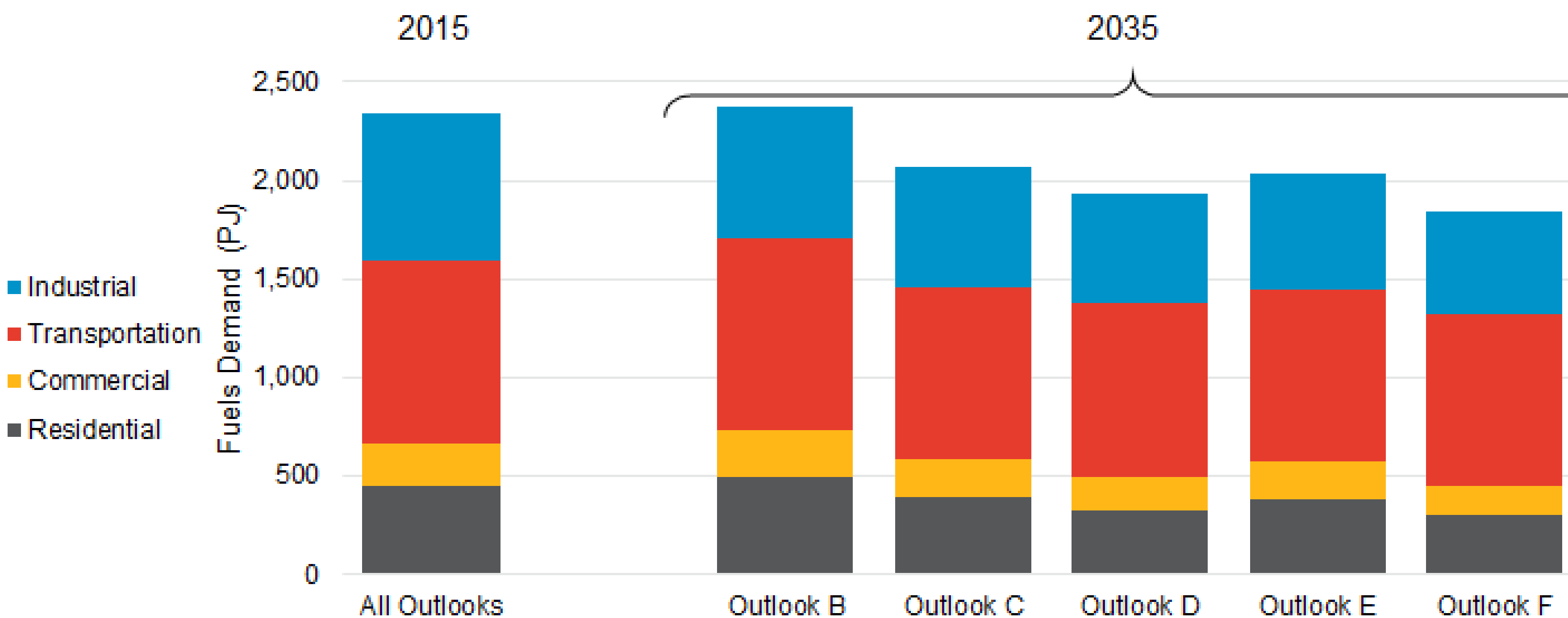
ANNUAL NET FUELS ENERGY DEMAND ACROSS DEMAND OUTLOOKS



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	740
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

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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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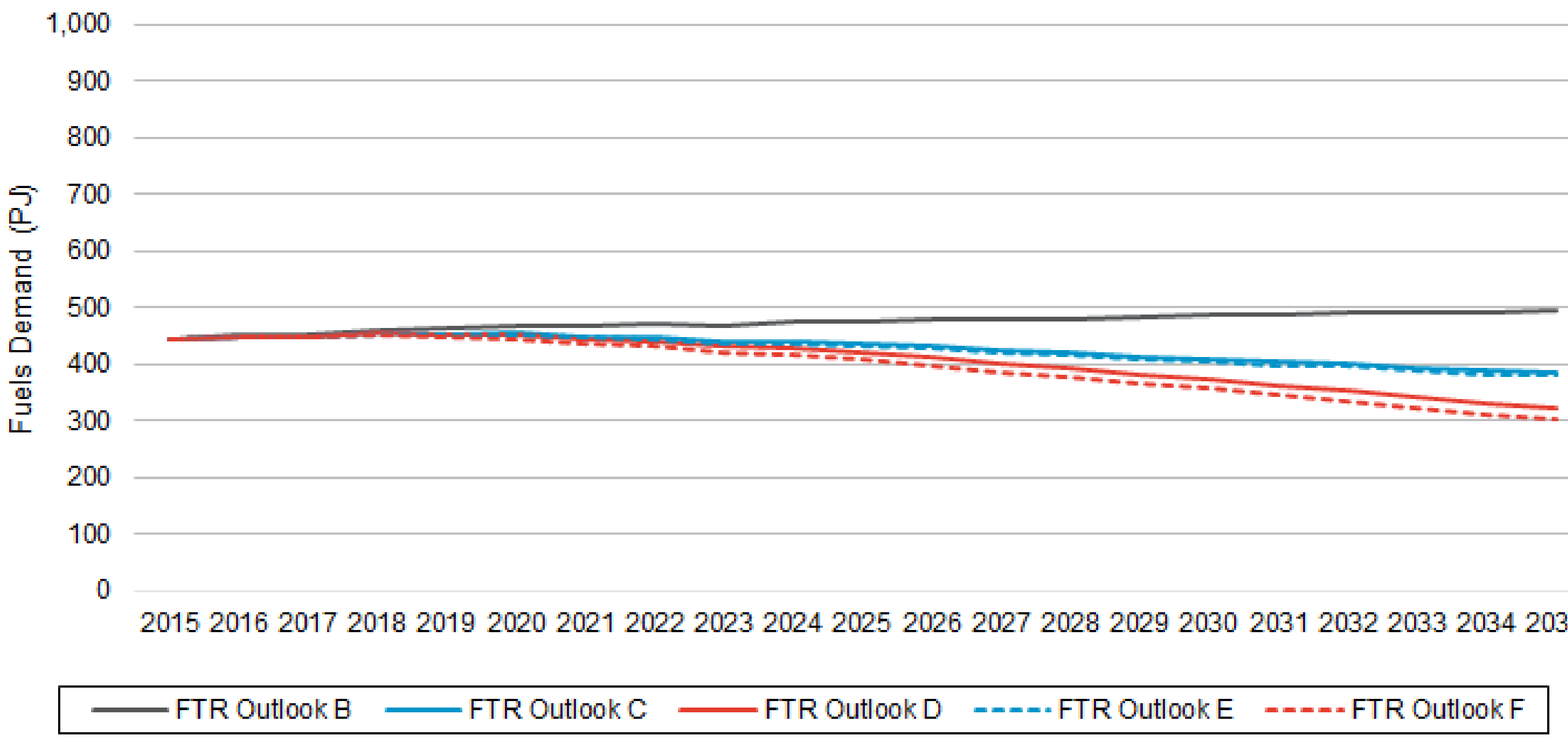
RESIDENTIAL SECTOR

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 estimates, and outlook-specific, hence why they differ very slightly across outlooks.

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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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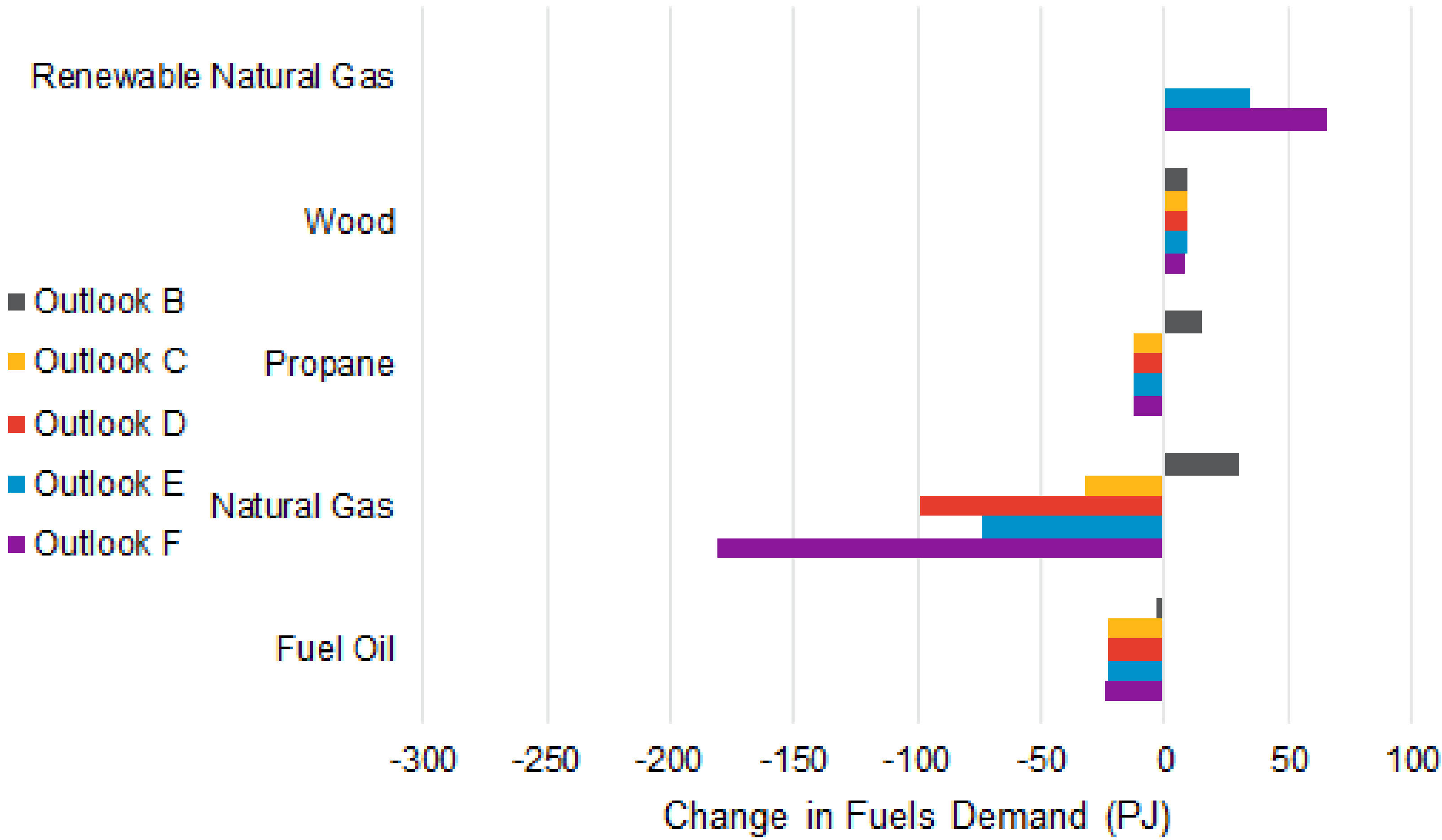
FORECAST CHANGE IN RESIDENTIAL FUELS DEMAND BY FUEL TYPE 2015 - 2035



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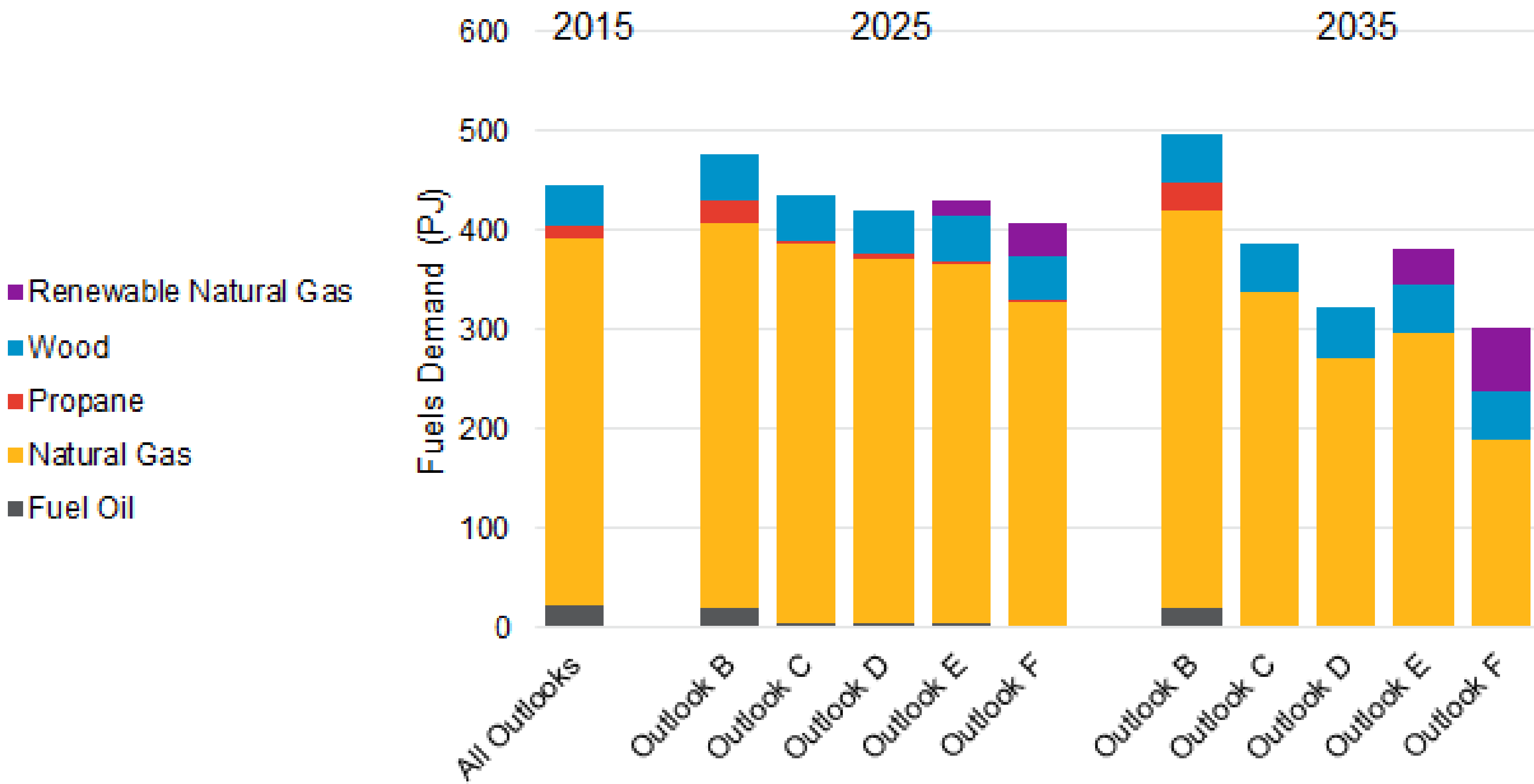
RESIDENTIAL DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F



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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**

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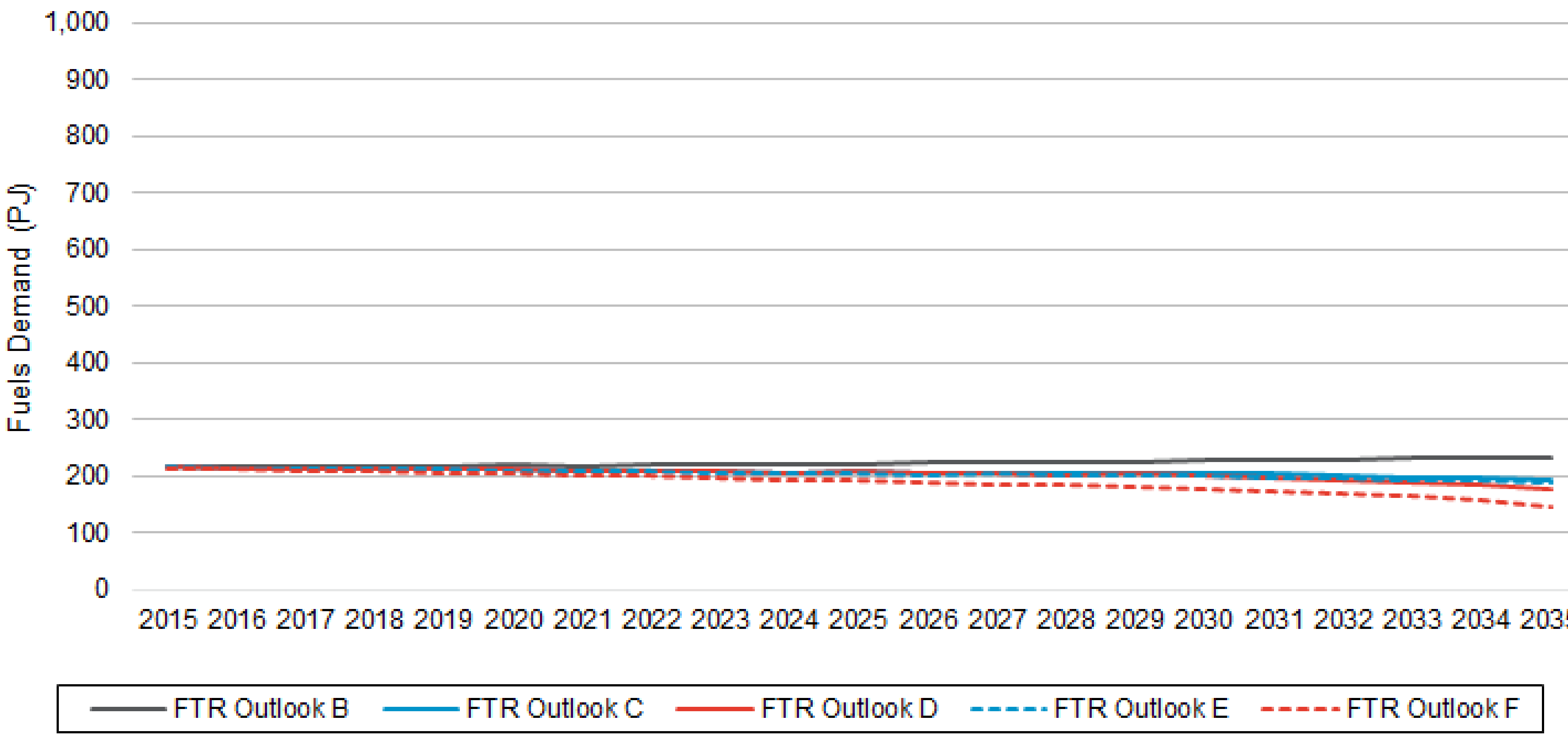
COMMERCIAL

COMMERCIAL FUELS ENERGY DEMAND 2015-2035: OUTLOOKS B, C, D, E, F



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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.

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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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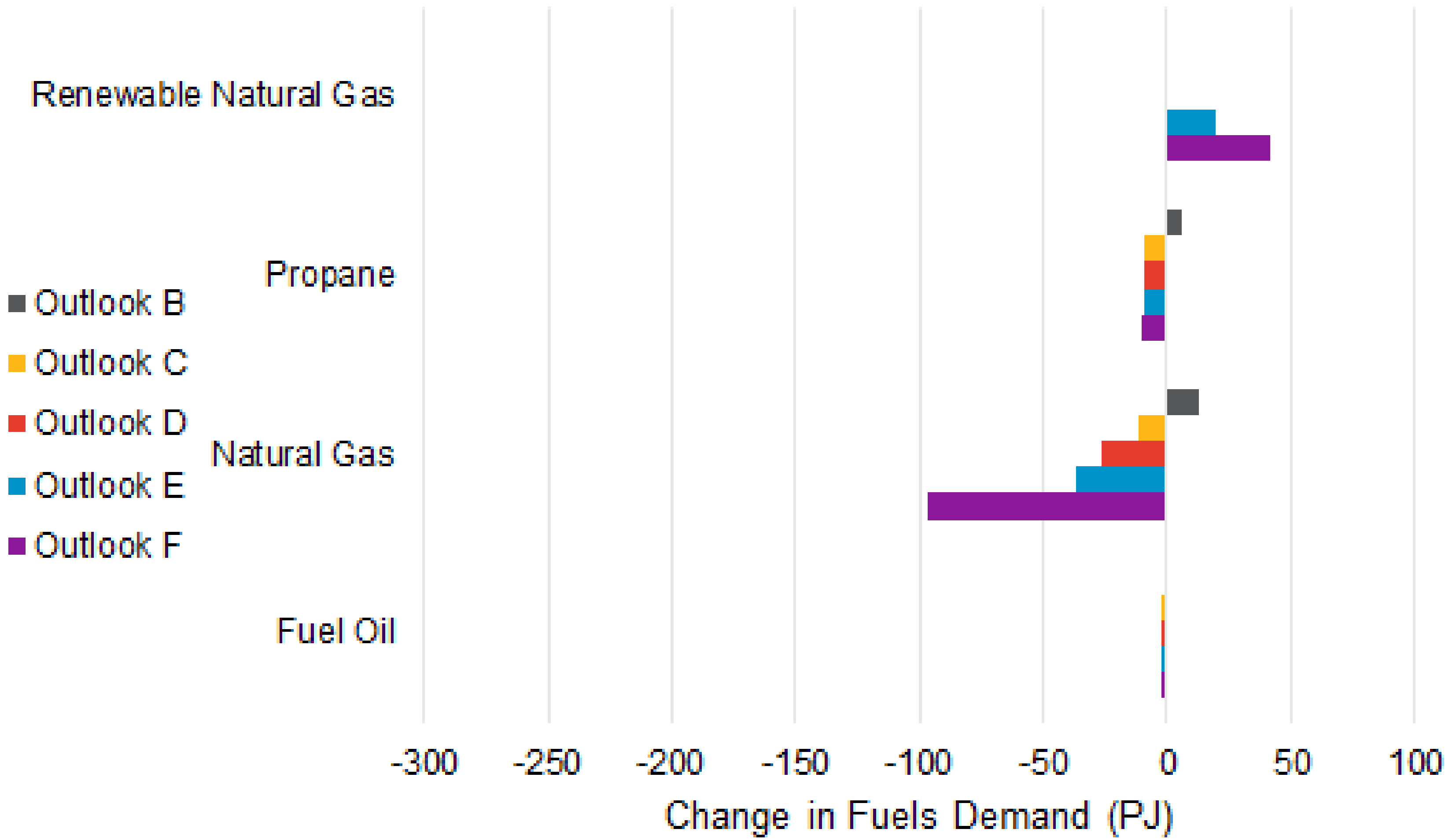
FORECAST CHANGE IN COMMERCIAL FUELS DEMAND BY FUEL TYPE 2015 - 2035



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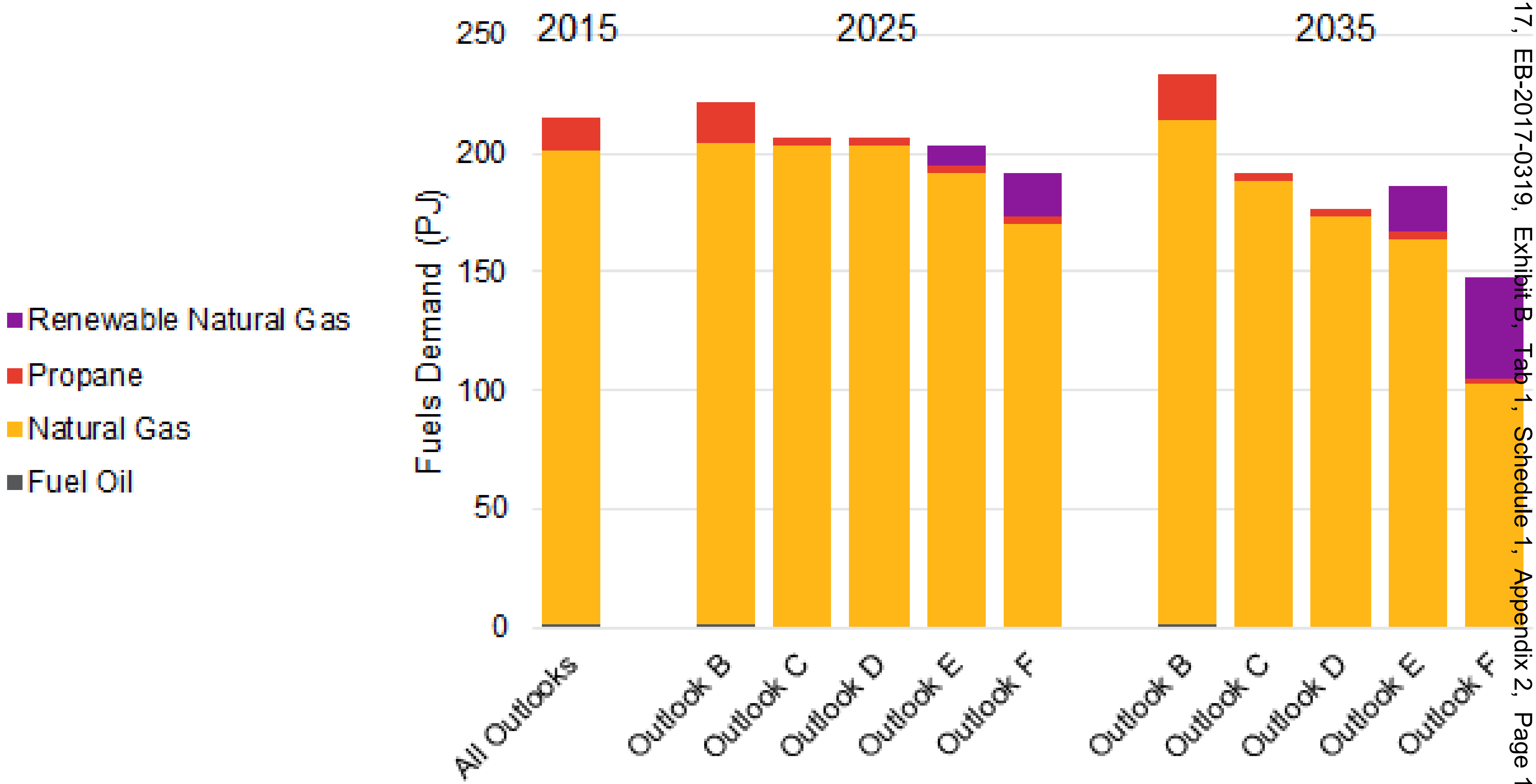
COMMERCIAL DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F

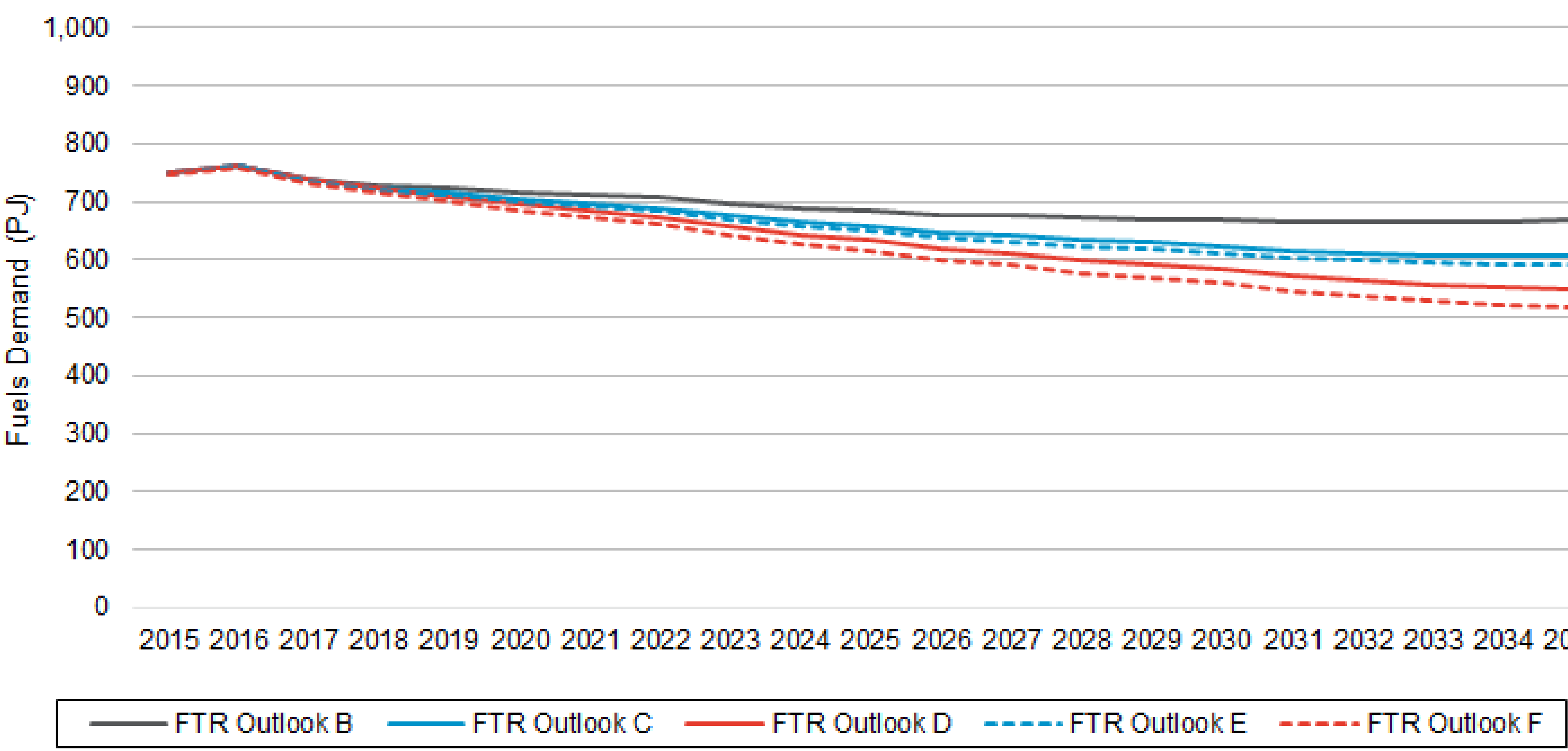


COMMERCIAL DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F

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**

INDUSTRIAL

INDUSTRIAL FUELS ENERGY DEMAND 2015-2035: OUTLOOKS B, C, D, E, F



Note: does not include industrial non-energy fuels demand

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NAVIGANT

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 estimates, and outlook-specific, hence why they differ very slightly across outlooks.

Note: does not include industrial non-energy fuels demand

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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.

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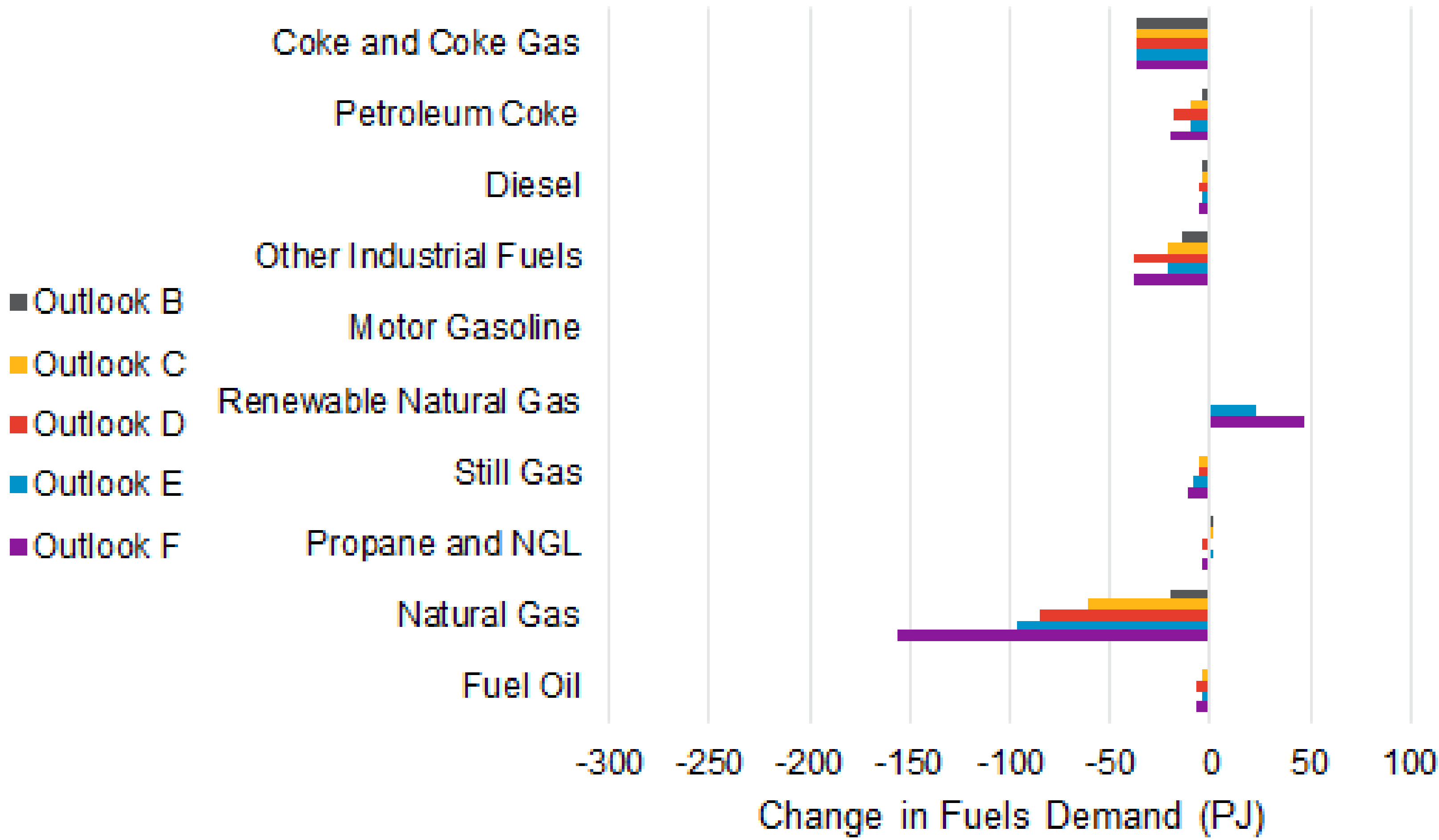
FORECAST CHANGE IN INDUSTRIAL FUELS DEMAND BY FUEL TYPE 2015 - 2035



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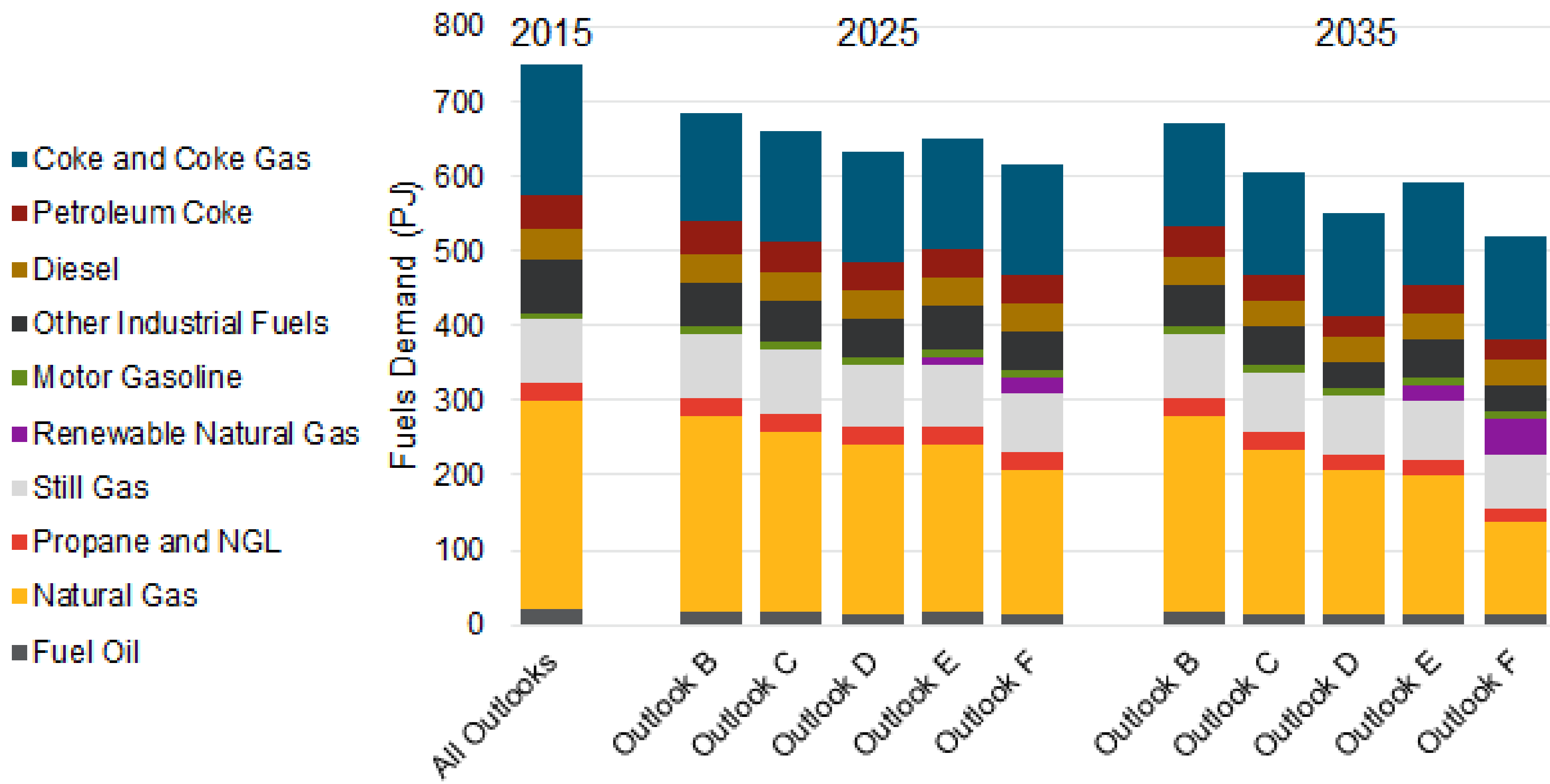
INDUSTRIAL DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F



Note: does not include industrial non-energy fuels demand

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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

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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.

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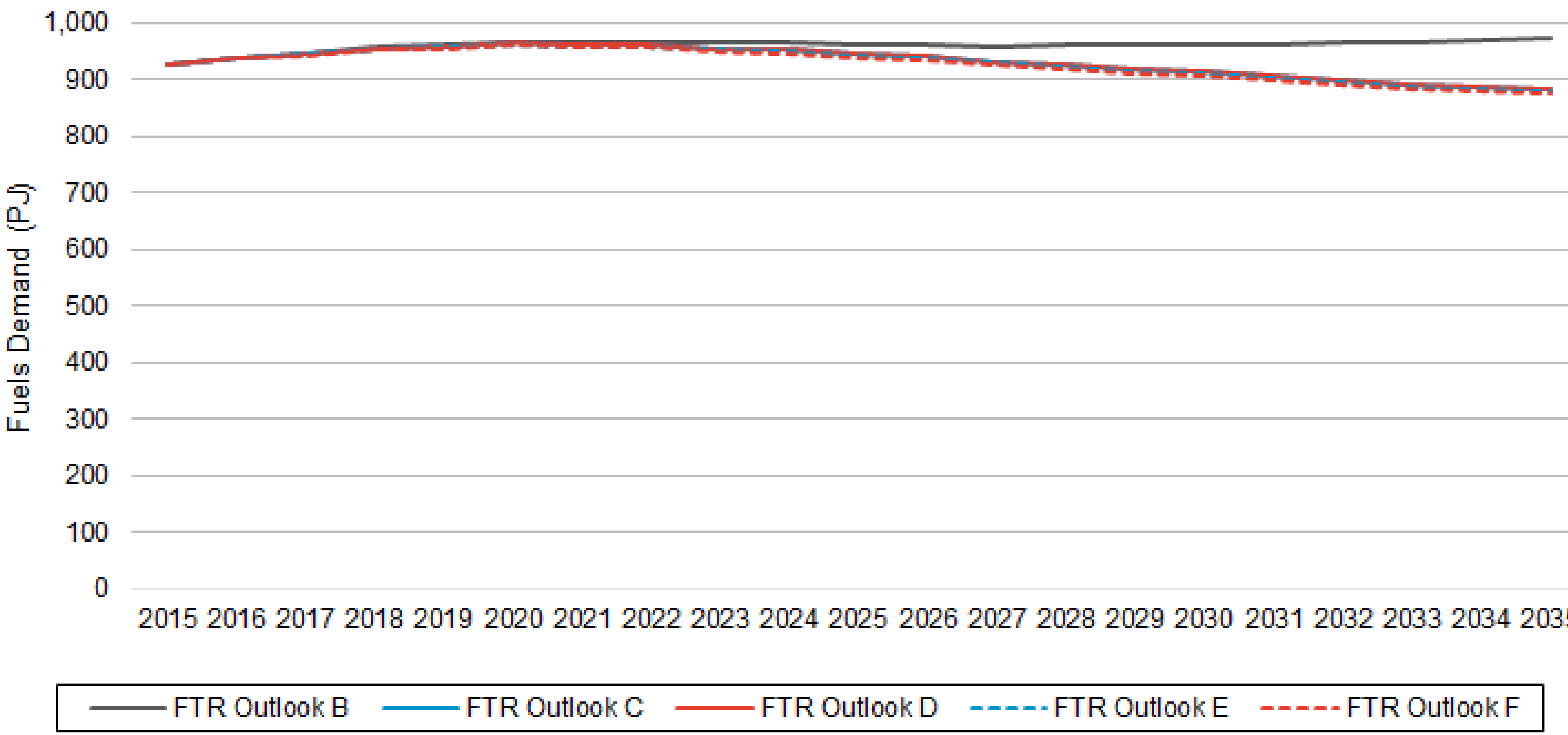
TRANSPORTATION

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 estimates, and outlook-specific, hence why they differ very slightly across outlooks.

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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.

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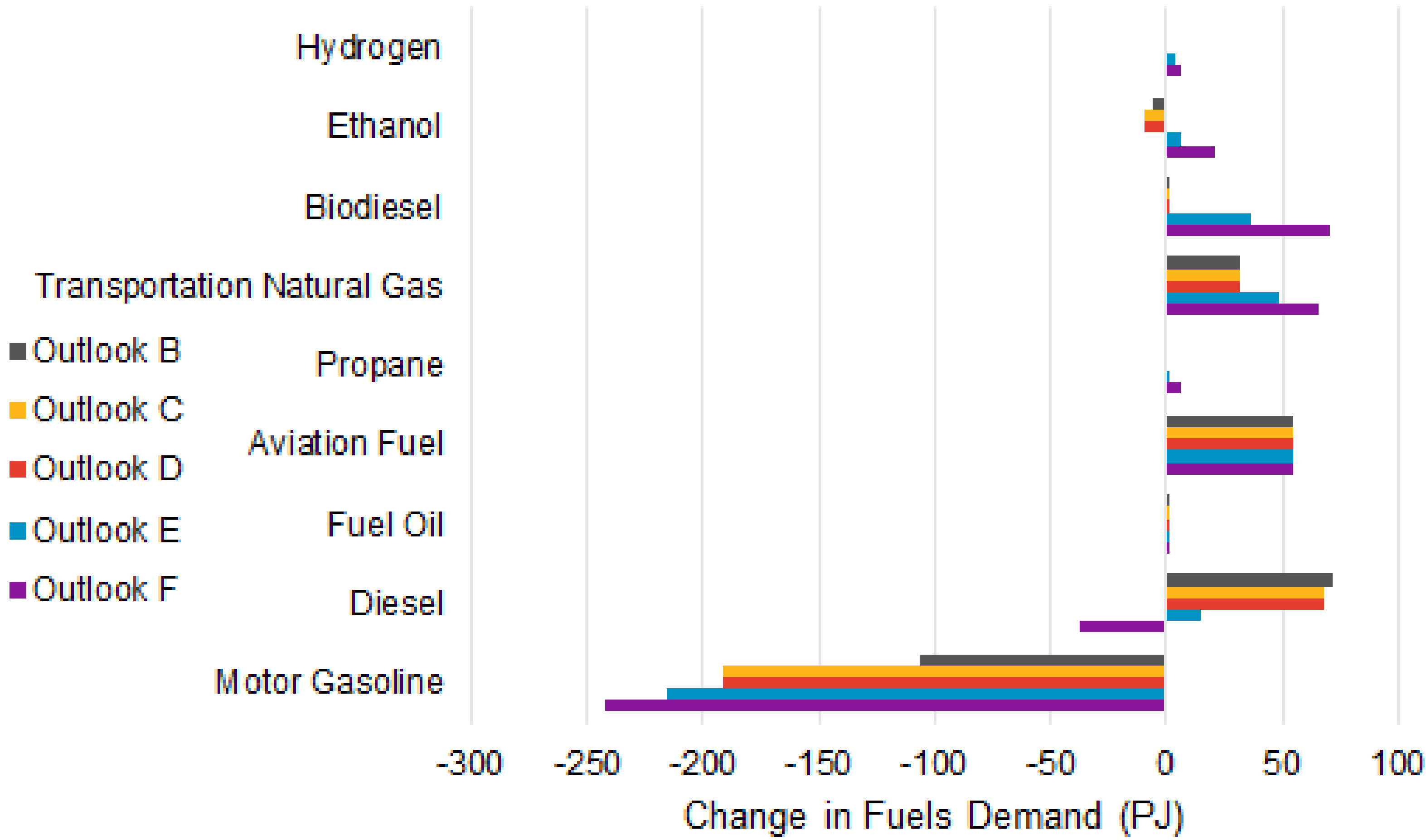
FORECAST CHANGE IN TRANSPORTATION FUELS DEMAND BY FUEL TYPE 2015 - 2035



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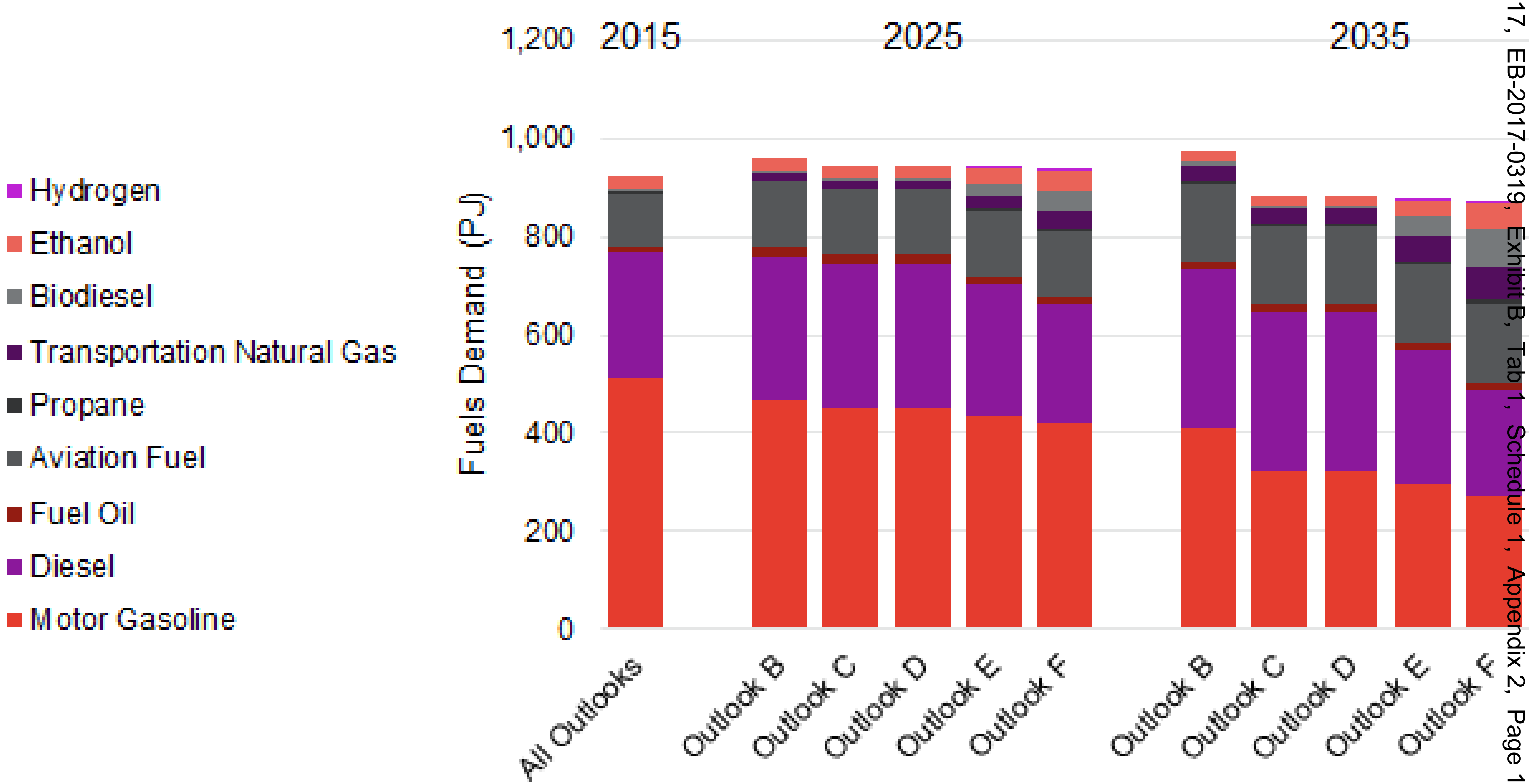
TRANSPORTATION DEMAND BY FUEL TYPE (PJ), 2015, 2025, 2035: OUTLOOKS B, C, D, E, F



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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**

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FUELS TECHNICAL REPORT – MODULE 3: EMISSIONS OUTLOOK

SEPTEMBER 2016

NAVIGANT REFERENCE 187360

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.

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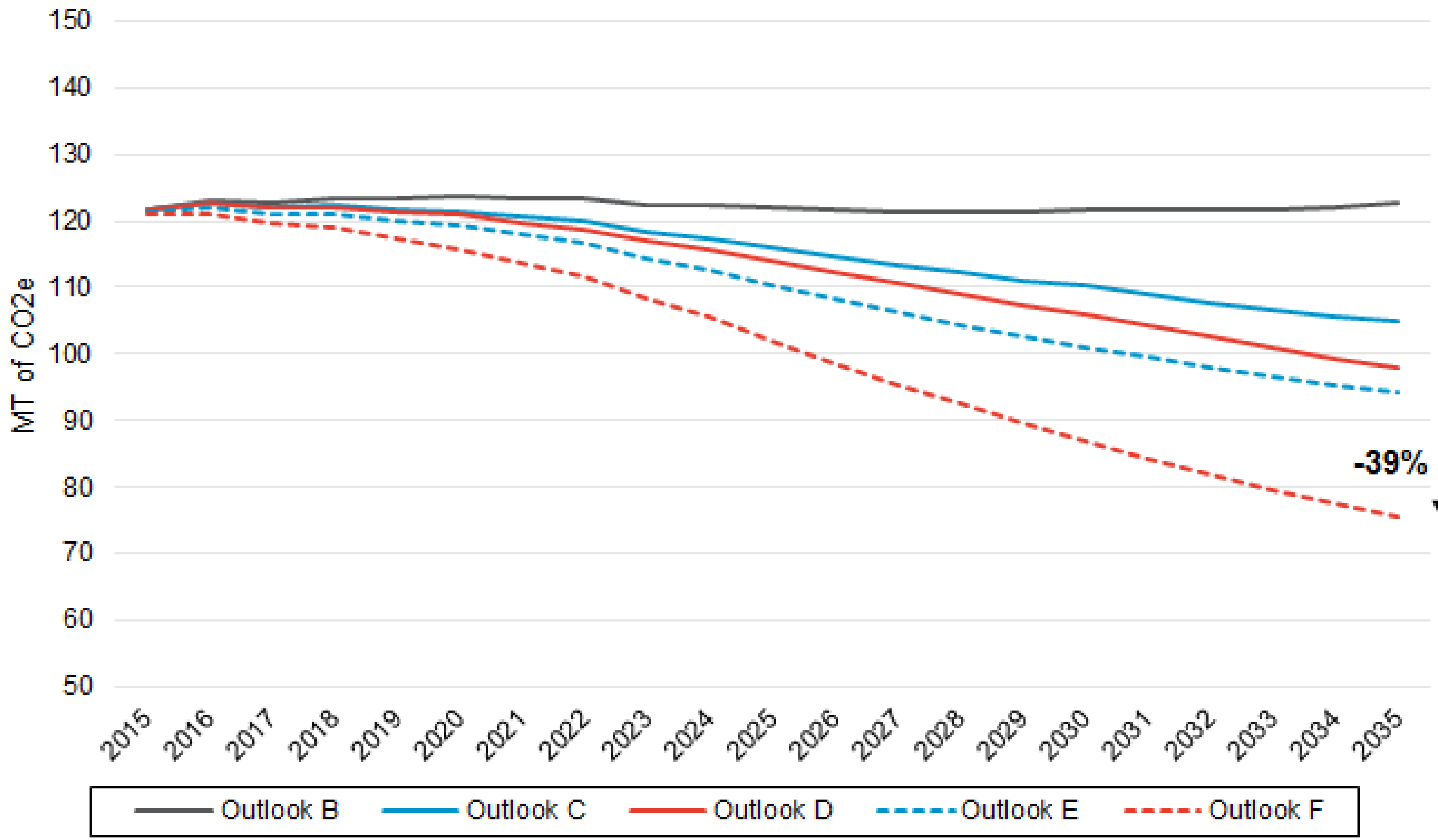
FUELS COMBUSTION GHG EMISSIONS OUTLOOK



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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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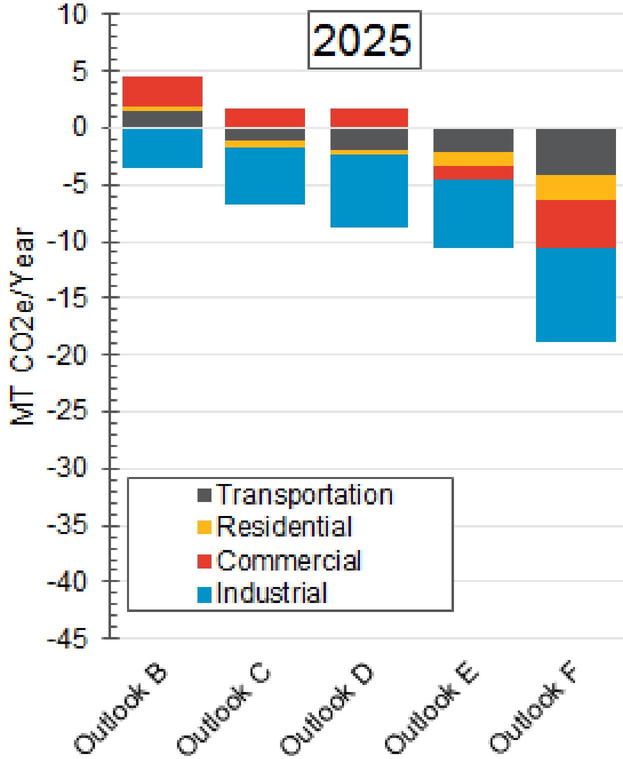
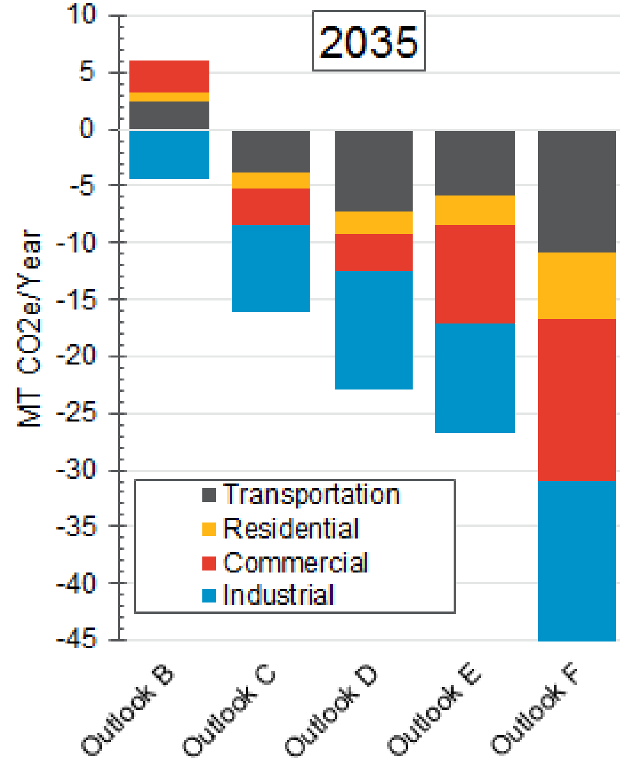
EMISSIONS RELATIVE TO 2014 LEVELS





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

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

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

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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

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

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.

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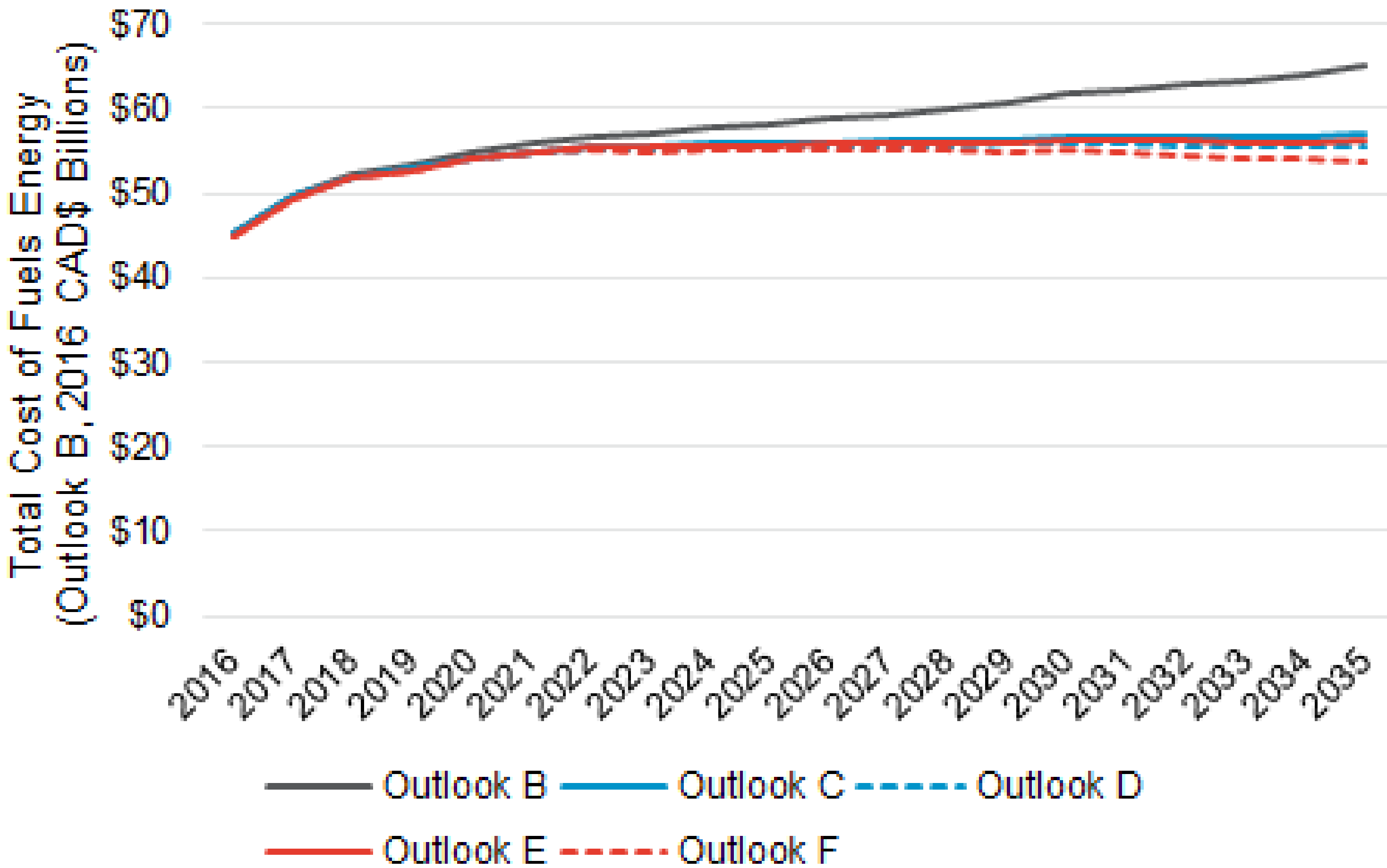
FUELS SYSTEM COST OUTLOOK

TOTAL SYSTEM COSTS



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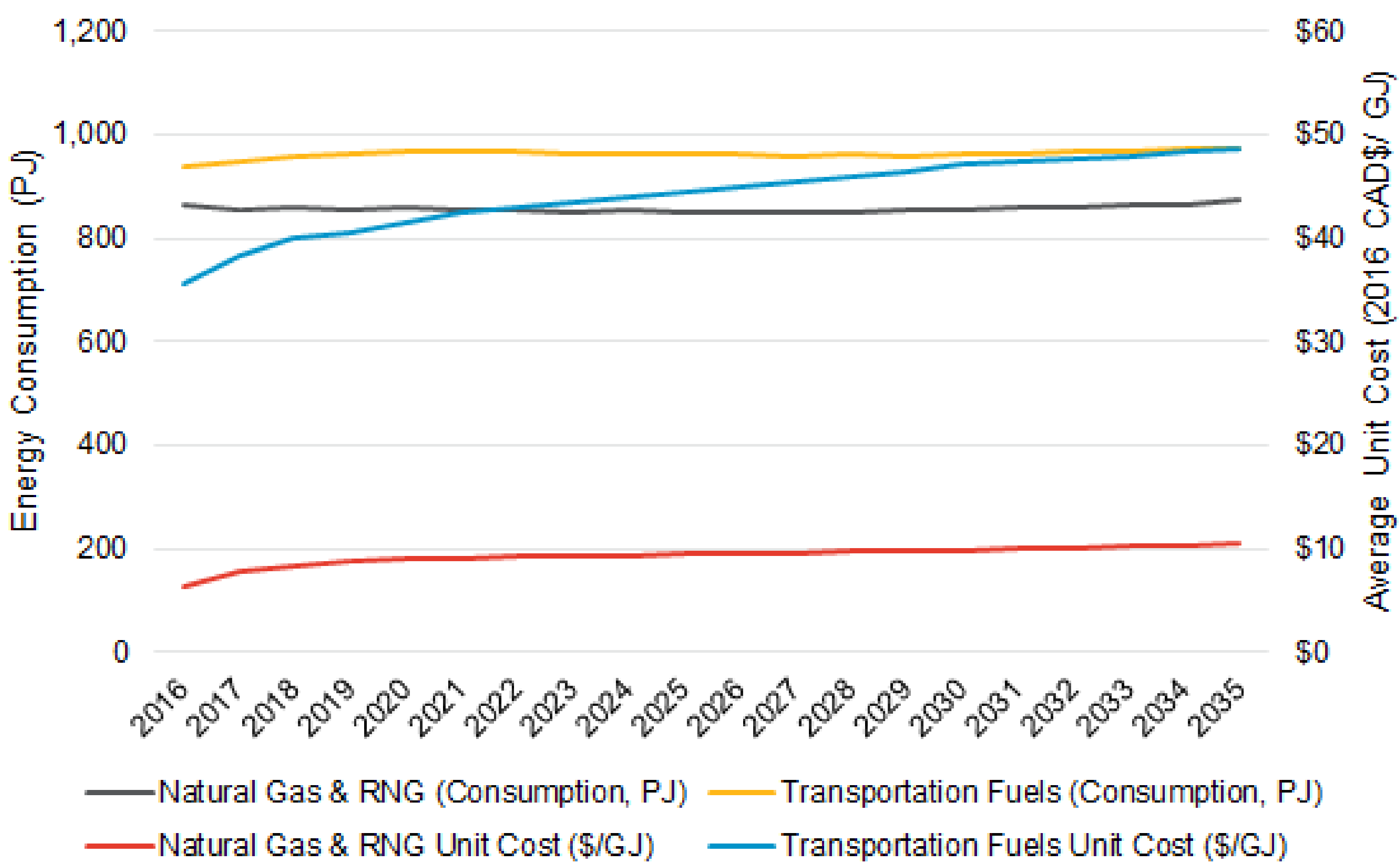
TOTAL SYSTEM COSTS (2016 CAD$ BILLIONS)

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



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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

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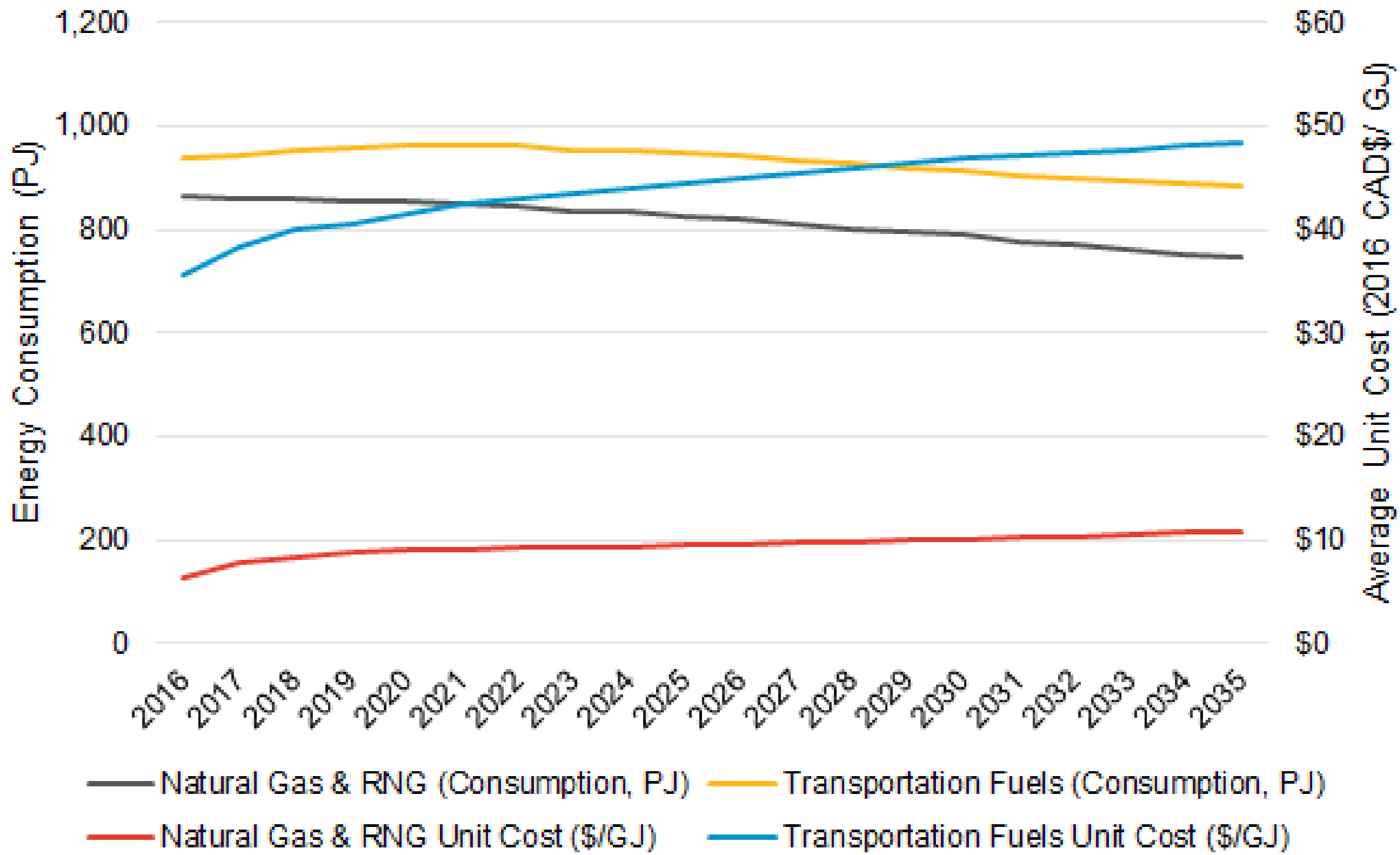
AVERAGE UNIT COSTS – OUTLOOK C



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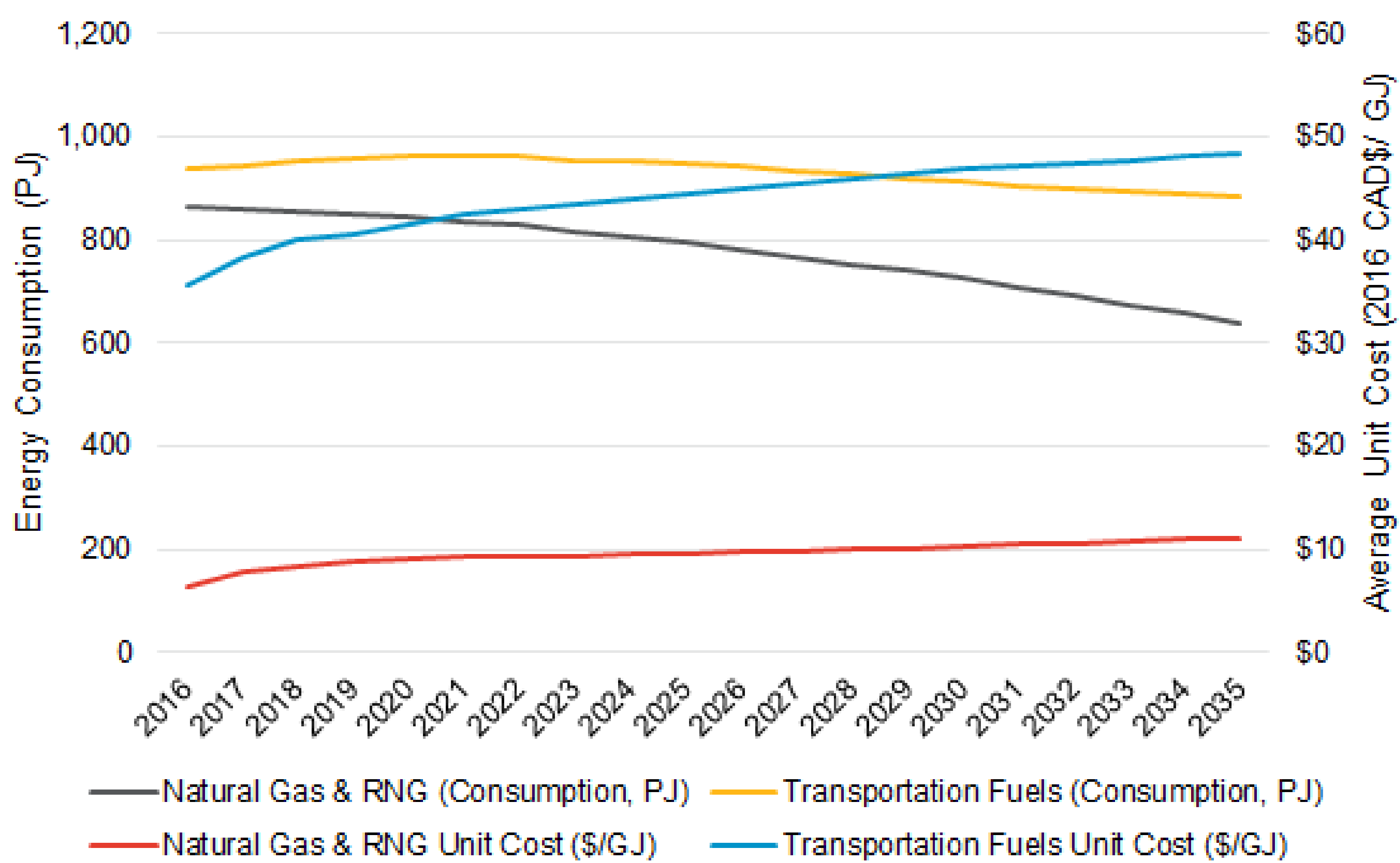
AVERAGE UNIT COSTS – OUTLOOK C

	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

AVERAGE UNIT COSTS – OUTLOOK D



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

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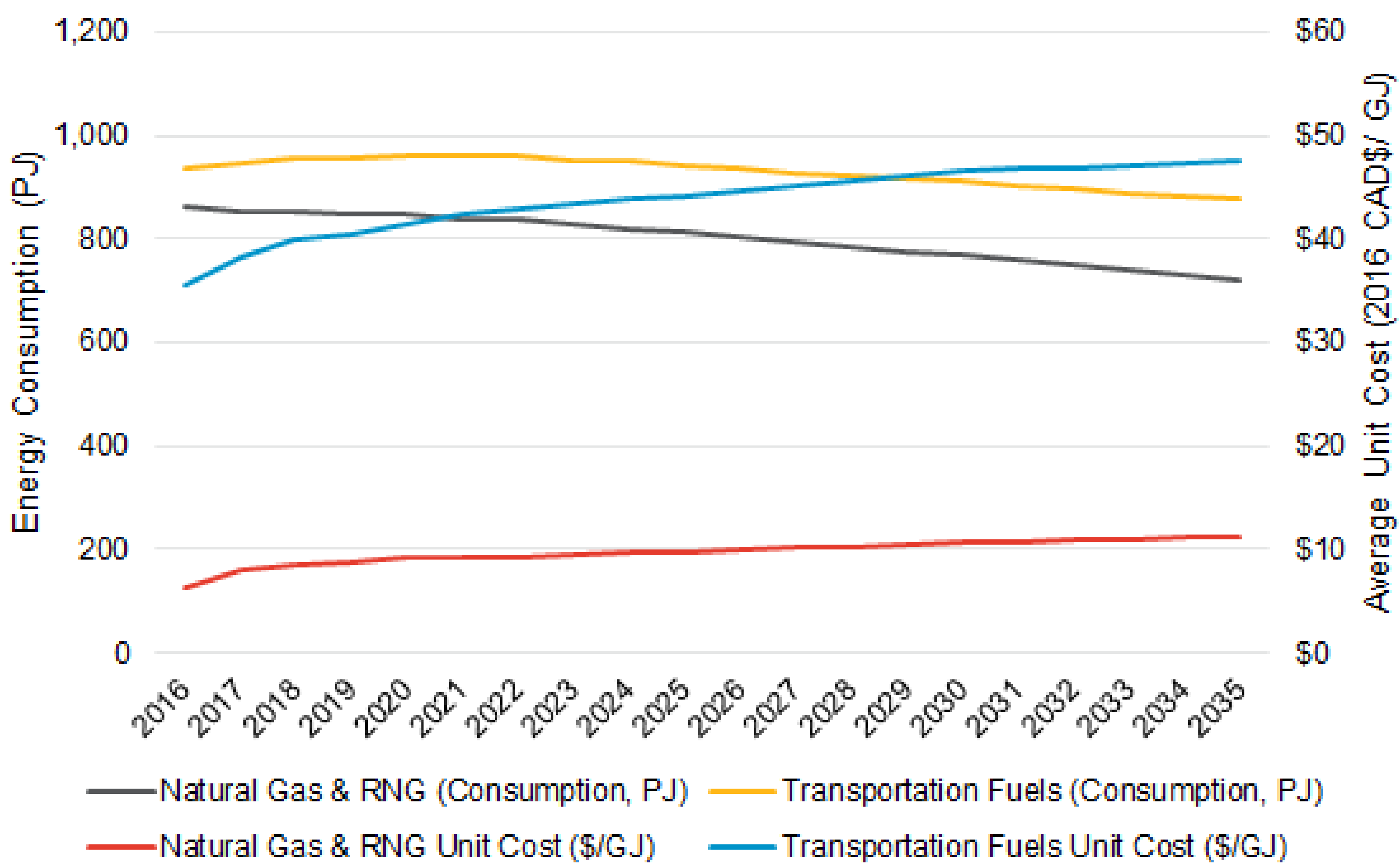
AVERAGE UNIT COSTS – OUTLOOK E



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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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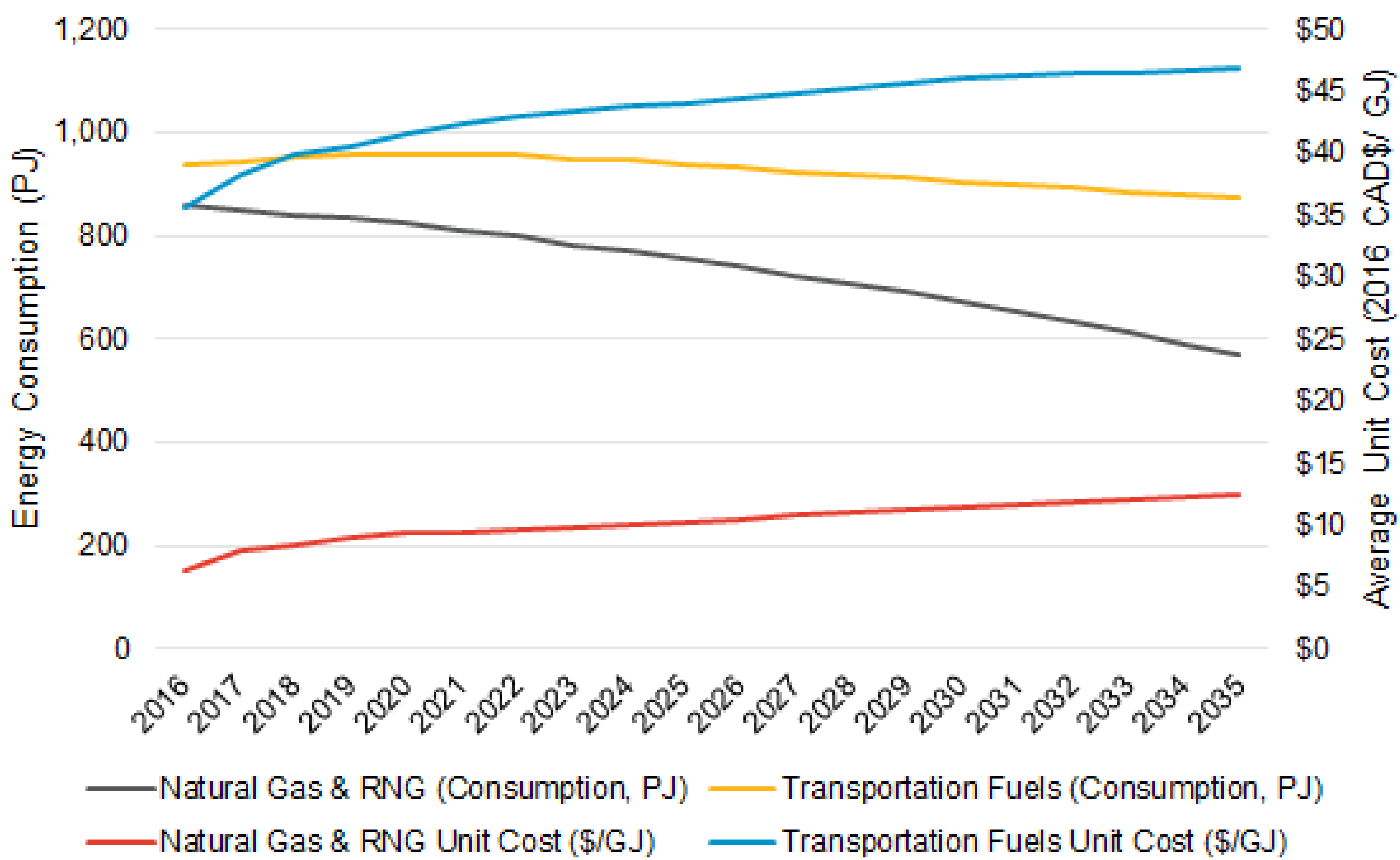
AVERAGE UNIT COSTS – OUTLOOK F



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

NAVIGANT

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

APPENDIX

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/

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.

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

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

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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

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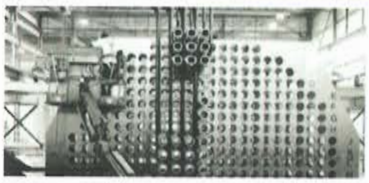
NAVIGANT

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



ONTARIO'S
LONG-TERM
ENERGY PLAN
2017

Delivering Fairness and Choice

Ontario

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2017 Long-Term Energy Plan

Minister's Message

Ontario's 2017 Long-Term Energy Plan is principally focused on the consumer while ensuring a reliable and innovative energy system. *Delivering Fairness and Choice* makes an important commitment: we will strive to make energy more affordable, and give customers more choices in their energy use, ensuring that Ontarians and their families continue to be at the center of everything we do.

Ontarians are benefiting from the years of investment we have made in the province's electricity system. We can be proud of what we have all accomplished. These investments mean we no longer have to worry about brownouts or blackouts. By eliminating coal-fired generation, we now have an electricity system that is more than 90 per cent free of emissions that cause climate change. The phase-out of coal-fired generation and our investments in clean generation have contributed to dramatically improved air quality in Ontario – smog advisories have dropped from 53 as recently as 2005 to zero in 2016. This means that our children can play outside without their health being threatened by smog and air pollution. Our investments are delivering a robust supply of electricity, one that is expected to meet Ontario's electricity demand into the middle of the next decade, and makes us well positioned to plan for and meet future challenges. Our success in building a clean and reliable electricity system means we can maintain our focus on helping Ontarians and their families.

We have already taken steps through Ontario's Fair Hydro Plan to make the electricity system as affordable as possible. Ontario's Fair Hydro Plan reduced electricity bills for residential consumers by an average of 25 per cent and will hold any increases to the rate of inflation for four years. These benefits aren't limited to residential consumers; as many as half a million small businesses and farms are also benefiting from the reduction. Lower-income Ontarians and those living in eligible rural and northern communities are receiving even greater reductions, as much as 40 to 50 per cent. These measures were the right thing to do. They're better for Ontario, and fairer for families.

Delivering Fairness and Choice would not have been possible without your suggestions and advice. This Plan is the product of the most extensive consultations and engagements my ministry has ever undertaken. Thousands of organizations, communities, businesses and citizens wrote to us. Hundreds came to the 17 open houses that were held across the province. We also engaged with representatives of more than 100 different First Nation and Métis organizations and communities.

In written submissions and at meetings, you told us that affordability is a top priority and that you wanted more control and choice over how you use and pay for electricity. Our government has listened to what you had to say. *Delivering Fairness and Choice* recognizes that a retired couple in London uses energy differently than a condo-dweller living in Vaughan. Pricing pilots are underway to help inform new electricity pricing plans that could give consumers greater choice, and the ability to reduce their monthly electricity bills.

Delivering Fairness and Choice ensures that consumer protection remains a top priority for this government. We have already given the Ontario Energy Board the authority to prohibit disconnections when customers are more vulnerable, such as over the winter months. We will now give added protection to consumers living in condominiums and other multi-unit residential buildings who are billed for electricity by private companies that provide metering services to their unit. These consumers will benefit from increased oversight of fees charged by those providers. Consumers will also benefit from the Board's new *Consumer Charter*, which ensures all energy consumers have the right to a fair, reasonable and timely process for resolving their complaints.

On another front, the Ministry of Energy is working with local distribution companies to redesign electricity bills to give consumers easily accessible information they find valuable and can use. The electricity bill is, after all, the most common way for consumers to receive information about their electricity system.

Ontario is helping consumers keep pace with rapidly changing technology. The costs of new wind and solar energy installations are coming down, and new smart grid and storage technologies are becoming more readily available. Updates to the Province's net metering framework will increase the ability of consumers to generate their own renewable electricity and receive a credit on electricity bills for any extra power they send to their local distribution company.

All of this is possible because Ontario has a stable electricity system that produces a steady supply of electricity. *Delivering Fairness and Choice* is using this opportunity to move ahead with innovative ideas for managing the system and reducing costs. Initiatives such as Market Renewal will ensure the province has appropriate sources of electricity at the lowest possible price. This initiative could save Ontarians up to $5.2 billion over a 10-year period.

Energy is key to the well-being and prosperity of the people of Ontario. Our plan will ensure we can all depend on a clean and reliable supply of affordable energy to power our households and businesses for many years to come. From this position of strength, we are able to make an important commitment to Ontario's energy consumer: that we will strive to give consumers more choices in their energy use and ensure that Ontarians and their families will continue to be at the heart of everything we do.

Glenn Thibeault
Minister of Energy

EXECUTIVE SUMMARY

Overview

The 2017 Long-Term Energy Plan, *Delivering Fairness and Choice*, builds on the years of investment that Ontarians made to renew and clean up the province's electricity system. As a result of phasing out coal-fired electricity generation in 2014, emissions for Ontario's electricity sector are forecast in 2017 to account for only about two per cent of the province's total greenhouse gas emissions. The province's robust supply of electricity will be sufficient to meet Ontario's foreseeable electricity demand well into the next decade. This leaves the province well positioned to plan for and meet future challenges.

Ontario's success in building a clean and reliable energy system means we can renew our focus on helping Ontarians and their families. That is the key priority of *Delivering Fairness and Choice*. The government has already brought in a number of measures to reduce electricity costs. The *Fair Hydro Act, 2017* reduced electricity bills for residential consumers by an average of 25 per cent and will hold any increases to the rate of inflation for four years. Ontario's Fair Hydro Plan is also helping as many as half a million small businesses and farms. Lower-income Ontarians and those living in eligible rural and northern communities are receiving even greater reductions, of as much as 40 to 50 per cent. *Delivering Fairness and Choice* will continue our focus on managing electricity system costs over the long term.

Since the release of the 2013 Long-Term Energy Plan (LTEP), Ontario has taken a number of measures to combat climate change. These include the passage of the *Climate Change Mitigation and Low-Carbon Economy Act, 2016*, the introduction of Ontario's cap and trade program, and the release of the first Climate Change Action Plan. *Delivering Fairness and Choice* builds on the province's leading role in the global fight against climate change.

Key Elements of Delivering Fairness and Choice

Below is a summary of the key initiatives identified in *Delivering Fairness and Choice.*

Chapter 1. Ensuring Affordable and Accessible Energy

The projected residential price for electricity will remain below the outlooks published in the 2010 and 2013 LTEPs. The projected electricity prices for large consumers will, on average, be in line with inflation over the forecast period. This is the result of previous investments that delivered a cleaner and more reliable energy system, anticipated benefits from Market Renewal, and cost-reduction measures.

- Ontario's Fair Hydro Plan reduced electricity bills by an average of 25 per cent for residential consumers and will hold any increases to the rate of inflation for four years. As many as half a million small businesses and farms are also benefiting from the reduction. Ontario's Fair Hydro Plan builds on previous actions that reduced electricity costs for families, farms and businesses.
- Ontario will share the costs of existing electricity investments more fairly with future generations by refinancing a portion of the Global Adjustment, spreading the cost of the investments over a longer period of time.
- Residential customers served by local distribution companies (LDCs) with some of the highest rates are getting enhanced distribution rate protection. This will save eligible customers as much as 40 to 50 per cent on their electricity bills.
- The First Nations Delivery Credit reduces the monthly electricity bills of on-reserve First Nation residential customers of licensed distributors.
- The government will enhance consumer protection by giving the Ontario Energy Board (OEB) increased regulatory authority over unit sub-meter providers.
- The government will continue to support expanded access to natural gas, giving consumers greater choice and aiding in the economic development of their communities.

Chapter 2. Ensuring a Flexible Energy System

While the demand for electricity is expected to remain steady, and the demand for fossil fuels is expected to decline, Ontario needs a flexible energy system that can meet any of the possible future outlooks. Market Renewal in the electricity sector will allow the province to adjust to changes and cost-efficiently acquire the electricity resources that are needed to meet future demand.

- Market Renewal will transform Ontario's wholesale electricity markets and ultimately result in a more competitive and flexible marketplace.
- The Market Renewal process will develop a "made in Ontario" solution, taking lessons learned from other jurisdictions while collaborating with domestic market participants and taking into account the Province's greenhouse gas (GHG) emission reduction targets.
- Ontario's cap and trade program, as well as programs and initiatives in the Climate Change Action Plan will support efforts to decarbonize the fuels sector.
- *Delivering Fairness and Choice* aims to maximize the use of Ontario's existing energy assets in order to limit any future cost increases for electricity consumers.
- Cap and trade will increase the price of fossil fuels and affect how often fossil-fueled generators get called on to meet the province's electricity demand. This will help reduce the province's greenhouse gas emissions and shift Ontario towards a low-carbon economy.
- The government will direct the Independent Electricity System Operator (IESO) to establish a formal process for planning the future of the integrated provincewide bulk system.
- Ontario will continue to exercise strict oversight of nuclear refurbishments and ensure they provide value for ratepayers.

Chapter 3. Innovating to Meet the Future

Innovative technologies have the potential to transform Ontario's energy system. New pricing plans, net metering, energy storage and the electrification of transportation will give customers more control and choice over how they generate, use and pay for energy.

- The government will work with the OEB to provide customers greater choice in their electricity price plans.
- The net metering framework will continue to be enhanced to give customers new ways to participate in clean, renewable energy generation and to reduce their electricity bills.
- Barriers to the deployment of cost-effective energy storage will be reduced.
- Utilities will be able to intelligently and cost-effectively integrate electric vehicles into their grids, including smart charging in homes.
- The government's vision for grid modernization in Ontario focuses on providing LDCs the right environment to invest in innovative solutions that make their systems more efficient, reliable and cost-effective, and provide more customer choice. The government will build on its success and renew and enhance the Smart Grid Fund. This will continue the Province's support of Ontario's innovation sector and help overcome other barriers to grid modernization.

- The IESO will work with the government to develop a program to support a select number of renewable distributed generation demonstration projects that are strategically located and help inform the value of innovative technologies to the system and to customers.
- The government intends to fund international demonstration projects to help Ontario's innovative energy companies diversify to foreign markets.
- The Province will collaborate with the federal government, universities and industry to support the province's nuclear sector.
- The government will work with the IESO to explore the development of a pilot project that explores the energy system benefits, and GHG emission reductions, from the use of electricity to create hydrogen.
- Innovative uses for Ontario's natural gas distribution system will be pursued.

Chapter 4. Improving Value and Performance for Consumers

As the energy sector becomes more consumer-focused, users will want increased transparency and accountability from the companies and agencies that provide energy services. Utilities and regulators will need to respond by renewing their focus on efficiency and reliability, and looking at new ways of doing business.

- The Province expects the OEB to continue to enhance its efforts to improve the performance of LDCs.
- The government will look to the OEB to identify additional tools and powers that could be used to make utilities more accountable to their customers, promote efficiencies and cost reductions, encourage partnerships, and ensure regulatory processes are cost-effective and streamlined while also accommodating changing utility business models.
- The government will work with the OEB and LDCs to redesign the electricity bill to make it more useful for consumers in understanding and managing their energy costs.
- The government will look to the OEB to review the standards for reliability and quality of service for transmitters and distributors and for options to improve the standards and will ask the IESO to review how its planning and policies can improve reliability for customers.
- The government will direct the IESO to develop a competitive selection or procurement process for transmission, and to identify possible pilot projects.
- The government will look to the IESO and the OEB to promote the right-sizing of transmission and distribution assets at their end of life.

- A new transmission corridor is needed in the northwest Greater Toronto Area given the size of the forecasted growth. Further studies will identify a specific corridor.
- The Province will provide greater transparency for consumers on gasoline pricing through the OEB's transportation fuels review.

Chapter 5. Strengthening our Commitment to Energy Conservation and Efficiency

Ontario is committed to putting conservation first, both as a resource for the energy system and as a tool for consumers to manage their energy costs. The government and its agencies will continue to assess the achievable potential for energy conservation, explore how to integrate existing conservation programs with new Green Ontario Fund programs, and empower consumers with access to data and tools, such as through the Green Button initiative. The transition to a capacity auction will present opportunities for demand response to grow further and compete with other resources, based on system needs.

- Demand Response capacity realized each year will depend on system needs and the competitiveness of demand response with other resources.
- The government will continue to set advanced efficiency standards for products and appliances, and will explore setting or updating energy efficiency standards for key electrical equipment in drinking water and wastewater treatment plants.
- The government and its agencies will further encourage LDCs to pursue energy efficiency measures on their distribution systems to achieve customer electricity and cost savings.
- The Green Ontario Fund will provide energy consumers with a co-ordinated, one-window approach to encourage conservation across multiple energy sources and programs.
- The government is committed to expanding Green Button provincewide and intends to propose legislation that would, if passed, enable it to require electricity and natural gas utilities to implement Green Button Download My Data and Connect My Data.
- Beginning July 1, 2018, combined heat and power projects that use supplied fossil fuels to generate electricity will no longer be eligible to apply for incentives under the Conservation First Framework or the Industrial Accelerator Program. Behind-the-meter waste energy recovery projects will continue to be eligible, as will renewable energy projects, including those paired with energy storage systems.

Chapter 6. Responding to the Challenge of Climate Change

Ontario's robust supply of electricity will play a key role in enabling the transition to a low-carbon economy. The Province will continue to work to support the deployment of clean energy technologies.

- Ontario remains committed to an electricity system that includes renewable energy generation and supports the goals of Ontario's Climate Change Action Plan.
- The government will encourage the construction of near net zero and net zero energy and carbon emission homes and buildings to reduce emissions in the building sector.
- The government is proposing to expand the options for net metering to give building owners more opportunities to access renewable energy generation and energy storage technologies.
- The government will continue to work with industry partners to introduce renewable natural gas into the province's natural gas supply and expand the use of lower-carbon fuels for transportation.
- Building on current activities, the government will strengthen the ability of the energy industry to anticipate the effects of climate change and integrate its impacts into its operational and infrastructure planning.

Chapter 7. Supporting First Nation and Métis Capacity and Leadership

First Nations and Métis are showing leadership in Ontario's energy sector, with an unprecedented level of involvement. At the same time, First Nations and Métis face unique challenges in accessing clean, reliable and affordable energy – challenges the province and its agencies will work with them to address.

- The government will review current programs in order to improve the availability of conservation programs for First Nations and Métis, including communities served by Independent Power Authorities.
- The Province, working with the federal government, will continue to prioritize the connection of remote First Nation communities to the grid and support the four First Nation communities for which transmission connection is not economically feasible.
- The Aboriginal Community Energy Plan program will be expanded to help communities implement their energy plans and support Ontario's Climate Change Action Plan.
- The government will engage with First Nations and Métis to explore options for supporting energy education and capacity building, the integration of small-scale renewable energy projects, net metering and other innovative solutions that address local or regional energy needs and interests.

- Innovative financing models and support tools will be investigated to address barriers to the financing of projects led or partnered by First Nations or Métis.
- The government will report back to First Nations and Métis between LTEPs to provide updates on the Province's progress and seek ongoing feedback.
- The government's Natural Gas Grant Program will support the expansion of natural gas access to First Nation communities.

Chapter 8. Supporting Regional Solutions and Infrastructure

The Province is working with regions and local communities to develop plans for meeting their diverse energy requirements.

- The government will continue to work with its agencies to implement the Conservation First policy in regional and local energy planning processes.
- With the first cycle of regional planning completed, the government is directing the IESO to review the regional planning process and report back with options and recommendations that address the challenges and opportunities that have emerged.
- Ontario's Climate Change Action Plan has reinforced the importance of community energy plans, and indicated the government's continued support for them.
- The Province has established seven pipeline principles to evaluate oil and natural gas pipelines, and is committed to public engagement when it undertakes reviews of major pipeline projects.

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ENSURING AFFORDABLE AND ACCESSIBLE ENERGY

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ENSURING AFFORDABLE AND ACCESSIBLE ENERGY

Ontario's electricity system is well positioned to meet any challenges and pursue any opportunities that may occur over the next 20 years.

Nearly $70 billion has been invested in the electricity system since 2003. These investments have several benefits, including providing a clean, reliable electricity system.

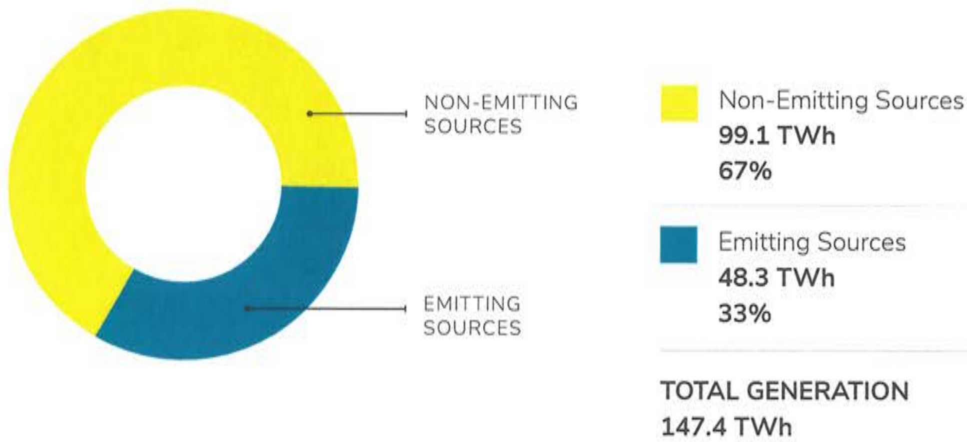
This is a significant change compared to 2003, when power from sources emitting greenhouse gases (GHG) made up one-third of the province's generation mix.

WHAT WE HEARD FROM YOU

- Electricity costs are too high
- High prices hurt industrial competitiveness
- Reduce rates by funding from tax base
- Consider new technologies and methods to manage energy use
- Promote the benefits of conservation for both customers and the system
- Delivery charges should be the same provincewide
- Expand access to natural gas

FIGURE 1.

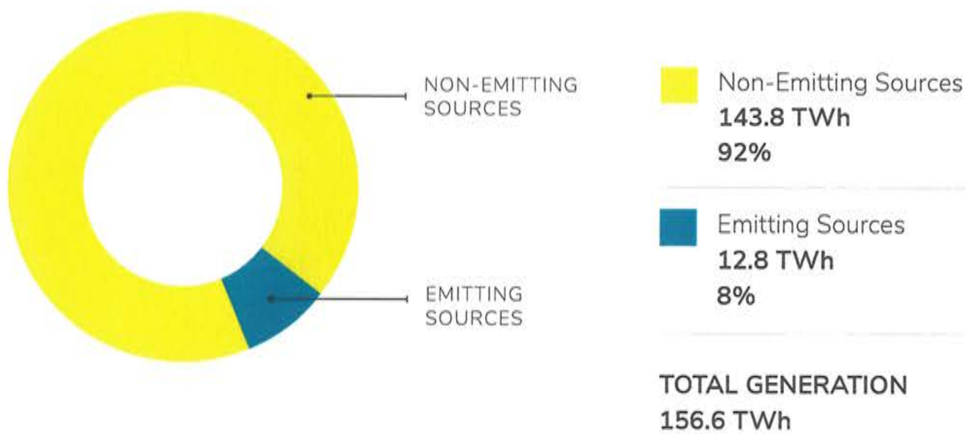
2003 Total Generation By Emitting and Non-Emitting Sources (TWh)



Source: IESO

FIGURE 2.

2016 Total Generation By Emitting and Non-Emitting Sources (TWh)



Source: IESO

DID YOU KNOW?

In 2003, the electricity sector represented about 20 per cent of Ontario's total greenhouse gas emissions. As a result of phasing out coal-fired electricity generation in 2014, emissions for Ontario's electricity sector are forecast in 2017 to account for only about two per cent of the province's total greenhouse gas emissions.

Making Energy Affordable

The much-needed investments in our electricity system have led to higher electricity prices. As a result, Ontario's Fair Hydro Plan was developed to relieve the cost pressures caused by these system improvements. It builds on actions already taken over the past several years that reduced electricity costs for families, farms and businesses, including:

- Deferring the construction of two new nuclear reactors at the Darlington Nuclear Generating Station, avoiding an estimated $15 billion in new construction costs;
- Driving down the cost of renewable energy generation through annual reviews of Feed-In Tariff (FIT) pricing, revised procurement totals, and the introduction of competitive procurement for large renewable projects. This reduced the cost of renewable energy generation by at least $3 billion, compared to the forecast in the 2013 Long-Term Energy Plan (2013 LTEP);
- Suspending the second round of the large renewable procurement process (LRP II) and the Energy-from-Waste Standard Offer Program. This is expected to save up to $3.8 billion compared to the forecast in the 2013 LTEP;
- Renegotiating the Green Energy Investment Agreement with Samsung, reducing contract costs by $3.7 billion;
- Starting the refurbishments at the Bruce Nuclear Generating Station in 2020, instead of 2016, helping to save $1.7 billion compared to the forecast in the 2013 LTEP; and
- Pending regulatory approvals, continuing to operate the Pickering Nuclear Generating Station up to 2024, for an estimated saving for ratepayers of as much as $600 million.

Ontario's Fair Hydro Plan

On June 1, 2017, the *Fair Hydro Act, 2017* became law, providing additional help for electricity consumers. Ontario's Fair Hydro Plan:

- Reduces electricity bills by an average of 25 per cent for residential consumers, and will hold any increases to the rate of inflation for four years. As many as half a million small businesses and farms are also benefiting from the reduction;
- Expands the Ontario Electricity Support Program (OESP) by increasing the on-bill credits by 50 per cent and making more Ontarians eligible for the program;

- Provides enhanced distribution rate protection for residential customers served by the local distribution companies (LDCs) that have some of the highest rates. This will let eligible customers save as much as 40 to 50 per cent on their electricity bills. The enhanced distribution rate protection broadens the support provided under the existing Rural or Remote Electricity Rate Protection (RRRP);
- Reduces the monthly electricity bills for on-reserve First Nation residential customers of licensed distributors by giving the customers a 100 per cent credit on the delivery line or service charge of their bills. This provides eligible customers with an average monthly benefit of $85;
- Shifts the funding of the OESP and most of the RRRP program from electricity bills to provincial revenues. This will reduce the regulatory charges paid by all Ontario ratepayers;
- Allows smaller manufacturers and greenhouses with average monthly peak demand greater than 500 kilowatts (kW) to participate in the Industrial Conservation Initiative (ICI). This gives them a strong incentive to lower their consumption during peak hours and can reduce their bills by an average of one-third;
- Includes the 8 per cent rebate that took effect on January 1, 2017, a reduction equal to the provincial portion of the Harmonized Sales Tax; and
- Establishes an Affordability Fund to help Ontarians who do not qualify for low-income conservation programs to make energy efficiency improvements to their homes, improvements that could not otherwise be done without the support.

Additional Details on Ontario's Fair Hydro Plan

Ontario Electricity Support Program

In order to benefit more low-income Ontarians and provide them with additional support, Ontario has expanded the eligibility criteria for the OESP and increased the monthly credits on their electricity bills by 50 per cent. This means that:

- A single customer earning under $28,000 can now receive $45 per month, up from $30;
- A family of four with combined earnings under $48,000 can now receive $40 per month; and
- Seven or more people living together who earn a total of $39,000 or less can receive $75 per month, up from $50.

Electricity customers are eligible if they meet the program's household size and income requirements. The amounts of the basic credits are in figure 3.

FIGURE 3.

Amounts of Monthly Credits of Ontario Electricity Support Program (OESP) by Household Income Level

HOUSEHOLD INCOME AFTER TAX	HOUSEHOLD SIZE (NUMBER OF PEOPLE LIVING IN HOUSEHOLD)						
	1	2	3	4	5	6	7+
$28,000 or less	$45	$45	$51	$57	$63	$75	$75
$28,001 - $39,000		$40	$45	$51	$57	$63	$75
$39,001 - $48,000			$35	$40	$45	$51	$57
$48,001 - $52,000					$35	$40	$45

If a customer is eligible, uses electric heat as their primary heating source, has certain electrically intensive medical devices, or is Indigenous or lives with Indigenous family members, the OESP provides an enhanced credit (see figure 4).

FIGURE 4.

Amounts of Monthly Credits of Ontario Electricity Support Program (OESP) by Household Income Level – Energy Intensive

HOUSEHOLD INCOME AFTER TAX	HOUSEHOLD SIZE (NUMBER OF PEOPLE LIVING IN HOUSEHOLD)						
	1	2	3	4	5	6	7+
$28,000 or less	$68	$68	$75	$83	$90	$113	$113
$28,001 - $39,000		$60	$68	$75	$83	$90	$113
$39,001 - $48,000			$52	$60	$68	$75	$83
$48,001 - $52,000					$52	$60	$68

Ontario is also working to improve co-ordination across provincial programs that provide support to low-income Ontarians. Synchronizing the OESP with social assistance programs will help get more vulnerable consumers into the program so they can receive the support they need on electricity bills. This includes ensuring that anyone deemed financially eligible for Ontario Works or the Ontario Disability Support Program will automatically be eligible for the OESP.

Distribution Rate Protection

The RRRP program lowers the distribution rates paid by rural and remote customers who face higher distribution costs compared to other areas.

Ontario has expanded this rate protection to provide distribution rate relief to residential customers served by LDCs with some of the highest rates. About 800,000 customers now benefit from the enhanced distribution rate protection.

LDCs whose customers are benefiting from the enhanced distribution rate protection include: Hydro One (medium- and low-density rate classes), Northern Ontario Wires, Lakeland Power (Parry Sound service territory), Chapleau, Sioux Lookout, InnPower, Atikokan and Algoma. The level of benefits differs from utility to utility.

First Nations Delivery Credit

The First Nations Delivery Credit benefits approximately 21,500 residential customers living on reserves.

The credit provides much needed relief from the high electricity costs faced by First Nation on-reserve households and encourages their socio-economic well-being. This is an important step towards reconciliation and strengthening the relationship between Ontario and First Nations.

> "The elimination of the delivery charge will assist our citizens by reducing energy poverty in our communities. It also represents recognition for the use of the land in the development and expansion of the provincial energy grid." "Poverty, lack of opportunity and choosing to pay for electricity over food is a reality that affects our people. Ontario's commitment is commendable and allows a path forward for greater quality of life for First Nations in Ontario."
>
> **Ontario Regional Chief Isadore Day**

Industrial Conservation Initiative

The Industrial Conservation Initiative (ICI) provides incentives to large electricity consumers to reduce their consumption and lower their electricity costs during peak hours. This also benefits the electricity system by deferring the longer-term need for new peaking generation.

To give more businesses the opportunity to participate in the ICI, Ontario has lowered the threshold for entry and increased the number of companies that can benefit. As of July 1, 2017, all customers with an average monthly peak demand of greater than one megawatt (MW) are eligible for the program. In addition, small manufacturing companies and greenhouses with average monthly peak demand greater than 500 kW and one MW or less are also eligible.

Affordability Fund

Ontario offers a suite of conservation and energy efficiency programs that can help customers manage their energy usage and reduce their costs over the long-term. The government has recently taken steps to improve the availability of programs so that all Ontarians can take advantage of conservation opportunities (see Chapter 5). Among these, the government has launched an Affordability Fund to help those Ontarians not eligible for low-income conservation programs and who need support to improve the energy efficiency of their homes. The fund is expected to pay for the installation of household improvements such as energy-saving LED light bulbs, power bars, better insulation, and energy-efficient window air conditioners and refrigerators.

The Affordability Fund is administered by an independent trust that distributes funds to the LDCs that apply. LDCs, working with community partners, are in the best position to provide energy efficiency improvements to consumers in need of assistance.

Refinancing the Global Adjustment to Ensure Intergenerational Fairness

Ontario's Fair Hydro Plan helps electricity consumers by refinancing a portion of the Global Adjustment (GA). The GA pays costs associated with contracted and rate-regulated generation, as well as conservation and demand management programs in Ontario.

The majority of the province's electricity generators have 20-year contracts, but many facilities are expected to operate beyond the life of those contracts and thus provide additional benefits to Ontarians in the future.

Present-day consumers should not be burdened with paying a disproportionate share of investments that provide benefits for decades to come. To relieve the burden on today's ratepayers and share costs more fairly with future generations, a portion of the GA is being refinanced to spread the cost of electricity investments over a longer period of time. This refinancing, which reflects the expected longer life cycle of existing facilities, provides significant and immediate rate relief and helps ensure intergenerational fairness.

Expanding the Low-Income Conservation Program

To enhance and improve the availability of conservation programs helping low-income customers, the government directed the Independent Electricity System Operator (IESO) in August 2017 to centrally design, fund and deliver a conservation program for low-income customers. The program, to start in January 2018, is expected to enhance and increase access to the Save on Energy Home Assistance Program. LDCs may continue to deliver their own program if the IESO determines they have demonstrated a commitment to serve this sector.

Existing Help for Families and Individuals

The measures included in Ontario's Fair Hydro Plan build on existing programs that Ontario families and individuals can use to help reduce their electricity costs. This assistance includes:

- The Ontario Energy and Property Tax Credit, for low- to moderate-income individuals;
- Low-income Energy Assistance Programs, for emergency situations;
- The Save on Energy for Home programs, which help households to become more energy efficient; and
- The Northern Ontario Energy Credit, for eligible families and individuals living in Northern Ontario.

In addition, new incentives programs, to be created under the Climate Change Action Plan, will provide increased benefit to low-income households.

Existing Help for Businesses and Industry

There are a number of measures already in place to help industries, business and commercial operations and institutions lower their electricity costs. These measures include:

- The Industrial Accelerator Program (IAP), which assists eligible transmission-connected companies and their distribution-connected sites to fast-track the capital investment needed for major energy conservation projects;
- The Save on Energy for Business programs, which provide financial incentives that help distribution-connected businesses to reduce their electricity use and manage costs though energy audits, retrofits and process and system improvements; and
- The Northern Industrial Electricity Rate (NIER) Program, which provides rate rebates to Northern energy-intensive industries facing competitiveness pressures due to higher energy costs. The program also assists industrial consumers in developing and implementing energy management plans to manage their usage and reduce costs.

In addition to these measures, Ontario is looking for new ways to provide electricity rate assistance to consumers that are too large to be eligible for the OEB's Regulated Price Plan (RPP). The government and the Ontario Energy Board (OEB) are working together on potential approaches to regulatory changes including how the GA is charged to these consumers, also known as non-RPP Class B consumers. For these consumers, the GA is charged at the same rate regardless of the time that they consume electricity. A GA charge that varies with time of use would lower prices for some Class B consumers and encourage more efficient consumption. Consultations will take place before any changes would be made.

Ontario will continue to explore innovative ways to provide assistance to these mid-sized consumers, while striving to increase system efficiency. The government will continue to engage with businesses and industry to explore options to reduce costs for these consumers. The government is collaborating with the Ontario Chamber of Commerce to raise awareness about energy efficiency and the savings programs available for small and medium businesses.

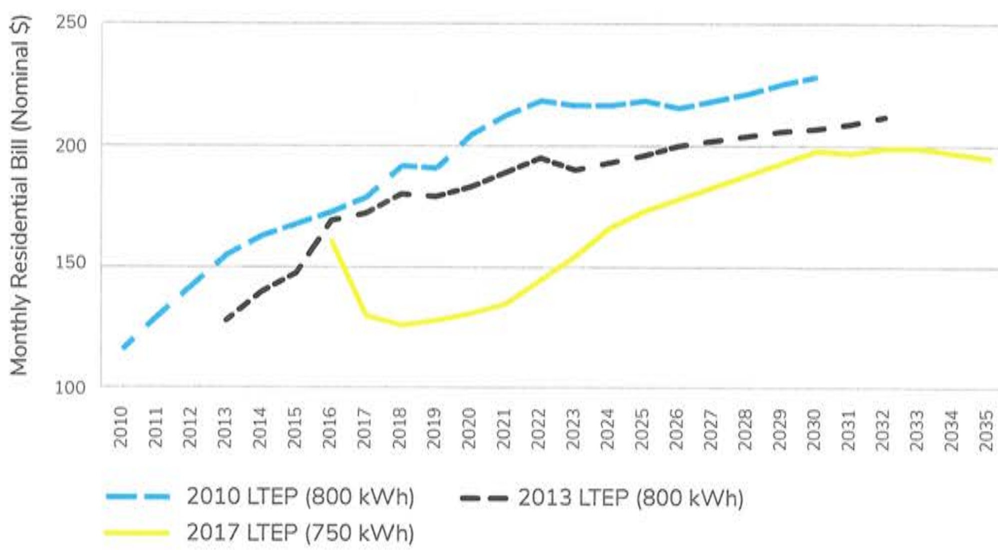
Program offerings through the new Green Ontario Fund will help Ontario businesses and industries increase their use of low-carbon technologies while also reducing costs.

Electricity Price Forecast

The 2017 LTEP's outlook for residential prices shows progress compared to earlier outlooks in the 2010 and 2013 LTEPs. The residential price outlook in the 2017 LTEP remains below the 2013 LTEP outlook for the full forecast horizon due to the Ontario Fair Hydro Plan, removing costs from the electricity system, the anticipated benefits from implementing Market Renewal initiatives, and more efficient consumption of electricity. The outlook also considers the impacts of cap and trade and assumes that some of our generation assets will continue to be available for the duration of the planning outlook.

FIGURE 5.

Electricity Price Outlook – Residential Consumers



Source: IESO, Ministry of Energy

Note: Forecasts used in *Delivering Fairness and Choice* reflect prevailing patterns of consumption. Between late-2009 and mid-2016, the OEB defined the typical residential customer as a household that consumed 800 kWh of electricity per month. As of May 2016, the OEB changed their typical residential consumption to 750 kWh per month, due to declining household consumption.

Electricity Price Outlook – Residential Consumers

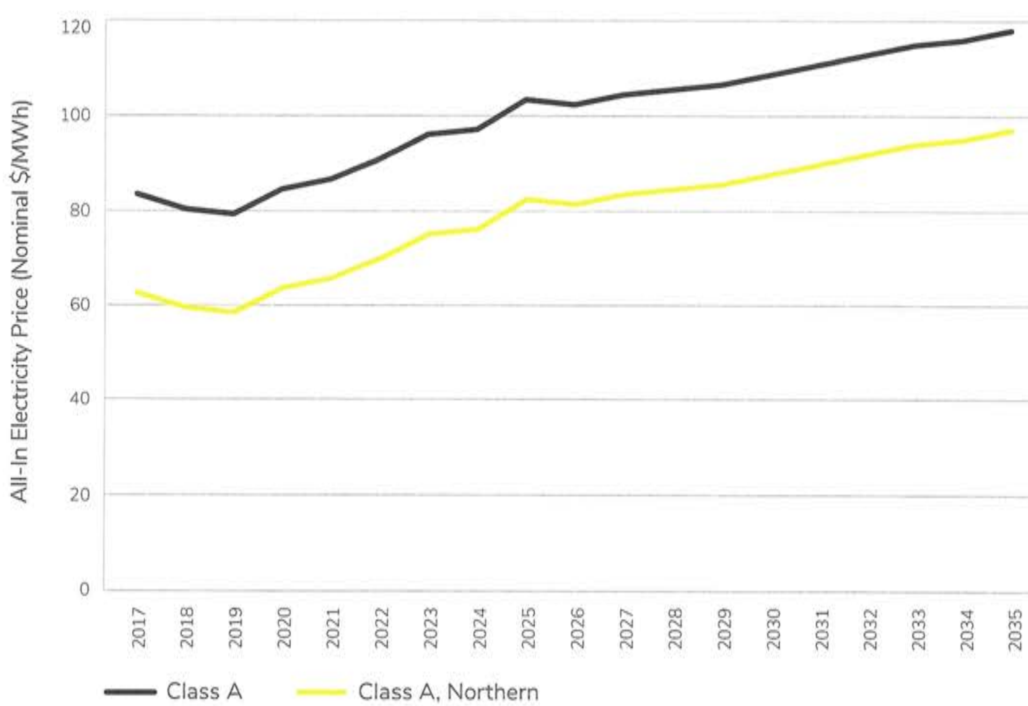
	2010 LTEP (800 kWh)			2013 LTEP (800 kWh)			2017 LTEP (750 kWh)		
	Monthly Residential Bill (Nominal $)	Annual Change ($)	Annual Change (%)	Monthly Residential Bill (Nominal $)	Annual Change ($)	Annual Change (%)	Monthly Residential Bill (Nominal $)	Annual Change ($)	Annual Change (%)
2010	$114								
2011	$128	$14	12%						
2012	$141	$13	10%						
2013	$154	$13	9%	$125					
2014	$162	$8	5%	$137	$12	10%			
2015	$167	$5	3%	$145	$8	6%			
2016	$172	$5	3%	$167	$22	15%	$158		
2017	$178	$6	3%	$170	$3	2%	$127	-$31	-20%
2018	$191	$13	7%	$178	$8	5%	$123	-$4	-3%
2019	$190	-$1	-1%	$177	-$1	-1%	$125	$2	2%
2020	$204	$14	7%	$181	$4	2%	$128	$3	2%
2021	$212	$8	4%	$187	$6	3%	$132	$4	3%
2022	$218	$6	3%	$193	$6	3%	$142	$10	8%
2023	$216	-$2	-1%	$188	-$5	-3%	$152	$10	7%
2024	$216	$0	0%	$191	$3	2%	$164	$12	8%
2025	$218	$2	1%	$194	$3	2%	$171	$7	4%
2026	$215	-$3	-1%	$198	$4	2%	$176	$5	3%
2027	$218	$3	1%	$200	$2	1%	$181	$5	3%
2028	$221	$3	1%	$202	$2	1%	$186	$5	3%
2029	$225	$4	2%	$204	$2	1%	$191	$5	3%
2030	$228	$3	1%	$205	$1	0%	$196	$5	3%
2031				$207	$2	1%	$195	-$1	-1%
2032				$210	$3	1%	$197	$2	1%
2033							$197	$0	0%
2034							$195	-$2	-1%
2035							$193	-$2	-1%

Note: The Ontario Energy Board (OEB) determined rates effective July 1, 2017 under Ontario's Fair Hydro Plan (OFHP) that resulted in an average bill of $121, which is 25 per cent lower than the $162 bill that would have been in place absent the OFHP. All data series in Figure 5 represent average monthly bills for each calendar year.

As shown in Figure 6, the 2017 LTEP price outlook for large industrial electricity consumers reflects average increases in line with inflation over the forecast period. The actual price paid by a large industrial electricity consumer is dependent on their consumption patterns and can vary among industries and specific consumers.

Currently, the electricity price for industrial electricity consumers in Ontario is lower than the average price in the Great Lakes region as reported by the U.S. Energy Information Administration. Consumers in Northern Ontario that participate in the NIER Program can achieve even lower rates.

FIGURE 6. Electricity Price Outlook – Large Industrial Consumers



Source: IESO, Ministry of Energy

Note: Commodity price based on forecast Hourly Ontario Energy Price (HOEP) and GA averaged across Class A. Actual prices for Class A are dependent on each consumer's participation under ICI. Class A above reflects a transmission-connected facility. Participants in the NIER Program, which is funded through provincial revenues, receive a $20/MWh reduction.

Electricity Price Outlook – Large Industrial Consumers

	Class A			Class A, Northern		
	All-In Electricity Price (Nominal $/MWh)	Annual Change ($)	Annual Change (%)	All-In Electricity Price (Nominal $/MWh)	Annual Change ($)	Annual Change (%)
2017	$83			$63		
2018	$80	-$3	-4%	$60	-$3	-5%
2019	$79	-$1	-1%	$59	-$1	-2%
2020	$84	$5	6%	$64	$5	8%
2021	$86	$2	2%	$66	$2	3%
2022	$90	$4	5%	$70	$4	6%
2023	$95	$5	6%	$75	$5	7%
2024	$96	$1	1%	$76	$1	1%
2025	$102	$6	6%	$82	$6	8%
2026	$101	-$1	-1%	$81	-$1	-1%
2027	$103	$2	2%	$83	$2	2%
2028	$104	$1	1%	$84	$1	1%
2029	$105	$1	1%	$85	$1	1%
2030	$107	$2	2%	$87	$2	2%
2031	$109	$2	2%	$89	$2	2%
2032	$111	$2	2%	$91	$2	2%
2033	$113	$2	2%	$93	$2	2%
2034	$114	$1	1%	$94	$1	1%
2035	$116	$2	2%	$96	$2	2%

Note: Data table shows the all-in electricity prices in nominal $/MWh.

Increasing Consumer Protection

The Province has been working consistently to increase protection for electricity consumers. On January 1, 2017, new provisions of the *Energy Consumer Protection Act, 2010*, came into force that protect Ontario consumers from fraudulent claims and high-pressure sales tactics by restricting the door-to-door sale of energy contracts. Additionally, the Protecting Vulnerable Energy Consumers Act, 2017 gave the OEB the authority to prohibit disconnections during certain periods of time, such as winter. The Province will now turn its attention to protecting consumers who live in condominiums and other multi-unit residential buildings and are served by unit sub-meter providers (USMPs).

USMPs are private companies that meter and send bills directly to residents of units in multi-unit residential buildings for the electricity they consume. The OEB currently licenses 28 USMPs that provide services to 326,000 individually-metered units in 2,500 buildings. Residential customers inherit the pricing arrangements; costs are agreed to by the owner or developer of the building or by the condominium board.

Consumers have told both the Province and the OEB that they would like to know more about how these decisions are made and what they are being asked to pay for. That is why the government will enable the OEB to increase its oversight of sub-metering companies and bring in new consumer protection measures.

Improving consumer protection and strengthening the OEB's regulatory powers over USMPs would ensure that their fees and charges are just and reasonable, and that customers served by these companies receive value for money. It would also give the OEB more insight into how these companies determine their costs and set their rates and how they set up their contractual agreements with developers.

The Province intends that broader USMP regulation will enable consumers living in condominiums and other multi-unit residential buildings to enjoy similar protections as LDC customers. Consumers served by USMPs could benefit from:

- Clarity about what goes into the prices they are charged;
- Practices regarding disconnections; and
- Access to the OEB's processes to resolve issues regarding the quality of service USMPs provide to their customers.

The Minister of Energy will request that the OEB make it a priority to review these issues.

Natural Gas Expansion

Ontario is expanding access to natural gas to give consumers greater choice in their energy supply and to aid the economic development of their communities. To do this, the government launched a new $100 million Natural Gas Grant Program in April 2017. It supports both the expansion of natural gas pipelines and the construction of new infrastructure for liquefied or compressed natural gas. The average consumer could save an estimated $1,100 a year under this program by switching from heating with oil to natural gas.

A new regulatory framework issued by the OEB in November 2016 makes natural gas expansion more economically feasible for unserved communities by giving utilities more flexibility in how they structure their rates. The framework also encourages multiple utilities to compete to serve these communities. On August 10, 2017, the OEB released its first decision under the new framework, approving an expansion of natural gas service to several communities. Natural gas is one of several different energy options that provide greater consumer choice and can help to reduce overall energy costs.

Summary

- Ontario's Fair Hydro Plan reduced electricity bills by an average of 25 per cent for residential consumers and will hold any increases to the rate of inflation for four years. As many as half a million small businesses and farms are also benefiting from the reduction. Ontario's Fair Hydro Plan builds on previous actions that reduced electricity costs for families, farms and businesses.
- Ontario will share the costs of existing electricity investments more fairly with future generations by refinancing a portion of the Global Adjustment, spreading the cost of the investments over a longer period of time.
- Residential customers served by local distribution companies with some of the highest rates are getting enhanced distribution rate protection. This will save eligible customers as much as 40 to 50 per cent on their electricity bills.
- The First Nations Delivery Credit reduces the monthly electricity bills of on-reserve First Nation residential customers of licensed distributors.
- Residential electricity prices over the 2017 LTEP outlook period are forecast to remain below the level forecast in the 2013 LTEP. The outlook for electricity prices for large business reflects average increases in line with inflation over the forecast period.
- The government will enhance consumer protection by giving the Ontario Energy Board increased regulatory authority over unit sub-meter providers.
- The government will continue to support expanded access to natural gas, giving consumers greater choice and aiding in the economic development of their communities.

2 ENSURING A FLEXIBLE ENERGY SYSTEM

2

ENSURING A FLEXIBLE ENERGY SYSTEM

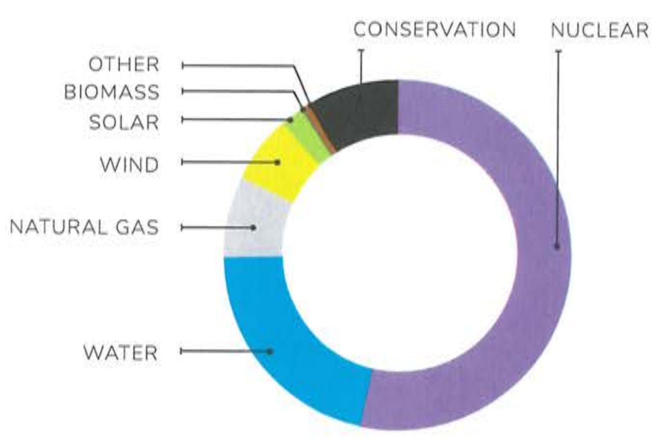
Ontario has made significant progress in rebuilding its electricity system. Nearly $70 billion has been invested in Ontario's electricity system since 2003.

Ontario now has an electricity system that is well-positioned to pursue emerging opportunities and meet future challenges, including the fight against climate change.

In 2016, Ontario produced more than 50 per cent of its electricity from nuclear, with renewable resources providing about 30 per cent and emitting generation providing less than 10 per cent. Conservation reduced energy consumption by about nine per cent.

FIGURE 7.

Ontario's Electricity Generation and Conservation, 2016 (TWh)



Nuclear	**53.5%**
Water	**21.3%**
Natural Gas	**7.5%**
Wind	**6.2%**
Solar	**2.0%**
Biomass	**0.4%**
Other	**0.4%**
Conservation	**8.6%**

Source: Ministry of Energy

Note: Generation reflects the sum of transmission and distribution connected sources. Conservation value represents persistent savings in 2016 from programs and codes and standards since 2006.

WHAT WE HEARD FROM YOU

- Consider costs first when deciding on supply
- Use a technology-neutral competitive process to acquire electricity supply
- Optimise use of our existing energy facilities and infrastructure, including nuclear generation
- Acquire more power from neighboring jurisdictions
- Both support and concerns expressed about various forms of generation
- Innovation should include storage solutions

Ontario's electricity system provides the province with a firm base on which to take further steps to fight climate change. Currently, the province's fuels sector supplies most of the energy needed for our transportation, heating and manufacturing. Ontario's clean and reliable electricity system provides the province with the energy to increase electrification and reduce greenhouse gas (GHG) emissions. The province's existing network of pipelines and retail outlets can also be used to deliver future alternative fuels, such as renewable natural gas.

The Need for Flexibility

Ontario's current robust supply provides us with the opportunity to explore and efficiently implement new approaches to procuring electricity resources. These approaches will need to be designed to be flexible enough to ensure that Ontario is well positioned to accommodate and benefit from emerging energy technologies, while also ensuring that system needs are met at the lowest cost to ratepayers.

Ontario is moving away from relying on long-term electricity contracts and is enhancing its market-based approach to reduce electricity supply costs and increase flexibility. Electricity system operators in New England, New York and the Pennsylvania-New Jersey-Maryland Interconnection have successfully implemented this type of approach.

The Independent Electricity System Operator (IESO) has begun a Market Renewal initiative to redesign the province's electricity markets. This undertaking is expected to save up to $5.2 billion between 2021 and 2030 and forms a key component of the government's plan to bring down the cost of electricity.

The Market Renewal Initiative consists of three work streams: energy, capacity and operability. The IESO will continue its work on the design of mechanisms for these streams in order to maximize the benefits to the system while ensuring reliability and affordability. When new supply needs are identified, the IESO would use competitive mechanisms to procure new supply resources. An example of a market-based mechanism that could be used is an incremental capacity auction.

Generators, demand response providers, importers and emerging new technologies could all participate in the auction, with the most cost-effective resources winning out. Market Renewal will ensure that resources will be able to provide flexibility, reliability and ancillary services. This will help provide transparent revenue streams for the needed services and ensure that all resources can compete on a level playing field.

Market Renewal is expected to result in a more competitive marketplace that more flexibly and efficiently meets system needs and government policy goals. Market Renewal will be aligned with the objectives of Ontario's Climate Change Action Plan, and will be designed to meet system needs, reduce ratepayer costs and reduce GHG emissions. It can be flexible enough to meet various scenarios from higher demand due to increased electrification of our economy to lower demand scenarios as a result of increased use of distributed energy.

Market Renewal will help Ontario prepare for the future by creating a competitive framework that cost-effectively incorporates clean energy resources and new and emerging clean technologies. This will help meet our climate change and GHG reduction commitments. The IESO, together with its sector partners, has identified the need to ensure that this new framework can properly value environmental attributes and the benefits they provide to the system. At the same time, existing resources will be able to continue to meet system needs in the redesigned electricity markets. Maximizing the use of these assets will allow Ontario to limit future cost increases.

A reformed electricity market would not only help reduce costs, but also increase two-way electricity trade with other jurisdictions. Imports and exports could be scheduled more frequently on the interties, which are the transmission lines going to states and other provinces. This could allow more imports of lower-cost generation, and provide greater revenue and access to export markets for Ontario generators.

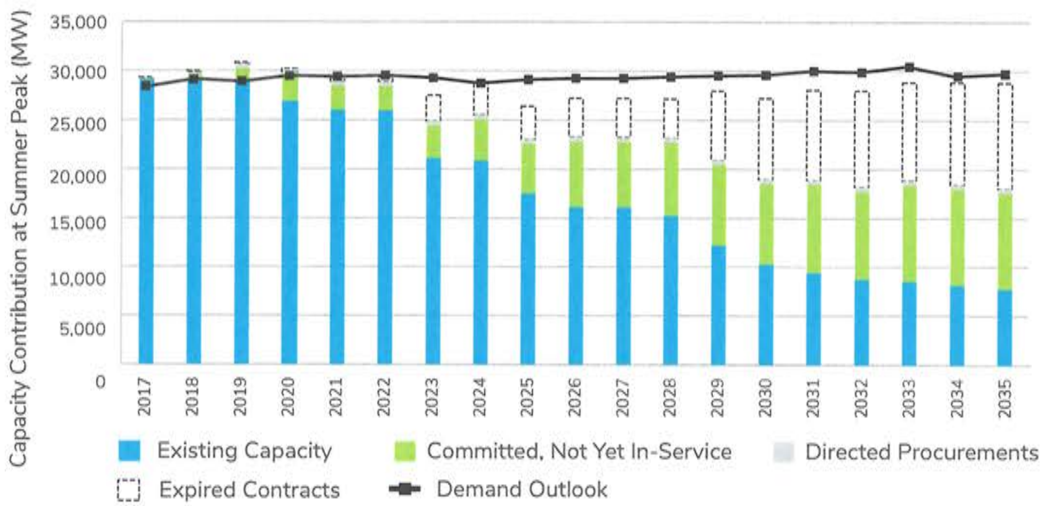
The IESO is working closely with partners in the electricity sector to design the significant changes that will become the foundation of Market Renewal and a plan for bringing them into effect. The plan will specify the changes to be implemented and the timelines for completing the work. This will allow the IESO and its partners to address the known challenges of our existing markets and lay a solid foundation for a more competitive and flexible energy market that can meet future needs.

Electricity Supply and Demand

While there is currently an adequate supply of electricity, a shortfall in capacity is expected beginning in the early-to-mid 2020s as the Pickering Nuclear Generating Station reaches its end of life, and nuclear units at Darlington and Bruce are temporarily removed from service for refurbishment.

FIGURE 8.

Supply and Demand Outlook (2017-2035)



Source: IESO

This need for additional capacity will be met through initiatives under Market Renewal. The auction will allow existing and new clean generation facilities to compete in a robust market with clean imports, demand-side initiatives and new emerging technologies. In addition, the continued growth of distribution-connected wind and solar power is expected to reduce local demand and the need for LDCs to draw electricity from the province's transmission networks.

The demand for electricity is forecast to be relatively steady over the planning period. In the long-term, the IESO projects an increase in overall demand as electrification of the economy increases. The possibility of electrification exists in nearly every part of the energy system. In particular, there is a great potential in the transportation sector, where electrification would be an economical and clean alternative to fossil-fuel powered engines. The outlook assumes the equivalent of approximately 2.4 million electric vehicles by 2035. The outlook also includes the electrification of the GO rail system, as well as new light rail transit projects in Hamilton, Mississauga, Kitchener, Toronto and Ottawa.

Transmission

The IESO's demand outlook indicates that there will be no need for any major expansion of the province's transmission system beyond the projects already planned or under development. See figure 9 for some of the major projects planned or underway on the high-voltage transmission system. Regional electricity needs are discussed in Chapter 8.

The government will direct the IESO to establish a formal process for planning the future of the integrated provincewide bulk system, which includes the high voltage system that typically carries 230 and 500 kilovolts (kVs) in Ontario. As part of the process, the IESO will engage with its partners and communities around the province.

FIGURE 9. Major Transmission Projects Under Development Across Ontario

Note: All projects are subject to regulatory approvals.

1 Northwest Bulk Transmission Line

The Northwest Bulk line is needed to support growth and maintain a reliable electricity supply to areas west of Atikokan and north of Dryden. The project will proceed in phases:

- A **Phase One,** a line from Thunder Bay to Atikokan, should come into service as soon as is practical, and no later than 2024.
- B **Phase Two,** a line from Atikokan to Dryden, should come into service by 2034 unless the IESO's outlook on the demand forecast suggests an earlier date.
- C **Phase Three,** a line from Dryden to the Manitoba border, could be needed after 2035 (or earlier if recommended by the IESO) to enable the better integration of provincial electricity grids.

Development work for Phases One and Two will proceed at the same time.

2 East-West Tie Transmission Line

The East-West Tie Line would provide a long-term, reliable supply of electricity to meet the growth in demand and changes to the supply mix in Northwest Ontario. As the project has moved through development, estimates on its total cost have increased. This is a concern, as Ontario is focused on making the electricity system more cost-effective. The government will review all options to protect ratepayers as the project continues to be developed.

3 Greater Toronto Area West Bulk Reinforcement

Growth in demand, the eventual retirement of the Pickering Nuclear Generating Station and new renewable generation all impact the bulk transmission system in the western section of the Greater Toronto Area (GTA). The IESO is presently studying the need for and timing of reinforcements to the transmission system in the region. Transmission solutions being investigated include building new transmission lines along the existing Parkway Belt West transmission corridor (between Milton Switching Station to Hurontario Switching Station) and expanding station facilities at the existing Milton switching station.

4 Hawthorne to Merivale

The 230 kV circuits between the Hawthorne and Merivale transformer stations require upgrades to their capability to serve growth in western Ottawa and optimize the use of its interties with Québec. This project is being developed by Hydro One and is expected to be in service in 2020.

5 Lake Erie Connector

ITC Lake Erie Connector LLC is proposing to build a 1,000 MW High Voltage Direct Current transmission cable under Lake Erie, running from Nanticoke, Ontario to Erie County, Pennsylvania. The two-way line would provide the first direct link between Ontario electricity markets and markets in 13 states in the Eastern U.S. The generators and electricity traders who would transmit electricity and related products over the line would pay the entire cost of the project. Under this merchant funding model, the costs of the project would not impact the transmission rates paid by Ontario ratepayers.

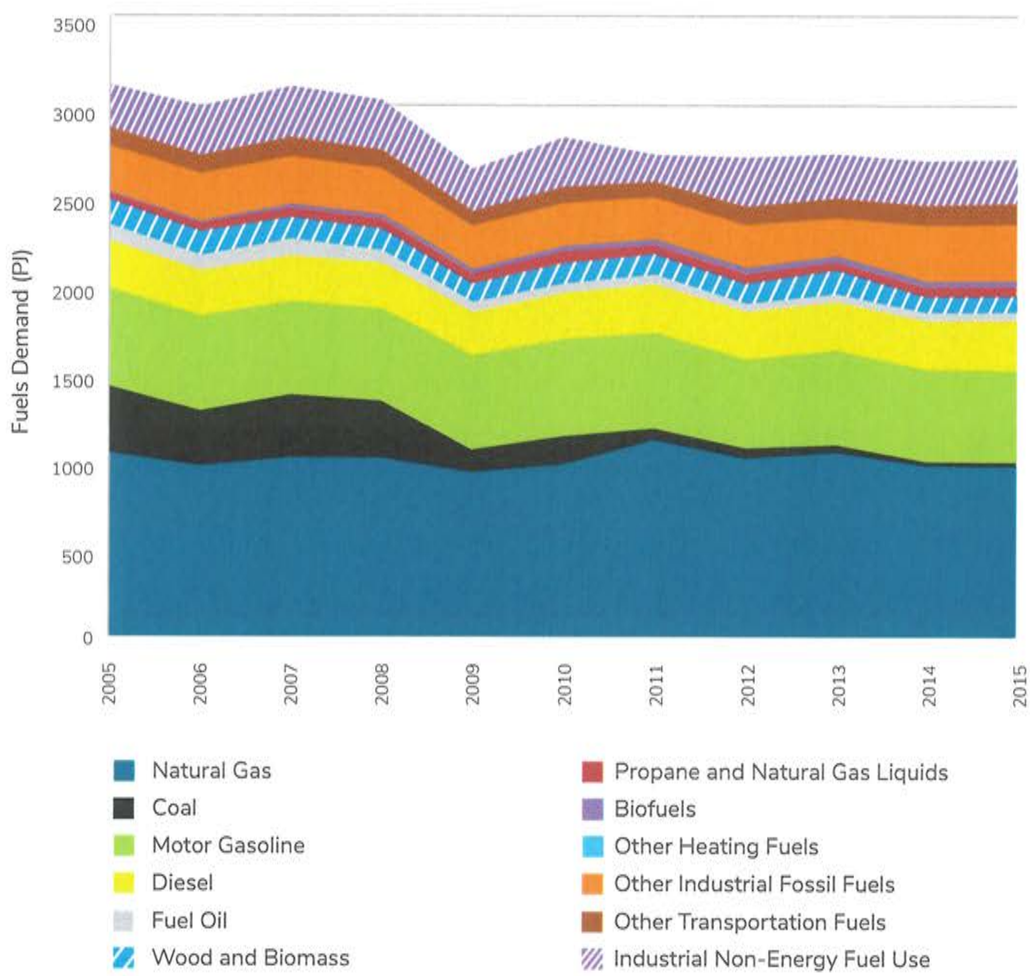
6 Clarington Transformer Station

To meet the needs of the growing eastern GTA and prepare for the eventual retirement of Pickering Nuclear Generating Station, Hydro One is building the Clarington Transformer Station in the Municipality of Clarington. Hydro One expects to bring the station into service in 2018.

Fuels Supply and Demand

Fuels are an important component of the province's economy, and are critical for households, businesses and industry. Ontario's fuels sector is multi-faceted in its sources and uses. Natural gas and transportation fuels, such as gasoline and diesel, make up the majority of Ontario's fuels supply. There are also a variety of other fuels such as propane, wood, aviation fuel and biofuels.

FIGURE 10. Historical Fuels Energy Use



Source: Fuels Technical Report, 2016

Fuels consumption has generally declined between 2005 and 2015, largely due to the retirement of coal-fired generating stations. In the past few years, fuels consumption has been relatively flat with lower use of natural gas being offset by higher use of transportation fuels. About 10 per cent of Ontario's fuels are used for non-energy uses such as feedstock for manufacturing.

Ontario's fuel supply is produced and delivered through a variety of means and markets, including supplies of crude oil and natural gas from outside of the province. As such, the government does not have the same policy and planning functions as it does for electricity.

Nonetheless, Ontario's cap and trade program provides efficient, market-based incentives to transition from conventional fuels to renewable and lower-carbon sources. In addition, programs and initiatives in the Climate Change Action Plan and delivered by the Green Ontario Fund will further support efforts to decarbonize the fuels sector. Over the next 20 years, the electrification of transportation, enhanced conservation and switching to lower-carbon fuels are expected to transform the fuels sector. As a result, both the demand for fuels and the emissions they release are expected to decline.

The outlook for the supply and demand of fuels will depend on policy and program decisions over the next 20 years, as well as on technological innovation and adoption. Given these uncertainties, the government will continue to undertake modelling and analysis to identify opportunities to decarbonize the fuels sector consistent with the provincial target of reducing GHG emissions by 37 per cent from 1990 levels in 2030.

The Influence of the Carbon Market

On January 1, 2017, the Province implemented a cap and trade program. This program is a flexible, market-based program that will be a cornerstone in Ontario's fight against climate change, and is the most cost-effective way of achieving reductions in GHG emissions. In addition, all proceeds from the cap and trade program will be used to fund actions to reduce GHG emissions, such as supporting Ontarians in shifting away from fossil fuels and investing in emerging clean technologies.

The price of fossil fuels such as natural gas, gasoline, diesel and propane includes a carbon cost as a result of the cap and trade program. The price signal provided by the cap and trade program will help move the province's energy system to even cleaner sources.

The costs that regulated natural gas utilities incur when they comply with cap and trade, including the cost of acquiring emission allowances, are subject to approval by the OEB. These costs are included in the rates charged to consumers. Natural gas utilities whose rates are not regulated by the OEB and large facilities that must independently comply with cap and trade will decide on their own how to manage their compliance costs. Alternative fuels that do not incur cap and trade charges – like renewable natural gas – could be used to reduce emissions and mitigate cap and trade costs in the natural gas sector.

Suppliers of other fuels in Ontario, such as gasoline, diesel and propane, operate in a competitive market. They are responsible for complying with cap and trade regulations and are expected to pass through their compliance costs to retail consumers. Switching to renewable fuels like ethanol, bio-based diesel and renewable diesel, and to lower-carbon transportation fuels such as natural gas are ways for consumers and obligated parties to reduce emissions and lower their cap and trade costs.

Maximizing Existing Assets

Delivering Fairness and Choice aims to limit any future cost increases for electricity consumers by maximizing the use of the province's existing energy assets. This can be achieved because many of the electricity generation facilities built in the last decade-and-a-half will be able to generate power beyond their planned contract life.

Renewable Energy

Contracts for over 4,800 MW of wind energy, 2,100 MW of solar energy, and 1,200 MW of hydroelectric generation will expire between 2026 and 2035, with most expiring after 2030. While wind and solar contracts last for 20 years and hydroelectric contracts for 40 years, wind turbines and photovoltaic panels are often able to still generate electricity after their contracts expire, and we know from experience that hydroelectric facilities can operate for as long as a century.

Due to the substantial decline in the cost of wind and solar technologies over the last decade, renewables are increasingly competitive with conventional energy sources and will continue to play a key role in helping Ontario meet its climate change goals.

In many cases, the province's wind and solar energy facilities can be upgraded with new or more efficient technology so they can continue operating, increase their output and provide additional system benefits.

There is an opportunity to get more from existing waterpower assets, including increasing their operational flexibility. The performance of older hydroelectric projects can be improved by using new, more efficient turbines. With the growing need for flexibility in our electricity system, Ontario's pumped storage potential could also play an important role in the provision of services that ensure the electricity system operates reliably.

As part of the IESO's ongoing work to find efficiencies and the best value for ratepayers, maximizing value from existing assets is key for Market Renewal, which will provide an open platform for project upgrades to participate in meeting Ontario's future resource adequacy.

Natural Gas

The natural gas generating stations that produce electricity in Ontario can respond quickly to match any changes in demand. The province relies on these generators to meet its needs during the periods of highest demand, including hot summer days and cold winter nights. Natural gas can also be used to ensure the reliability of the power supply when other generators are unavailable or require maintenance.

Most of Ontario's natural gas generating stations could operate beyond the life of their contracts. This will be important over the coming decade during ongoing nuclear refurbishments and with the retirement of the Pickering Nuclear Generating Station in 2024. In the early-to-mid 2020s, it is forecasted that there will no longer be enough contracted and rate-regulated facilities to meet reliability requirements.

Many of the existing generation contracts will expire over the same time frame. These natural gas facilities could continue to be available during times of peak demand by participating in a capacity auction being considered under Market Renewal, but only if they are more competitive relative to other resources.

Nuclear

Refurbishing Nuclear

The most cost-effective option for producing the baseload generation the province needs while releasing no GHG emissions is to refurbish Ontario's nuclear generating stations. Ontario is moving forward with the plans laid out in the 2013 LTEP to refurbish a total of ten nuclear units between 2016 and 2033 – four units at Darlington and six units at Bruce.

The Darlington Nuclear Generating Station, in the Municipality of Clarington, and the Bruce Nuclear Generating Station, in the Municipality of Kincardine, are two of the world's best-performing nuclear power plants. Together, Darlington and Bruce provide around 50 per cent of the province's electricity needs.

Refurbishing these 10 units will lock-in more than 9,800 MW of affordable, reliable and emission-free generation capacity for the long-term benefit of Ontario. It will also support the 180 companies and 60,000 jobs that make up Ontario's globally-recognized nuclear supply chain.

Ontario Power Generation (OPG) is taking a phased approach to refurbishing the Darlington Nuclear Generating Station. This approach benefits from the lessons learned during previous refurbishment projects, which highlighted the need for in-depth planning and preparation prior to starting the work.

In November 2015, OPG's Board of Directors approved a total estimated cost of $12.8 billion for refurbishing all four Darlington units. This includes all spending to date, interest and inflation, and is $1.2 billion lower than OPG's original estimate in 2009.

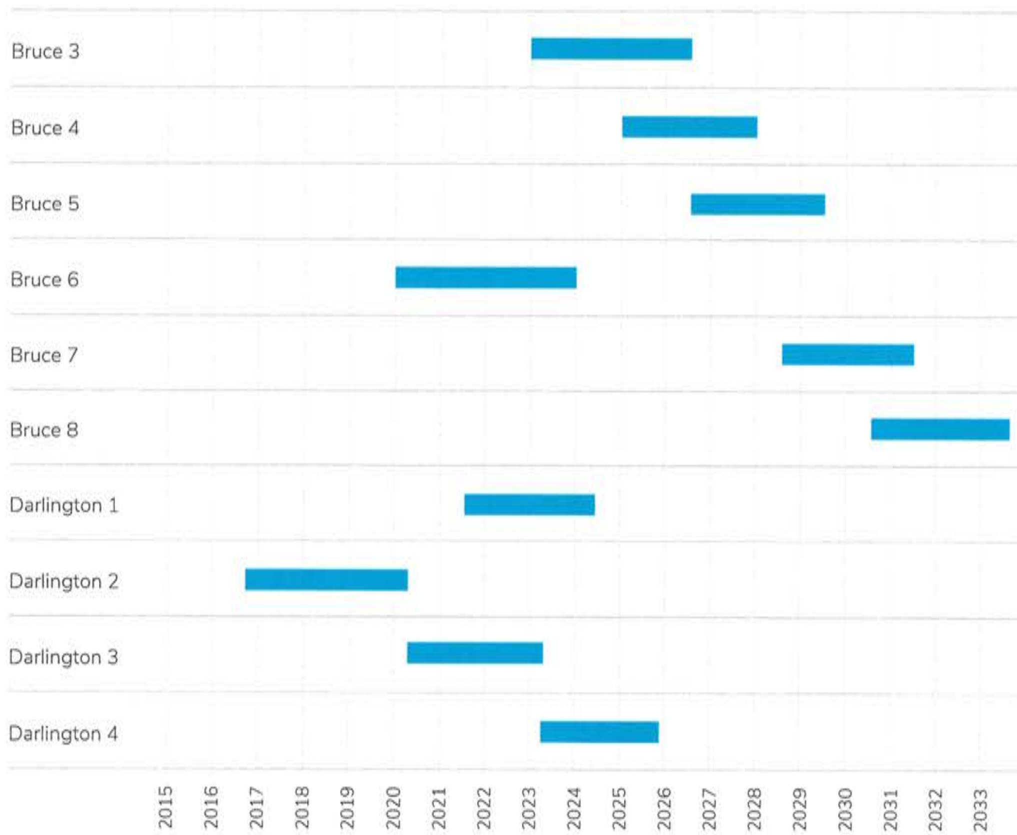
In January 2016, the government gave OPG approval to proceed with refurbishing the first of the Darlington units. In April 2017, OPG announced it had successfully completed the first of four major phases in refurbishing Unit 2 and isolated the unit from the rest of the Darlington plant. OPG has now moved on to the next phase of work and is on track to complete the entire project on budget and on schedule.

The refurbishment and continued operation of Darlington is expected to contribute a total of $90 billion to Ontario's gross domestic product and increase employment by an average of 14,200 jobs annually.

In December 2015, the IESO updated its contract with Bruce Power for the refurbishment of six nuclear units at the Bruce Nuclear Generating Station. Bruce Power plans to invest approximately $13 billion of its own funds in the project. Ontario further adjusted the schedule for refurbishment to get the most value out of the existing nuclear units. The new schedule will see construction start in 2020, instead of the previously-estimated start date of 2016. This updated agreement saved $1.7 billion for electricity customers, compared to the cost forecast in the 2013 LTEP.

FIGURE 11.

Nuclear Refurbishment Schedule



Source: IESO

BRUCE POWER AND OPG COLLABORATION

As operators of Ontario's nuclear fleet, OPG and Bruce Power have a long-standing relationship, regularly sharing best practices and information with one another.

On November 12, 2015, Bruce Power and OPG signed a Memorandum of Understanding (MOU) that was facilitated by the Ministry of Energy to formalize the collaboration between the two companies on nuclear refurbishment and power plant operation.

The MOU addressed a key objective of the 2013 LTEP: that the two companies work together to identify efficiencies and innovation that lower costs for ratepayers, share lessons learned on refurbishments and leverage economies of scale to ensure Ontario's refurbishments remain on time and on budget.

Bruce Power is currently undertaking a number of activities in support of the Bruce refurbishments and their long-term operation, including:

- Implementing an asset management program to optimize the life of the Bruce units before and after refurbishment;
- Developing a final cost estimate for refurbishing the first unit, Unit 6;
- Executing contracts with suppliers across Ontario, including BWXT Canada and SNC-Lavalin; and
- Developing a regional network of suppliers to benefit local communities in the Bruce region.

The refurbishment and long-term operation of Bruce are expected to generate up to $4 billion in economic benefits annually and increase employment by up to 22,000 jobs.

CAMECO

Cameco is one of the world's largest uranium companies with facilities in Blind River, Cobourg and Port Hope.

In May 2017, Cameco agreed to continue supplying fuel to Bruce Power for another 10 years, reducing the cost of electricity to Ontarians by an estimated $200 million over the 10-year period. This stable partnership will also bring long-term economic benefits to the County of Northumberland.

Cameco is also supporting the Darlington refurbishment, and in May 2017 delivered a first shipment of more than 200 calandria tubes ahead of schedule and on budget. Calandria tubes hold nuclear fuel and coolant and play a critical role in the safe and efficient operation of the reactor.

BWXT

BWXT Canada Ltd employs 850 people in Ontario, including at its headquarters in Cambridge and facilities across the province such as Peterborough and Arnprior. The company is a leader in the design, manufacturing, commissioning and servicing of nuclear power generation equipment.

BWXT played a key role in defueling Darlington's Unit 2 ahead of schedule. The company will continue to manufacture the feeder tubes that deliver coolant to the reactor as part of the Darlington refurbishment program.

BWXT will also supply eight new steam generators for the Bruce refurbishment. That contract is worth about $175 million and will secure more than 100 jobs.

ONTARIO PARTNERS WORKING ON NUCLEAR REFURBISHMENT

LAKER

Laker Energy Products is a leading supplier of reactor components for the CANDU nuclear power industry. This Ontario company is building on its success and exporting its precision-tooled products around the world.

Laker recently purchased a new 65,000 square foot facility to handle more than $130 million in contracts to help refurbish the Bruce and Darlington nuclear reactors. The facility will also support Laker's sales to international markets, including existing and new-build projects in Argentina, Romania, China and the United Kingdom.

ONTARIO'S LABOUR UNIONS –
POWER WORKERS' UNION AND SOCIETY OF ENERGY PROFESSIONALS

For more than four decades, Ontario's electricity sector labour unions have been key partners in Ontario's nuclear industry. Today, Power Workers' Union and Society of Energy Professionals together represent more than 23,000 employees in Ontario's electricity system, including our nuclear plants and supply chain companies. OPG and Bruce Power will continue to rely on their skills and expertise to refurbish our nuclear fleet and ensure safe operation for decades to come.

LABOURERS' INTERNATIONAL UNION OF NORTH AMERICA

Labourers' international Union of North America (LiUNA) is a building trades union representing more than 100,000 members and retirees in Canada. LiUNA members are involved in the construction of highways, bridges, waterways and dams, hospitals, schools and government institutions. Today, LiUNA is an important partner in Ontario's refurbishment program. To ensure the smooth and successful execution of refurbishments, LiUNA and all key building trade unions have struck special nuclear project agreements with OPG and Bruce Power that will remain in force through the period of peak refurbishment activities, until December 31, 2032.

Managing the Risks

One of the principles of the 2013 LTEP was to include potential off-ramps for nuclear refurbishment. Off-ramps ensure that refurbishments only proceed if they continue to deliver value for ratepayers.

The Province has established off-ramps for the Darlington refurbishment that may be used in the event of OPG failing to adhere to the approved costs and schedule. This could result in the Province not proceeding with the remaining units.

Ontario's contract with the privately-owned Bruce Power also includes strong protection from cost overruns with the refurbishments. For example, Bruce Power is paying for approximately $2 billion in cost overruns that occurred when two of the Bruce units were refurbished and restarted in 2012.

Under its recently updated agreement with the IESO, Bruce Power will be assuming the risk of any cost overruns during the execution of the refurbishment of each of the six remaining Bruce units. Contractual off-ramps allow Ontario to stop work on any Bruce refurbishment if the estimated cost exceeds a pre-defined amount. Refurbishment at Bruce can also be stopped if demand drops or lower-cost resources emerge.

Ontario is protecting ratepayers by strictly controlling the cost and timetable of refurbishments. There is strict oversight of OPG and Bruce Power to ensure that they complete the refurbishments on time and on budget.

In addition to OPG's oversight of the Darlington refurbishment, the government has its own independent advisor to ensure that it has continued and effective oversight. All of OPG's expenditures on nuclear refurbishment will also be reviewed by the OEB as part of its rate-setting process.

The government subjected the updated agreement with Bruce to extensive due diligence, as did the financial and technical advisors who were engaged by the IESO when it negotiated the contract.

The IESO will continue to manage the Bruce contract and closely scrutinize the basis for costs underlying the refurbishment and ongoing operation of the Bruce reactors. It has full-time representatives on-site and will regularly report back to the Province.

Pickering Nuclear Generating Station

OPG is working on plans to continue to operate the Pickering Nuclear Generating Station until 2024. The continued operation of Pickering will ensure Ontario has a reliable source of emission-free baseload electricity to replace the power that will not be available during the Darlington and initial Bruce refurbishments. The continued operation of Pickering would also reduce the use of natural gas to generate electricity, saving up to $600 million for electricity consumers and reducing GHG emissions by at least eight million tonnes.

The Province announced in January 2016 that it had approved OPG's plan to ask the OEB and the Canadian Nuclear Safety Commission (CNSC) to approve the continued operation of Pickering until 2024. The OEB will ensure that the costs of OPG's plan for continued Pickering operation are prudent, while the CNSC will ensure that Pickering operates safely during this period. OPG will still need to get final approval from the government to proceed with the continued operation of Pickering after these regulatory reviews are completed. OPG will also update the government on the safety and operational performance of Pickering as part of its regular reporting and business planning.

Summary

- Market Renewal will transform Ontario's wholesale electricity markets and ultimately result in a more competitive and flexible marketplace. This Market Renewal process will develop a "made in Ontario" solution, taking lessons learned from other jurisdictions while collaborating with domestic market participants and taking into account the Province's greenhouse gas emission reduction targets.
- Ontario's cap and trade program, as well as programs and initiatives in the Climate Change Action Plan will support efforts to decarbonize the fuels sector.
- *Delivering Fairness and Choice* aims to maximize the use of Ontario's existing energy assets in order to limit any future cost increases for electricity consumers.
- Cap and trade will increase the price of fossil fuels and affect how often fossil-fueled generators get called on to meet the province's electricity demand. This will help reduce the province's greenhouse gas emissions and shift Ontario towards a low-carbon economy.
- The government will direct the Independent Electricity System Operator to establish a formal process for planning the future of the integrated provincewide bulk system.
- Ontario will continue to exercise strict oversight of nuclear refurbishments and ensure they provide value for ratepayers.

3

INNOVATING TO MEET THE FUTURE

3

INNOVATING TO MEET THE FUTURE

The way we deliver and use electricity is changing.

New technologies allow us to capture, store and use energy locally and deliver it in new and innovative ways. Clean, distributed energy resources are powering our economy and moving closer to home. New tools and devices are appearing on smartphones and in homes, harnessing the power of data that can give customers greater choice and control over their energy use. Customers' expectations of their utilities are rising.

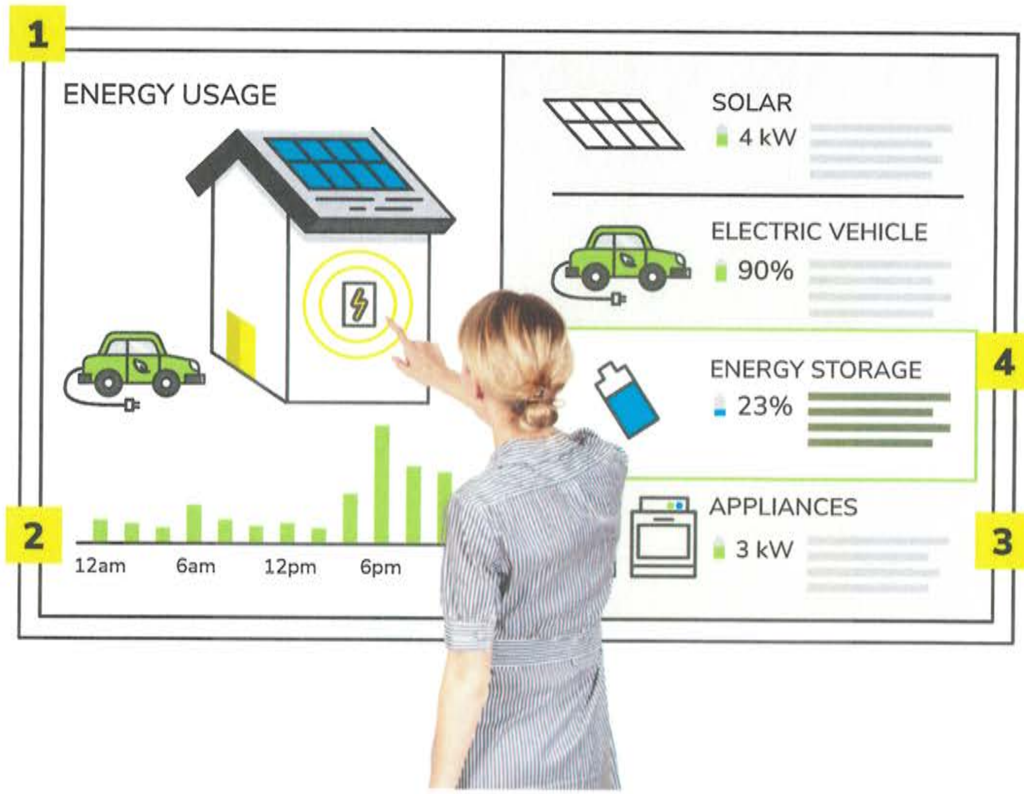
WHAT WE HEARD FROM YOU

- Support increased use of electric vehicles (EVs)
- Support and enable options for home energy storage, including EV batteries
- New business models can drive innovation
- Offer more pricing plans
- Modernize regulations and rate designs
- Customers will decide which technologies best meet their needs
- Government support is needed for research and development
- Distributed generation will transform conventional electricity distribution networks

Modernizing the System

These new technologies present a significant opportunity to make Ontario's electricity systems more efficient, reduce costs and give customers more choice.

FIGURE 12. Customer of Tomorrow



1 **Energy Management System** – An energy management system can give users real time information on how they are using electricity, reduce their electricity bills, and can balance their preferences with the needs of the system to make the best use of energy.

2 **Flexible Pricing** – Consumers can choose the electricity pricing plan that works best for their needs and complements their lifestyle.

3 **Internet of Things** – Technologies already on the market can connect appliances, lighting and other plugged-in electronics to smart controllers. Smartphones can turn on lights and a dishwasher, or consumers can let an energy management system run the show.

4 **Distributed Energy Resources** – Prices continue to drop for solar panels, home energy storage and electric vehicles, giving consumers more choice and making them less dependent on electricity from their local distribution company (LDC). The connected smart home will make the best use of these emerging technologies.

Innovative Pricing Plans

The government is working with the Ontario Energy Board (OEB) to give consumers more choice in their electricity price plans. As part of its review of the Regulated Price Plan (RPP), the OEB is using pilot projects to test innovative time-of-use price structures. Consumers can better manage their costs with time-of-use pricing by reducing or shifting their consumption to off-peak times when electricity is less expensive to produce. Time-of-use pricing also ensures that consumers pay a price for electricity that reflects the cost of producing it at peak and off-peak times.

The pilot projects are testing a variety of innovative price structures, including:

- Different ratios between on and off-peak prices;
- Different times for on- and off-peak periods;
- Prices that increase during critical peaks – the short time periods with extremely high demand; and
- Seasonal pricing plans that have a flat rate for spring and fall, and on- and off-peak price periods for summer and winter.

Some of the pricing pilots will be combined with smart technologies, such as smart thermostats, energy use apps and electric vehicles, to give customers additional ability to manage their electricity use.

The pilots have begun rolling out and will run for at least one calendar year. The results will help guide OEB decisions on potential new price plans that could give customers greater control, reduce their bills and help improve system efficiency.

In addition to these pilot programs, the government and the OEB are considering changes to the way the Global Adjustment is charged to mid-sized commercial and industrial consumers, otherwise known as non-RPP Class B consumers. For these consumers, the GA is a fixed charge that is the same regardless of the time that they consume electricity. Consultations will take place before any changes would be made.

Net Metering

Changes to Ontario's net metering framework will give businesses and consumers more opportunities to generate and store renewable electricity.

Net metering is a billing arrangement with an LDC that allows a customer to offset the electricity they buy from their LDC with electricity generated by their own renewable energy systems. Net-metered customers also receive credits on their electricity bill for the electricity they send to the grid, reducing their total bill charges. These credits can be carried over for up to 12 months for application on future bills. A net-metered customer is still able to draw power from the local distribution grid when needed.

FIGURE 13.

How Net Metering Works

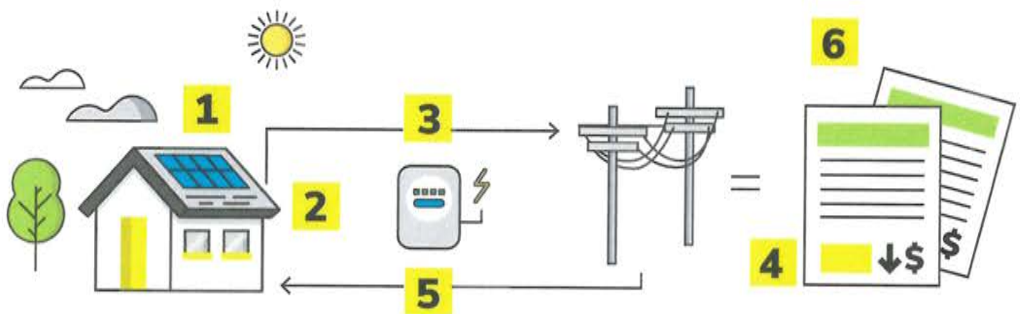


Figure 13 describes a rooftop solar net metering arrangement for a typical home. Other types of renewable energy can also be net-metered in Ontario.

1 Solar panels mounted on the roof of a house generate electricity.

2 The electricity generated is used to power the house first.

3 Any extra electricity generated is sent to the local grid.

4 Net-metered customers receive credits on their electricity bill for electricity sent to the local grid.

5 Electricity is drawn from the local grid when the home's electricity needs are higher than the amount of electricity generated by the solar panels.

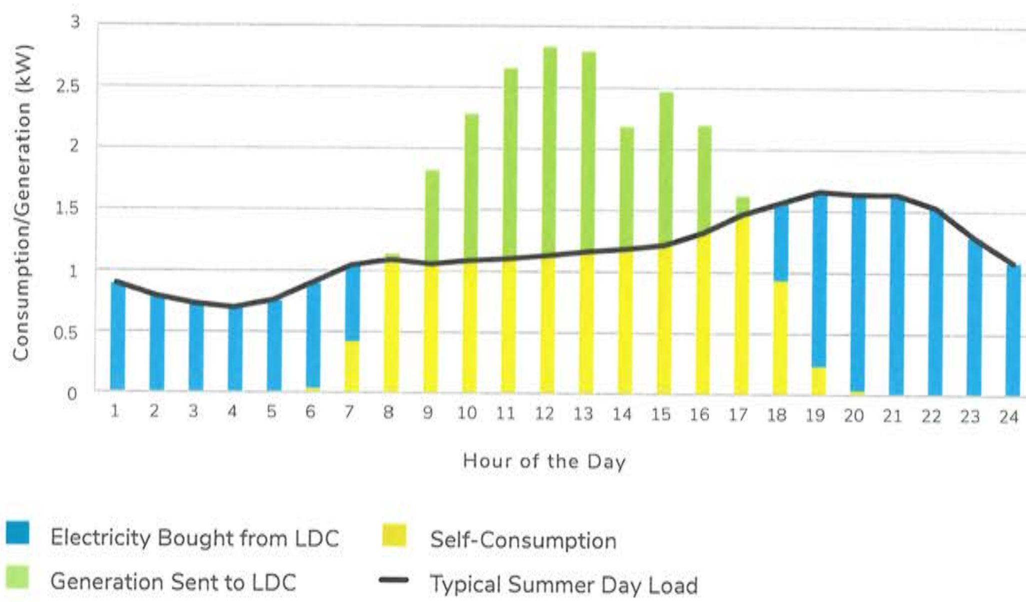
6 Net-metered customers' monthly electricity charges are calculated based on the difference between the amount of electricity used from the local grid and the credits received from any electricity sent to the local grid from the solar panels.

Figure 14 shows the electricity generated by a typical net-metered solar installation on a residential rooftop in the summer:

- The blue columns show the electricity bought from their LDC;
- The yellow columns show the electricity generated and used on-site; and
- The green columns show the electricity that is generated and sent back to their LDC.

FIGURE 14.

Residential Net-Metering with 4 kW Rooftop Solar PV



Source: Ontario Ministry of Energy

The government has recently taken significant steps to enhance net metering by removing the limit on the size of eligible generation systems and allowing them to be paired with energy storage technologies.

The government will expand and enhance net metering by proposing legislative and regulatory amendments that would allow third-party providers to own and operate net-metered renewable generation systems while ensuring appropriate consumer protection measures are in place. This would give Ontario electricity consumers added opportunities to reduce their electricity bills by offsetting their electricity purchases with clean power generated on-site. Net-metered renewable energy systems can also help reduce peak demand and defer or avoid the need for LDCs to invest in certain costly upgrades to their networks.

The government will also propose legislative and regulatory amendments that would enable the deployment of demonstration projects for virtual net metering. The government will work with the Independent Electricity System Operator (IESO) to develop a program to support a select number of innovative renewable distributed generation demonstration projects, as well as virtual net-metering demonstration projects. Virtual net metering could allow Ontarians who may not be able to install their own renewable energy system to participate in renewable energy projects located away from their homes or businesses, and still receive a credit offsetting their electricity bill. It could also support the siting of renewable generation where the electricity is most needed and valuable on the distribution grid. The goal of these demonstration projects would be to better understand the impacts of virtual net metering and guide future policy decisions on net metering. Proposed legislative amendments are expected to be brought forward in fall 2017. Pending passage of legislative amendments, regulatory changes would be made in 2018.

Taken together, these proposed enhancements would provide a platform for future innovation in clean, distributed energy and put Ontario at the forefront of renewable energy integration in Canada.

OXFORD COUNTY

In 2015, Oxford County became the first municipality in Ontario to commit to 100 per cent renewable energy by 2050. This means that Oxford County will meet or exceed 100 per cent of its net energy demand from renewable sources. Oxford's 100 per cent Renewable Energy Plan outlines the county's investment in innovative technologies and approaches like renewable energy, conservation, energy storage, microgrids and sustainable transportation. *Delivering Fairness and Choice* supports communities like Oxford County in achieving its community sustainability goals.

Energy Storage

Energy storage is a game-changing technology. Sometimes, it acts like a home or business, consuming electricity from a local network. At other times, it acts like a power plant, sending out electricity when needed.

Energy storage can offer benefits throughout the grid, from large-scale facilities that can reduce the need to build new supply, import electricity or use GHG-emitting generation sources, to smaller-scale devices that can provide backup services to buildings.

The Province has made it a priority since 2013 to understand the value of energy storage for Ontarians. This includes:

- procuring 50 megawatts of different types of energy storage to test how they can support Ontario's electricity network;
- using the Smart Grid Fund to support several energy storage projects and test the full range of their capabilities on distribution systems; and
- undertaking studies that look at realizing the different benefits of storage.

A March 2016 study by the IESO found that energy storage facilities can provide many of the services needed to ensure the electricity system in Ontario operates reliably. The government also commissioned Essex Energy to study the benefits of storage for distribution networks. The study found that energy storage can provide many benefits including cost reduction, for larger consumers.

Customer-connected energy storage could also provide benefits to the grid, particularly if the LDCs partner with these customers to share both the cost and the benefit. However, as discussed in the Barriers to Innovation section later in this chapter, the rules are not clear about how these partnerships could work. The Government and its agencies will move forward to provide the right environment for LDCs and customers to partner on storage where it makes sense for both parties.

The unique aspects of energy storage come into conflict with some of the rules governing the electricity system. The government started to understand these challenges in the 2013 LTEP, and since that time has been engaging with agencies and the energy storage industry to target the barriers that unfairly disadvantage this technology.

The government has now identified these market and regulatory barriers and is updating regulations, including addressing how the GA is charged for storage projects. Concurrently, it is seeking support from the IESO and OEB to take similar steps with their respective codes and rules that prevent the cost-effective development of energy storage where it can provide value to customers and the electricity system.

Electrification of Transportation

Ontario's Climate Change Action Plan focuses significant attention on using low-emission transportation to drive down greenhouse gas emissions in the province. This is critical to establishing a low carbon economy. The continued adoption of EVs will have an impact on our distribution networks. If too many EVs in a neighbourhood charge at the same time, important parts of the distribution system could be strained. As EVs become more popular, pressures on our distribution networks will grow and utilities will need the tools to manage this change in a cost-effective way.

Utilities have begun to test ways to work with EV owners to minimize these impacts. FleetCarma, a clean tech firm based in Waterloo, successfully tested a project that guarantees EV owners the amount of charge they need in the morning, but allows an LDC to control charging to minimize the impact on its network. Burlington and Oakville Hydro are testing how to do the same thing by offering smart chargers at a reduced cost in exchange for some control of the charging activity.

The government wants to provide LDCs with more options for integrating EVs into their networks at the lowest cost. The OEB will support this goal by looking at how LDCs can facilitate investments in technologies such as residential smart chargers that would avoid more costly system upgrades. These new technologies could also use incentives to give more choices to EV owners. For example, an EV owner could be rewarded for allowing the car to be charged at times when the distribution network is being used less. The customer would work with the LDC to find the right combination of preferences so both parties can benefit from smart charging.

The government will also promote the sharing of information and data on EV usage, and work to harmonize the province's energy, climate change, transportation, and infrastructure policies. Beyond personal EVs, the government is broadening its attention to include other types of mobility, including electrified transit and school buses.

GOLDCORP AND ELECTRIC MINING

Goldcorp produces roughly half of Ontario's yearly gold production. The company employs over 3,000 Ontarians, 99 per cent of them in Northern Ontario.

Goldcorp is developing an all-electric mine in Borden. Teaming up with Sandvik Mining and MacLean Engineering, nearly all the underground vehicles at Borden will be powered by batteries. By using electricity to power its equipment, Goldcorp can avoid 7,000 tonnes of carbon dioxide emissions, and eliminate the need for 2 million litres of diesel and 1 million litres of propane.

Vehicle-Grid Integration

Vehicle-grid integration is a perfect example of what can be gained by modernizing the grid. It provides more choice for customers while giving utilities the information and tools to optimize their systems.

A car is parked 95 per cent of the time. For EVs, some of that time is dedicated to charging; the rest of the time, it sits idle, waiting for its next trip. In the future, the battery of an electric vehicle could be used to deliver electricity to the home in the event of an outage. The battery could also deliver electricity back to the community, or even to the entire grid. Essentially, the EV becomes a distributed energy resource, one that can help avoid system upgrades and reduce costs for everyone.

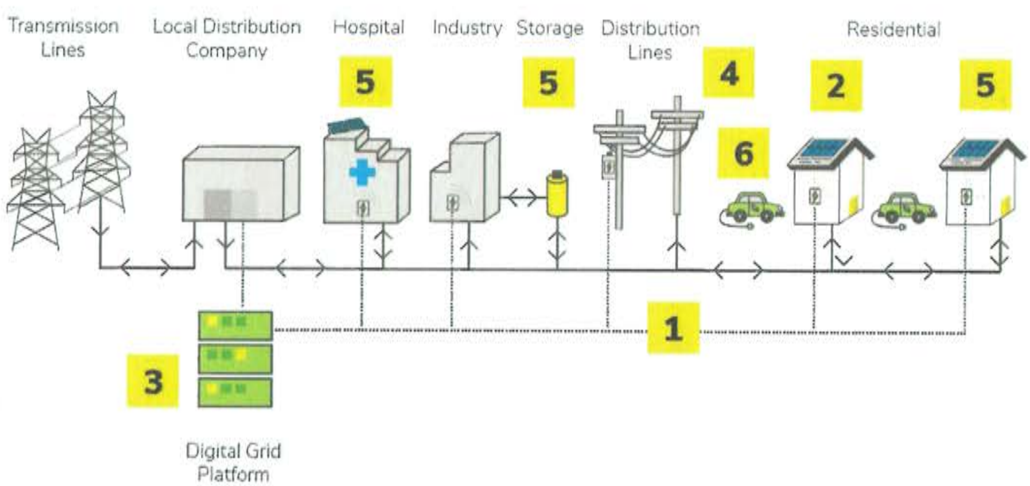
The government will engage with its partners in the energy sector and vehicle manufacturers to develop a roadmap for vehicle-grid integration that will look closely at this technology and what it could mean for Ontario.

Grid Modernization

Electricity distribution is a critical piece of Ontario's grid. The province's LDCs are the final step in a system that delivers electricity from generators to homes and businesses. Ontario is a world leader in deploying smart meters, which are the foundation for a smart grid. The meters continue to provide data to LDCs, allowing them to locate and respond more quickly to power outages, monitor their systems and better plan for the future – all to the benefit of Ontario's consumers.

A modern grid is a digital grid. It harnesses the power of data so that customers and utilities can make the right decisions. For LDCs, it means having the information critical to making their networks run as smoothly as possible. For customers, it means the local network will be ready when you want to buy an electric vehicle, install a battery, put up solar panels or choose a new pricing plan. It means more tools for you to track your energy usage. It means a more efficient, reliable and resilient grid. Above all, it means potential savings on your bill.

FIGURE 15. Distribution Grid Modernization



1 **Communication Lines** – Data from smart meters is sent to the LDC using communications infrastructure. In the future, this will also include data from sensors and other devices monitoring the entire grid.

2 **Smart Meters** – In addition to their use for billing, smart meters also provide critical data on system health for LDCs and smart meters can also be used for distributed energy resources (DERs) and large consumers to provide even more information on how the grid is operating.

3 **Digital Grid Platform** – LDCs use powerful software platforms to analyze data and use that information to make their networks as efficient and reliable as possible, potentially avoiding costly upgrades.

4 **Sensors** – Sensors instantaneously feed data back to the LDC about the health of its network's wires, transformers, and other assets.

5 **Distributed Energy Resources** – Today, DERs are mostly renewable generation. In the future, they will include energy storage, microgrids and even electric vehicles. DERs have a range of benefits that are optimized by a Digital Grid Platform.

6 **Vehicle Grid Integration (VGI)** – In the future, EVs can be used to power homes and even support the local network. VGI can turn EVs into highly responsive DERs and give owners more services and choice.

A modern grid can also give customers more choice, ranging from flexible pricing to enabling home energy management systems and realizing the full value of EVs. A modern grid can ensure that distributed energy resources like solar power, storage and microgrids can be integrated in the most efficient way possible. Above all, a modern grid can drive down costs for customers.

Now is the time to build on our investments in smart meters and the smart grid. A study by an expert third party in 2015 found that Ontario's consumers and businesses stand to gain $6.3 billion in economic, environmental and reliability benefits if the grid is modernized over the coming decades. A modern grid would be more resilient to the effects of climate change and utilize the real-time data needed to respond to problems or address them before they happen.

However, that same study found there were several barriers to modernizing the grid further in Ontario. LDCs, for example, are challenged by diffuse benefits. This is when they bear the costs of technologies such as energy storage, but do not get the benefits, which can accrue to customers other parties in the electricity sector. Without clear rules for addressing diffuse benefits, LDCs are less motivated to explore solutions that may be more cost-effective and provide greater benefits to the grid. Ontario is committed to removing these barriers so that utilities can make the right investments.

Grid modernization can also support new business models. One exciting opportunity is peer-to-peer frameworks for transactive energy. One way to implement transactive energy is through Blockchain, a computer protocol that tracks transactions within a marketplace. Blockchain uses secure, distributed databases to enable, for example, the management of EVs, the trade of renewable electricity and peer-to-peer demand response opportunities.

Combining other distributed energy resources with Blockchain technology holds the potential to provide significant value to the electricity sector, including:

- Increasing system reliability by providing greater visibility on where and how distributed energy resources and loads are affecting the system;
- More efficient balancing of the needs of the provincial grid with those of the local distribution system;
- Allowing DERs to participate and provide service in Ontario's electricity markets;
- Facilitating new business models like community-owned DERs and virtual net metering;
- Providing instantaneous feedback on how DERs are responding to price signals; and,
- Encouraging new participants in the electricity sector, which can lead to greater customer choice.

Transactive energy and Blockchain pilots are being undertaken in many jurisdictions. These models are also being studied and developed in Ontario, and the government plans to explore how Blockchain and other transactive energy models could benefit Ontarians.

Enhancing the Smart Grid Fund

The Smart Grid Fund was launched in 2011 to support innovation in Ontario's electricity sector. Innovation has produced a wide range of technologies – home energy management, grid automation, energy storage, microgrids, cyber security and EV integration. Through the Fund, Ontario companies have solved problems on distribution grids, and utilities have increased their understanding of how the smart grid can benefit the system and their customers.

The Smart Grid Fund is also supporting jobs and growth in the province. The Fund has given Ontario businesses the support they need to turn demonstrations into commercial successes. A number of recipients and products are gaining traction in foreign markets, including:

- N-Dimension Solutions, a cyber security firm with over 100 utility customers in North America;
- Utilismart's distribution monitoring software, which has been installed by over 140 utility customers; and
- A transformer sensor manufactured in Ontario by GRID20/20, which has been tested in 11 countries.

As part of the government's grid modernization strategy, now is the right time to build on this success by renewing and enhancing the Smart Grid Fund. An enhanced Smart Grid Fund will focus on encouraging a culture of innovation within the electricity sector that explores new solutions for integrating many technologies, tests new business models, integrates electricity and other energy resources and generates new ideas for advancing grid modernization.

POWER.HOUSE

Alectra Utilities launched the POWER.HOUSE pilot in 2015 with the support of the IESO's Conservation Fund. This innovative program for residential solar storage installed solar panels on 20 homes, and equipped them with an energy storage device and an energy management system that allows the homes to communicate with the LDC.

The pilot allows Alectra to treat the 20 homes as a single, virtual power plant and provide demand response or electricity when outages occur. The 20 homeowners saved money, and Alectra saw how POWER.HOUSE could delay the need for upgrades to its distribution network, which benefits all customers. Alectra believes POWER.HOUSE could be expanded to include 30,000 homes in Markham, Richmond Hill and Vaughan alone.

FleetCarma

With support from the Smart Grid Fund, FleetCarma developed a system that lets LDCs control when an EV is charged, helping them protect their local network infrastructure. FleetCarma's solution takes the needs of EV owners into account as well. They can opt out on a day-to-day basis and set a minimum, guaranteed charge for the morning commute.

FleetCarma is a great example of Ontario exporting its expertise. Building on its success from its Smart Grid Fund project in the Toronto area, the company announced in April 2017 that the New York City utility Con Edison will be using its system to dampen the impact of EV charging on the grid while collecting critical data on how EVs are used.

Distributed Energy Resources

A distributed energy resource (DER) is a decentralized source of energy that provides electricity services to individual customers or to the wider system located nearby.

Specific examples of DER include:

- **Distributed generation (DG)** – electricity generated for self-consumption and/or export to the distribution grid;
- **Energy storage** – energy stored for use close to where it is needed;
- **Microgrid** – a mini network that can operate independently when it is disconnected from the main electricity grid;
- **Energy efficiency** – measures to reduce overall electricity use, either behind the customer's meter, or on the distribution system (see Chapter 5); and
- **Demand response** – a temporary reduction or shift in demand in response to higher prices or requests from a system operator.

Each DER offers its own distinct benefits. However, the biggest gains occur when LDCs use smart communications systems to integrate a number of the technologies across their distribution networks.

Renewable Distributed Energy Resources

Renewable generation systems, such as solar photovoltaic (PV) panels, are becoming more widely adopted across the province. When strategically located and combined with smart communications and control systems, renewable distributed generation can benefit LDCs and their customers: utilities can defer or avoid certain costly investments in their local distribution networks, and customers can generate and store their own power, lowering bills and ensuring reliable access to electricity when power from their network is not available.

The government will work with the IESO to develop a program to support a select number of innovative renewable distributed generation demonstration projects strategically located and paired with other DERs and smart grid technologies, as well as virtual net metering demonstration projects. These demonstration projects will help inform the value of DG and DER to customers and the grid, and inform future grid modernization and net-metering policies, guide the treatment of renewable DG by regulators and energy markets, and steer further integration of these resources into Ontario's energy system.

Barriers to Innovation

Ontario's approach to grid modernization is to create the right environment for LDCs to make the best decisions for their systems and their customers. To get there, the government and its partners need to address the barriers to innovation. Many of these barriers are a legacy of the old way of doing things, when power only flowed one way and the technologies were simple and straightforward.

The government has taken a number of steps to encourage innovation in a changing energy sector. In 2010, it directed the OEB to give guidance to utilities on building smart grid technologies into their systems and putting innovation into their business practices. The OEB incorporated these ideas through a new regulatory framework. The OEB also established a Smart Grid Advisory Committee in 2013 to provide it with ongoing assistance in facilitating grid modernization.

Despite these efforts, there has been an unclear and uneven level of investment in grid modernization by Ontario's LDCs. Some of them, such as Hydro Ottawa and Greater Sudbury Utilities, are implementing plans to build a modern grid and a culture of innovation within their organizations. Nevertheless, the Electricity Distributors Association found that half of Ontario LDCs still approach innovation in a gradual or incremental way. It is clear that barriers to innovation remain. With the rapid development of new technology and the increase in customer expectations, the time to address these barriers is now.

To encourage change in the energy sector, the government will work with utilities and other partners to build a culture of innovation, and will look to the OEB to explore, where cost-appropriate:

- Building a stronger culture of innovation in the sector;
- Ensuring that there are no unfair barriers that disadvantage the deployment of energy storage;
- Utility participation in residential smart charging;
- The deployment of renewable distributed generation and other distributed energy resources that provide value to customers;
- The use of innovative, non-wires solutions that could, among other things, allowing utilities to manage their systems better and encourage customer choice including the principles of efficiency and cost-effectiveness;
- The regulatory treatment of LDC capital and operational expenditures, which can inhibit the uptake of these non-wires solutions;
- A cost-benefit framework that provides clarity on the treatment of investments, such as those with localized costs that provide benefits to other electricity system participants (also known as the diffuse benefits issue);

- The ability of utilities to make non-traditional distribution system investments and participate in market opportunities that would ultimately reduce ratepayers' costs associated with capital or other investments; and
- Opportunities for utilities to partner with their customers to use in-front and behind-the-meter applications to address system needs.

Taking these actions should create the right environment for LDCs to overcome barriers and modernize their businesses and systems. In such an environment, LDCs will have more clarity on how they can pursue the innovation contemplated under the *Strengthening Consumer Protection and Electricity System Oversight Act, 2015* and invest in solutions that make the most sense for the systems and their customers.

As part of this effort, the government will encourage LDCs to develop plans that demonstrate how they intend to modernize their grids and their businesses. These modernization plans could be incorporated into a LDC's asset management practices and their filings to the OEB.

IESO Market Renewal and Innovation

The IESO is preparing for the future by laying the foundation through Market Renewal, which will develop a made-in-Ontario solution to create better price signals and establish more competitive market-based mechanisms to meet system needs. The long-term goal of Market Renewal is to create a more dynamic market where all resources, including new technologies, have the opportunity to compete alongside traditional forms of supply for a variety of system products such as energy, capacity and operability. As costs come down and new business models are developed, emerging technologies, often at the local level, will be increasingly competitive compared to traditional resources. At the same time, the existing and new markets will present opportunities and choice to a wide variety of consumers looking to become more active in Ontario's energy markets.

Market Renewal also aims to enhance and improve existing market mechanisms and create new mechanisms that will allow new technologies like energy storage to compete on an equal footing with traditional assets and showcase the different values they provide in meeting system needs, including managing surplus baseload generation, regulation, operating reserve and flexibility.

Building on the Success of Renewables

The tremendous growth of Ontario's clean tech and renewable energy sectors has attracted billions of dollars in investment to Ontario and led to the creation of thousands of new jobs across many trades and professions. That explains why a broad coalition of employers, labour and industry groups, including the International Union of Operating Engineers, the Laborers' International Union of North America (LiUNA) and the Aboriginal Apprenticeship Board of Ontario, support Ontario's investment in renewable energy.

Ontarians have every reason to expect that these economic benefits will continue. According to a report from an expert third-party, the renewables sector is forecast to contribute nearly $5.4 billion to Ontario's gross domestic product and create 56,500 jobs between 2017 and 2021. Many of the companies that participated in Ontario's expansion of renewable energy are now poised to export their expertise and products to foreign markets. This could contribute as much as $1 billion to Ontario's GDP and could add as many as 10,700 jobs between 2017 and 2021.

Ontario-based manufacturers of hydroelectric components have been successfully exporting to the United States for years. Many of Ontario's solar manufacturers are also reporting increased export activity to the U.S., despite strong global competition. Wind component manufacturers have also developed expertise that will help them succeed in nearby American markets that are replacing coal-fired generation with renewables and other clean sources of electricity.

Exporting Ontario's Energy Expertise

Ontario's energy innovators are experts in smart grid, renewables, nuclear and other technologies, and are using the solid base they have established in the province to export to other markets in North America and around the world.

A NORTHERN ONTARIO SUCCESS IN MANUFACTURING

Heliene Canada has been manufacturing solar PV panels in Sault Ste. Marie since 2010. The company's manufacturing facility uses state of the art technology and currently exports over half of its modules to the U.S. and other markets. Heliene collaborates with other industry players and universities, such as ePower, the micro-electronics laboratory of Queen's University and the Rotman School of Business at the University of Toronto, to create a link between academic research and industrial applications.

The government continues to support the dynamic and innovative business climate that made this possible and will expand assistance to Ontario companies wanting to diversify their energy-related goods, services and expertise, by:

- Working with the federal and other provincial governments, industry and postsecondary institutions to develop and support trade initiatives that support market entry and new business opportunities;
- Developing market intelligence that determines which foreign markets hold promise for Ontario's energy goods and services;
- Participating in energy-related trade missions abroad; and
- Promoting Ontario's technical expertise at appropriate international forums.

In consultation with industry and the federal government, the government intends to develop a pilot program that provides financial support for the demonstration of locally-developed technologies abroad. The pilot will help Ontario energy companies get a foothold with utilities and buyers in global markets, and support the Province's commitments to help Ontario companies go global.

> "Global economies are demanding clean and low-cost energy solutions and Ontario entrepreneurs are poised to seize that opportunity."
> **MaRS Cleantech**

Nuclear Innovation

Ontario's expertise in nuclear energy has enabled it to be a leading jurisdiction in nuclear research and nuclear medicine. Ontario can help create new export opportunities for nuclear innovations, such as:

- **Small Modular Reactor (SMR) Technology:** This is a new generation of nuclear power reactors that have smaller footprints than conventional reactors and the promise of lower costs from mass production. In 2016, the government released a consultant's study on the feasibility of SMRs for remote mining applications in Ontario, which found that SMRs could be an economic and emission-free alternative to diesel power. The government continues to monitor SMR technologies and engage with key stakeholders involved in advancing these innovative designs.
- **Nuclear Fuel Research:** Technological innovations could lead to the reprocessing or recycling of used nuclear fuel or the use of thorium to power nuclear reactors.
- **Hydrogen:** Ontario's nuclear technology could be used for the large-scale production of hydrogen. Hydrogen is a source of low-carbon energy that could, in the future, replace gasoline for transportation or natural gas for heating.

Ontario is keenly interested in collaborating with the federal government, universities and industry partners to continue its support of the nuclear industry for both energy and non-energy applications.

MEDICAL ISOTOPES

Ontario's nuclear reactors transform chemical elements, such as cobalt, into isotopes that can diagnose and treat life-threatening diseases. These isotopes can also sterilize medical equipment such as hospital gowns, gloves, masks, implantable devices and syringes, as well as some food products.

Cobalt-60 is a key isotope for medical applications. Currently, 70 per cent of the world's supply of the medical-grade Cobalt-60 isotope is produced in nuclear reactors at Chalk River, Pickering and Bruce B. The isotope is used for 10 million cancer therapy treatments around the world every year, as well as for medical imaging, equipment sterilization and non-invasive brain surgery. Bruce Power has also established a new long-term supply of medical-grade cobalt from Bruce B that will help replace the supply from Chalk River's reactor when it is closed in March 2018.

Recently, Cobalt-60 harvested from the Bruce reactor was used in the Sterile Insect Technique or SIT, to combat the spread of Zika, West Nile and dengue viruses.

The Ottawa-based health-sciences company Nordion is exploring the use of the Bruce A and Darlington reactors to expand the production of Cobalt-60.

Innovative Uses for Ontario's Natural Gas System

Renewable Natural Gas

Renewable natural gas (RNG) can be an innovative Ontario-made source of energy. 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 the 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. Ontario's new *Waste-Free Ontario Act, 2016* and its Organic Waste Action Plan, will create more opportunities to use organic waste to produce clean energy. As an added benefit, RNG can use the existing natural gas distribution system to replace the use of conventional natural gas in today's stoves and furnaces.

A PILOT PROGRAM FOR RENEWABLE NATURAL GAS IN TRANSPORTATION

Ontario's Climate Change Action Plan commits the Province to increasing the availability and use of lower-carbon fuel.

The government is now developing a pilot program that would extract methane from agricultural materials or food waste and use it for vehicle fuel. The pilot is expected to demonstrate the business models and technology that will allow agricultural and food sectors to produce RNG, and support businesses as they upgrade their vehicles and fueling infrastructure to use RNG.

In May 2017, the government issued a discussion paper to gather feedback from businesses, partners and the public to help guide the design of the program.

Power-to-Gas

Electrolysis, also known as power-to-gas, uses electricity to break down water molecules into hydrogen and oxygen. This transforms electricity into hydrogen gas, another type of fuel. Hydrogen can be stored or transported in existing natural gas pipelines and used to heat homes and fuel vehicles.

Power-to-gas could potentially become a new and important link between the province's electricity system and its natural gas system. The IESO recognizes this, and has already awarded a contract to Hydrogenics, an Ontario-based manufacturer of electrolysis and fuel cell technology, to provide electricity grid services during the production of hydrogen.

Using electricity to create hydrogen is one way to help decarbonize the natural gas supply. The Province has acknowledged the potential versatility of this fuel and is undertaking a feasibility study of using hydrogen to fuel GO Transit passenger trains.

To support this technology going forward, the government will work with the IESO to evaluate the development of a pilot project that explores the energy system benefits and GHG emission reductions from the use of electricity to create hydrogen.

Summary

- The government will work with the Ontario Energy Board to provide customers with greater choice in their electricity price plans.
- The net metering framework will continue to be enhanced to give customers new ways to participate in clean, renewable energy generation and to reduce their electricity bills.
- Barriers to the deployment of cost-effective energy storage will be reduced.
- Utilities will be able to intelligently and cost-effectively integrate electric vehicles into their grids, including smart charging in homes.
- The Province's vision for grid modernization focuses on providing LDCs the right environment to invest in innovative solutions that make their systems more efficient, reliable, and cost-effective, and provide more customer choice.
- The government will build on its success and renew and enhance the Smart Grid Fund. This will continue the Province's support of Ontario's innovation sector and help overcome other barriers to grid modernization.
- The Independent Electricity System Operator will work with the government to develop a program to support a select number of renewable distributed generation demonstration projects that are strategically located and help inform the value of innovative technologies to the system and to customers.
- The government intends to fund international demonstration projects to help Ontario's innovative energy companies diversify to foreign markets.
- The Province will collaborate with the federal government, universities and industry to support the province's nuclear sector.
- Innovative uses for Ontario's natural gas distribution system will be pursued.
- The government will work with the IESO to explore the development of a pilot project that evaluate the energy system benefits, and GHG emission reductions from the use of electricity to create hydrogen.

4

IMPROVING VALUE AND PERFORMANCE FOR CONSUMERS

4

IMPROVING VALUE AND PERFORMANCE FOR CONSUMERS

The government and its partners are focusing their efforts on improving service to the province's electricity consumers.

This requires a continuous search for efficiencies, and maintaining a culture of innovation in the sector. These new technologies and systems can benefit energy consumers by enabling more intelligent planning and investments. The Province expects transmission and distribution utilities to deliver high-quality service while finding efficiencies and opportunities to lower costs.

WHAT WE HEARD FROM YOU

- Eliminate regulatory barriers
- Encourage consolidation and partnerships
- Expedite approvals for new technologies
- Support innovative business models
- Improve reliability

Continued innovation in the electricity sector enables customers to use data and information in their decision-making and gives them the additional choice they have in many other parts of their lives. However, more choice requires more information, so consumers will need more openness and information from energy companies and agencies. The government is making this change possible by ensuring that the standards and performance of the sector's entities are readily accessible.

Modernizing the Utility Business

Ontario's local distribution companies (LDCs) are the main point of contact when customers deal with the electricity system. They provide the services that consumers count on, such as restoring power after outages, maintaining the safety of the system and fielding calls and questions.

In the coming years, utilities will face a number of challenges as to how they conduct their business. New and innovative technologies and companies are ready to respond to changing consumer expectations. LDCs need to determine how they will continue to provide value to consumers and participate effectively to meet system needs in the future.

The Ontario Distribution Sector Review Panel determined in 2012 that the consolidation of LDCs could reduce costs from the distribution sector by $1.2 billion over 10 years. The Ontario Energy Board (OEB) must lead, innovate and provide LDCs with incentives to become more cost-effective and efficient. The OEB has made improving LDC performance a priority.

The OEB's Performance Scorecard uses several key measures, such as resolving customer complaints during the first phone call or the first visit, to track whether LDCs have improved their performance. The Scorecard also allows customers to see if the service they receive from their LDC meets OEB standards. The OEB is planning to enhance this framework to encourage greater efficiencies and make LDCs more accountable to consumers.

The government will look to the OEB to further strengthen the accountability that both distributors and transmitters need to show to their customers. By focusing on the principles of transparency, responsiveness to customers, efficiency and cost-effectiveness, the OEB will support a future in which:

- Utilities (LDCs and transmitters) have incentives to cut costs and make annual improvements to productivity and cost-efficiency;
- Utilities are constantly striving to improve;
- Utilities are held to account when expectations are not met;
- Customers get the highest possible value from their electricity services; and
- Businesses and other large customers have a timely and predictable process to connect to the grid or modify their existing connections.

LDCs are already responding to the changing landscape and finding opportunities to achieve further efficiencies and savings.

Improving Grid-Connection Processes

Increasing efficiency and transparency in our electricity sector supports Ontario's Open for Business strategy. This strategy includes a Red Tape Challenge to cut unnecessary red-tape to save businesses time and money. As part of this initiative, the government will engage the mining sector and other large industrials to discuss opportunities to improve grid-connection processes so that they do not pose barriers to investment in Ontario.

Enhancing Reliability

Ontario's market participants must comply with standards that define the reliability requirements for planning and operating the interconnected North American bulk electricity system. The North American Reliability Corporation defines standards which address physical and cyber security, emergency planning and response, power system modelling and planning, and real time operating practices for the bulk electricity system. The Independent Electricity System Operator (IESO) is responsible for compliance monitoring and enforcement of the reliability standards in Ontario.

The OEB also sets reliability and quality of service standards for transmission and distribution utilities. Distributors report the frequency and duration of outages in their annual performance scorecard to the OEB. Transmitters also have customer standards, including a process to address areas of poor performance.

Reliability and quality of service are of vital importance to electricity consumers. This is especially true for communities on long, radial lines that can fail more frequently, and for businesses that are particularly sensitive to electricity outages or fluctuations. The OEB has considered a number of ways to improve reliability over the years and the government will look to the OEB to examine further cost-effective steps that could help provide customers with useful knowledge about the reliability of their service and opportunities to resolve their concerns.

The Province believes that an enhanced framework for the reliability and quality of service of transmission and distribution utilities could provide customers with increased benefits, for example by:

- Introducing incentives and consequences to ensure utilities are held to account for performance. For example, as in done in some other jurisdictions, Ontario customers could receive an on-bill credit when service standards are not met;

- Establishing new standards and measurements of reliability that, in addition to the current system-wide averages, give customers more detailed insights into the reliability of their local networks;
- Ensuring that utilities report whether they are meeting the standards in a way that customers find meaningful and easy to understand; and
- Setting out clear timelines and steps that utilities must follow when they do not meet reliability standards or when customers report problems with reliability, power quality or other quality of service issues.

The government will look to the OEB to review the standards that transmission and distribution utilities currently have for reliability and quality of service and for options to improve the standards. The government will also ask the IESO to review how its planning and policies can improve customer reliability.

EXAMPLES FROM OUTSIDE ONTARIO: COMPENSATING CUSTOMERS FOR POOR SERVICE

In Michigan, residential customers can get a credit of $25 USD if their utility fails to restore power after 16 hours of outage under normal conditions, after 120 hours under catastrophic conditions and after seven outages within a 12-month period.

RAISING AWARENESS OF LOCAL ISSUES

More detailed information about reliability would create greater transparency for customers and the regulator. This is particularly relevant for large transmitters and distributors.

For example, the current LDC scorecard requires Ontario distributors to report their system-wide reliability. This means a small distributor, like Whitby Hydro with approximately 40,000 customers, reports the same level of detail as a large distributor like Hydro One with 1.3 million customers.

Changing Business Models

To meet the challenges of the future, LDCs may need to adopt more flexible and innovative approaches to service delivery than have been allowed in the past.

Non-wires alternatives represent an opportunity for LDCs to adopt new approaches to how they deliver electricity and conduct business. While traditional investments are capital-intensive, non-wires alternatives often involve expenditures that the OEB considers "operational" in nature. The current regulatory framework inherently favours LDCs' capital investments over operational investments, reducing the incentive for utilities to explore these innovative solutions. As part of its review of barriers to innovation (Chapter 3) the government will look to the OEB for ways to appropriately address the treatment of LDC expenditures to ensure cost-effective outcomes for ratepayers.

Many LDCs have entered into joint service agreements to improve customer service and reduce their operating, maintenance and administration costs. Organizations such as GridSmart City, the Coalition of Large Distributors and Cornerstone Hydro Electricity Concepts are examples of LDCs leading the way in these partnerships.

ENCOURAGING PARTNERSHIPS AND EFFICIENCIES

GridSmartCity Cooperative is a partnership of 13 LDCs created to improve service to electricity customers by increasing the efficiencies of scale and scope within each of their operations. The partnership has reduced costs by having joint purchasing for services such as information technology, human resources and infrastructure procurement.

The government will look to the OEB to explore ways of facilitating these partnerships where they make economic sense. It will also consult with LDCs on additional ways to realize these savings and provide better customer service. The OEB will continue to promote efficiencies in its own rules and requirements so that LDCs and transmitters benefit from further regulatory streamlining.

Making Electricity Bills More Understandable

Electricity bills need to be clearer and more understandable. They are the customer's main window into the electricity system. Consumers have told both the Province and LDCs that they find current bills confusing and inaccessible. Action is underway to address this. Hydro One is introducing a redesigned electricity bill for its low-volume consumers in late 2017. Hydro One's redesigned bill, the product of testing and research into consumer behaviour, is expected to increase customers' understanding of their electricity charges.

To expand this effort across Ontario, the government is working with the OEB and LDCs to redesign electricity bills to give Ontarians the information they have said they want on the bill. This will make bills easier for customers to understand and ensure they get the most useful information out of their bills. Customers expect LDCs to adopt more consumer-friendly billing systems, such as bills that can be viewed and paid on mobile devices.

Improving Customer Choice through Data Accessibility

The Province is promoting improved access to data to help consumers view and understand the information they need to make decisions on their energy use. Recent initiatives include:

- The Ontario Energy Report, an online portal that provides consumers and stakeholders with an up-to-date snapshot of Ontario's energy sector;
- Green Button, a data standard that can give consumers access to data on their energy and water consumption. Green Button can also allow consumers to securely and automatically transfer that data to various applications that can help them manage and conserve energy and water; and
- Enhancing the Meter Data Management and Repository (MDMR), Ontario's central repository for smart meter data. The IESO Smart Metering Entity is leading a project that will support more rigorous analysis of consumption data across the province, with the end goal of making better planning decisions and improving services to customers.

The government will continue to improve peoples' ability to use data to make decisions. But it cannot stop there. Ontario's energy sector as a whole must continue to improve its ability to analyze data and use advanced mapping tools and other cutting-edge technologies to further modernize our grid. This is discussed further in Chapter 5.

These efforts always need to keep the individual in mind. While the digital economy is integral to an efficient government and an affordable energy sector, it will be built on the protection of personal privacy.

Cyber Security

Cyber security is increasingly important in protecting critical infrastructure, such as the province's electricity system. It includes a body of technologies, processes and practices designed to protect networks, computers, programs and data against attack, damage or unauthorized access.

Cyber security standards for the bulk electricity system are defined by the North American Electric Reliability Corporation. These Critical Infrastructure Protection standards have been adopted in Ontario and are enforced by the OEB and the IESO. Generators, transmitters and other industry participants are required to implement and comply with the standards.

Cyber security at the distribution level is an emerging issue, and is an operational necessity for the distribution sector. It includes both the protection of customer-specific information held by LDCs and the protection of distribution-level system operations.

The government is working with both the IESO and the OEB to ensure that cyber security is being addressed in the electricity system and that there is appropriate regulatory oversight to mitigate cyber risks and threats.

In the spring of 2017, the OEB issued a draft framework that will define cyber security guidance and reporting requirements for LDCs. This framework will be in place by the end of 2017.

Competitive Transmitter Selection

To help ensure lowest-cost solutions for transmission, the Energy Statute Law Amendment Act, 2016 enabled the IESO to use a competitive process to select companies or consortia for the construction of new transmission lines in Ontario.

As a first step in implementing the new legislation, the government will direct the IESO to develop a process for the competitive selection or procurement of transmission and identify possible pilot projects. The results of these pilots will be used to develop a procurement process that is clear, cost-effective, efficient and able to respond to changing policy, market and system needs.

Right-Sizing

The aging of transmission and distribution infrastructure across the province presents challenges for the electricity industry. These challenges include managing costs and the outage requirements necessary to deal with replacing or refurbishing end-of-life equipment, while maintaining safe and reliable service to customers. Equipment reaching end of life also presents opportunities to ensure that the new or refurbished facilities are "right-sized". That means downgrading or removing equipment if demand is expected to decrease and upgrading equipment in communities with growing demand or increasing reliability needs. New facilities will also consider technological advances and other solutions that may be more cost effective in the long run.

The IESO and OEB have key information associated with forecasts for growth, changing customer needs and technological advancements based on government policies and programs, while transmitters and distributors have information related to asset end-of-life and the related reliability and other risks. Together, this information provides important perspectives on the likelihood and consequence of asset failure, the forecast of growth, changing customer requirements and the impact of new technologies, to ensure new and refurbished infrastructure is built to the right size and is capable of meeting the future service quality needs of customers.

As they exercise their respective responsibilities for planning, the government will look to the IESO and the OEB to promote a co-ordinated, streamlined and longer-term approach to the replacement of transmission and distribution assets that are at end of their lives. The approach needs to be consistent with the beneficiary pays principle, where the consumers that benefit from the asset are responsible for the costs.

Transmission Corridors

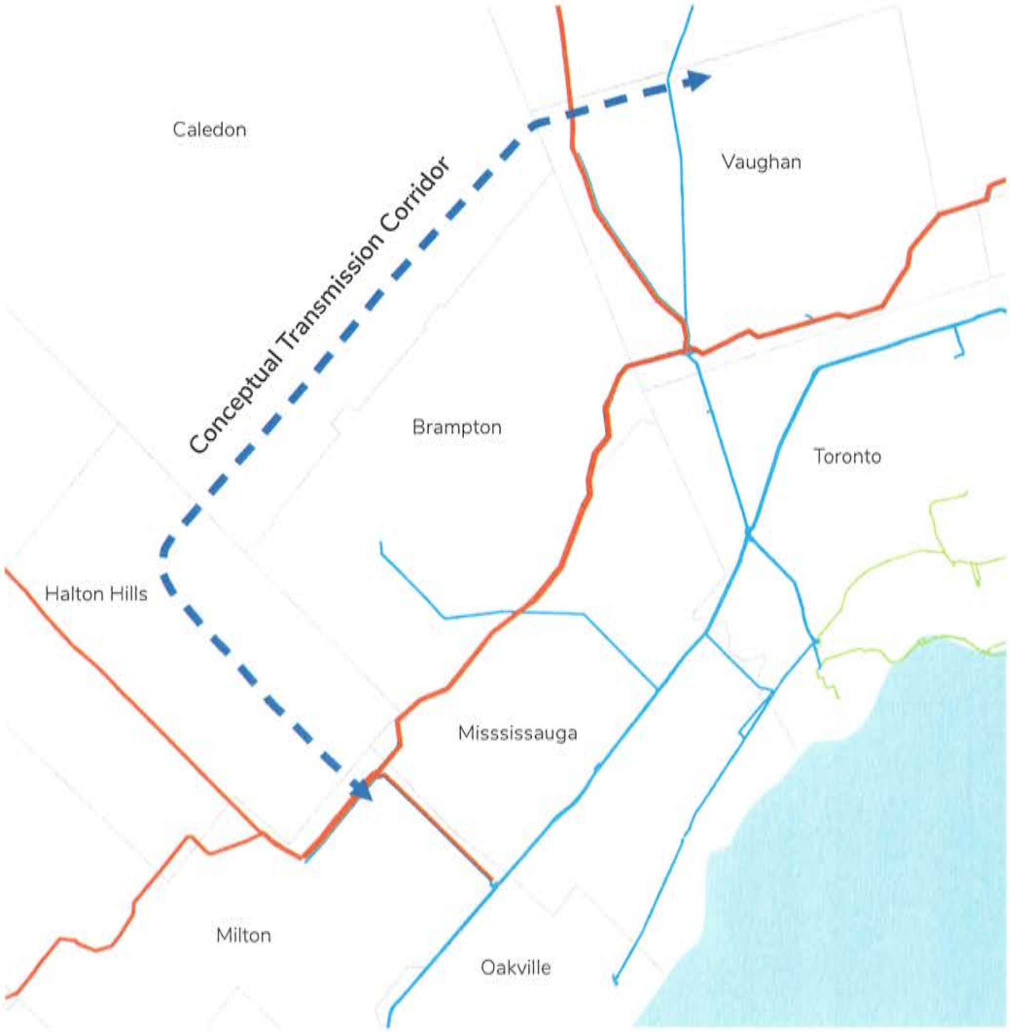
The Provincial Policy Statement, 2014 states that efficient patterns of land use and development are essential for healthy, livable and financially-viable communities. The statement connects the planning for land use and energy infrastructure by endorsing the planning and protection of transmission corridors and discouraging development that could preclude or limit the use of a planned corridor.

The Provincial Policy Statement is the foundation of the Growth Plan for the Greater Golden Horseshoe (2017), which requires the Province, municipalities and other public agencies to encourage the co-location of linear infrastructure, such as roads and transmission lines, when they are planning for development. The Growth Plan says governments and public agencies should also protect existing and planned corridors to meet current and projected needs.

The IESO's regional plan identifies that the northwest Greater Toronto Area has a long-term need for a transmission corridor (Figure 16). The IESO relied on the population and employment forecasts included in the Growth Plan to forecast demand for the area. The transmission corridor would supply portions of the Regions of Halton, Peel and York.

Given the size of the forecasted growth and the distance from existing transmission lines, alternatives to a new transmission corridor are either not economical or not technically feasible. The IESO estimates that there could be additional costs of hundreds of millions of dollars to build underground transmission lines later on, if an overhead transmission corridor is not reserved before the area develops. Further studies will identify a more specific corridor.

FIGURE 16. Future Transmission Corridor in the West GTA



For illustrative purposes only

Transparency for Consumers on Gasoline Pricing

Many Ontario consumers pay attention to their gasoline prices. A number of components are part of the retail price of gas, including crude oil costs, taxes, the gross refining/wholesale margin and the gross retail margin. Families and businesses have requested more information about how gasoline and diesel retail prices are set.

As a result, the government asked the OEB in November 2016 to review the operation of Ontario's retail market for gasoline and diesel fuel. The review will focus on three main topics:

- The extent and causes of variations in retail prices over time and between one region in Ontario and another;
- How pricing and competition in Ontario compare with other jurisdictions; and
- The information available to consumers about pricing and price variations.

The OEB expects to report on its findings by the end of 2017. The government will review the OEB's report in detail and consider the information in its future decision-making.

The government monitors the supply and price of gasoline in the province and other jurisdictions, and makes this information publicly available through the quarterly Ontario Energy Report.

Summary

- The Province expects the Ontario Energy Board (OEB) to continue to enhance its efforts to improve the performance of local distribution companies (LDCs).
- The government will look to the OEB to identify additional tools and powers that could be used to make utilities more accountable to their customers, promote efficiencies and cost reductions, encourage partnerships, and ensure regulatory processes are cost-effective and streamlined, while also accommodating changing utility business models.
- The government will work with the OEB and LDCs to redesign the electricity bill to make it more useful for consumers in understanding and managing their energy costs.
- The government will look to the OEB to review the standards for reliability and quality of service for transmitters and distributors, and options for improving the standards, and will ask the Independent Electricity System Operator (IESO) to review how its planning and policies can improve reliability for customers.
- The government will direct the IESO to develop a competitive selection or procurement process for transmission, and to identify possible pilot projects.
- The government will look to the IESO and the OEB to promote the right-sizing of transmission and distribution assets at their end of life.
- A new transmission corridor is needed in the northwest Greater Toronto Area given the size of the forecasted growth. Further studies will identify a specific corridor.
- The Province will provide greater transparency for consumers on gasoline pricing through the OEB's transportation fuels review.

5 STRENGTHENING OUR COMMITMENT TO ENERGY CONSERVATION AND EFFICIENCY

Ontario has been building a culture of conservation since 2005 and can be proud of what has been accomplished.

According to the Independent Electricity System Operator's (IESO) 2015 study on Ontario's conservation efforts, businesses are investing in energy-efficiency upgrades to increase their productivity and residents are choosing to install energy-efficient equipment in their homes, often with the help of Ontario's suite of residential and business conservation and demand management programs. Between 2005 and 2015, the average monthly household consumption of electricity decreased from more than 800 to about 750 kilowatt-hours (kWh).

WHAT WE HEARD FROM YOU

- Reaffirm and enhance commitment to Conservation First
- Improve building codes and standards
- Increase awareness of conservation and demand management programs and the value of conservation
- Ensure conservation and demand management programs are in sync with programs in the Climate Change Action Plan
- Expand conservation to other fuels
- Encourage energy efficiency on the distribution system

Energy efficiency is becoming more of a part of our everyday lives. Between 2006 and 2015, Ontario conserved 13.5 terawatt-hours (TWh) of electricity. That is equivalent to the electricity used annually by 1.5 million households, or the amount of electricity that powered the cities of London, Kingston, Ottawa, Peterborough and Thunder Bay in 2015. During the same time, the conservation programs delivered by Ontario's natural gas utilities saved more than 1,700 million cubic meters of natural gas, equivalent to the natural gas used by about 800,000 homes in a year, or taking about 750,000 cars off Ontario's roads for one year.

Since the 2013 Long-Term Energy Plan (2013 LTEP), the government, its agencies, and electricity and natural gas distributors have been putting Ontario's Conservation First policy into effect.

Conservation and energy efficiency require a sustained commitment if they are to achieve persistent savings over the long term. Ontario is enhancing its commitment to Conservation First to improve affordability and choice for people, businesses and communities, and to co-ordinate its conservation programs with Ontario's climate change objectives.

Additionally, the government will help Ontario homes and businesses transition to a low-carbon future by expanding program offerings through the new Green Ontario Fund.

The Savings from Conservation and Energy Efficiency

ELECTRICITY

1.01 billion kilowatt-hours
Energy savings achieved in 2015 through business conservation programs.

4.1 million
The coupons for energy-efficient products redeemed across the province in 2015.

$2
The added costs that are traditionally avoided in the electricity system every time $1 is invested in energy efficiency.

$0.04 per kWh
Cost of electricity conservation programs in 2015, which is cheaper than most forms of new supply.

NATURAL GAS

Over 80 million cubic metres
The amount of natural gas saved in 2015 through conservation programs for businesses.

8,000+
The energy efficiency projects completed through home energy audit and retrofit programs in 2015.

$7 to $11 per month
A typical household that participates in residential natural gas conservation programs can save about $7 to $11 per month.

$0.04 per cubic metre
The cost of natural gas conservation programs in 2015, significantly cheaper than the cost of purchasing natural gas.

Getting More from Conservation

Ontario has an adequate supply of energy. Any additional demand for electricity supply is not expected to appear until the early-to-mid 2020s. In this context, the Province will continue to use conservation programs and improved energy efficiency standards to drive toward its long-term target of saving 30 TWh of electricity in 2032, helping to offset almost all of the forecast growth in electricity demand. The government and its agencies will continue to assess the achievable potential for energy conservation, consider initiatives under Ontario's Climate Change Action Plan, and explore options to enhance the value of our existing investments in conservation.

The IESO is currently conducting a mid-term review of the 2015-2020 Conservation First Framework and the Industrial Accelerator Program for electricity conservation. The Ontario Energy Board (OEB) is conducting a similar review of the Demand Side Management Framework for natural gas programs. These reviews are looking at how the programs are meeting customer needs, distributor budgets and targets for conservation savings, and co-ordination with the Province's climate change objectives, including Green Ontario Fund programs.

The IESO is also using the mid-term review to look at how conservation programs can better meet the needs of local and regional electricity planning.

Demand Response

Demand response programs reward electricity customers for reducing their electricity use when needed. Demand response provides benefits to Ontario's electricity system by enhancing reliability, as well as reducing system costs and greenhouse gas (GHG) emissions. An example of demand response is a factory temporarily halting a process, or a group of residential consumers reducing their air conditioning when electricity demand is high.

The IESO has successfully transitioned away from using multi-year contracts to secure demand response, holding an annual competitive auction instead. The demand response auctions held in 2015 and 2016 reduced the cost of obtaining demand response resources by up to 27 per cent when compared to previous contracts. The IESO is now working with industry partners to use demand response to better respond to rapid increases or decreases in electricity demand. Demand response is spurring innovation in new technologies, such as smart thermostats, energy management software and communication technologies.

Through collaborative efforts by the IESO and the Demand Response Working Group, Ontario's demand response resources have grown significantly above the 2013 LTEP projections, and demand response has become a mature and competitive resource. Demand Response capacity realized each year will depend on system needs and the competitiveness of demand response with other resources.

DEMAND RESPONSE

Ontario has a number of initiatives that contribute towards its demand response capacity. These include the Industrial Conservation Initiative, demand response auctions, demand response pilots and time-of-use pricing. In 2015, demand response resources amounted to about 1,750 MW, which is over 20 per cent higher than what was projected in the 2013 LTEP.

Ensuring a Customer-Centred Approach

The current conservation frameworks encourage electricity and natural gas distributors to collaborate in providing more efficient programs and a streamlined experience for customers. Such partnerships can offer energy consumers a co-ordinated, one-window approach to help meet their energy management needs. Currently, 46 electricity distributors are involved in joint conservation plans, and electricity distributors are partnering with natural gas distributors to design and develop programs that cover multiple fuels. Partnerships can enable multi-fuel programs to improve customer convenience and expand choice.

Distributors are being encouraged to develop new and innovative programs for their customers. New pilots and programs include Hydro One's Heat Pump Advantage pilot, a provincewide Business Refrigeration Incentive Program (originally developed by Alectra Utilities), Toronto Hydro's incentive program for Energy Star pool pumps, and Enbridge Gas Distribution's School Energy Competition.

For its part, the IESO has launched the first full-scale, pay-for-performance program in North America. The Save on Energy Multi-Distributor Pay-for-Performance Program rewards businesses for improving their overall energy performance over a number of years. Businesses are paid for each kilowatt-hour they conserve, and are given flexibility on how they achieve those savings. Ratepayers benefit as well; participants only have to file a single project application, reducing the administration costs of the program.

BUSINESS REFRIGERATION INCENTIVE

Donaleigh's Irish Public House in Barrie installed energy efficient motors on its refrigeration units and reduced its annual electricity costs by $2,394. The project was implemented at no cost to the owner, as the Save on Energy Business Refrigeration Incentive Program covered the entire cost of $2,536 for materials and labour. The local electricity utility, Alectra Utilities, helped identify the specific energy-saving opportunity and developed a customized Energy Action Plan for the restaurant and pub.

"This is beneficial to the company and to our environmental footprint. We try to look at our footprint and make it as small as possible."

Don Kellett, Owner, Donaleigh's Irish Public House

UNION GAS AND SOCIAL HOUSING HALDIMAND NORFOLK HOUSING CORP

Haldimand Norfolk Housing Corporation is saving $14,000 a year and has improved tenant comfort by installing variable frequency drives on the heating systems of six rental buildings. The $14,500 incentive through Union Gas's Affordable Housing Conservation Program covered 50 per cent of the project's total cost and is reducing annual natural gas consumption by 45,000 cubic meters.

"This methodology has proven to save significant amounts of energy required to heat incoming fresh air. The resulting savings have been instant and the incentive was able to cut the payback time in half."

Marc Puype, Technical Services Manager, Haldimand Norfolk Housing Corporation

Expanding Home Retrofits

As part of its Climate Change Strategy, Ontario has invested $100 million from its Green Investment Fund to help eligible homeowners who primarily heat with natural gas, oil, propane or wood. They can improve the energy efficiency of their homes, reduce their energy bills and cut GHG emissions by participating in enhanced audit and retrofit programs offered by Enbridge Gas Distribution and Union Gas.

Launched provincewide in October 2016, the program is expected to allow about 37,000 additional homes to be audited and retrofitted by 2019, and cumulatively reduce their lifetime GHG emissions by approximately 1.6 million tonnes.

The Province made additional improvements to the home energy audit and retrofit programs in May 2017. Partnering with Enbridge Gas Distribution and Union Gas, the IESO expanded the program to include electrically-heated homes and added electricity savings measures for all participants. This 'Whole Home' approach is now providing residential consumers with a co-ordinated, one-window approach to energy efficiency improvements.

ENERGY EFFICIENCY FOR YOUR WHOLE HOME

Incentives from the Home Energy Conservation Program allow families like the O'Haras to reduce their energy bills, increase their home comfort, and cut GHG emissions. The O'Haras improved the efficiency of their more than century-old home by upgrading their furnace, hot water heater and windows. They also added basement insulation and air sealed their home. The upgrades will reduce the O'Hara's consumption of natural gas by 36 per cent, and cut their annual GHG emissions by 1.67 tonnes. In addition to retrofitting their home, the O'Haras installed a smart thermostat, which increases their savings by allowing them to reduce home temperatures when they are away.

Providing Choice Through Information, Tools and Access to Energy Data

Ontario is leading the way in helping consumers choose devices and technologies that can give them greater control over their energy use, and help them find opportunities to lower their energy bills.

Smart Thermostats

Smart thermostats can be an important piece of technology for homeowners or businesses who want to reduce their heating and cooling costs and carbon footprint. Smart thermostats:

- Give consumers more information about their energy use;
- Enable customers to use a smart phone app to remotely control the temperature of their home or small business; and
- Automatically adjust the temperature to respond to changes in pricing, a customer's schedule, or to changes in the season.

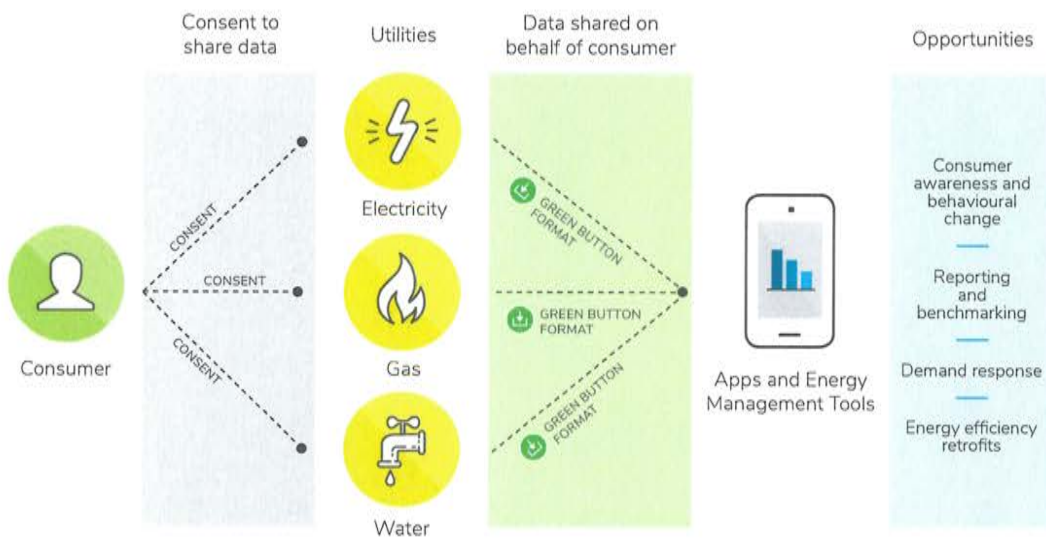
To standardize incentives for the purchase of smart thermostats and expand their availability across Ontario, the government's August 2017 direction enables the IESO to design and deliver, with the support of the Green Ontario Fund, a provincewide rebate program for smart thermostats. In addition, the Green Ontario Fund has launched the GreenON Installations program, which provides, on a limited basis and at no cost, a smart thermostat installation and in-home energy review.

Green Button

Ontario's Climate Change Action Plan committed to expanding the Green Button initiative. Green Button Download My Data can give households and businesses easy electronic access to data on their energy and water consumption. Green Button Connect My Data lets households and businesses securely and automatically transfer their own data to applications of their choice. Greater access to information through Green Button will allow consumers to better understand their energy and water usage and use the information to make decisions, such as reducing or shifting their energy use or retrofitting their home or business to improve its energy efficiency. Green Button can also support energy reporting and benchmarking, and create new opportunities for economic development. In the long-term, implementing Green Button provincewide would support the Province's continued efforts to put conservation first and help drive toward its long-term target of saving 30 TWh of electricity in 2032.

The government is committed to expanding Green Button provincewide and intends to propose legislation that would, if passed, allow Ontario to require electricity and natural gas utilities to implement Green Button Download My Data and Connect My Data. In addition, the government will collaborate with the province's electricity, natural gas and water utilities to adapt the Green Button standard, update existing guidance documents for LDCs and create new guidance documents for natural gas and water utilities. Guidance documents for water utilities will support those utilities with metering infrastructure to implement Green Button on a voluntary basis.

FIGURE 17. Green Button Connect My Data



GREEN BUTTON

"Budweiser Gardens uses Event Assist, with information gathered through the Green Button initiative, to help us better understand the hydro usage associated with the size, type and configuration of each event. This has the capability to change how we book events in the future, not only for our building, but within the industry. Working with the team at London Hydro has shown me what a truly professional organization they are from top to bottom."

Gary Turrell, Director of Operations, Budweiser Gardens

Energy Benchmarking

The Province's energy benchmarking and rating initiatives give people and organizations the tools and information they need to understand the energy performance of their homes and businesses, and compare it with similar buildings. They can use this information to manage their usage and costs, and justify investments in energy efficiency. Fifteen local distribution companies (LDCs) have social benchmarking programs in their Conservation and Demand Management Plans; five of them are currently being offered to electricity customers. To promote participation in their residential audits and retrofits, Enbridge Gas Distribution and Union Gas are each including social benchmarking in their outreach and education programs.

Organizations in Ontario's broader public sector are required to annually report their energy consumption and GHG emissions to the Province and to make that information available to the public. Building on this success, as well as on lessons learned from similar programs in the United States, the government has introduced a requirement for energy and water reporting and benchmarking for large private sector buildings as well.

Starting July 1, 2018, and phased in over three years, owners of large commercial, multi-unit residential and some industrial buildings will be required to annually report their buildings' use of energy and water and their GHG emissions to the Province. Some of that data will be posted on Ontario's Open Data website every year, so that owners can compare the energy and water usage of their buildings with that of similar facilities, and identify where improvements can be made.

The Climate Change Action Plan envisions providing free energy audits for pre-sale homes in order to include energy ratings in real estate listings. The Province is examining options to deliver a Home Energy Rating and Disclosure program that would improve customer awareness by allowing homebuyers to compare homes by energy rating and encourage uptake of retrofit incentive programs.

Access to Energy Efficiency Financing

The Province is also exploring how to increase access to corporate financing for energy efficiency projects. The Investor Confidence Project gives financiers the information and tools they need to determine the viability of energy efficiency projects. The Project was established by the Environmental Defense Fund in the United States in 2013. The MaRS Advanced Energy Centre is partnering with the Province to pilot Investor Confidence Project protocols in Ontario and explore how they can be adapted for the Canadian market.

Raising the Bar for Energy and Water Efficiency

The Province continues to play a leading role in improving the energy efficiency of the equipment in homes, offices and factories. Since 2013, the government has improved or set new energy efficiency standards for more than 60 products. The gains in energy efficiency have endured and have helped consumers save on their energy bills. In addition, economies of scale have lowered the cost of the technologies, making them more popular, affordable and more available than ever before.

A 2016 amendment to the *Green Energy Act, 2009* allows the government to regulate the water efficiency of products that consume both energy and water. As a result, Ontario is now on a path to achieve more efficient use of water, even greater energy savings and reductions in GHG emissions.

DID YOU KNOW?

Ontario recently updated energy and water efficiency standards for clothes washers. Because of these improvements, in 2032 we expect to save:

- The amount of water that flows over Niagara Falls in 2.75 hours; and
- The amount electricity consumed by the City of Stratford in 2015.

The government will continue to set advanced efficiency standards for products and appliances and work with other provinces and the federal government to harmonize and raise the bar for energy and water efficiency standards.

Efficiency Standards for Drinking Water and Wastewater Treatment Plants

The Province is exploring opportunities to set or update energy efficiency standards for key electrical equipment in drinking water and wastewater treatment plants. As Ontario's Climate Change Action Plan pointed out, this would help municipalities to save on their electricity bills by reducing one of their largest uses of electricity.

"Municipal water and wastewater services are typically one-third to one-half of a municipality's total electrical use, so there is potential for reductions in both costs and emissions."

Climate Change Action Plan 2016, pg. 83

Expanding the Scope of Conservation

The government and its agencies have taken important steps to implement the Conservation First policy when planning to meet regional and local needs for electricity and natural gas, and are exploring how to further integrate this policy into their planning processes (see Chapter 8). During the LTEP consultations and engagements, LDCs and technology vendors expressed interest in using in front of the meter conservation (IFMC) technologies to help meet electricity conservation targets and reduce peak demand.

DID YOU KNOW?

In front of the meter conservation (IFMC) technologies reduce line losses and optimize voltage levels. LDCs deploy them on their distribution networks to save electricity and reduce their peak demand.

Several pilots across North America have demonstrated the potential benefits of deploying IFMC technologies, and the Smart Grid Fund and the Conservation Fund have supported pilots in Ontario. A recent study commissioned by the government estimated they can be cost-effectively deployed on 30 per cent of Ontario's electricity distribution networks.

The government and its agencies will encourage distributors to make their networks more energy efficient, by allowing them to use the electricity savings from IFMC measures to meet their targets for electricity savings under the 2015 to 2020 Conservation First Framework. IFMC project costs will continue to be funded through distribution rates, and subject to the OEB's review process. The OEB will also identify steps for pursuing energy efficiency measures on the distribution system.

Integrating Conservation and Climate Change Programs

Ontario's Climate Change Action Plan emphasized the need to increase the use of low-carbon technology, such as solar panels and heat pumps, in homes and businesses. Several programs to increase energy choices for Ontarians are being introduced, funded by the proceeds from auctions in the carbon market.

The Green Ontario Fund is helping Ontarians move to a low-carbon future by offering them incentives, financing and services to increase the use of technologies that reduce GHG emissions. The Green Ontario Fund website provides a co-ordinated, one-window approach where Ontarians can get help, information and access to its programs, as well as to other conservation and renewable energy programs in the province.

Green Ontario Fund programs are building on the success of the province's existing conservation and energy efficiency programs, providing Ontarians with more opportunities to reduce their energy costs and carbon footprint. The IESO is a partner in the delivery of certain Green Ontario Fund programs to help promote an efficient and customer-focused approach and minimize duplication with existing programs.

The government and its agencies will explore how to further integrate conservation and low-carbon technology programs for both electricity and fuels.

Under current conservation programs, combined heat and power projects that use supplied fossil fuels to generate electricity on-site are eligible for incentives because they can significantly reduce demand on the electricity grid. To help meet the Province's climate change goals, these projects will no longer be eligible to apply for incentives under the Conservation First Framework and the Industrial Accelerator Program (IAP), starting July 1, 2018.

Because of their energy efficiency and environmental benefits, behind-the-meter waste energy recovery projects and projects that use renewable energy, such as solar thermal water heating or biomass fuel for boilers, will continue to be eligible for funding under the Conservation First Framework and the Industrial Accelerator Program. Electricity distributors may also develop incentive programs for energy storage systems that are integrated with a customer's own renewable energy project. When added to on-site renewable generation, energy storage systems can provide reliability and help customers reduce their demand when prices are highest. This can help reduce peaks in demand on the local and provincial systems.

Summary

- Demand Response capacity realized each year will depend on system needs and the competitiveness of demand response with other resources.
- The government will continue to set advanced efficiency standards for products and appliances and is exploring setting or updating energy efficiency standards for key electrical equipment in drinking water and wastewater treatment plants.
- The government and its agencies will further encourage distributors to pursue energy efficiency measures on their distribution systems to achieve customer electricity and cost savings.
- The Green Ontario Fund will provide energy consumers with a co-ordinated, one-window approach to encourage conservation across multiple energy sources and programs.
- The government is committed to expanding Green Button provincewide and intends to propose legislation that would, if passed, enable the government to require electricity and natural gas utilities to implement Green Button Download My Data and Connect My Data.
- Beginning July 1, 2018, combined heat and power projects that use supplied fossil fuels to generate electricity will no longer be eligible to apply for incentives under the Conservation First Framework or the Industrial Accelerator Program. Behind the meter waste energy recovery projects will continue to be eligible, as will renewable energy projects, including those paired with energy storage systems.

6 RESPONDING TO THE CHALLENGE OF CLIMATE CHANGE

6

Ontario is taking a leading role in Canada and abroad in the global fight against climate change.

The energy sector will play a role in meeting the challenge. The robust supply of electricity will give it a central task in assisting the transition to a clean economy. At the same time, Ontario must strengthen its energy infrastructure and make it more resilient to lessen the damage that climate change can cause.

WHAT WE HEARD FROM YOU

- Support increased electrification of transportation
- Support options for home storage, including electric vehicle (EV) batteries
- Microgrids can help resiliency and northern communities
- Customers will decide which technologies work best
- Modernize regulations and rate designs
- Integrate conservation programs with initiatives announced in the Climate Change Action Plan
- Government support needed for research and development
- Distributed generation will transform conventional networks
- Introduce renewable natural gas into Ontario's natural gas supply

Ontario's cap and trade program came into effect on January 1, 2017. The cap and trade program is a flexible, market-based program that sets an annual cap for greenhouse gas (GHG) emissions, with the targets becoming more stringent over time. The cap will be lowered each year to enable Ontario to meet its GHG reduction targets.

Cap and trade creates a market to provide incentives to reduce emissions. Large emitters must have enough allowances to cover their GHG emissions. Switching from high carbon fossil fuels to lower carbon alternatives, including renewable fuels, is one way for large emitters to reduce emissions.

Putting a price on carbon through cap and trade will also impact the operation of the fuels market. Renewable alternatives do not incur cap and trade costs and, consequently, will become relatively more attractive than carbon intensive fuels. This could increase the adoption and use of fuels like renewable natural gas, ethanol and renewable diesel. Similarly, in the transportation sector, lower carbon alternatives like natural gas may become more attractive compared to diesel.

Some companies are currently allocated free allowances in recognition of their exposure to international trade and/or the amount of energy they need to use. Companies that emit more than their allocation can buy additional allowances through government auctions or from other companies that have more allowances than emissions.

Under the *Climate Change Mitigation and Low-Carbon Economy Act, 2016*, proceeds from Ontario's cap and trade auctions will be used to reduce the province's GHG emissions by helping Ontarians shift away from higher carbon fuels and reduce their energy consumption. Proceeds are projected to be $1.8 billion in 2017-18 and $1.4 billion annually, starting in 2018-19. These funds will help to fight climate change, reduce greenhouse gas emissions and transition Ontario to a low-carbon economy.

Putting a price on carbon through cap and trade will have a significant impact on the operation of the electricity market in Ontario. It will encourage a transition away from generation that uses fossil fuels towards a clean imports and generation that are free of GHG emissions. It will also encourage more efficient natural gas generation. As Ontario moves forward with Market Renewal, the cost of carbon will become increasingly important in the economics of electricity generation. Market Renewal has the potential to create a framework that effectively incorporates emerging clean technologies into our supply mix.

Together, cap and trade and Market Renewal initiatives can help to ensure electricity sector emissions remain well below historical levels, while also helping to meet our climate change and GHG reduction commitments.

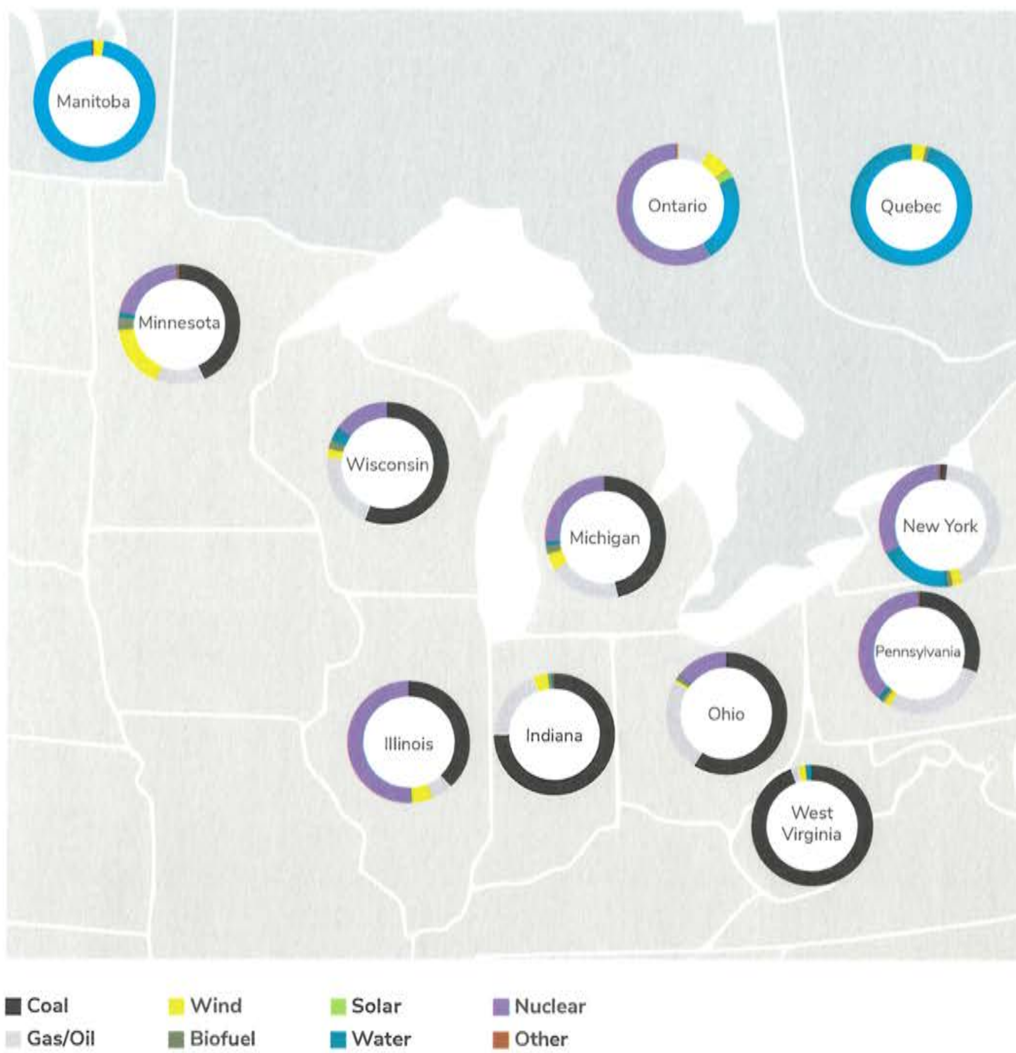
Building on a Clean Electricity System

About 90 per cent of the electricity used in Ontario in 2016 was free of GHG emissions, generated from sources such as water, nuclear, wind, solar and bioenergy. Our investments in these types of clean generation sources, along with the elimination of coal-fired electricity generation, have significantly reduced GHG emissions in the province.

In comparison to neighbouring states such as Michigan, Minnesota, Ohio, Pennsylvania and New York, which still rely heavily on fossil fuel-fired electricity generation, Ontario has a much cleaner electricity system. We have accomplished this without the abundant hydroelectric resources enjoyed by Québec and Manitoba.

FIGURE 18.

Ontario's Clean Generation Mix

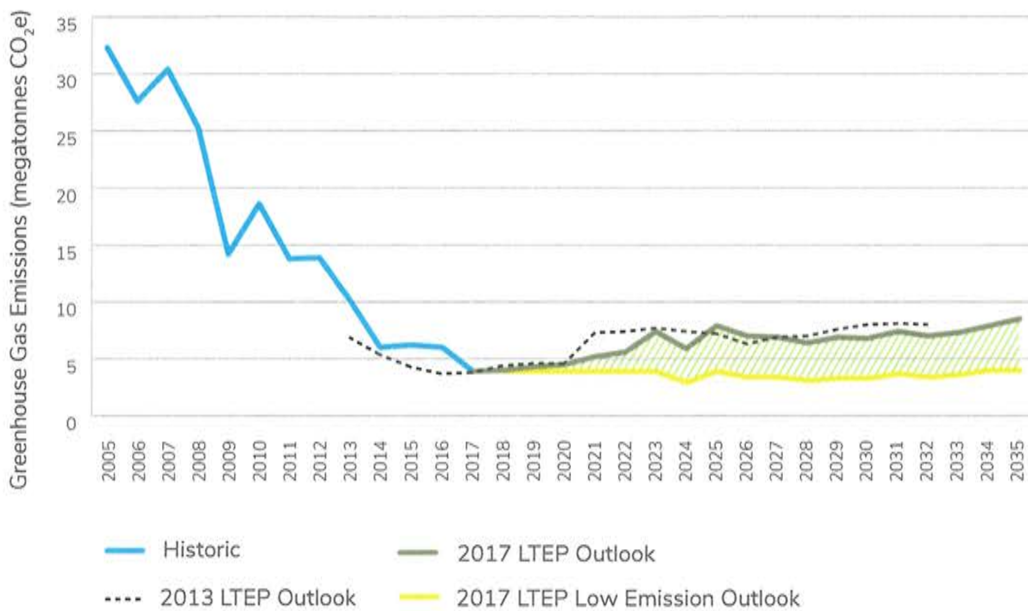


Source: IESO, U.S. Energy Information Administration, Manitoba Hydro, Hydro Quebec
Generation data for US states is from 2015; Ontario, Manitoba and Quebec Data is from 2016
Ontario generation data includes both transmission-connected and distribution-connected (embedded generation).
Data for Manitoba, Quebec and US states is for transmission-connected generation only.

Thanks to these investments, Ontario's electricity sector is forecast to account for only about two per cent of Ontario's total GHG emissions in 2017 and the emissions are forecast to be more than 80 per cent below 1990 levels. As shown in figure 19, emissions are expected to remain well below historical levels and to be relatively flat over the planning period. Ontario will continue to look for ways to keep GHG emissions in the electricity sector low, and work with carbon-free market participants to meet the Province's emissions targets.

FIGURE 19.

Electricity Sector GHG Emissions Outlook



Source: IESO, Environment Canada and Climate Change

These investments have significantly decarbonized Ontario's electricity sector, leaving it well positioned to help the province move towards a low-carbon economy and meet its emission reduction commitments. Ontario's clean and reliable electricity system gives the province a strong foundation on which to pursue increased electrification, including the use of more EVs.

The province's robust supply of energy will also allow it to combine different energy sources into integrated energy systems that provide new services for homeowners and businesses. Natural gas will continue to play a critical role in space and water heating, but we must use it as efficiently as possible and supplement it with the next generation of clean energy technologies, such as ground-source and air-source heat pumps. Proceeds from cap and trade auctions will help fund the further application of these technologies. By making the best use of our existing energy sources and infrastructure, a more integrated energy system will allow the Province to chart the most effective course for achieving its goals for reducing GHG emissions.

Renewable Energy Success

Ontario is Canada's leader in installed wind and solar power. There is more wind and solar capacity in Ontario than in any other province or territory. When you add hydroelectric generation and bioenergy into the mix, renewables accounted for 40 per cent of Ontario's electricity supply mix in 2015, up from 26 per cent in 2005. Currently, Ontario has 18,300 megawatts (MW) of wind, solar, hydroelectric and bioenergy generation capacity in operation or under development.

The introduction of the Large Renewable Procurement (LRP) process in 2014 resulted in strong competition between developers of large renewable projects, drove down prices and secured clean, reliable generation. This significantly reduced the costs of wind and solar energy, saving money for electricity ratepayers.

The results of the final Feed-in-Tariff (FIT) procurement were announced in September 2017, with a total of 390 contracts offered for small-scale renewable energy projects representing about 150 MW of clean generation.

A highlight of Ontario's renewable energy programs has been the success that individuals, schools, municipalities, co-operatives and Indigenous communities have had in participating in clean energy projects. In the FIT 5 procurement, more than 80 per cent of successful applications had Indigenous, municipal, public sector or community participation. From smaller home or farm-sized projects to larger community-scale projects, Ontarians are using renewable energy to help meet their community's electricity needs and reduce their demand on the provincial electricity grid.

Since 2009, prices paid for new electricity from FIT and microFIT projects have been reduced between 50 and 75 per cent, reflecting the decreasing costs of equipment and ensuring value to ratepayers.

As a result of annual price reviews, revised procurement totals and the introduction of competitive procurement for large renewable energy projects, the FIT, microFIT and LRP initiatives are expected to cost at least $3 billion less than forecast in the 2013 LTEP.

COMMUNITIES BENEFITING FROM RENEWABLE ENERGY

The Municipality of Chatham-Kent is widely recognized as one of Ontario's leading green energy communities, which has helped spur local economic development. The municipality has received significant benefits for hosting a number of wind energy projects. Recent and proposed wind projects will deliver an estimated $27 million in community benefits and property tax revenue over a 20-year period for the municipality.

Renewable energy companies have also invested heavily in the social fabric of the community through partnerships with local organizations for sponsorship of projects such as splash pads.

A Strong Renewable Future

The Province's renewable energy policies have made Ontario's electricity supply mix cleaner, and are providing real benefits for communities and municipalities. Recognizing this success, *Delivering Fairness and Choice* is focused more on outcomes rather than specifying targets and technologies. With a solid foundation of electricity provided by renewable energy, Ontario can now focus on new opportunities for innovation, modernization and exporting our expertise. Ontario is poised to take advantage of advances being made in distributed energy resources and smart-grid technologies that can help deliver a more efficient and cleaner electricity system. The government remains committed to having an electricity system where renewable energy generation plays an essential role, supporting the goals of the Climate Change Action Plan.

Wind

Wind power has become an important source of clean electricity for Ontario. There were only 15 MW of installed capacity in Ontario in 2003, compared with 4,800 MW today. That is enough wind energy to power approximately 1.4 million homes each year.

Wind power is also being produced more efficiently. Turbines use state-of-the-art controls to adjust their blades and orientation to get the maximum output of energy in changing wind conditions. The Independent Electricity System Operator (IESO) has been able to send instructions to renewable energy generators since 2013 to stop producing electricity when it is not required to meet provincial needs. Actively controlling wind energy generation results in the more efficient operation of the electricity system.

Solar

Ontario has become a North American leader in the development of solar photovoltaic (PV) systems with about 2,300 MW of capacity online, enough to power about 300,000 homes each year. Solar power can help the electricity system to meet Ontario's needs on hot and sunny days when air conditioning use is highest. Advances in solar PV technology have seen improved performance and a significant decline in costs, resulting in more cost-effective solar generation. Solar PV systems also support ongoing modernization of the grid. They can be large or small, and can be located close to where electricity is needed. Solar PV systems can also be paired with other innovative technologies like energy storage. These advantages mean that solar PV will continue to be a valuable asset for Ontario's distribution systems, and can help improve the operation of the electricity grid in the future.

Hydroelectric

Most of Ontario's supply of renewable energy continues to come from the province's hydroelectric facilities, which provided 23 per cent of Ontario's total generation in 2015. Ontario has approximately 8,800 MW of installed hydroelectric capacity.

Assessments over the years, including the November 2013 Northern Hydro Assessment – Waterpower Potential in the Far North of Ontario, have identified significant remaining waterpower potential in the province. These potential resources are mostly concentrated in Northern Ontario and major transmission enhancements would be required to effectively contribute to Ontario's electricity supply.

Additionally, there are opportunities to redesign older hydroelectric projects to improve performance by using new, more efficient turbines.

Bioenergy

Bioenergy refers to electricity that is generated by burning biomass, such as plant or animal by-products and wastes. It also describes biogas and landfill gas, which is methane gas produced by the decomposition of organic matter that is then burned in a generator to produce electricity. Ontario currently has about 500 MW of bioenergy generation capacity in operation.

Going forward, the shift toward Renewable Natural Gas (RNG), a low-carbon fuel produced by the decomposition of organic materials, gives biogas producers an additional market opportunity. Bioenergy systems also support the implementation of the Province's Strategy for a Waste-Free Ontario.

Shifting to Lower Carbon Gasoline and Diesel

Delivering Fairness and Choice recognizes the commitment in the Climate Change Action Plan to introduce a Renewable Fuel Standard (RFS) for gasoline. This is an important step towards reducing GHG emissions from the transportation sector. Since it uses the existing fuels infrastructure, an RFS standard is one of the more flexible and cost-effective ways to increase the use of renewable and low-carbon fuels.

The use of renewable and low-carbon transportation fuels can be expanded by:

- Increasing the use of renewable liquid fuels in existing vehicles. Drop-in fuels such as ethanol can be mixed with gasoline to produce blended fuels and can be used the same way as regular gasoline;
- Having existing fuel stations offer higher blends of ethanol and bio-based diesel;
- Making renewable liquid fuels available to more regions of the province;
- Adding biofuels to the crude oil that Ontario refineries process; and
- Lowering the carbon intensity of renewable fuels produced by Ontario manufacturers.

Delivering Fairness and Choice acknowledges there are other ways to achieve deep reductions in emissions and transform the transportation sector. While current outlooks predict an increased electrification of light-duty vehicles and the use of alternative fuels, including bioenergy for long-haul road freight and aviation, technological innovation remains inherently unpredictable. The technology-neutral approach of the RFS lets the alternatives compete on their merits.

Shifting to Renewable Natural Gas

Natural gas remains a reliable and cleaner option for many Ontarians, and will continue to play an important role in the province's energy supply mix. Homeowners, businesses and industries use natural gas for space heating, domestic hot water, steam and process heat. There were about 3.6 million natural gas customers in Ontario in 2016. Natural gas was also used to generate about 10 per cent of Ontario's electricity in 2015.

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.

Integrated Energy Solutions

Renewable energy technologies can be the foundation for innovative integrated clean energy systems that provide the space heating, cooling, and energy storage solutions that help to address the climate change challenges facing Ontario.

Power-to-Gas

Electrolysis, also known as power-to-gas, uses surplus electricity to break down water molecules into hydrogen and oxygen. The hydrogen can then be stored in the vast storage system that currently exists for natural gas in Ontario and transported in existing natural gas pipelines and used to heat homes and fuel vehicles.

Power-to-gas could potentially become a new and important link between the province's electricity and natural gas systems. The Independent Electricity System Operator (IESO) recognizes this, and has already awarded a contract to Hydrogenics, an Ontario-based manufacturer of electrolysis and fuel cell technology, which will deliver two MW of storage capacity in the Greater Toronto Area.

Heating and Cooling with Renewable Energy Technologies

Ontario aims to reduce greenhouse gas (GHG) emissions by increasing the use of low-carbon technologies, such as solar, air- and ground-source heat pumps, to heat and cool Ontario homes and businesses.

This has the potential to deliver a big payoff in the fight against climate change. Space heating accounts for approximately 75 per cent of the total fuels energy demand in Ontario homes, making it an important area to target for reducing GHG emissions.

The government will continue to work with its agencies, including the IESO and the Green Ontario Fund, to encourage the deployment of thermal and alternative technologies for residential, commercial, industrial and institutional buildings. This will involve planning how to integrate the technologies and the delivery of conservation and low-carbon technology programs into the province's energy system.

Solar Air and Hot Water Heating

A typical residential solar hot water system can supply between 40 to 60 per cent of a home's hot water needs. Solar air systems capture air warmed by the sun and circulate it to heat buildings.

Ground Source and Air Source Heating and Cooling

Ground-source heat pumps, also known as geothermal energy systems, use buried pipes to absorb heat from the ground and transfer it to a home or building, and can reduce heating bills by up to 70 per cent. Air-source heat pumps take air from outside, extract the heat and transfer it to the air inside a home or building. A heat pump, running on electricity, concentrates the heat from both sources, and moves it to where it is needed. The same systems can also be used to provide cooling in the summer; and more advanced air-source systems can even provide domestic water heating.

In July 2017, the Save on Energy Heating and Cooling Incentive program began offering incentives of up to $4,000 to help Ontarians who live in electrically-heated homes to purchase and install air-source heat pumps.

District Heating and Cooling

District energy systems generate and supply heating and cooling, domestic hot water and electricity for blocks or neighbourhoods in a community.

District heating and cooling can use local energy resources such as biomass, geothermal energy and mechanical waste heat from industrial operations to reduce GHG emissions.

Implementation can be made easier if underground district energy pipes are incorporated into the initial design of new residential or commercial developments. When used in more densely populated areas, district energy systems can be more cost-effective than providing heating and cooling systems for each individual building.

ENWAVE ENERGY CORPORATION

Enwave Energy Corporation is a Toronto-based company that provides sustainable energy services in Toronto, Windsor and numerous American cities, including Chicago, Houston, Los Angeles and Portland OR. In each community, the company operates highly efficient thermal energy plants that distribute steam, hot water and/or chilled water to customer buildings. Customers benefit from reduced operating costs, lower emissions, and increased reliability.

Enwave generates chilled water, steam, hot water and electricity which is distributed to more than 155 buildings in downtown Toronto. Their Deep Lake Water Cooling system is one of the world's largest sustainable cooling systems, using Lake Ontario to recycle energy from more than 70 buildings in downtown Toronto to the city's potable water system. Currently, this system reduces peak electrical demand by 61MW, with plans underway to expand.

The London system is a Combined Heat and Power (CHP) system that currently provides 15MW of electricity to the grid, and serves 60 customers with a steam and chilled water system. There are plans to increase the CHP plant capacity by an additional 18MW in the near future.

Near and Net Zero Carbon Emission Buildings

The Climate Change Action Plan aims to reduce emissions in the building sector by encouraging the construction of near net zero and net zero carbon emission homes and buildings. To help create a pathway to these new building standards, the electricity and natural gas conservation frameworks will continue to support the development and enhancement of high efficiency, low-carbon homes and buildings. New programs will also be offered through the Green Ontario Fund.

New high-performance standards for space and water heating equipment could significantly reduce the energy use, environmental footprint and GHG emissions of new and existing homes and buildings and lower consumers' energy costs.

Working with the federal and other provincial governments, Ontario is exploring opportunities to develop markets for new high efficiency technologies, such as air source heat pumps, supporting the joint aspirational goals on achievable energy performance levels and the transition to a low-carbon economy.

In addition, planned updates to the Ontario Building Code would make a significant contribution to reducing GHG emissions in the building sector and support Ontario's Climate Change Action Plan.

An important part of transitioning to near and net zero energy or carbon emission buildings is to minimize their energy use. Generally, the most cost-effective way is to first improve their energy efficiency, with increased insulation, advanced air sealing, and high efficiency heating and cooling systems. Once that has been done, some type of on-site renewable energy generation is generally required to achieve net zero energy or carbon emission status. The government is taking steps to expand and enhance its net metering framework, which would give building owners increased opportunities to integrate renewable energy generation and energy storage technologies.

REID'S HERITAGE HOMES – GUELPH

Reid's Heritage Homes built five net zero homes in Guelph in 2016. These homes were the first in Canada to meet new net zero home standards set up by the Canadian Home Builders' Association.

Key features include:

- Air source heat pumps;
- High efficiency water heaters;
- Increased insulation values in exterior walls, attic and basement;
- Advanced air sealing to avoid air leakage;
- Right sized mechanicals and energy recovery ventilators; and
- Solar panels.

WEST 5 – SIFTON PROPERTIES LIMITED - LONDON

The West 5 development in London is Ontario's first sustainable, net zero community. It will have a total of 2,000 apartments, condominiums and townhomes along with 400,000 sq. ft. of commercial and retail space, and a 1.6-acre central park. Construction of West 5 will create about 2,500 jobs over 10 years.

Key features include:

- Solar panels and solar streetlights;
- Solar parkades;
- Green roofs;
- EV charging stations;
- Community gardens; and
- Rainwater harvesting.

Climate Change Adaptation

Ensuring a Resilient Energy Supply

Ontarians need to have a reliable supply of energy, not just for for their economic prosperity but for their basic health and safety. In order to provide vital energy services to Ontarians, the province's energy system must remain resilient and able to withstand a changing climate.

The facilities and equipment that currently generate, transmit and distribute energy across the province can be threatened by the extended heat waves, high winds, severe rainfall and ice storms that come with climate change. Climate change may also lower the flows of rivers and the water levels and temperatures of lakes, possibly reducing the ability to generate electricity.

To address these concerns, Ontario's energy organizations are taking a number of actions that will ensure the province's energy system is better prepared to meet extreme weather events:

- Together with several partner organizations, the IESO studied Ontario's transmission system and found it resilient enough to substantially withstand most extreme weather scenarios. However, the study recommended continued monitoring and refinement of climate scenarios.
- More local distribution companies are making adaptation and system resilience a priority. Both Toronto Hydro and the former Horizon Utilities (now part of Alectra Utilities) conducted vulnerability assessments of their systems. A leader in this regard in Canada, Toronto Hydro is addressing climate change vulnerabilities by improving its engineering practices and tools, such as its load forecasting model, and installing more resilient equipment on its system. In its last rate application, Toronto Hydro identified extreme weather as a driver for its capital and maintenance expenditures.
- Local distribution companies (LDCs) such as Oshawa PUC Networks, Veridian and Whitby Hydro are developing adaptation plans to match the adaptation planning done by their local transit, water and communications authorities.

Building on its current activities, the government will strengthen the ability of the energy industry to prepare for the effects of climate change and integrate its impacts into their operational and infrastructure planning.

The government and its agencies will facilitate the exchange of information and knowledge among utilities and other partners to allow them to share best practices and increase their ability to adapt to climate change. Since these activities are best co-ordinated with other public services, the Province will encourage utilities to work with municipalities and other public and private infrastructure operators. This knowledge-sharing platform will be a key first step to help with the following initiatives:

- The government will help develop a vulnerability assessment of the energy distribution sector so utilities can develop state-of-the-art strategies to manage risk. This will complement the vulnerability assessment done of the transmission system in 2015.
- The OEB will give utilities guidance on cost-effectively integrating climate change adaptation into their planning and operations. The IESO will ensure that climate change adaptation is considered and integrated into the bulk system and regional planning processes.

ADAPTATION INITIATIVES BY LOCAL DISTRIBUTION COMPANIES

Building on its distribution system vulnerability assessment, the former Horizon Utilities (now part of Alectra Utilities), developed a long-term plan for adapting to climate change. The plan considers the risk of flooding when planning infrastructure, and improvements to the LDC's geographic information and outage management system reduce response times.

Hydro Ottawa focused its storm hardening initiative, completed in 2015, on revising the schedule for removing and trimming overhanging tree branches. As a result, public safety has been increased, the distribution system is less vulnerable to damage from high winds and ice storms, and the LDC's budget for vegetation management was reduced by $750,000.

Summary

- Ontario remains committed to a clean electricity system that includes renewable energy generation and supports the goals of the Climate Change Action Plan.
- The government will encourage the construction of near net zero and net zero carbon emission homes and buildings to reduce emissions in the building sector.
- The government is proposing to expand the options for net metering to give building owners more opportunities to access renewable energy generation and energy storage technologies.
- The government will continue to work with industry partners to introduce renewable natural gas into the province's natural gas supply and expand the use of lower-carbon fuels for transportation.
- Building on current activities, the government will strengthen the ability of the energy industry to anticipate the effects of climate change and integrate its impacts into its operational and infrastructure planning.

SUPPORTING FIRST NATION AND MÉTIS CAPACITY AND LEADERSHIP

First Nations and Métis are leaders in Ontario's energy sector, bringing their unique perspectives, knowledge and leadership to energy planning, projects and policies.

They have created an unprecedented level of First Nation and Métis involvement in the energy sector:

- First Nations and Métis are now leading or partnering on over 600 wind, solar, and hydroelectric generation projects across Ontario, accounting for over 2,200 megawatts (MW) of clean energy capacity.
- First Nations lead, or are partners with, transmission companies on several major transmission lines.
- Nearly 100 First Nations are participating in the Independent Electricity System Operator's (IESO) Aboriginal Community Energy Plan program. These community-led energy plans assess a community's current energy needs and priorities and explore options for conservation and renewable energy.

The Province takes its duty to consult First Nation and Métis seriously and is committed to ensuring they are consulted on any energy activity that could potentially affect their Aboriginal and Treaty rights.

WHAT WE HEARD FROM YOU

- Need to connect remote communities
- Unreliable electricity service hurts quality of life and hinders community development
- Eliminate the on-reserve electricity delivery charge to improve electricity affordability
- Need for funding to assist with implementing Community Energy Plans
- Conservation programming should better meet community needs
- General preference for renewable energy over nuclear power
- Desire for First Nation and Métis ownership of and partnerships on projects
- Need for federal funding for connection of remote communities

Many First Nations and Métis across Ontario face energy-related challenges: the need for reliable and affordable power, energy-inefficient housing and inadequate infrastructure, to name just a few. The causes and solutions to these challenges are rooted in complex historical, jurisdictional, geographic and regulatory contexts, but progress is being made. The Province is committed to working together with First Nations and Métis to identify issues and propose actions that advance reconciliation and healing.

The Chiefs of Ontario and the Province signed the First Nations-Ontario Political Accord on August 25, 2015, creating a formal bilateral relationship framed by the recognition of the treaty relationship.

THE FIRST NATIONS-ONTARIO POLITICAL ACCORD

- Affirms First Nations' inherent right to self-government
- Commits the parties to work together on issues of mutual interest, such as resource benefits sharing and jurisdictional matters
- Sets a path for reconciliation

The Ontario-Métis Nation Framework Agreement, signed in 2008 and renewed in 2014, guides the Province's relationship with the Métis Nation.

ONTARIO-MÉTIS NATION OF ONTARIO (MNO) FRAMEWORK AGREEMENT

- Facilitates the recognition and advancement of Métis people in Ontario
- Fosters collaboration between the province and the MNO on issues of mutual interest to support the goals and objectives of the new agreement
- Increases awareness of Métis history, identity and culture

The Province will continue the direction established in the 2013 LTEP and support First Nation and Métis leadership and capacity in Ontario's evolving energy sector. Reflecting the Province's strong energy supply position, *Delivering Fairness and Choice* responds to the concerns heard through the LTEP engagement process and the ongoing dialogue between the government, its agencies and First Nation and Métis partners.

Building on the conversations during the LTEP engagement process, the Province commits to a more regular and ongoing dialogue with First Nations and Métis. This will include energy awareness and education initiatives, the involvement of youth in the energy conversation, and a more regular communication to ensure First Nations and Métis are informed about the Province's energy commitments and have opportunities to provide insight and feedback.

Addressing Electricity Affordability

A major priority for Indigenous and non-Indigenous electricity consumers is to improve the affordability of their electricity. The government is working to address the issue with programs such as:

- The Ontario Electricity Support Program (includes enhanced credits for First Nations, Métis and Inuit electricity consumers) (more details in Chapter 1);
- Ontario's Fair Hydro Plan (more details in Chapter 1);
- The Low-Income Energy Assistance Program (more details in Chapter 1); and
- The Conservation First Framework (more details in Chapter 4).

First Nation Delivery Credit

The Province recognizes that First Nation electricity consumers living on-reserve face unique challenges with respect to electricity affordability. Customers living on-reserve often pay higher distribution costs than customers in more populated areas because distribution rates are partially based on population density. The problem of higher distribution rates is often exacerbated by energy-inefficient homes on reserves that lead to higher levels of energy consumption.

To address these unique energy affordability challenges, First Nation leaders recommended the elimination of delivery charges for electricity transmission and distribution when they met with the Minister of Energy and other energy sector leaders at the First Nations-Ontario Energy Table in April 2016.

The minister directed the Ontario Energy Board (OEB) to work with First Nations to research options that would address energy affordability on reserves, and to report back on its findings. Acting on the OEB's findings and feedback from First Nations, the Province collaborated with the Chiefs of Ontario to develop the First Nations Delivery Credit. The First Nations Delivery Credit was implemented on July 1, 2017 and provides a credit equal to 100 per cent of the electricity delivery charge on the bills of on-reserve First Nation residential customers of licenced distributors. This collaborative effort between the Province and First Nations is another example of the Political Accord being brought to life.

Connecting Off-Grid First Nation Communities

Twenty-five remote First Nation communities in the province's northwest rely on diesel fuel to power their communities. The Province recognizes the distinct challenges they face and, because of the high cost of diesel fuel, there is a good economic case to connect as many as 21 of those communities to Ontario's electricity grid.

The Province has made it a priority to connect these remote First Nations. Communities cannot improve their housing, their water treatment systems or other community infrastructure if they do not have a reliable and adequate supply of electricity.

Connection to Ontario's low-carbon electricity grid will not only improve the quality of life of these communities and enable their economic development, but it will also reduce local pollution, greenhouse gas (GHG) emissions, and the environmental risks associated with transporting and storing diesel fuel.

FIGURE 20. Reducing Diesel Generation in Remote First Nation Communities

- Remote communities proposed for connection through the Wataynikaneyap power project
- Remote communities that could be connected through future proposals
- Remote communities uneconomical to connect where other diesel reduction initiatives will be pursued
- Other First Nations
- First Nation settlements
- Roads

Transmission Line
- 230 kV
- 115 kV

For these reasons, the government has taken several steps to begin the connection of remote First Nation communities. These include:

- Selecting Wataynikaneyap Power as the transmitter for connecting most of the remote First Nations;
- Creating a mechanism for funding a portion of project costs; and
- Advocating for a fair cost-sharing arrangement with the federal government that ensures the project is fully funded and can proceed to construction.

ONTARIO POWER GENERATION AND GULL BAY FIRST NATION

Left to right: Gillian MacLeod, Anthony "AJ" Esquega, Wayne King and Ryan Morin

Ontario Power Generation (OPG) and Gull Bay First Nation (GBFN) are in the early stages of building an advanced renewable microgrid on the GBFN reserve on the western shore of Lake Nipigon. GBFN has an on-reserve population of 300 people and is one of the four remote First Nation communities that the IESO has determined to be economically unfeasible to connect to the provincial grid at this time.

The Gull Bay Diesel Offset Microgrid project will create a community microgrid by integrating new solar photovoltaic generation, battery energy storage, and a microgrid control system with the existing on-site diesel generators that currently supply the community's entire energy needs. The development, construction and operation of the project will create additional opportunities for capacity building and employment.

The Province also supports the connection of the five remote Matawa communities that are not currently part of the Wataynikaneyap Power project. Further steps will be taken to advance their connection when proposals are brought forward.

Grid connection is not currently feasible for four of the 25 remote First Nations in Ontario. Each of these communities has begun the planning and development work to add sustainable technologies that will reduce their reliance on diesel. Projects that reduce diesel reliance could include renewable microgrids, battery storage, and other innovative technologies that meet identified community needs.

The government will continue to partner with these communities and other collaborators, and is looking to the federal government to support these projects. The Government of Canada has agreed to financially support the early connection of Pikangikum First Nation and Wataynikaneyap Power plans to begin construction in 2017 to connect this First Nation.

Conservation

Over 40 First Nations participated in the Aboriginal Conservation Program between 2013 and 2015. The program funded energy efficiency upgrades such as new insulation, appliances and lighting for approximately 3,000 First Nations households.

Through the 2015–2020 Conservation First Framework, First Nation and Métis customers also have access to other energy efficiency and conservation programs, such as the Save on Energy programs offered by local distribution companies.

CONSERVATION ON THE COAST

Local Distribution Companies (LDCs) owned by Attawapiskat, Kashechewan and Fort Albany First Nations are collaborating to provide conservation programs to their customers, using the name Conservation on the Coast (COTC).

COTC began in 2013 by conducting annual energy audits in the three communities.

By October 2017, 30 homes per community will have LED bulbs, power bars, low flow aerators and showerheads, hot water pipe wrap, and improved insulation. This has reduced electricity usage by 20 to 25 per cent per home. In addition to the energy savings, residents say their homes are more comfortable to live in, they are burning less wood, and moisture and mold problems have diminished.

WIKWEMIKONG FIRST NATION

In June 2017, the Wikwemikong First Nation launched its Ignite Energy and Infrastructure Project. This is a long-term community driven strategy to address the high energy costs faced by the community and upgrade its aging infrastructure. Phase One is a major retrofit and upgrade to LED lighting for three schools, a nursery school, the community's health centres, arenas, and the band administration office.

It is estimated this will save the community more than $157,000 per year in energy costs, a 58 per cent savings in the energy used for lighting. The $1.1 million project will be financed with a contribution of $127,900 from the IESO's Save on Energy Program and private debt financing.

Wikwemikong First Nation is also looking to expand its portfolio of renewable energy projects with the Wikwemikong Solar Micro-grid construction project. The 300kW micro-grid is expected to begin construction in 2018/19 and will include a solar generation plant, improvements to the energy efficiency through insulation and replacements of high energy heating and cooling systems of five community buildings and the development of a microgrid software program. This project will receive funding through the Small Communities Fund, co-funded by the Ontario and the federal governments.

While conservation programs are working well in some First Nation and Métis households, participants in *Delivering Fairness and Choice* engagement sessions said the programs need to be more flexible and more widely available.

In conjunction with the mid-term review of the Conservation First Framework and engagement with the Indigenous communities, the IESO will give the Province options for improving conservation programs and their availability for First Nations and Métis, including the 10 communities served by unlicensed LDCs in North-Western Ontario known as the Independent Power Authorities: Eabametoong, Keewaywin, Muskrat Dam, Nibinamik , North Spirit Lake, Pikangikum, Poplar Hill, Wawakapewin, Wunnumin and Weenusk.

The Climate Change Action Plan allocates $85-$96 million from cap and trade auction proceeds for collaboration with Indigenous communities. This includes establishing a fund for community level GHG reduction projects and for community energy and climate action planning in First Nation communities, particularly to reduce emissions from buildings and infrastructure, and for the development of carbon sequestration projects.

Implementing Community Energy Plans

Community energy plans are an important way to understand local energy needs better. They help communities identify opportunities for energy efficiency and clean energy and develop a plan to meet their community's energy goals. Close to 100 First Nations are now developing community energy plans, using funding from the Aboriginal Community Energy Plan (ACEP) program. The Province is committed to continuing this funding.

But energy plans are just a first step and the Province recognizes that further support is needed to turn these plans into tangible actions and results. That is why the ACEP program will be expanded to help communities implement their community energy plans and support the Climate Change Action Plan.

The IESO will engage with First Nation and Métis communities and organizations to identify the strengths and weaknesses of the current ACEP program, explore the use of conservation projects or other community-directed energy initiatives, and then recommend changes that allow community energy plans to flourish. Funding will come from the $10 million the IESO has dedicated annually for this and other support programs.

Supporting Local Opportunities

Building Sector Knowledge and Capacity

The IESO's Education and Capacity Building (ECB) program supports the education, training and skill building of First Nations and Métis. The ECB program will continue to support initiatives that help build local business skills, energy literacy, and youth engagement.

Exploring Energy Projects and Partnerships

The IESO's Energy Partnerships Program (EPP) supports First Nation and Métis communities and organizations that want to lead or be partners on renewable energy and transmission projects.

Three streams of funding from the EPP help support:

- Financial, legal and technical due diligence so First Nations and Métis can partner on major priority transmission lines and renewable energy projects;
- The development of renewable energy projects, including costs for regulatory approvals; and
- Initiatives that reduce the reliance on diesel fuel for the four First Nations that can't be feasibly connected to the transmission grid.

The government will engage further and explore how to change these programs so they better reflect the needs of First Nations and Métis within the current energy system. This may include an examination of how programs can help integrate small-scale renewable energy projects into the local energy system, or the use of net metering and other innovative solutions that address local or regional energy needs and interests.

Access to Financing

The development of energy projects requires significant financial and human capital. Barriers can prevent First Nation and Métis communities and organizations from accessing this capital so they can actively participate in the energy sector. Barriers to more widespread First Nation and Métis participation include:

- Lack of capital at reasonable terms;
- High financing costs; and
- A shortage of capacity around financing and building partnerships.

The Aboriginal Loan Guarantee Program has helped First Nations and Métis obtain lower-cost financing to participate in large-scale energy projects. However, Ontario recognizes that barriers to financing remain, particularly for smaller-scale projects. As a result, the government will engage with First Nations and Métis to identify gaps in financing, possible changes to existing programs, and alternative financing models.

WHAT IS THE ABORIGINAL LOAN GUARANTEE PROGRAM?

Launched in 2009, the $650 million Aboriginal Loan Guarantee program (ALGP) provides a provincial guarantee to support a First Nation or Métis corporation borrowing to purchase up to 75 per cent of the corporation's equity in a qualifying energy project application, to a maximum of $50 million. To date, the ALGP has supported First Nation or Métis equity interests in nine projects, including the 438MW Lower Mattagami hydro-electric project, the Bruce to Milton transmission reinforcement project, the 28MW Peter Sutherland hydro-electric project, and the 4MW Mother Earth Renewable Energy wind project.

The government can build on its strong record and apply innovative financing models to promote First Nation and Métis participation in energy projects. These financing models and social finance tools have been successfully used in the United States, Australia, and elsewhere in Canada to facilitate greater Indigenous economic participation.

The Province also appreciates the unique social benefits that can accrue to First Nations and Métis with their participation in energy projects. Measuring and assessing these non-financial benefits could help the government take a broader and more inclusive view of outcomes when deciding on energy policies and projects.

RAINY RIVER FIRST NATIONS SOLAR PROJECT

Rainy River First Nations signed a memorandum of understanding with Ontario Solar PV Fields to purchase three solar projects located in their community. The cost of the projects was around $154 million, of which $19 million was guaranteed by the ALGP.

Rainy River First Nations partnered with Clark, Conner and Lunn for the project. The projects are expected to generate around 37 million kilowatt-hours of electricity a year, enough to meet the needs of approximately 3,000 households.

Building on these and other successes across the province, Ontario will take the following actions to increase First Nation and Métis access to financing:

- Engage with leaders, organisations and financing experts to identify financing gaps and barriers to the participation of First Nations and Métis in energy projects;
- Investigate innovative financing models to better support First Nation and Métis participation in energy projects; and
- Develop methods to better capture the social, environmental, and local benefits of First Nation and Métis participation in energy projects.

Expanding Access to Natural Gas

Natural gas remains a clean, reliable energy option, and it will continue to play a critical role in Ontario's energy mix. Access to natural gas is an important issue, especially for First Nations.

To assist with natural gas expansion, the government launched a new $100 million Natural Gas Grant Program in April 2017. Through the program, municipalities and First Nation communities are able to work with natural gas utilities to bring forward proposals to expand access to natural gas. The guidelines for the Natural Gas Grant Program state that special consideration will be given to projects located in Northern Ontario or located within First Nation reserves. Successful applicants under this program can then apply to the OEB for leave-to-construct approval for their expansion projects.

Over the coming years, the Province looks forward to seeing natural gas expansion projects deliver greater consumer choice and economic growth to municipalities and First Nations in Ontario.

Summary

- The government will review current programs in order to improve the availability of conservation programs for First Nations and Métis, including communities served by Independent Power Authorities.
- The Province, working with the federal government, will continue to prioritize the connection of remote First Nation communities to the grid and support the four First Nation communities for which transmission connection is not economically feasible.
- The Aboriginal Community Energy Plan program will be expanded to help communities implement their energy plans and support Ontario's Climate Change Action Plan.
- The government will engage with First Nations and Métis to explore options for supporting energy education and capacity building, the integration of small-scale renewable energy projects, net metering and other innovative solutions that address local or regional energy needs and interests.
- Innovative financing models and support tools will be investigated to address barriers to the financing of projects led or partnered by First Nations or Métis.
- The government will report back to First Nations and Métis between Long-Term Energy Plans to provide updates on the province's progress and seek ongoing feedback.
- The government's Natural Gas Grant Program will support the expansion of natural gas access to First Nation communities.

8 SUPPORTING REGIONAL SOLUTIONS AND INFRASTRUCTURE

8

SUPPORTING REGIONAL SOLUTIONS AND INFRASTRUCTURE

Different regions and communities may require different solutions to address their specific energy needs and the local impacts of large energy infrastructure projects on their communities.

For example, some regions may experience an increase in demand due to population growth, while others may be more concerned about the reliability of their energy supply.

Regions also have different priorities for large infrastructure projects. It is crucial that the process for reviewing interregional projects such as pipelines reflects these priorities. Ontarians need to be able to influence these energy solutions through community planning and engagement.

Regional Planning

Since 2013, communities have participated in a formalized regional planning process to identify their electricity needs and develop cost-effective solutions for meeting them. It could mean additional supply from transmission lines, local resources like district energy or conservation, or a combination of both. Over the past three years, the electricity needs of all 21 of Ontario's planning regions have been evaluated, completing the first full cycle of regional planning assessments across the province.

WHAT WE HEARD FROM YOU

- Integrate electricity planning with municipal planning
- Consider impact on economic development
- Improve local reliability
- Innovative technologies and fuels face special barriers in the North
- Programs should meet customer and regional needs

ESSEX COUNTY

Agri-business is growing in rural Essex County, near Kingsville and Leamington. The region has the largest concentration of greenhouse vegetable production in North America. Greenhouses, food processing operations and increasing wineries-related tourism are adding to electricity demand, particularly in the summer months.

At the same time, other needs in the area are triggering infrastructure upgrades that would benefit not just the local agri-business sector, but those looking to connect distributed generation, other customers in the Windsor-Essex region and Ontario ratepayers as a whole.

If the infrastructure upgrades were carried out separately, they would have cost about $100 million. Instead, by looking at the totality of the needs, the recommended solution, which includes a new 13-kilometre line and a new transformer station in Leamington, addressed the same needs for over $20 million less. Collaborative solutions like these are critical to realizing the benefits of the enhanced regional planning.

Regional planning gives communities the opportunity to consider all the cost-effective resources for meeting their regional needs. It promotes the principle of Conservation First by first incorporating conservation targets into the forecasts of net regional electricity demand. Only then are other economical solutions considered, such as new supply, distributed generation, additional conservation and demand management or investments in transmission and distribution.

In order to increase the range of cost-effective solutions, barriers to non-wires solutions such as conservation, demand response and other distributed energy resources must be reduced.

"Our Local Demand Response initiative at Cecil TS allows us to cost-effectively defer capacity investments and provide other valuable benefits. This project exemplifies Toronto Hydro's commitment to delivering customer value and building a more flexible, integrated grid."

Anthony Haines, CEO Toronto Hydro Corporation

The Ontario Energy Board (OEB) is also working to integrate conservation into regional and local planning for natural gas infrastructure. The OEB's 2015-2020 Demand Side Management (DSM) Framework says natural gas utilities need to consider conservation as a key principle in their infrastructure planning. As part of the mid-term review of the DSM Framework that is currently underway, natural gas utilities are expected to propose transition plans to integrate natural gas conservation into their planning for future infrastructure.

ROLE OF CONSERVATION

Targeted conservation initiatives can be the most cost-effective solutions for meeting local and regional electricity needs. The Independent Electricity System Operator (IESO) is working with local distribution companies (LDCs) in Ottawa, Toronto, Barrie-Innisfil and Parry Sound-Muskoka to determine whether targeted conservation initiatives can defer costly upgrades to specific local distribution and transmission infrastructure. In the mid-term reviews of the 2015–2020 Conservation First Framework and Industrial Accelerator Program, the IESO is also exploring how to further integrate conservation initiatives into the regional planning process.

Local advisory committees have helped their communities to understand regional electricity issues. These committees allow residents to provide input, and their advice improves the implementation and the regional plan. Community engagement is also crucial to linking regional energy plans with community energy planning.

Now that the first cycle of regional planning has been completed, the government is directing the IESO to review the regional planning process and report back with options and recommendations to address the challenges and opportunities that have emerged.

Community Energy Planning

Ontario's Municipal Energy Plan program and the IESO's Aboriginal Community Energy Plan (ACEP) program both support the efforts of municipalities and Indigenous communities to assess their energy use and needs, consider the impact of future growth, and foster local economic development. Communities are encouraged to develop their own energy plans that identify opportunities for conservation and priorities for infrastructure. The resulting community energy plans have helped communities recognize opportunities to conserve energy, improve energy efficiency and reduce greenhouse gas (GHG) emissions. More information on the ACEP program can be found in Chapter 7.

ABORIGINAL COMMUNITY ENERGY PLAN

Funding is available:

- For up to $90,000 to create a new community energy plan.
- For up to $25,000 to update an existing plan.
- For remote communities, an additional $5,000 for both streams.

MUNICIPAL ENERGY PLAN

Funding is available:

- For 50 per cent of eligible costs, up to a maximum of $90,000 to develop a new plan.
- For 50 per cent of eligible costs, up to a maximum of $25,000 to enhance an existing energy plan.

Ontario's Climate Change Action Plan has reinforced the importance of community energy and community GHG plans, and indicated Ontario will continue to support them. The Climate Change Action Plan also includes a funding for projects to reduce GHG emissions proposed by a municipality that has completed a community energy or community GHG plan and meets program eligibility criteria. The government launched the Municipal GHG Challenge Fund in August 2017. Municipalities may request up to $10 million per project to reduce GHGs in the building, energy supply, water, transportation, waste and organics sectors. Any Ontario municipality with a community-wide GHG emissions inventory, emissions reduction targets and a strategy to reduce emissions is eligible to apply. Municipal Energy Plan program participation is one path to eligibility for the Municipal GHG Challenge Fund.

REGIONAL AND COMMUNITY ENERGY PLANNING BY THE NUMBERS:

21 Electricity Regions

11 Active Local Advisory Committees (including both general and First Nations)

97 Aboriginal Community Energy Plans underway

36 Municipalities have Municipal Energy Plans underway or complete

19 Regional Infrastructure Plans (RIP) underway or complete. An RIP, led by the transmitter, identifies investments in transmission and/or distribution facilities to meet a region's electricity needs.

16 Integrated Regional Resources Plans (IRRP) completed. An IRRP, led by the IESO, integrates a range of resource options to address the electricity needs of the region.

More information on your region can be found by entering your postal code online at http://www.ieso.ca/en/get-involved/regional-planning

FIGURE 21. Regional Highlights

North of Dryden and Remote Connection

The construction of a new line to Pickle Lake and the connection of remote First Nation communities currently served by diesel generators are priorities for Ontario. The regional plan for North of Dryden recommended two projects to meet the near-term electricity needs of the region:

- Building a new 230 kV transmission line from the Dryden/Ignace area to Pickle Lake; and
- Upgrading the existing transmission lines from Dryden to Ear Falls and from Ear Falls to Red Lake.

Together, these projects will substantially increase the ability of the systems in Pickle Lake and Red Lake to meet demand.

Wataynikaneyap Power is the proponent of the 230-kilovolt (kV) transmission line from the Dryden/Ignace area to Pickle Lake and is currently acquiring the necessary approvals. The line is expected to be in service in 2020.

Ring of Fire

The Ring of Fire is in one of the most significant mineral regions of the province and includes the largest deposit of chromite ever discovered in North America. Electricity supply for the development of mines and the connection of remote First Nations in the area was assessed in the North of Dryden regional plan and the most economic option was found to be transmission connection to the Ontario grid.

The final approach to electricity supply in the Ring of Fire will depend on decisions related to transportation infrastructure, Indigenous community preferences and the electricity needs of mining companies.

Ottawa

Work is underway or complete on five transmission projects to address the near-to-medium term reliability needs and growth in demand in the Ottawa region.

The projects include the upgrading of a 115-kV circuit to provide increased supply capability for downtown Ottawa and a new transformer station and transmission line to meet the growing electricity needs of new developments in South Nepean.

A Local Advisory Committee has been established to provide advice on the development of the region's longer-term electricity plan.

Central Toronto

Increased density, new large transit projects, system reliability and resilience, and aging infrastructure are all driving new investments in Toronto's electricity infrastructure.

Conservation will be a key component of meeting the city's future electricity needs, with conservation resources expected to offset nearly 40 per cent of the growth in demand until 2036.

Investments in the Runnymede, Horner and Copeland transformer stations will ensure new customers can be connected to the grid.

As early as the mid-to-late 2020s, two major autotransformer stations and key transmission facilities are expected to reach the limit of their ability to supply growth in Central Toronto.

A Local Advisory Committee has been established to provide advice on the development of the region's longer-term electricity plan.

Windsor-Essex

Agri-business is growing in the rural portion of Essex County, increasing the demand for electricity. Hydro One is building a new transmission line, a new transformer station near Leamington, and refurbishing the Kingsville and Keith transformer stations to address this growth and improve restoration timelines. The new line and transformer station are expected to be in service by 2018.

York Region

Several transmission projects are underway to address the near-term needs for capacity and reliability in York Region, including a new transformer station in the City of Markham.

Based on current projections, York sub-regions' electricity system is expected to reach its capacity to supply growth in the medium to long term. A Local Advisory Committee has been established to provide advice on the region's longer-term electricity plan.

CITY OF TEMISKAMING SHORES

The City of Temiskaming Shores began developing its Municipal Energy Plan (MEP) in 2015. Thanks to its MEP, the city has found ways to be more energy-efficient. For example, it installed LED lighting in 955 street lights, converted to smaller pumps and motors in water and wastewater treatment facilities, and installed more efficient heating systems. The energy efficiency changes the city made have resulted in 20 per cent reductions in the utility bills for some projects. The MEP ensures that city council will approve one energy-related project each year. Temiskaming Shores has also increased its public transit service to reduce the number of private vehicles on the road.

Setting Standards for Pipelines

Apart from a small share of domestic production, Ontario's oil and natural gas is delivered from outside the province by interprovincial and international pipelines. These pipelines are under federal jurisdiction and regulated by the National Energy Board (NEB). The 2013 Long-Term Energy Plan outlined a set of principles that Ontario will use to evaluate oil and natural gas pipelines. In November 2014, Ontario and Québec agreed on the following seven principles for pipeline reviews:

- Pipelines must meet the highest available technical standards for public safety and environmental protection;
- Pipelines must have world-leading contingency planning and emergency response programs;
- Proponents and governments must fulfill their duty to consult obligations with Indigenous communities;
- Local municipalities must be consulted;
- Projects should provide demonstrable economic benefits and opportunities to the people of Ontario, over both the short and long term;
- Economic and environmental risks and responsibilities, including remediation, should be borne exclusively by the pipeline companies, who must also provide financial assurance demonstrating their capability to respond to leaks and spills; and
- GHG emissions and the interests of energy consumers must be taken into account.

The Province is committed to public engagement on major pipeline developments. In November 2013, the government asked the OEB to conduct provincewide consultations regarding TransCanada's Energy East proposal. The consultation process focused on four areas of potential impact:

- The impacts on Ontario natural gas consumers in terms of rates, reliability and access to supply, especially those consumers in eastern and northern Ontario;
- The impacts on pipeline safety and the natural environment in Ontario;
- The impacts on First Nations, Métis and local communities; and
- The short and long term economic impacts of the project in Ontario.

The OEB undertook an extensive consultation and review process. It hired experts in the subjects of pipelines, environmental reviews and economics to assist in understanding of the project and made their reports public. The OEB visited seven cities and towns along the route, meeting with local residents, First Nations and Métis in the spring of 2014 and again in the winter of 2015, to get their views on TransCanada's application. In addition, the OEB received about 10,000 written submissions during its review.

In August 2015, the OEB published its report *Giving a Voice to Ontarians on Energy East*. The report concluded there was not an appropriate balance between the economic and environmental risks of the project and its expected benefits for Ontarians. The report will help guide Ontario's participation in the NEB's regulatory proceeding on Energy East.

To ensure its strategic interests in pipeline projects are represented, the government will continue to participate in regulatory proceedings at the NEB and at intergovernmental forums that discuss the delivery of energy in a safe and environmentally sustainable manner. Ontario is also working with the federal government on regulatory initiatives such as modernizing the NEB to ensure major energy projects are reviewed in a predictable manner that increases public confidence.

Summary

- The government will continue to work with its agencies to implement the Conservation First policy in regional and local energy planning processes.
- With the first cycle of regional planning completed, the government is directing the Independent Electricity System Operator to review the regional planning process and report back with options and recommendations that address the challenges and opportunities that have emerged.
- Ontario's Climate Change Action Plan has reinforced the importance of community energy plans, and indicated the government's continued support for them.
- The Province has established seven pipeline principles to evaluate oil and natural gas pipelines, and is committed to public engagement when it undertakes reviews of major pipeline projects.

CONCLUSION

CONCLUSION

Delivering Fairness and Choice sets out a vision for the future of Ontario's energy sector and highlights the commitment to a clean, affordable and reliable energy system. The primary focus is on Ontario's energy consumers.

The development of *Delivering Fairness and Choice* followed a new legislated long-term energy planning process. The process included the development of electricity and fuels technical reports, a comprehensive engagement process with Ontarians and the issuance of implementation directives to the OEB and IESO.

The next step is for the OEB and IESO to submit implementation plans to the Minister of Energy for approval. The implementation plans will outline the steps these agencies will take to implement the policies and programs outlined in the implementation directives. The government looks forward to working with Ontario's energy sector in the implementation of *Delivering Fairness and Choice*.

GLOSSARY

GLOSSARY

Aboriginal Rights – Rights held by Indigenous peoples though long-standing use and occupancy of the land, protected under Section 35 of the *Constitution Act, 1982*.

Baseload Generation – Generation sources designed to operate more or less continuously through the day and night and across the seasons of the year. Nuclear and many hydro generating stations are examples of baseload generation.

Behind-the-Meter Applications – A range of technologies that are installed on the customer's electricity system to help manage the customer's load.

Beneficiary Pays – An approach to cost allocation where consumers pay for an asset in proportion to the benefits they derive from it. This protects ratepayers from paying for infrastructure that benefits only a few customers.

Bioenergy – The conversion of energy from organic matter to produce electricity. Sources for bioenergy generation can include agricultural residues, food processing by-products, animal manure, waste wood and kitchen waste.

Biofuels – Unlike other renewable energy sources, biomass can be converted directly into liquid fuels, called "biofuels," to help meet transportation fuel needs. The two most common types of biofuels in use today are ethanol and biodiesel.

Cap and Trade Program – A market-based system that sets a hard cap on greenhouse gas emissions while giving flexibility to businesses and industry in terms of how they meet their obligations under the program. Companies must have enough allowances (also known as permits or credits) to cover their emissions. As the cap declines, companies can invest in clean technologies to become more efficient, switch to lower carbon fuels, or purchase additional credits from other participants that have more allowances and credits than they need.

Climate Change Action Plan – A five-year plan, part of Ontario's long-term fight against climate change. The current Climate Change Action Plan will be followed by a revised plan in 2020.

Climate Change Mitigation and Low Carbon Economy Act, 2016 – Ontario legislation that creates a long-term framework for climate action. The Act establishes the province's greenhouse gas reduction targets in legislation, sets out the framework for the cap and trade program, requires the creation of a climate change action plan, and ensures accountability and transparency in how cap and trade proceeds are spent.

Conservation First – Conservation First is Ontario's policy that makes conservation the first resource considered, wherever cost-effective, in planning to meet the province's energy needs.

Conservation First Framework – Launched January 1, 2015, the six-year Conservation First Framework, overseen by the IESO, governs the delivery of electricity conservation and energy efficiency programs in Ontario and provides the funding, guidelines and certainty needed for electricity distributors to deliver conservation and energy efficiency programs to their customers.

Demand Side Management (DSM) Framework – Launched December 22, 2014, the six-year DSM Framework, overseen by the OEB, governs the delivery of natural gas conservation and energy efficiency programs in Ontario and provides the funding, guidelines and certainty needed for natural gas distributors to deliver energy efficiency programs to their customers.

Demand Response – Provides price or financial incentives to residential and business users to shift or reduce their electricity usage away from peak periods of consumption.

Distributed Generation (also known as Embedded Generation) – Electricity produced by small, decentralized generators, such as wind turbines and solar panels.

Energy Audit – The process to determine where, when, why and how energy is being used by energy-consuming systems, such as buildings. The information can then be used to identify opportunities to improve efficiency, decrease energy costs and reduce GHGs.

Energy Retrofit – The process for upgrading a building's energy consuming systems. Retrofitting may involve improving or replacing lighting fixtures, ventilation systems, windows and doors, or adding insulation. Retrofitting also means including energy efficiency measures in all renovation and repair activities.

Energy Storage – Equipment or technology that is capable of withdrawing electrical energy from the grid for the purposes of re-injecting it back into the grid; storing it as another form of energy to offset electricity demand at a later time; or for converting and storing electricity as an alternative form of energy for secondary, non-electric uses.

Ethanol – A renewable fuel made from plants such as corn, sugar cane and grasses whose use can reduce greenhouse gases.

Gigawatt – A unit of power equal to one million kilowatts (kW) or one billion watts (W).

Global Adjustment (GA) – The GA is the difference between the total payments made to certain contracted or regulated generators and demand management projects, and market revenues. The GA serves a number of functions in Ontario's electricity system: it provides more stable electricity prices for Ontario's consumers and generators; it maintains a reliable energy supply; and it recovers costs associated with conservation initiatives that benefit all Ontarians. The GA is calculated each month by taking into account the following components: generation contracts administered by the Ontario Electricity Financial Corporation; OPG's nuclear and baseload hydroelectric generation; and IESO contracts with generators and suppliers of conservation services.

Green Button – A data standard that gives customers the ability to access and share their utility data in an electronic, standardized and secure way. Customers can share their data with innovative software applications that allow them to view and manage their energy and water use.

Heat Pumps – A device that heats or cools buildings by absorbing heat from one area and transferring it to another. Heat pumps can replace the need for furnaces and air conditioners.

In-Front-of-the-Meter Technologies – A range of technologies that are deployed on distribution networks or transmission networks. Examples include technologies that reduce line losses and optimize voltage levels.

Capacity Auction – A competitive market that commits a supplier to provide a specified amount of electricity in the future.

Independent Electricity System Operator (IESO) – The provincial agency that delivers key services across the electricity sector including: managing the power system in real-time, planning for the province's future energy needs, enabling conservation and designing a more efficient electricity marketplace to support sector evolution.

Independent Power Authority – An unlicensed LDC that serves one of 10 First Nation communities in Northwestern Ontario.

Kilovolt (KV) – One thousand volts.

Kilowatt (kW) – A standard unit of power equal to 1,000 watts. Ten 100-watt light bulbs operated together require one kW of power.

Megatonnes (Mt) – One million metric tons.

Megawatt (MW) – A unit of power equal to 1,000 kilowatts (kW) or one million watts (W).

Megawatt-Hour (MWh) – A measure of the energy produced by a generating station over time: a one MW generator, operating for 24 hours, generates 24 MWh of energy.

Microgrid – A local electricity network linking smaller sources of electricity with nearby uses such as homes, businesses and institutions. In the event of a failure of the larger network, a microgrid can seal itself off and continue to provide power locally.

National Energy Board (NEB) – The federal agency that regulates the international and inter-provincial operations of oil and gas pipelines and electricity transmitters.

Net Metering – A billing arrangement allowing customers to generate their own electricity on site for their personal use and receive bill credits for any extra electricity sent to the local distribution system.

Net-Zero Energy Buildings – Buildings that annually produce at least as much energy as they consume.

Ontario Energy Board (OEB) – The OEB is the independent agency that regulates Ontario's electricity and natural gas sectors in the public interest.

Pumped Storage – A form of energy storage that uses electricity to pump water from a lower reservoir to a higher reservoir. When required, the water in the upper reservoir can be returned through turbines to the lower reservoir to generate electricity.

Regulated Price Plan (RPP) – A time-of-use pricing plan revised every six months by the OEB that sets the prices for electricity during peak, off-peak, and mid-peak periods of the day.

Terawatt-Hours (TWh) – One billion kilowatts of electricity used for one hour.

Time-Of-Use Prices – Prices for electricity that vary according to the demands put on the system. Under a time-of-use plan, prices are higher during periods of peak consumption when it costs more to generate electricity. Conversely, prices are lower during off-peak periods, when the cost of electricity is less.

Virtual Net Metering – A billing arrangement allowing customers who may not be able to install their own renewable energy system to participate in renewable energy projects located away from their homes or businesses. The electricity conveyed into the grid from the renewable energy system creates bill credits which can be used by one or more participating customers to offset charges on their electricity bills.

Watt (W) – A unit that measures how much electricity is generated or used at any one time.

ONTARIO'S LONG-TERM ENERGY PLAN 2017

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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

APPENDIX 5

RNG BMS

ECONOMIC FEASIBILITY

RNG BMS
Economic Feasibility
Parameters and Results

Line No.	Col. 1 Description	Col. 2
	FEASIBILITY PARAMETERS	
1.	Discount Rate	5.43%
2.	CCA Rate - Biogas Upgrading Plant	
3.	Energy components	50.00%
4.	Non- Energy components	20.00%
5.	Buildings components	4.00%
6.	Income Tax Rate	26.50%
7.	Municipal Tax Rate	0.59%
8.	Customer Revenue Horizon (Years)	20
9.	Capital Investment (Dollars)	
10.	Biogas Conditioning and Upgrading Plant Capital	7,419,759
11.	Working Capital (Days of Revenue)	30
	FEASIBILITY RESULTS	
12.	Net Present Value (Dollars)	731,134
13.	Profitability Index	1.10

RNG BMS
Economic Feasibility - 20 year Horizon
DCF Analysis

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
Line No.	Description	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
	Discount factors to project outset	0.9739	0.9237	0.8762	0.8310	0.7882	0.7476	0.7091	0.6726	0.6379	0.6051	0.5739
	INCREMENTAL CAPITAL INVESTMENT											
1.	Biogas Conditioning and Upgrading Plant	(7,419,759)										-
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	(7,419,759)	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	(110,750)	-	-	-	-	-	-	-	-	-
5.	Total Investment	(7,419,759)	(110,750)	-	-	-	-	-	-	-	-	-
6.	PV Of Total Investment At Project Outset	(7,226,130)	(102,304)	-	-	-	-	-	-	-	-	-
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(7,226,130)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)
	CCA TAX SHIELD											
8.	CCA Tax Shield	-	414,990	632,014	333,302	180,763	101,938	60,469	38,080	25,552	18,211	13,671
9.	PV Of CCA Tax Shield At Project Outset	-	383,341	553,741	276,981	142,480	76,210	42,879	25,612	16,300	11,019	7,846
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	-	383,341	937,083	1,214,063	1,356,544	1,432,754	1,475,632	1,501,244	1,517,544	1,528,564	1,536,409
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)											
11.	Biogas Conditioning and Upgrading Service Revenues	-	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000
12.	O&M Expenses	-	(448,800)	(457,776)	(466,932)	(476,270)	(485,796)	(495,511)	(505,422)	(515,530)	(525,841)	(536,358)
13.	Net Operating Cash (Before Taxes)	-	880,200	871,224	862,068	852,730	843,204	833,489	823,578	813,470	803,159	792,642
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	-	813,073	763,326	716,397	672,134	630,390	591,028	553,918	518,936	485,966	454,898
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	-	813,073	1,576,398	2,292,796	2,964,929	3,595,319	4,186,347	4,740,264	5,259,200	5,745,166	6,200,064
	TAXES											
16.	Income Tax (Before Interest Tax Shield)	-	(221,536)	(219,040)	(216,496)	(213,902)	(211,257)	(208,560)	(205,811)	(203,008)	(200,150)	(197,236)
17.	Municipal Tax	-	(44,214)	(44,656)	(45,103)	(45,554)	(46,010)	(46,470)	(46,934)	(47,404)	(47,878)	(48,357)
18.	Total Taxes	-	(265,751)	(263,697)	(261,599)	(259,456)	(257,266)	(255,030)	(252,745)	(250,411)	(248,027)	(245,592)
19.	PV of Total Taxes At Project Outset	-	(245,483)	(231,039)	(217,394)	(204,507)	(192,335)	(180,842)	(169,990)	(159,745)	(150,073)	(140,945)
20.	**ACCUMULATED PV OF TOTAL TAXES**	-	(245,483)	(476,522)	(693,917)	(898,423)	(1,090,758)	(1,271,600)	(1,441,590)	(1,601,335)	(1,751,408)	(1,892,354)
	ACCUMULATED NPV AND PI											
21.	Net Present Value	(7,226,130)	(6,377,504)	(5,291,475)	(4,515,492)	(3,905,384)	(3,391,120)	(2,938,056)	(2,528,516)	(2,153,025)	(1,806,113)	(1,484,315)
22.	Profitability Index	0.000	0.130	0.278	0.384	0.467	0.537	0.599	0.655	0.706	0.754	0.797

RNG BMS
Economic Feasibility - 20 year Horizon
DCF Analysis

	Col. 1	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22
Line No.	Description	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
	Discount factors to project outset	0.5443	0.5163	0.4897	0.4645	0.4406	0.4179	0.3963	0.3759	0.3566	0.3382
	INCREMENTAL CAPITAL INVESTMENT										
1.	Biogas Conditioning and Upgrading Plant	-	-	-	-	-	-	-	-	-	
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	-	-	-	-	-	-	-	-	-
5.	Total Investment	-	-	-	-	-	-	-	-	-	-
6.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	**(7,328,434)**
	CCA TAX SHIELD										
8.	CCA Tax Shield	10,696	8,636	7,141	6,013	5,137	4,443	3,884	3,429	3,054	24,068
9.	PV Of CCA Tax Shield At Project Outset	5,822	4,459	3,497	2,793	2,263	1,857	1,539	1,289	1,089	8,140
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	1,542,231	1,546,690	1,550,187	1,552,980	1,555,243	1,557,100	1,558,639	1,559,928	1,561,017	**1,569,156**
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)										
11.	Biogas Conditioning and Upgrading Service Revenues	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000
12.	O&M Expenses	(547,085)	(558,026)	(569,187)	(580,571)	(592,182)	(604,026)	(616,106)	(628,428)	(640,997)	(653,817)
13.	Net Operating Cash (Before Taxes)	781,915	770,974	759,813	748,429	736,818	724,974	712,894	700,572	688,003	675,183
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	425,626	398,052	372,082	347,628	324,606	302,936	282,544	263,357	245,310	228,338
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	6,625,690	7,023,742	7,395,824	7,743,453	8,068,059	8,370,995	8,653,538	8,916,895	9,162,205	**9,390,543**
	TAXES										
16.	Income Tax (Before Interest Tax Shield)	(194,265)	(191,236)	(188,148)	(184,999)	(181,789)	(178,515)	(175,178)	(171,775)	(168,306)	(164,768)
17.	Municipal Tax	(48,840)	(49,329)	(49,822)	(50,320)	(50,823)	(51,331)	(51,845)	(52,363)	(52,887)	(53,416)
18.	Total Taxes	(243,105)	(240,564)	(237,970)	(235,319)	(232,612)	(229,847)	(227,023)	(224,138)	(221,193)	(218,184)
19.	PV of Total Taxes At Project Outset	(132,331)	(124,203)	(116,534)	(109,300)	(102,477)	(96,043)	(89,977)	(84,258)	(78,867)	(73,787)
20.	**ACCUMULATED PV OF TOTAL TAXES**	(2,024,685)	(2,148,888)	(2,265,422)	(2,374,722)	(2,477,200)	(2,573,243)	(2,663,220)	(2,747,477)	(2,826,344)	**(2,900,131)**
	ACCUMULATED NPV AND PI										
21.	Net Present Value	(1,185,198)	(906,890)	(647,845)	(406,724)	(182,332)	26,417	220,523	400,912	568,443	731,134
22.	Profitability Index	0.838	0.876	0.912	0.945	0.975	1.004	1.030	1.055	1.078	**1.100**

RNG BMS
Revenue and Revenue Requirement

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
Line No.	Description	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
1	Capital	7,419,759											
2	**Rate Base**												
3	Balance, beginning		7,419,759	7,159,521	6,788,533	6,417,545	6,046,557	5,675,569	5,304,581	4,933,593	4,562,605	4,191,617	3,820,629
4	+ Additions												
5	+ Working Capital Additions		110,750	0	0	0	0	0	0	0	0	0	0
6	- Depreciation		(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)
7	Balance, ending	7,419,759	7,159,521	6,788,533	6,417,545	6,046,557	5,675,569	5,304,581	4,933,593	4,562,605	4,191,617	3,820,629	3,449,641
8	Average Rate Base		7,289,640	6,974,027	6,603,039	6,232,051	5,861,063	5,490,075	5,119,087	4,748,099	4,377,111	4,006,123	3,635,135
9	**Revenue Requirement**												
10	Return on Rate Base		452,333	432,748	409,728	386,708	363,687	340,667	317,647	294,626	271,606	248,586	225,565
11	O&M		448,800	457,776	466,932	476,270	485,796	495,511	505,422	515,530	525,841	536,358	547,085
12	Municipal Taxes		44,214	44,656	45,103	45,554	46,010	46,470	46,934	47,404	47,878	48,357	48,840
13	Deprecation		370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988
14	Taxes		(344,556)	(643,564)	(241,544)	(38,401)	64,453	116,481	142,550	155,204	160,799	162,584	162,240
15	Revenue Requirement		971,779	662,605	1,051,207	1,241,119	1,330,934	1,370,117	1,383,541	1,383,752	1,377,111	1,366,872	1,354,718
16	**Revenue**												
17	Biogas Conditioning and Upgrading Service Revenue		1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000
18	**Sufficiency / (Deficiency)**		**357,221**	**666,395**	**277,793**	**87,881**	**(1,934)**	**(41,117)**	**(54,541)**	**(54,752)**	**(48,111)**	**(37,872)**	**(25,718)**

RNG BMS
Revenue and Revenue Requirement

Line No.	Col. 1 Description	Col. 14 Year 12	Col. 15 Year 13	Col. 16 Year 14	Col. 17 Year 15	Col. 18 Year 16	Col. 19 Year 17	Col. 20 Year 18	Col. 21 Year 19	Col. 22 Year 20
1	Capital									
2	**Rate Base**									
3	Balance, beginning	3,449,641	3,078,654	2,707,666	2,336,678	1,965,690	1,594,702	1,223,714	852,726	481,738
4	+ Additions									
5	+ Working Capital Additions	0	0	0	0	0	0	0	0	0
6	- Depreciation	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)
7	Balance, ending	3,078,654	2,707,666	2,336,678	1,965,690	1,594,702	1,223,714	852,726	481,738	110,750
8	Average Rate Base	3,264,147	2,893,160	2,522,172	2,151,184	1,780,196	1,409,208	1,038,220	667,232	296,244
9	**Revenue Requirement**									
10	Return on Rate Base	202,545	179,525	156,504	133,484	110,464	87,443	64,423	41,403	18,382
11	O&M	558,026	569,187	580,571	592,182	604,026	616,106	628,428	640,997	653,817
12	Municipal Taxes	49,329	49,822	50,320	50,823	51,331	51,845	52,363	52,887	53,416
13	Deprecation	370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988
14	Taxes	160,650	158,293	155,436	152,235	148,788	145,156	141,384	137,502	133,533
15	Revenue Requirement	1,341,538	1,327,814	1,313,819	1,299,712	1,285,596	1,271,538	1,257,586	1,243,776	1,230,136
16	**Revenue**									
17	Biogas Conditioning and Upgrading Service Reve	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000
18	**Sufficiency / (Deficiency)**	**(12,538)**	**1,186**	**15,181**	**29,288**	**43,404**	**57,462**	**71,414**	**85,224**	**98,864**

APPENDIX 7

RNG INJECTION

ECONOMIC FEASIBILITY

RNG INJECTION
Economic Feasibility
Parameters and Results

Line No.	Col. 1 Description	Col. 2
FEASIBILITY PARAMETERS		
1.	Discount Rate	5.43%
2.	CCA Rate - Biomethane Injection Capital	6.00%
3.	Income Tax Rate	26.50%
4.	Municipal Tax Rate	0.59%
5.	Customer Revenue Horizon (Years)	20
6.	Capital Investment (Dollars)	
7.	Biomethane Injection Capital	5,439,025
8.	Working Capital (Days of Revenue)	30
FEASIBILITY RESULTS		
9.	Net Present Value (Dollars)	545,619
10.	Profitability Index	1.10

RNG INJECTION
Economic Feasibility - 20 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 2 Year 0	Col. 3 Year 1	Col. 4 Year 2	Col. 5 Year 3	Col. 6 Year 4	Col. 7 Year 5	Col. 8 Year 6	Col. 9 Year 7	Col. 10 Year 8	Col. 11 Year 9	Col. 12 Year 10
	Discount factors to project outset	0.9912	0.9569	0.9076	0.8608	0.8165	0.7744	0.7345	0.6967	0.6608	0.6268	0.5945
	INCREMENTAL CAPITAL INVESTMENT											
1.	Bio-methane Injection capital	(5,439,025)										
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	(5,439,025)	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	(63,083)	-	-	-	-	-	-	-	-	-
5.	Total Investment	(5,439,025)	(63,083)	-	-	-	-	-	-	-	-	-
6.	PV Of Total Investment At Project Outset	(5,391,295)	(60,364)	-	-	-	-	-	-	-	-	-
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(5,391,295)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)
	CCA TAX SHIELD											
8.	CCA Tax Shield	-	39,750	77,115	72,488	68,139	64,050	60,207	56,595	53,199	50,007	47,007
9.	PV Of CCA Tax Shield At Project Outset	-	38,036	69,989	62,401	55,635	49,603	44,225	39,430	35,155	31,344	27,945
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	-	38,036	108,025	170,426	226,062	275,665	319,890	359,320	394,476	425,819	453,765
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)											
11.	Bio-methane Injection Revenues	-	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
12.	O&M Expenses	-	(107,100)	(109,242)	(111,427)	(113,655)	(115,928)	(118,247)	(120,612)	(123,024)	(125,485)	(127,994)
13.	Net Operating Cash (Before Taxes)	-	649,900	647,758	645,573	643,345	641,072	638,753	636,388	633,976	631,515	629,006
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	-	621,880	587,902	555,737	525,291	496,472	469,195	443,378	418,945	395,822	373,941
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	-	621,880	1,209,782	1,765,519	2,290,810	2,787,282	3,256,476	3,699,855	4,118,799	4,514,622	4,888,562
	TAXES											
16.	Income Tax (Before Interest Tax Shield)	-	(163,635)	(162,981)	(162,315)	(161,637)	(160,946)	(160,242)	(159,525)	(158,795)	(158,051)	(157,293)
17.	Municipal Tax	-	(32,411)	(32,735)	(33,063)	(33,393)	(33,727)	(34,064)	(34,405)	(34,749)	(35,097)	(35,448)
18.	Total Taxes	-	(196,046)	(195,716)	(195,378)	(195,030)	(194,673)	(194,307)	(193,931)	(193,544)	(193,148)	(192,740)
19.	PV of Total Taxes At Project Outset	-	(187,593)	(177,631)	(168,190)	(159,242)	(150,763)	(142,728)	(135,113)	(127,898)	(121,061)	(114,583)
20.	**ACCUMULATED PV OF TOTAL TAXES**	-	(187,593)	(365,224)	(533,414)	(692,656)	(843,419)	(986,147)	(1,121,261)	(1,249,159)	(1,370,220)	(1,484,803)
	ACCUMULATED NPV AND PI											
21.	Net Present Value	(5,391,295)	(4,979,335)	(4,499,075)	(4,049,127)	(3,627,443)	(3,232,131)	(2,861,439)	(2,513,744)	(2,187,542)	(1,881,437)	(1,594,134)
22.	Profitability Index	0.000	0.087	0.175	0.257	0.335	0.407	0.475	0.539	0.599	0.655	0.708

RNG INJECTION
Economic Feasibility - 20 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 13 Year 11	Col. 14 Year 12	Col. 15 Year 13	Col. 16 Year 14	Col. 17 Year 15	Col. 18 Year 16	Col. 19 Year 17	Col. 20 Year 18	Col. 21 Year 19	Col. 22 Year 20
	Discount factors to project outset	0.5639	0.5348	0.5073	0.4811	0.4564	0.4329	0.4106	0.3894	0.3693	0.3503
	INCREMENTAL CAPITAL INVESTMENT										
1.	Bio-methane Injection capital										
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	-	-	-	-	-	-	-	-	-
5.	Total Investment	-	-	-	-	-	-	-	-	-	-
6.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	**(5,451,658)**
	CCA TAX SHIELD										
8.	CCA Tax Shield	44,186	41,535	39,043	36,701	34,499	32,429	30,483	28,654	26,935	233,522
9.	PV Of CCA Tax Shield At Project Outset	24,916	22,214	19,806	17,658	15,744	14,037	12,515	11,158	9,948	81,808
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	478,680	500,894	520,700	538,358	554,102	568,139	580,654	591,812	601,760	**683,568**
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)										
11.	Bio-methane Injection Revenues	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
12.	O&M Expenses	(130,554)	(133,165)	(135,829)	(138,545)	(141,316)	(144,142)	(147,025)	(149,966)	(152,965)	(156,024)
13.	Net Operating Cash (Before Taxes)	626,446	623,835	621,171	618,455	615,684	612,858	609,975	607,034	604,035	600,976
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	353,235	333,643	315,105	297,567	280,974	265,277	250,429	236,384	223,099	210,536
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	5,241,797	5,575,440	5,890,546	6,188,112	6,469,086	6,734,364	6,984,792	7,221,176	7,444,276	**7,654,811**
	TAXES										
16.	Income Tax (Before Interest Tax Shield)	(156,521)	(155,734)	(154,932)	(154,115)	(153,283)	(152,436)	(151,572)	(150,692)	(149,796)	(148,882)
17.	Municipal Tax	(35,802)	(36,160)	(36,522)	(36,887)	(37,256)	(37,628)	(38,005)	(38,385)	(38,769)	(39,156)
18.	Total Taxes	(192,323)	(191,894)	(191,454)	(191,002)	(190,539)	(190,064)	(189,577)	(189,077)	(188,564)	(188,038)
19.	PV of Total Taxes At Project Outset	(108,445)	(102,630)	(97,120)	(91,900)	(86,955)	(82,270)	(77,832)	(73,628)	(69,646)	(65,874)
20.	**ACCUMULATED PV OF TOTAL TAXES**	(1,593,249)	(1,695,878)	(1,792,998)	(1,884,898)	(1,971,853)	(2,054,123)	(2,131,955)	(2,205,583)	(2,275,229)	**(2,341,103)**
	ACCUMULATED NPV AND PI										
21.	Net Present Value	(1,324,429)	(1,071,202)	(833,411)	(610,086)	(400,323)	(203,278)	(18,166)	155,748	319,149	545,619
22.	Profitability Index	0.757	0.804	0.847	0.888	0.927	0.963	0.997	1.029	1.059	**1.100**

RNG INJECTION
Revenue and Revenue Requirement

Line No.		Col. 1 Description	Col. 2 Year 0	Col. 3 Year 1	Col. 4 Year 2	Col. 5 Year 3	Col. 6 Year 4	Col. 7 Year 5	Col. 8 Year 6	Col. 9 Year 7	Col. 10 Year 8	Col. 11 Year 9	Col. 12 Year 10
1		Capital	5,439,025										
2		**Rate Base**											
3		Balance, beginning		5,439,025	5,250,157	4,998,206	4,746,255	4,494,303	4,242,352	3,990,401	3,738,450	3,486,498	3,234,547
4	+	Additions											
5	+	Working Capital Additions		63,083	0	0	0	0	0	0	0	0	0
6	-	Depreciation		(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)
7		Balance, ending	5,439,025	5,250,157	4,998,206	4,746,255	4,494,303	4,242,352	3,990,401	3,738,450	3,486,498	3,234,547	2,982,596
8		Average Rate Base		5,344,591	5,124,181	4,872,230	4,620,279	4,368,328	4,116,376	3,864,425	3,612,474	3,360,523	3,108,571
9		**Revenue Requirement**											
10		Return on Rate Base		331,640	317,963	302,329	286,695	271,061	255,427	239,793	224,159	208,525	192,891
11		O&M		107,100	109,242	111,427	113,655	115,928	118,247	120,612	123,024	125,485	127,994
12		Municipal Taxes		32,411	32,735	33,063	33,393	33,727	34,064	34,405	34,749	35,097	35,448
13		Deprecation		251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951
14		Taxes		100,030	46,584	49,896	52,831	55,411	57,657	59,589	61,226	62,586	63,686
15		Revenue Requirement		823,132	758,475	748,666	738,526	728,079	717,346	706,350	695,110	683,644	671,970
16		**Revenue**											
17		RNG Injection Revenue		757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
18		**Sufficiency / (Deficiency)**		**(66,132)**	**(1,475)**	**8,334**	**18,474**	**28,921**	**39,654**	**50,650**	**61,890**	**73,356**	**85,030**

RNG INJECTION
Revenue and Revenue Requirement

	Col. 1	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22
Line No.	Description	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Capital										
2	**Rate Base**										
3	Balance, beginning	2,982,596	2,730,645	2,478,693	2,226,742	1,974,791	1,722,840	1,470,888	1,218,937	966,986	715,035
4	+ Additions										
5	+ Working Capital Additions	0	0	0	0	0	0	0	0	0	0
6	- Depreciation	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)
7	Balance, ending	2,730,645	2,478,693	2,226,742	1,974,791	1,722,840	1,470,888	1,218,937	966,986	715,035	463,083
8	Average Rate Base	2,856,620	2,604,669	2,352,718	2,100,766	1,848,815	1,596,864	1,344,913	1,092,961	841,010	589,059
9	**Revenue Requirement**										
10	Return on Rate Base	177,257	161,623	145,990	130,356	114,722	99,088	83,454	67,820	52,186	36,552
11	O&M	130,554	133,165	135,829	138,545	141,316	144,142	147,025	149,966	152,965	156,024
12	Municipal Taxes	35,802	36,160	36,522	36,887	37,256	37,628	38,005	38,385	38,769	39,156
13	Deprecation	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951
14	Taxes	64,540	65,164	65,572	65,777	65,790	65,624	65,288	64,794	64,150	63,366
15	Revenue Requirement	660,105	648,065	635,863	623,516	611,035	598,433	585,723	572,915	560,021	547,050
16	**Revenue**										
17	RNG Injection Revenue	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
18	**Sufficiency / (Deficiency)**	**96,895**	**108,935**	**121,137**	**133,484**	**145,965**	**158,567**	**171,277**	**184,085**	**196,979**	**209,950**

RATE NUMBER: 400	BIOGAS CONDITIONING AND UPGRADING SERVICE

APPLICABILITY:

To any biogas producer (“Applicant”) who enters into a Biogas Services Agreement (“Agreement”) with the Company for biogas conditioning and upgrading services located on or adjacent to the property employed by the Applicant for producing biogas in an area served by the Company’s Gas Distribution Network. Biogas Conditioning and Upgrading Services under this Schedule are conditioned upon arrangements mutually satisfactory to the Applicant and the Company for design, location, construction, and operation of required facilities.

RATE:

The Company will set a rate based on the Applicant’s unique circumstances (“Services Fee”). The Services Fee shall be based on a cost-of-service calculation of the Company’s fully-allocated direct and indirect costs using the Company’s weighted average cost of capital (“WACC”) of providing the services under the Agreement for a period of time agreed to between the Company and the Applicant.

TERMS AND CONDITIONS OF SERVICE:

To be set out in the Agreement.

RATE NUMBER: 401	RENEWABLE NATURAL GAS INJECTION SERVICE

APPLICABILITY:

To any biogas producer ("Applicant") who enters into a Biogas Services Agreement ("Agreement") with the Company for Renewable Natural Gas injection services located on or adjacent to the property employed by the Applicant for producing biogas in an area served by the Company's Gas Distribution Network. Renewable Natural Gas Injection Service under this Schedule is conditioned upon arrangements mutually satisfactory to the Applicant and the Company for design, location, construction, and operation of required facilities.

RATE:

The Company will set a rate based on the Applicant's unique circumstances ("Services Fee"). The Services Fee shall be based on a cost-of-service calculation of the Company's fully-allocated direct and indirect costs using the Company's weighted average cost of capital ("WACC") of providing the services under the Agreement for a period of time agreed to between the Company and the Applicant.

TERMS AND CONDITIONS OF SERVICE:

To be set out in the Agreement.

APPENDIX 11

GEOTHERMAL

ECONOMIC FEASIBILITY

Geothermal
Economic Feasibility
Parameters and Results

Line No.	Col. 1 Description	Col. 2
FEASIBILITY PARAMETERS		
1.	Discount Rate	5.43%
2.	CCA Rate	50.00%
3.	Income Tax Rate	26.50%
4.	Customer Revenue Horizon (Years)	30
5.	Capital Investment (Dollars)	
6.	Geothermal Loops	237,148,543
7.	Total Capital Investment	237,148,543
8.	Working Capital (Days of Revenue)	30
FEASIBILITY RESULTS		
9.	Net Present Value (Dollars)	16,679,865
10.	Profitability Index	1.10

Geothermal
Economic Feasibility - 40 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 2 Year 1	Col. 3 Year 2	Col. 4 Year 3	Col. 5 Year 4	Col. 6 Year 5	Col. 7 Year 6	Col. 8 Year 7	Col. 9 Year 8	Col. 10 Year 9	Col. 11 Year 10	Col. 12 Year 11
	Discount factors to project outset	0.9739	0.9237	0.8762	0.8310	0.7882	0.7476	0.7091	0.6726	0.6379	0.6051	0.5739
	INCREMENTAL CAPITAL INVESTMENT											
1.	Geothermal Loops	(2,702,492)	(4,339,017)	(6,140,834)	(10,002,812)	(16,355,698)	(29,384,945)	(42,055,686)	(42,055,686)	(42,055,686)	(42,055,686)	-
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	(2,702,492)	(4,339,017)	(6,140,834)	(10,002,812)	(16,355,698)	(29,384,945)	(42,055,686)	(42,055,686)	(42,055,686)	(42,055,686)	-
4.	Working Capital	(8,524)	(23,566)	(36,602)	(58,664)	(98,274)	(173,484)	(273,764)	(322,902)	(322,902)	(322,902)	(161,451)
5.	Total Investment	(2,711,016)	(4,362,582)	(6,177,436)	(10,061,476)	(16,453,973)	(29,558,429)	(42,329,451)	(42,378,588)	(42,378,588)	(42,378,588)	(161,451)
6.	PV Of Total Investment At Project Outset	(2,640,268)	(4,029,876)	(5,412,381)	(8,361,300)	(12,969,251)	(22,098,231)	(30,015,863)	(28,502,746)	(27,034,525)	(25,641,933)	(92,657)
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(2,640,268)	(6,670,144)	(12,082,525)	(20,443,825)	(33,413,076)	(55,511,308)	(85,527,170)	(114,029,916)	(141,064,441)	(166,706,374)	(166,799,031)
	CCA TAX SHIELD											
8.	CCA Tax Shield	177,458	551,387	964,535	1,543,539	2,504,777	4,259,632	6,826,112	8,941,919	9,999,823	10,528,774	8,028,819
9.	PV Of CCA Tax Shield At Project Outset	172,827	509,336	845,081	1,282,714	1,974,301	3,184,551	4,840,404	6,014,104	6,379,176	6,370,626	4,607,740
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	172,827	682,163	1,527,243	2,809,957	4,784,258	7,968,808	12,809,212	18,823,317	25,202,492	31,573,118	36,180,858
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)											
11.	Geothermal Revenues	102,286	385,075	824,302	1,528,267	2,707,560	4,789,373	8,074,546	11,949,365	15,824,184	19,699,003	21,636,413
12.	O&M Expenses	(1,537,880)	(1,270,689)	(1,370,840)	(1,822,089)	(2,169,696)	(2,887,015)	(3,640,951)	(3,832,665)	(4,019,479)	(4,206,293)	(1,430,529)
13.	Net Operating Cash (Before Taxes)	(1,435,595)	(885,614)	(546,539)	(293,822)	537,864	1,902,358	4,433,595	8,116,700	11,804,705	15,492,710	20,205,884
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	(1,398,131)	(818,074)	(478,852)	(244,172)	423,952	1,422,225	3,143,867	5,459,083	7,530,562	9,374,145	11,596,159
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	(1,398,131)	(2,216,205)	(2,695,056)	(2,939,229)	(2,515,277)	(1,093,052)	2,050,816	7,509,899	15,040,461	24,414,606	36,010,765
	TAXES											
16.	Income Tax (Before Interest Tax Shield)	380,433	234,688	144,833	77,863	(142,534)	(504,125)	(1,174,903)	(2,150,925)	(3,128,247)	(4,105,568)	(5,354,559)
17.	Municipal Tax	-	-	-	-	-	-	-	-	-	-	- /u
18.	Total Taxes	380,433	234,688	144,833	77,863	(142,534)	(504,125)	(1,174,903)	(2,150,925)	(3,128,247)	(4,105,568)	(5,354,559)
19.	PV of Total Taxes At Project Outset	370,505	216,790	126,896	64,706	(112,347)	(376,890)	(833,125)	(1,446,657)	(1,995,599)	(2,484,148)	(3,072,982)
20.	**ACCUMULATED PV OF TOTAL TAXES**	370,505	587,294	714,190	778,896	666,548	289,659	(543,466)	(1,990,123)	(3,985,722)	(6,469,871)	(9,542,853)
	ACCUMULATED NPV AND PI											
21.	Net Present Value	(3,495,068)	(7,616,892)	(12,536,148)	(19,794,201)	(30,477,547)	(48,345,892)	(71,210,609)	(89,686,824)	(104,807,210)	(117,188,521)	(104,150,260)
22.	Profitability Index	(0.324)	(0.142)	(0.038)	0.032	0.088	0.129	0.167	0.213	0.257	0.297	0.376

Geothermal
Economic Feasibility - 40 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 13 Year 12	Col. 14 Year 13	Col. 15 Year 14	Col. 16 Year 15	Col. 17 Year 16	Col. 18 Year 17	Col. 19 Year 18	Col. 20 Year 19	Col. 21 Year 20	Col. 22 Year 21
	Discount factors to project outset	0.5443	0.5163	0.4897	0.4645	0.4406	0.4179	0.3963	0.3759	0.3566	0.3382
	INCREMENTAL CAPITAL INVESTMENT										
1.	Geothermal Loops	-	-	-	-	-	-	-	-	-	-
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	-	-	-	-	-	-	-	-	-
5.	Total Investment	-	-	-	-	-	-	-	-	-	-
6.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)
	CCA TAX SHIELD										
8.	CCA Tax Shield	4,014,409	2,007,205	1,003,602	501,801	250,901	125,450	62,725	31,363	15,681	7,841
9.	PV Of CCA Tax Shield At Project Outset	2,185,194	1,036,316	491,467	233,075	110,535	52,420	24,860	11,790	5,591	2,652
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	38,366,052	39,402,368	39,893,834	40,126,910	40,237,444	40,289,865	40,314,725	40,326,514	40,332,106	40,334,757
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)										
11.	Geothermal Revenues	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413
12.	O&M Expenses	(1,414,429)	(1,414,429)	(1,414,429)	(1,414,429)	(1,522,611)	(1,522,611)	(1,522,611)	(1,522,611)	(1,522,611)	(1,522,611)
13.	Net Operating Cash (Before Taxes)	20,221,984	20,221,984	20,221,984	20,221,984	20,113,802	20,113,802	20,113,802	20,113,802	20,113,802	20,113,802
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	11,007,586	10,440,568	9,902,758	9,392,651	8,861,161	8,404,709	7,971,769	7,561,130	7,171,644	6,802,222
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	47,018,352	57,458,920	67,361,678	76,754,329	85,615,490	94,020,198	101,991,967	109,553,097	116,724,742	123,526,963
	TAXES										
16.	Income Tax (Before Interest Tax Shield)	(5,358,826)	(5,358,826)	(5,358,826)	(5,358,826)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)
17.	Municipal Tax	-	-	-	-	-	-	-	-	-	- /u
18.	Total Taxes	(5,358,826)	(5,358,826)	(5,358,826)	(5,358,826)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)
19.	PV of Total Taxes At Project Outset	(2,917,010)	(2,766,751)	(2,624,231)	(2,489,053)	(2,348,208)	(2,227,248)	(2,112,519)	(2,003,700)	(1,900,486)	(1,802,589)
20.	**ACCUMULATED PV OF TOTAL TAXES**	(12,459,863)	(15,226,614)	(17,850,845)	(20,339,897)	(22,688,105)	(24,915,353)	(27,027,871)	(29,031,571)	(30,932,057)	(32,734,645)
	ACCUMULATED NPV AND PI										
21.	Net Present Value	(93,874,490)	(85,164,357)	(77,394,363)	(70,257,690)	(63,634,202)	(57,404,320)	(51,520,210)	(45,950,990)	(40,674,240)	(35,671,956)
22.	Profitability Index	0.437	0.489	0.536	0.579	0.618	0.656	0.691	0.725	0.756	0.786

Geothermal
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Line No.	Col. 1 Description	Col. 23 Year 22	Col. 24 Year 23	Col. 25 Year 24	Col. 26 Year 25	Col. 27 Year 26	Col. 28 Year 27	Col. 29 Year 28	Col. 30 Year 29	Col. 31 Year 30	Col. 32 Year 31
	Discount factors to project outset	0.3208	0.3042	0.2886	0.2737	0.2596	0.2462	0.2336	0.2215	0.2101	0.1993
	INCREMENTAL CAPITAL INVESTMENT										
1.	Geothermal Loops	-	-	-	-	-	-	-	-	-	-
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	-	-	-	-	-	-	-	-	8,524
5.	Total Investment	-	-	-	-	-	-	-	-	-	8,524
6.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	1,699
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,799,031)	(166,797,332)
	CCA TAX SHIELD										
8.	CCA Tax Shield	3,920	1,960	980	490	245	123	61	31	15	8
9.	PV Of CCA Tax Shield At Project Outset	1,258	596	283	134	64	30	14	7	3	2
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	40,336,015	40,336,611	40,336,894	40,337,028	40,337,092	40,337,122	40,337,136	40,337,143	40,337,146	40,337,148
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)										
11.	Geothermal Revenues	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,534,127
12.	O&M Expenses	(1,522,611)	(1,522,611)	(1,522,611)	(1,522,611)	(1,522,611)	(1,522,611)	(1,522,611)	(1,522,611)	(1,522,611)	(1,517,168)
13.	Net Operating Cash (Before Taxes)	20,113,802	20,113,802	20,113,802	20,113,802	20,113,802	20,113,802	20,113,802	20,113,802	20,113,802	20,016,959
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	6,451,828	6,119,484	5,804,260	5,505,273	5,221,688	4,952,711	4,697,589	4,455,608	4,226,093	3,989,101
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	129,978,792	136,098,276	141,902,536	147,407,810	152,629,498	157,582,209	162,279,797	166,735,406	170,961,499	174,950,600
	TAXES										
16.	Income Tax (Before Interest Tax Shield)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,304,494)
17.	Municipal Tax	-	-	-	-	-	-	-	-	-	- /u
18.	Total Taxes	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,330,157)	(5,304,494)
19.	PV of Total Taxes At Project Outset	(1,709,735)	(1,621,663)	(1,538,129)	(1,458,897)	(1,383,747)	(1,312,468)	(1,244,861)	(1,180,736)	(1,119,915)	(1,057,112)
20.	**ACCUMULATED PV OF TOTAL TAXES**	(34,444,380)	(36,066,043)	(37,604,172)	(39,063,070)	(40,446,817)	(41,759,285)	(43,004,146)	(44,184,883)	(45,304,797)	(46,361,909)
	ACCUMULATED NPV AND PI										
21.	Net Present Value	(30,928,604)	(26,430,187)	(22,163,773)	(18,117,263)	(14,279,258)	(10,638,986)	(7,186,244)	(3,911,365)	(805,183)	2,128,506
22.	Profitability Index	0.815	0.842	0.867	0.891	0.914	0.936	0.957	0.977	0.995	1.013

Geothermal
Economic Feasibility - 40 year Horizon
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Line No.	Col. 1 Description	Col. 33 Year 32	Col. 34 Year 33	Col. 35 Year 34	Col. 36 Year 35	Col. 37 Year 36	Col. 38 Year 37	Col. 39 Year 38	Col. 40 Year 39	Col. 41 Year 40
	Discount factors to project outset	0.1890	0.1793	0.1700	0.1613	0.1530	0.1451	0.1376	0.1305	0.1255
	INCREMENTAL CAPITAL INVESTMENT									
1.	Geothermal Loops	-	-	-	-	-	-	-	-	-
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	-	-	-	-	-	-	-	-	-
4.	Working Capital	23,566	36,602	58,664	98,274	173,484	273,764	322,902	322,902	322,902
5.	Total Investment	23,566	36,602	58,664	98,274	173,484	273,764	322,902	322,902	322,902
6.	PV Of Total Investment At Project Outset	4,454	6,562	9,976	15,851	26,540	39,723	44,440	42,151	40,511
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(166,792,878)	(166,786,316)	(166,776,340)	(166,760,489)	(166,733,950)	(166,694,226)	(166,649,787)	(166,607,636)	**(166,567,125)**
	CCA TAX SHIELD									
8.	CCA Tax Shield	4	2	1	0	0	0	0	0	0
9.	PV Of CCA Tax Shield At Project Outset	1	0	0	0	0	0	0	0	0
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	40,337,148	40,337,149	40,337,149	40,337,149	40,337,149	40,337,149	40,337,149	40,337,149	**40,337,149**
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)									
11.	Geothermal Revenues	21,251,338	20,812,111	20,108,146	18,928,853	16,847,040	13,561,867	9,687,048	5,812,229	1,937,410
12.	O&M Expenses	(1,502,120)	(1,478,748)	(1,441,288)	(1,378,535)	(1,267,757)	(1,092,946)	(886,757)	(680,569)	(288,738)
13.	Net Operating Cash (Before Taxes)	19,749,217	19,333,363	18,666,857	17,550,317	15,579,283	12,468,922	8,800,291	5,131,660	1,648,672
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	3,733,007	3,466,158	3,174,273	2,830,675	2,383,332	1,809,248	1,211,151	669,871	206,843
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	178,683,607	182,149,765	185,324,038	188,154,713	190,538,045	192,347,292	193,558,443	194,228,313	**194,435,157**
	TAXES									
16.	Income Tax (Before Interest Tax Shield)	(5,233,543)	(5,123,341)	(4,946,717)	(4,650,834)	(4,128,510)	(3,304,264)	(2,332,077)	(1,359,890)	(436,898)
17.	Municipal Tax	-	-	-	-	-	-	-	-	-
18.	Total Taxes	(5,233,543)	(5,123,341)	(4,946,717)	(4,650,834)	(4,128,510)	(3,304,264)	(2,332,077)	(1,359,890)	(436,898)
19.	PV of Total Taxes At Project Outset	(989,247)	(918,532)	(841,182)	(750,129)	(631,583)	(479,451)	(320,955)	(177,516)	(54,813)
20.	**ACCUMULATED PV OF TOTAL TAXES**	(47,351,156)	(48,269,688)	(49,110,870)	(49,860,999)	(50,492,582)	(50,972,032)	(51,292,987)	(51,470,503)	**(51,525,317)**
	ACCUMULATED NPV AND PI									
21.	Net Present Value	4,876,722	7,430,910	9,773,977	11,870,373	13,648,662	15,018,182	15,952,818	16,487,323	**16,679,865**
22.	Profitability Index	1.029	1.045	1.059	1.071	1.082	1.090	1.096	1.099	**1.100**

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Geothermal
Revenue and Revenue Requirement

Line No.	Col. 1 Description	Col. 2 Year 1	Col. 3 Year 2	Col. 4 Year 3	Col. 5 Year 4	Col. 6 Year 5	Col. 7 Year 6	Col. 8 Year 7	Col. 9 Year 8	Col. 10 Year 9	Col. 11 Year 10	Col. 12 Year 11	Col. 13 Year 12
1	Number of Customers	170	300	430	740	1,220	2,240	3,220	3,220	3,220	3,220		
2	Number of Cumulative Customers [50% Effective]	85	320	685	1,270	2,250	3,980	6,710	9,930	13,150	16,370	17,980	17,980
3	Number of Tonnes per Customer	4	4	4	4	4	4	4	4	4	4	4	4
4	Total Number of Tonnes	340	1,280	2,740	5,080	9,000	15,920	26,840	39,720	52,600	65,480	71,920	71,920
5	Capital	2,702,492	4,339,017	6,140,834	10,002,812	16,355,698	29,384,945	42,055,686	42,055,686	42,055,686	42,055,686		
6	**Rate Base**												
7	Balance, beginning	0	2,665,974	6,866,157	12,706,529	22,161,880	37,570,419	65,321,071	104,652,067	142,630,344	179,206,764	214,381,329	206,637,828
8	+ Additions	2,702,492	4,339,017	6,140,834	10,002,812	16,355,698	29,384,945	42,055,686	42,055,686	42,055,686	42,055,686		
9	+ Working Capital Additions	8,524	23,566	36,602	58,664	98,274	173,484	273,764	322,902	322,902	322,902	161,451	0
10	- Depreciation	(45,042)	(162,400)	(337,064)	(606,125)	(1,045,433)	(1,807,778)	(2,998,455)	(4,400,311)	(5,802,167)	(7,204,023)	(7,904,951)	(7,904,951)
11	Balance, ending	2,665,974	6,866,157	12,706,529	22,161,880	37,570,419	65,321,071	104,652,067	142,630,344	179,206,764	214,381,329	206,637,828	198,732,877
12	Average Rate Base	1,332,987	4,766,066	9,786,343	17,434,204	29,866,149	51,445,745	84,986,569	123,641,205	160,918,554	196,794,047	210,509,579	202,685,353
13	**Revenue Requirement**												
14	Return on Rate Base	82,714	295,741	607,257	1,081,817	1,853,238	3,192,283	5,273,539	7,672,115	9,985,228	12,211,354	13,062,422	12,576,918
15	O&M	1,537,880	1,270,689	1,370,840	1,822,089	2,169,696	2,887,015	3,640,951	3,832,665	4,019,479	4,206,293	1,430,529	1,414,429
16	Municipal Taxes	-	-	-	-	-	-	-	-	-	-	-	- /u
17	Deprecation	45,042	162,400	337,064	606,125	1,045,433	1,807,778	2,998,455	4,400,311	5,802,167	7,204,023	7,904,951	7,904,951
18	Taxes	(209,419)	(635,210)	(1,074,910)	(1,675,123)	(2,677,364)	(4,534,591)	(7,200,034)	(9,115,638)	(9,608,222)	(9,397,740)	(5,581,352)	(212,198)
19	Revenue Requirement	1,456,216	1,093,620	1,240,251	1,834,909	2,391,003	3,352,484	4,712,910	6,789,453	10,198,652	14,223,931	16,816,551	21,684,100
20	**Revenue**												
21	Revenue per Tonne per Month	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07
22	Geothermal Revenue	102,286	385,075	824,302	1,528,267	2,707,560	4,789,373	8,074,546	11,949,365	15,824,184	19,699,003	21,636,413	21,636,413
23	**Sufficiency / (Deficiency)**	**(1,353,931)**	**(708,545)**	**(415,950)**	**(306,642)**	**316,557**	**1,436,889**	**3,361,636**	**5,159,912**	**5,625,532**	**5,475,073**	**4,819,862**	**(47,688)**

Geothermal
Revenue and Revenue Requirement

Line No.	Col. 1 Description	Col. 14 Year 13	Col. 15 Year 14	Col. 16 Year 15	Col. 17 Year 16	Col. 18 Year 17	Col. 19 Year 18	Col. 20 Year 19	Col. 21 Year 20	Col. 22 Year 21	Col. 23 Year 22	Col. 24 Year 23	
1	Number of Customers												
2	Number of Cumulative Customers [50% Effective]	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	
3	Number of Tonnes per Customer	4	4	4	4	4	4	4	4	4	4	4	
4	Total Number of Tonnes	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	
5	Capital												
6	**Rate Base**												
7	Balance, beginning	198,732,877	190,827,926	182,922,974	175,018,023	167,113,071	159,208,120	151,303,168	143,398,217	135,493,265	127,588,314	119,683,363	
8	+ Additions												
9	+ Working Capital Additions	0	0	0	0	0	0	0	0	0	0	0	
10	- Depreciation	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	
11	Balance, ending	190,827,926	182,922,974	175,018,023	167,113,071	159,208,120	151,303,168	143,398,217	135,493,265	127,588,314	119,683,363	111,778,411	
12	Average Rate Base	194,780,401	186,875,450	178,970,498	171,065,547	163,160,595	155,255,644	147,350,693	139,445,741	131,540,790	123,635,838	115,730,887	
13	**Revenue Requirement**												
14	Return on Rate Base	12,086,404	11,595,891	11,105,377	10,614,864	10,124,350	9,633,836	9,143,323	8,652,809	8,162,295	7,671,782	7,181,268	
15	O&M	1,414,429	1,414,429	1,414,429	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	
16	Municipal Taxes	-	-	-	-	-	-	-	-	-	-	-	/u
17	Deprecation	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	
18	Taxes	2,425,110	3,696,972	4,286,112	4,533,890	4,610,987	4,602,745	4,551,832	4,479,584	4,396,668	4,308,419	4,217,503	
19	Revenue Requirement	23,830,894	24,612,243	24,710,869	24,576,316	24,162,900	23,664,143	23,122,717	22,559,955	21,986,526	21,407,763	20,826,333	
20	**Revenue**												
21	Revenue per Tonne per Month	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	
22	Geothermal Revenue	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	
23	**Sufficiency / (Deficiency)**	**(2,194,482)**	**(2,975,830)**	**(3,074,456)**	**(2,939,903)**	**(2,526,487)**	**(2,027,731)**	**(1,486,304)**	**(923,542)**	**(350,113)**	**228,650**	**810,080**	

Geothermal
Revenue and Revenue Requirement

Line No.	Col. 1 Description	Col. 25 Year 24	Col. 26 Year 25	Col. 27 Year 26	Col. 28 Year 27	Col. 29 Year 28	Col. 30 Year 29	Col. 31 Year 30	Col. 32 Year 31	Col. 33 Year 32	Col. 34 Year 33	Col. 35 Year 34	Col. 36 Year 35
1	Number of Customers												
2	Number of Cumulative Customers [50% Effective]	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,895	17,660	17,295	16,710	15,730
3	Number of Tonnes per Customer	4	4	4	4	4	4	4	4	4	4	4	4
4	Total Number of Tonnes	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,580	70,640	69,180	66,840	62,920
5	Capital												
6	**Rate Base**												
7	Balance, beginning	111,778,411	103,873,460	95,968,508	88,063,557	80,158,605	72,253,654	64,348,702	56,443,751	48,575,317	40,809,200	33,204,711	25,847,220
8	+ Additions												
9	+ Working Capital Additions	0	0	0	0	0	0	0	(8,524)	(23,566)	(36,602)	(58,664)	(98,274)
10	- Depreciation	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,859,910)	(7,742,551)	(7,567,887)	(7,298,826)	(6,859,518)
11	Balance, ending	103,873,460	95,968,508	88,063,557	80,158,605	72,253,654	64,348,702	56,443,751	48,575,317	40,809,200	33,204,711	25,847,220	18,889,428
12	Average Rate Base	107,825,935	99,920,984	92,016,033	84,111,081	76,206,130	68,301,178	60,396,227	52,509,534	44,692,259	37,006,955	29,525,966	22,368,324
13	**Revenue Requirement**												
14	Return on Rate Base	6,690,755	6,200,241	5,709,727	5,219,214	4,728,700	4,238,186	3,747,673	3,258,292	2,773,219	2,296,335	1,832,129	1,387,987
15	O&M	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,517,168	1,502,120	1,478,748	1,441,288	1,378,535
16	Municipal Taxes	-	-	-	-	-	-	-	-	-	-	-	- /u
17	Deprecation	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,859,910	7,742,551	7,567,887	7,298,826	6,859,518
18	Taxes	4,125,253	4,032,337	3,939,087	3,845,670	3,752,171	3,658,629	3,565,067	3,455,471	3,320,618	3,166,664	2,981,093	2,737,967
19	Revenue Requirement	20,243,570	19,660,140	19,076,377	18,492,447	17,908,433	17,324,378	16,740,302	16,090,841	15,338,509	14,509,634	13,553,336	12,364,007
20	**Revenue**												
21	Revenue per Tonne per Month	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07
22	Geothermal Revenue	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,534,127	21,251,338	20,812,111	20,108,146	18,928,853
23	**Sufficiency / (Deficiency)**	**1,392,843**	**1,976,273**	**2,560,036**	**3,143,966**	**3,727,980**	**4,312,035**	**4,896,111**	**5,443,286**	**5,912,829**	**6,302,477**	**6,554,809**	**6,564,845**

Geothermal
Revenue and Revenue Requirement

	Col. 1	Col. 37	Col. 38	Col. 39	Col. 40	Col. 41	
Line No.	Description	Year 36	Year 37	Year 38	Year 39	Year 40	
1	Number of Customers						
2	Number of Cumulative Customers [50% Effective]	14,000	11,270	8,050	4,830	1,610	
3	Number of Tonnes per Customer	4	4	4	4	4	
4	Total Number of Tonnes	56,000	45,080	32,200	19,320	6,440	
5	Capital						
6	**Rate Base**						
7	Balance, beginning	18,889,428	12,618,770	7,438,509	3,610,966	1,185,281	
8	+ Additions						
9	+ Working Capital Additions	(173,484)	(273,764)	(322,902)	(322,902)	(322,902)	
10	- Depreciation	(6,097,174)	(4,906,497)	(3,504,641)	(2,102,784)	(700,928)	
11	Balance, ending	12,618,770	7,438,509	3,610,966	1,185,281	161,451	
12	Average Rate Base	15,754,099	10,028,639	5,524,737	2,398,123	673,366	
13	**Revenue Requirement**						
14	Return on Rate Base	977,565	622,291	342,818	148,807	41,783	
15	O&M	1,267,757	1,092,946	886,757	680,569	288,738	
16	Municipal Taxes	-	-	-	-	-	/u
17	Deprecation	6,097,174	4,906,497	3,504,641	2,102,784	700,928	
18	Taxes	2,384,806	1,887,733	1,328,983	786,537	260,687	
19	Revenue Requirement	10,727,302	8,509,467	6,063,199	3,718,698	1,292,136	
20	**Revenue**						
21	Revenue per Tonne per Month	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	
22	Geothermal Revenue	16,847,040	13,561,867	9,687,048	5,812,229	1,937,410	
23	**Sufficiency / (Deficiency)**	**6,119,738**	**5,052,400**	**3,623,849**	**2,093,531**	**645,273**	